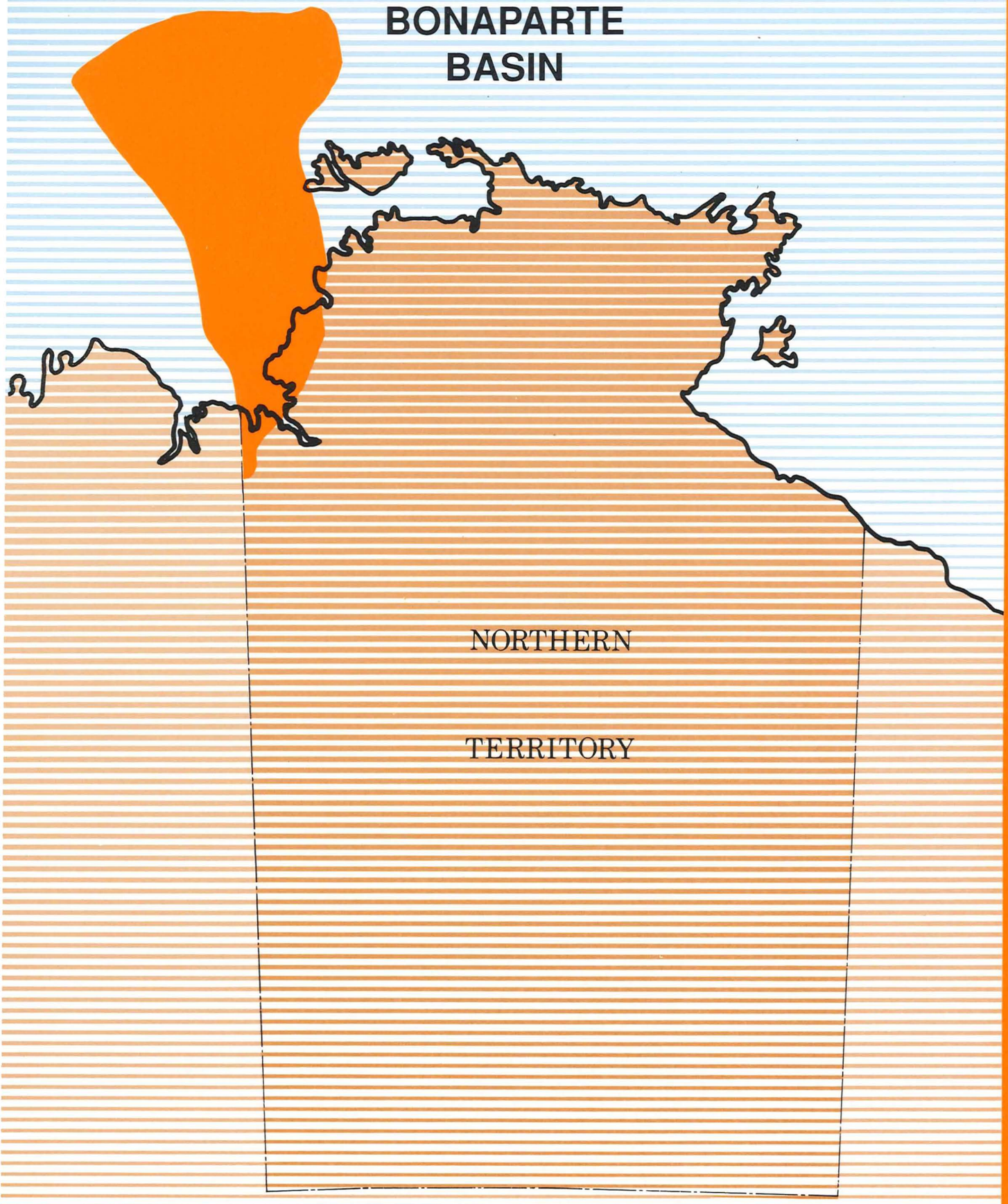
BONAPARTE BASIN



NORTHERN TERRITORY
DEPARTMENT OF MINES AND ENERGY

BONAPARTE BASIN

NORTHERN TERRITORY GEOLOGICAL SURVEY

PETROLEUM BASIN STUDY:

BONAPARTE BASIN

Prepared By:

Petroconsultants Australasia Pty Ltd

June, 1990

NORTHERN TERRITORY DEPARTMENT OF MINES AND ENERGY

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SECRETARY: Dr. E.K. Campbell

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1. SUMMARY

The Northern Territory portion of the Bonaparte Basin covers an area of approximately 220 000 km^2 and is located on the northwestern margin of the Australian craton. Within the Northern Territory, the basin extends both onshore and offshore and contains in excess of 700 000 km^3 of sediments ranging in age from Cambrian through to the present-day. The basin's structural elements have been shaped by a number of major tectonic events.

Sedimentation commenced in the Cambrian following outpourings of continental basaltic lavas and lithospheric thinning between the Precambrian continental blocks. Initial sediments were terrestrial clastics derived from the adjacent shield areas with subordinate carbonates. Restricted sedimentation during the Middle Palaeozoic resulted in extensive evaporitic development. Tension associated with the Tethyian rifting during the Devonian and Early Carboniferous formed the northwest-southeast trending Petrel Sub-basin, the site of extensive marine and terrestrial sedimentation. Further tensional episodes during the Mesozoic, associated with the breakup of Gondwana, resulted in the formation of the northeast-southwest trending Malita Graben and Sahul Platform. Sedimentation associated with this rifting resulted in a mix of terrestrial and marine facies. Northwesterly tilting of the basin during the later Cretaceous and Tertiary resulted in the deposition of thick, fine grained siliciclastic and prograding carbonate wedges.

Exploration within the basin to date remains in its infancy. Drilling has enabled the identification of regional source, reservoir and seal intervals, but there is little local geological control. Reconnaissance seismic data have identified numerous structural targets, but more sophisticated targets including stratigraphic traps have not been actively sought. Many of the earlier unsuccessful drilling efforts lacked the benefit of modern seismic control.

Only 28 exploration and appraisal wells have been drilled within the Northern Territory portion of the Bonaparte Basin giving a drilling ratio of approximately one well for every 7800 km^2. Of these wells only four had no shows, and, although there is as yet no production, significant discoveries have been made. Several are the subject of feasibility studies. Significant gas discoveries include Petrel with reserves of 109 to 440 x 10^9 m^3 (3.3 to 13.6 TCF), Weaber, and Evans Shoals. Gas and condensate discoveries have been made at Sunrise #1 and Troubadour #1 and in 1989 Barnett #2 had the first flow of oil (917 BOPD). These hydrocarbon accumulations occur in a wide variety of geological settings, the host reservoirs ranging in age from Early Carboniferous to Cretaceous. These occurrences, coupled with significant discoveries in the Western Australian portion of the basin, attest to the Bonaparte Basin having generated significant quantities of both gaseous and liquid hydrocarbons.

Notwithstanding these encouraging drilling results, exploration has languished, in part owing to a moratorium brought about because of uncertainties regarding international jurisdiction of the Timor Gap region. This has been now resolved. Exploration has been also hampered by geological prejudices, specifically that the basin is considered gas-prone and in the absence of perceived markets, the already discovered large gas accumulations at Petrel and Tern would remain undeveloped.

Changes in market perception for liquified natural gas (LNG), and recent oil discoveries in both the Western Australian and Northern Territory portions of the basin, have renewed exploration interest. Recently British Petroleum acquired interests in some 25 000 km^2 of the basin with the awarding of permits NT/P 44 and NT/P 45. However, many opportunities still remain for explorers to enter the region, either via vacant acreage, or by farm-in agreement with existing acreage holders or applicants.

The exploration history of the Bonaparte Basin demonstrates that it contains all the necessary prerequisites for major hydrocarbon discoveries with key reservoir, trapping, source rock and maturity trends overlapping across much of the basin. Moreover, given that the success to date has come from very limited testing of the more obvious targets one can only be optimistic about the Northern Territory portion of the Bonaparte Basin becoming an important hydrocarbon province in the future.

2. INTRODUCTION

2.1 PURPOSE, SCOPE & OBJECTIVES

This is one of three reports which form the second set of a series of reports, prepared by various consultants during 1989 and 1990 on behalf of the Northern Territory Department of Mines and Energy. These reports are aimed at encouraging the petroleum industry's awareness of, and active participation in, exploration opportunities within the Northern Territory's prospective sedimentary basins.

These reports provide comprehensive assessments of the petroleum potential of the basins through a detailed review of the regional geology, stratigraphy, structure, geochemistry, previous exploration history and play concepts.

This report, on the Bonaparte Basin, has relied heavily upon relatively large geophysical and geological data bases. Specifically, preparation of this report involved the following:

a) Digitization and preparation of regional well cross-sections, identification, and correlation of stratigraphic units.

b) Correlation of key regional seismic horizons and the compilation of regional seismic time structure contour maps at significant stratigraphic levels.

c) Formulation of detailed regional structural and geological histories of the basin.

d) Review of reservoir and source rock potential.

e) Review of geochemistry.

f) Play concept review and development with the identification of fairways, prospects and leads.

2.2 INFORMATION ON PETROLEUM TENEMENTS

2.2.1 Administration

The exploration for, and production of, petroleum in the onshore areas of the Northern Territory is controlled by the Petroleum Act. The Northern Territory is also responsible for the administration of offshore legislation in three separate areas:

- the coastal waters of the Northern Territory, that is, landwards of the three nautical mile limit;
- the adjacent area of the Northern Territory, that is beyond the three nautical mile limit;
- the adjacent area of the Territory of Ashmore and Cartier Islands.

The last two, that is the adjacent areas referred to above, are controlled by the Commonwealth Petroleum (Submerged Lands) Act 1967 whereas the coastal waters are administered under the Northern Territory Petroleum (Submerged Lands) Act. The maximum area of an offshore permit is 400

blocks. Each block comprises an area of five minutes of latitude by five minutes of longitude. Permits are granted for an initial period of six years. A permit may be renewed for further periods of five years with a 50% reduction of blocks held at the end of each term.

Permits are granted subject to a minimum "dry hole" programme for the first three years of the term and unless conditions of "force majeure" apply, failure to undertake each component of this programme in the designated year will result in cancellation of the permit.

Exploration for, and production of, petroleum in the onshore of the Northern Territory is controlled by the Petroleum Act which came into force on 15 October 1984. Prior to this the relevant legislation was the Petroleum (Prospecting and Mining) Act which by virtue of the savings provisions of the Petroleum Act, continues to apply to permits and leases that had been issued or granted prior to that date. The Petroleum Act was the first Australian petroleum legislation to introduce the concept of a retention tenement to provide a permittee with security of tenure over a currently non-commercial discovery. This initiative was later adopted by the Commonwealth in amendments to the Petroleum (Submerged Lands) Act 1967.

Under the terms of the Petroleum Act, an application for a permit may be made over any land not currently the subject of a petroleum tenement. The maximum area that can be applied for is 200 blocks. Each block comprises an area of five minutes of longitude by five minutes of latitude so that a permit of 200 blocks covers an area of about 16 000 km^2. The initial term of a permit is five years and it may be renewed for two further periods of five years with 50% relinquishment of the area held at the end of each term. Permits are granted subject to specific work commitments which must be met year by year (or earlier).

Where a commercial discovery is made the successful explorer may apply for a production licence. The maximum area of a production licence is 12 blocks, however a permittee may apply for more than one licence. The initial term of a production licence is 21 years and it may be renewed for further periods not exceeding 21 years as determined by the Minister for Mines and Energy.

If the original discovery proves to be currently non-commercial but is potentially of a commercial quality and quantity, the permittee may apply for a retention licence or licences of not more than 12 blocks for each licence. The initial term of a licence is five years and it may be renewed for further periods of five years.

2.2.2 Application Procedures

An application for an offshore petroleum permit may only be made in response to an invitation by the Joint Authority, that is, the Federal & Northern Territory Governments. Applications are invited by the Joint Authority by notice in the Government Gazette. The notice provides details of the manner in which an application may be made and the particulars that are required to accompany an application.

An application for an onshore permit may be made over any land that is not already the subject of a petroleum tenement. An applicant should provide the following information:

- the name and address of the applicant and an address for service within the Territory;
- the designated number of each block the subject of the application;
- a map clearly delineating the application area and the boundaries of existing permit or licence areas in the immediate vicinity of the application area;
- a proposed technical works programme for exploration of the blocks during each year of the term of the proposed permit;
- evidence of the technical and financial capacity of the applicant to carry out the proposed technical works programme to comply with the Act;
- where the application is made by two or more persons, the proposed sharing arrangement between the applicants;
- the name of the designated operator and evidence of his technical capacity to carry out the proposed technical works programme;
- a statutory declaration stating the applicant's interest, if any, in or in relation to a permit or licence applied for and granted under, or in force by virtue of, the Act or the repealed Act;
- the application fee of $3000; and
- such other information in support of the application as the applicant thinks fit.

2.2.3 Zone of Co-operation

Delineation of the seabed boundary between Indonesia and Australia has been the subject of much consideration and negotiation since the early 1960s when Australia first issued petroleum exploration licences to oil companies in the Timor and Arafura Seas. In September 1988 the Governments of Australia and Indonesia issued a joint statement confirming that the Indonesian-Australian Border Delineation Committee had developed a proposal to set up a Zone of Co-operation which was a compromise joint development arrangement that recognized both country's jurisdictional claims. Both Governments endorsed the proposal in October 1988 and the treaty was signed on the 11th December 1989, the treaty to be ratified by the Australian Parliament during 1990. It contains the jurisdictional and tax framework permitting both countries to proceed with rewards from development and eventually to share in the exploration of the area's resources prior to delineation of a permanent seabed boundary.

The "Treaty Between Australia and the Republic of Indonesia on the Zone of Co-operation in an area between The Indonesian Province of East Timor and Northern Australia" has as its main provisions the following.

A Zone of Co-operation is designated between the Indonesian Province of East Timor and Northern Australia and divided into Areas A, B and C (Enclosure 1).

Within the Zone of Co-operation the exploration for and development of petroleum resources will proceed on the following basis.

(a) Area A is under joint control for the purposes of exploration and production of petroleum resources with equal sharing of the benefits of any production in the area.

(b) Area B is administered by Australia with obligations to inform Indonesia of certain activities in the region and with Indonesia receiving a share of the Resource Rent Tax collections from the area.

(c) Area C is administered by Indonesia with reciprocal obligations to keep Australia informed of activities and with Australia receiving a share of the Indonesian Income Tax collections from the area.

Area A

Area A will be administered by a Ministerial Council and a Joint Authority with petroleum operations in this area carried out under production sharing contracts between the Joint Authority and limited liability corporations specifically established for that purpose.

Companies interested in exploration within Area A will submit a bid for an area in the form of a work program which will include annual exploration and expenditure commitments for a period of six years.

The Ministerial Council will comprise an equal number of Ministers from Australia and Indonesia. It will have final responsibility for overseeing all legislative and administrative aspects of the treaty concerning Area A, including the approval of proposals put forward by the Joint Authority.

The Joint Authority will be responsible to the Ministerial Council. It is responsible for the day to day management of exploration for, and production of, petroleum resources in Area A. These duties include the allocation of exploration permits and entering into production sharing contracts. The Joint Authority will own all petroleum produced in Area A and be responsible for collecting and distributing to the two countries a share of the proceeds from production. In addition, in circumstances determined by the Ministerial Council, it will market part or all petroleum production from Area A. It will be financed by fees collected within Area A supplemented by Australia and Indonesia when necessary.

Area B

Area B will be under the administration of Australia which will notify Indonesia of any change related to the exploration permits, retention leases, and production licences within it. It will be subject to the Australian Resource Rent Tax regime.

Area C
Indonesia will be responsible for the administration of Area C and will notify Australia of any changes in the petroleum exploration and production agreements within it. It will be subject to an Indonesian production sharing contract regime.

2.3 DATA AND MATERIALS USED

The data used in this study is that which is in published literature or on open file with the Northern Territory Department of Mines and Energy. Confidential, proprietary information has not been used in this study. Generally however, and in the case of the Bonaparte Basin, most of the area has been relinquished at some previous time or is currently vacant. Consequently a considerable amount of data held by the Department of Mines and Energy is on open file.

Appendices in the rear of this report detail specific sources of company information used in the preparation of this study. Where possible, and for ease of identification, company reports and basic data are tabulated with a Northern Territory Department of Mines and Energy library reference number.

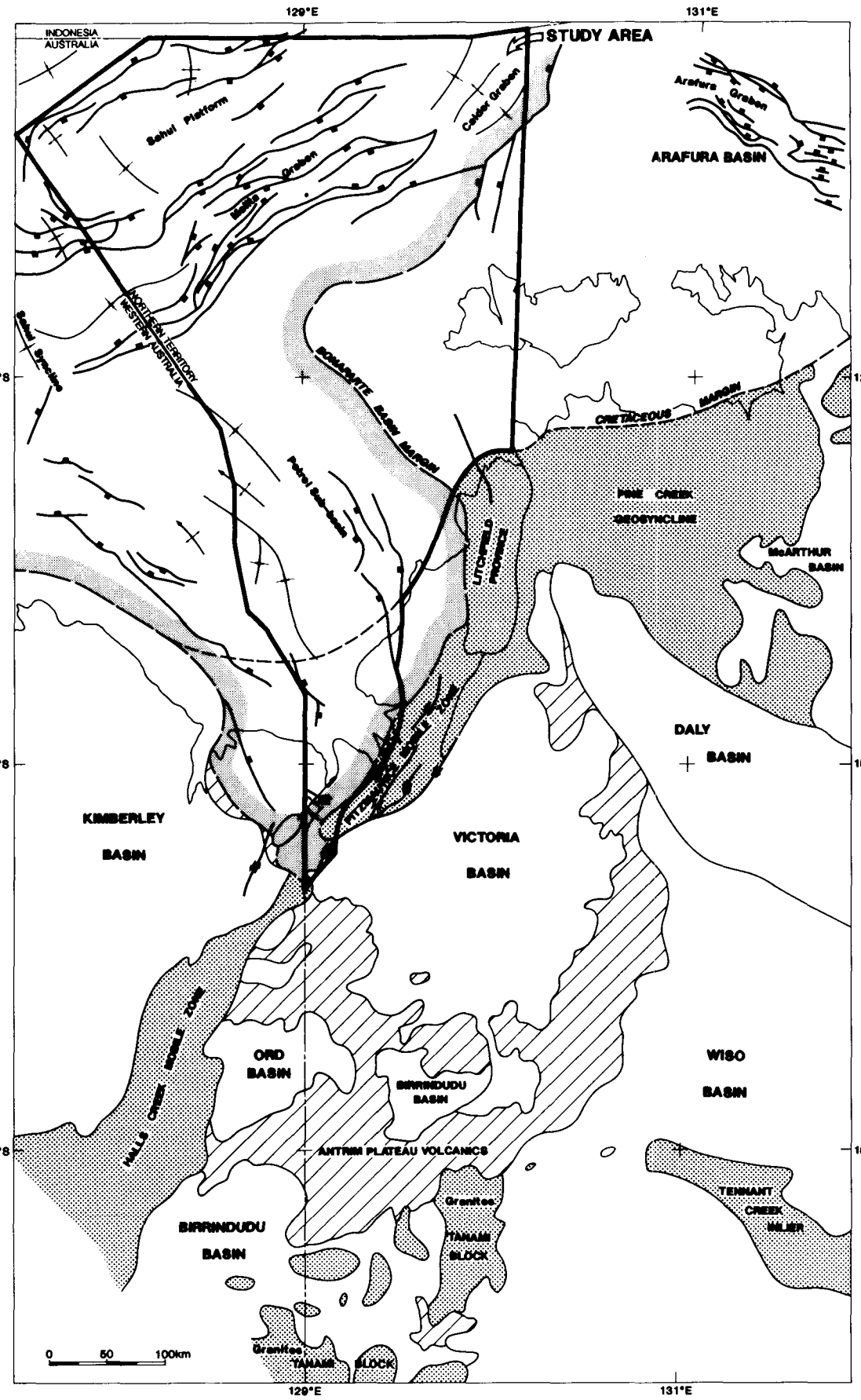
Original paper copies of well logs used in Enclosures 5, 6, 7 and 8 were digitized by Petroconsultants Digimap prior to plotting. Seismic lines in this study are shown on the seismic line location maps (Enclosure 2). These maps were prepared by Petroconsultants Digimap, having been compiled from individual seismic line location maps and/or navigational tapes. Some BMR sparker data and early vintage seismic refraction and reflection lines of poor quality have been omitted.

2.4 PERSONNEL AND ACKNOWLEDGEMENTS

Petroconsultants Australasia Pty Ltd was contracted to prepare this report for the Director of the Geological Survey, Northern Territory Department of Mines and Energy. Within the Department the project was supervised by David Pegum, Senior Petroleum Geologist.

The Petroconsultants team of geoscientists involved in this project were based in Sydney. Dr R. D. Shaw coordinated and managed the project for Petroconsultants. The team consisted of R. Shaw and F. Ientile (Geophysicists) and J. D. Gorter (Associate Geologist), D. Kirkham and G. May (Data Base). C. Roberts undertook much of the drafting supervision. A. Pearcy and C. Heffron provided technical assistance in compiling much of the basic data. Dr R. S. Nicoll of the Bureau of Mineral Resources co-operated with the helpful assistance of conodont colour alteration data. Access to information on the Evans Shoal #1 well by the NT/P40 Joint Venturers is gratefully acknowledged.

The assistance of David Pegum and numerous officers within the Geological Survey in obtaining data, reviewing, and discussing this report is also gratefully acknowledged.



LOCALITY MAP

Figure 1

3. BASIN LOCATION AND INFRA-STRUCTURE

The Bonaparte Basin covers an area of approximately 500 000 km^2 extending north-westward from the Kimberley Block in Western Australia across the coastal fringes and offshore out to the Sahul Rise. This report deals exclusively with that portion of the basin under the administration of the Northern Territory (Figure 1, Enclosure 1).

The locations of current petroleum exploration permits, petroleum wells, Australian International Boundaries, and regional bathymetry are shown on Enclosure 1.

Across the offshore area the water depth gently deepens to the north from 30 to 300 metres. Shoaling is confined to the northeast where carbonate banks fringe the coastline (Enclosure 1).

The region is located entirely within the southern hemisphere tropics, and is subject to northwest monsoonal influences from December through to March. During this period the region is prone to cyclones and severe wind and rain squalls. The period of April through to November is much drier and weather conditions are generally stable. Moderate southeast trade winds predominate during April to September. The annual mean rainfall for Darwin, located approximately 200 km to the east, is approximately 1550 mm, with most of the rainfall occurring during the wet season months of November to April.

Darwin is the closest and most suitable base for offshore exploration operations. Having a population in 1986 of approximately 65 000, Darwin is also the capital city and seat of Government for the Northern Territory. Onshore exploration is serviced from Katherine, Kununurra and Wyndham.

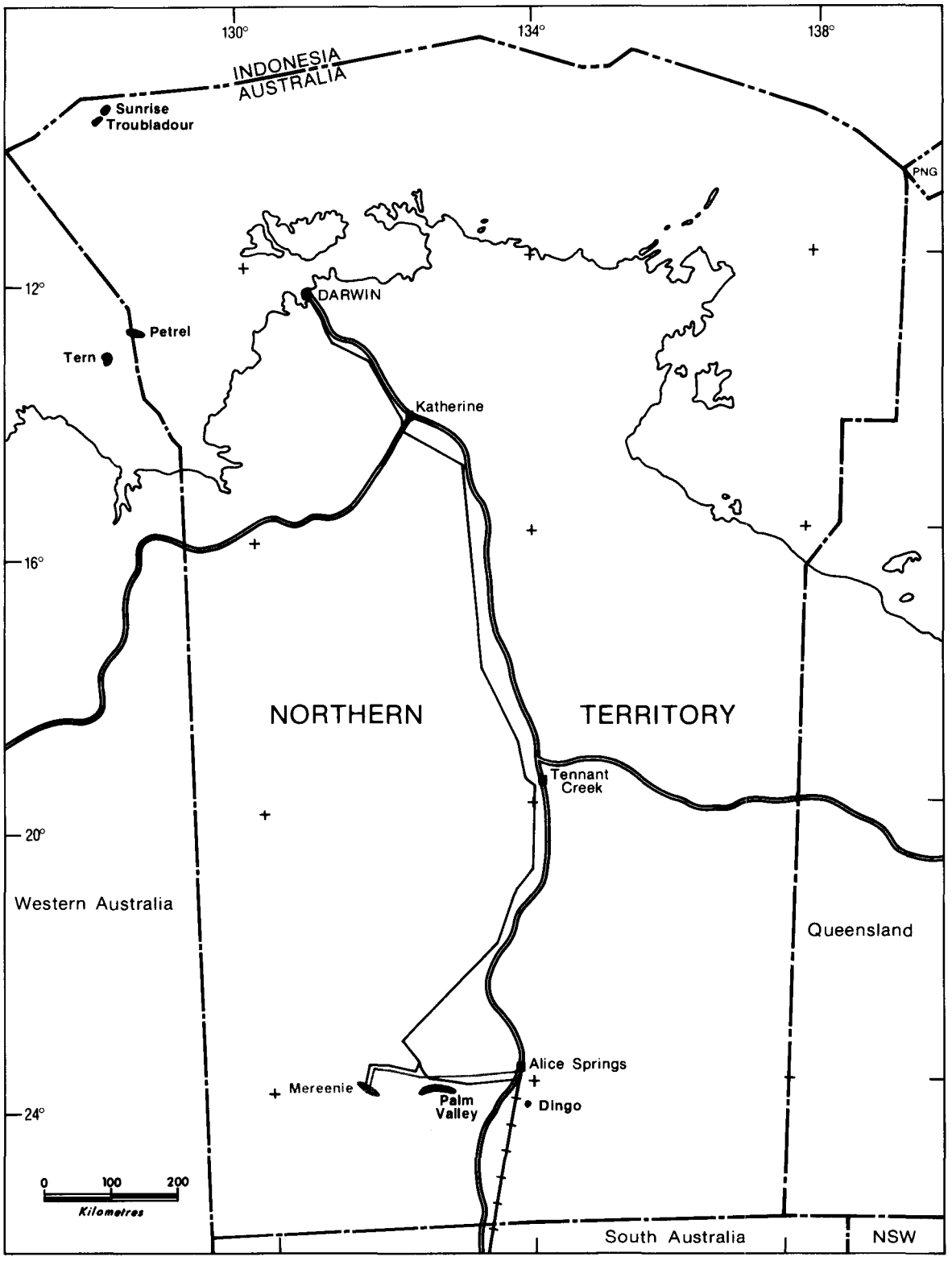
The Northern Territory was granted limited self-government in 1978 having previously been under the control of the Commonwealth Government since January 1st 1911. In 1986 the total population of the Northern Territory was approximately 154 000.

Located on the northern coastline, Darwin is also the Northern Territory's principal port. Regular freight services connect Darwin with other major Australian ports as well as overseas ports. The Port of Darwin is 997 km^2 in area; it is equipped to handle bulk, container and roll-on-roll-off traffic. The ports of Melville Bay (Gove) and Milner Bay (Groote Eylandt) are connected with Darwin, the eastern States, and overseas by regular shipping freight services. Regular barge services carry freight to many other coastal and river settlements.

Ansett and Australian Airlines operate daily services between the Northern Territory and southern Australian states. In addition, intra-Territory and smaller commuter and charter services are provided by some 45 aircraft companies which operate throughout the Northern Territory. QANTAS, Singapore Airlines, Garuda, Royal Brunei and Merpati currently provide regular international flights to South East Asia and Pacific destinations.

Sealed highways link Darwin with Alice Springs and Adelaide to the south, Mount Isa and Brisbane to the southeast, and Perth to the southwest. Rail links with the eastern states extend only as far north as Alice Springs (population 25 000) and Mount Isa.

The first significant hydrocarbon discoveries made in the Northern Territory occurred during the 1960s, although development of these reserves did not commence until, in 1983, the Palm Valley gas field was connected to Alice Springs via a 150 km pipeline. In 1986 this was extended a further 1500 km to Darwin to provide it, as well as the centres of Katherine and Tennant Creek, with gas supplies (Figure 2). Currently production rates for this gas line are 0.6 million cubic metres/day.



LEGEND

- Main roads
- Railway
- Gas pipeline
- Oil pipeline
- Gas field
- Oil field

NORTHERN TERRITORY INFRASTRUCTURE

FIGURE 2

In 1984 the Mereenie Oil and Gas Field was connected to Alice Springs via a 270 km pipeline. By 1986 daily oil production had peaked at 3,900 barrels/day. From Alice Springs oil is transported to South Australia's Port Stanvac refinery by rail.

Offshore several significant discoveries have been made including Tern, Petrel, Sunrise and Troubadour. Delineation of these latter two gas/condensate accumulations was delayed by uncertainties regarding Australia's jurisdiction (Section 2.2.3). For the Petrel Gas Field, discovered in 1969, Elf Aquitaine estimated that total gas in place lies between 190×10^9 m^3 and 440×10^9 m^3. In September 1983, the company estimated proved plus probable gas in place at Tern to be between 34×10^9 m^3 to 51×10^9 m^3 (median value 42×10^9 m^3). The Petrel Field estimates of gas-in-place depend critically on well-log interpretation, location of gas/water contacts and assumed field area.

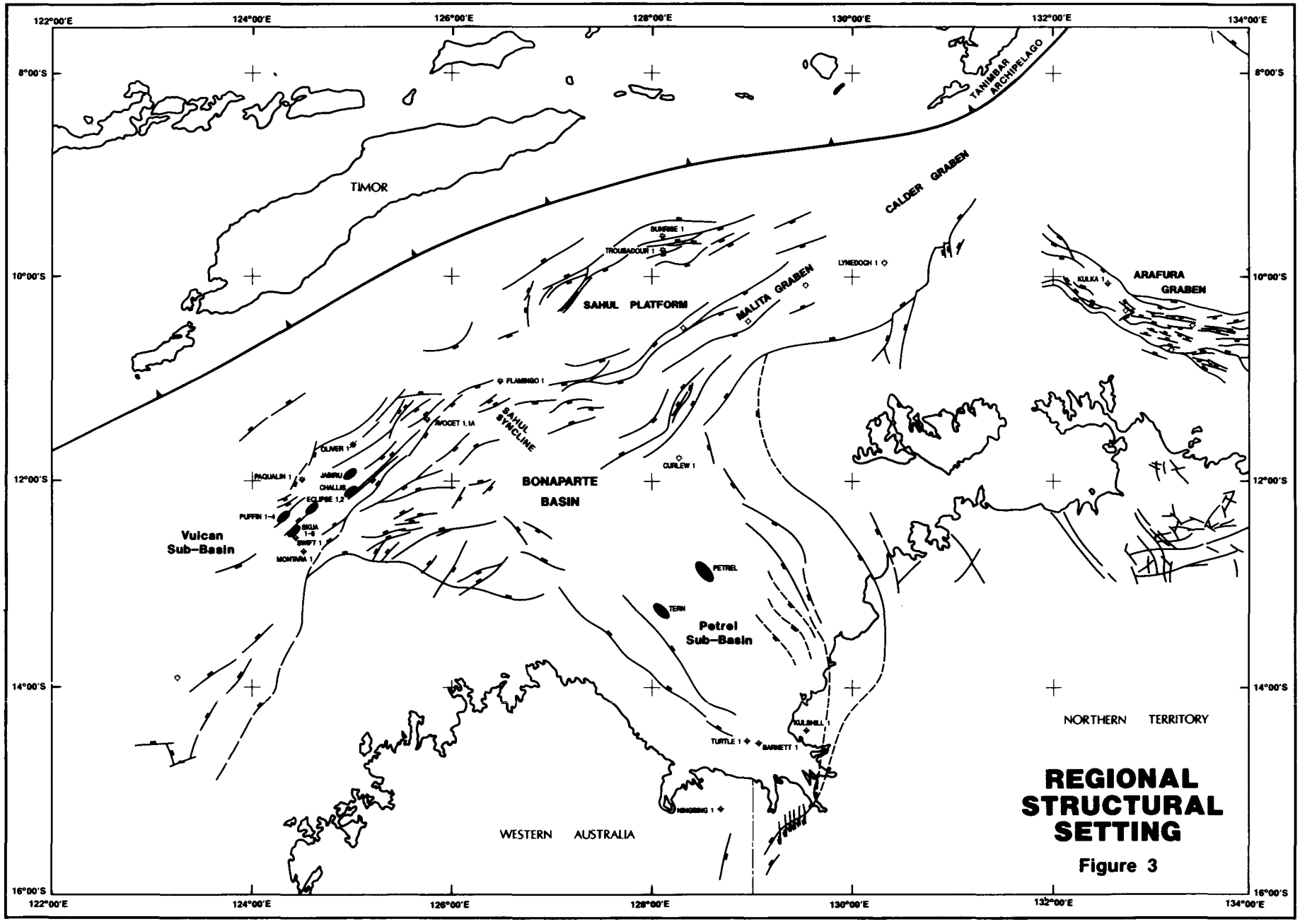
The Bonaparte Gulf Gas Project (NTDME, 1988) has been established to promote the development of the Petrel and Tern gas accumulations. With Darwin located geographically closer to Asia than it is to the main population centres of Australia, markets for liquified natural gas (LNG) are principally seen to be in that region, notably Korea and Japan. First deliveries are expected in the late 1990s to early 2000s, with annual shipments to exceed two million tonnes. The Northern Territory and Commonwealth Governments are fully supportive of this development. Other potential markets for LNG could also exist within Australia should a country-wide gas pipeline network, including Tern/Petrel, become a reality. Such a development has been long contemplated and may become feasible when traditional gas supplies to existing markets in Queensland and NSW begin to decline at the turn of the century.

Preliminary conceptual development options being studied for the Bonaparte Gulf Project include the separate or sequential development of Tern and Petrel. Development concepts are based on a perceived potential market for 2.3×10^6 tonnes per annum of LNG, requiring an annual field production of 3.5×10^9 m^3. Preliminary estimates of development costs made in the mid 1980s were of the order of A$3 billion (The Australian, 6/11/1985).

Prior to the sale of its petroleum interests to Santos Ltd., Elf Aquitaine had suggested that if Tern is developed first it would involve installation of a drilling/production platform with gas treatment plant and living quarters and a separate gas flare tripod on Tern. This would be followed by installation of the main drilling/production platform on Petrel (also with gas treatment facilities and living quarters). In the event that the Petrel Field was developed alone, the main drilling/production platform and one drilling platform would be initially required, while a third platform would be installed as required.

Gas treatment facilities would provide for condensate separation and gas and condensate dehydration. Condensate would be reinjected into the gas pipeline for transmission to the processing plant. The pipeline system would include 65 km of 30" subsea trunkline between Tern and Petrel, 20" inter-platform lines in the Petrel area, 185 km of 28" subsea trunkline to shore and 110 km of onshore trunkline to Darwin (NTDME, 1988). A liquefaction plant located near Port Darwin is envisaged, from which loading facilities for 130 000 m^3 LNG tankers could be supplied for transportation to foreign destinations.

In addition to these gas discoveries a number of significant oil discoveries have been made in the adjacent Timor Sea area. The Jabiru discovery, in 1983, was followed by the Challis discovery in 1984. First production from Jabiru, located 650 km west of Darwin, commenced in August 1986 through a single sub-sea well, anchored riser and disconnectable tanker. Challis commenced production in September 1989. The Barnett oil discovery, made in 1989, and the Weaber gas discovery are both potentially economic.



REGIONAL STRUCTURAL SETTING

Figure 3

4. GEOLOGICAL SETTING

4.1 BASIN DEFINITION

The offshore part of the Bonaparte Basin comprises a Palaeozoic northwest trending graben, the Petrel Sub-basin, overlain by a more extensive Mesozoic sedimentary cover. The depocentre of this Mesozoic cover lies within the northeast trending Malita Graben (Figure 3). A description of the main structural elements is given in Section 4.3.

Onshore, successively older Palaeozoic sequences outcrop as the Petrel Sub-basin narrows and merges into northeast to north trending depocentres which are truncated by the Cockatoo Fault Zone, part of the Halls Creek-Fitzmaurice Mobile Zone. This zone forms the boundary with the Precambrian Victoria Basin and Pine Creek Geosyncline, located further to the east. To the southwest, the onshore margin is defined by a series of northwest trending related fault blocks of pre-Late Devonian age that step up along the boundary between the basins and the Kimberley Block in Western Australia (Enclosure 3).

Offshore the Palaeozoic basin margin is obscured by Mesozoic and Tertiary sediment cover but Palaeozoic remnants of the basin extend across the Sahul Platform and adjacent Sahul Syncline.

For this study only that portion of the Bonaparte Basin within the Northern Territory and the Northern Territory Adjacent Area are considered.

4.2 STRATIGRAPHY

4.2.1 Introduction

The stratigraphy of the Bonaparte Basin (Enclosure 4) has been prepared from a review of published literature, well completion reports and other pertinent information in the public domain. The stratigraphic nomenclature is modified from that described by Mory (1988), who recognised the following five phases of basin evolution.

1) Cambrian to Ordovician intracratonic deposition.
2) Silurian to Carboniferous northwest-trending rifting.
3) Permo-Carboniferous reactivated northwest-trending rifting.
4) Mesozoic northeast-trending rifting, and continental breakup.
5) Cainozoic shelf progradation.

4.2.2 Sea Level fluctuations and Stratigraphy

The stratigraphic column (Enclosure 4) and well correlations (Enclosures 5-8) have been constructed using palaeontological data derived from several sources. Palynological correlations, based mainly on species range charts by Helby (1974a,b), from Petrel #1, Tern #1, Sandpiper #1 and Flamingo #1, were used to relate discrete bodies of sediments to sea level curves (Haq et al., 1987) through the Late Permian and Early Cretaceous ages. In undertaking this, Helby's palynological zonations have been fitted to the new Helby et al. (1987) subdivisions (Enclosure 4). Foraminiferal assemblages were used to correlate the later Cretaceous

(Albian to Maastrichtian) succession with sea level fluctuations, whereas the Tertiary scheme follows the published sea level/foram zones of Apthorpe (1988).

In the stratigraphic column of the Bonaparte Basin for the later Palaeozoic (Enclosure 4), the Carboniferous to Permian sea level curve given by Bradshaw et al. (1988, Figure 6) has been adopted, with Early Palaeozoic sea level fluctuations modified following Vail et al. (1977), and Johnson et al. (1985), for the Devonian period. Because of the uncertain correlations between these various sources, the sea level curve shown in Enclosure 4 is only relative, with notional high and low sea levels indicated.

The Cretaceous to Middle Jurassic correlations are considered the most reliable with the Triassic and Early Jurassic correlations less reliable. The Palaeozoic correlations are considered the least reliable owing to poorly controlled datings.

4.2.3 Cambrian to Ordovician

Over 2000 m (6500 ft) of clastics and carbonates of Cambro-Ordovician age (Kaulback & Veevers, 1969; Laws, 1981; Mory & Beere, 1988) exist in outcrop along the western basin margin, unconformably overlying the tholeiitic basalts of the latest Proterozoic to Early Cambrian Antrim Plateau Volcanics. These sediments (Enclosure 4), deposited after a Middle Cambrian marine transgression, form the Cambro-Ordovician Carlton Group (Mory & Beere, 1988) and represent the oldest sediments within the Bonaparte Basin. The identification of this section in the subsurface, especially offshore, is tentative at best. On offshore seismic profiles this section is correlated with bedded sequences dipping back into the basin margins on deep fault blocks, which are down-thrown basinwards.

The initial deposition resulted in the accumulation of up to 400m of the early Middle Cambrian (Ordian) Tarrara Formation, a shallow marine to intertidal siliciclastic and dolomitic unit deposited in a shallow epeiric sea and conformably overlying the Antrim Plateau Volcanics (Mory & Beere, 1988). The overlying Hart Spring Sandstone (Templetonian to Boomerangian) attains a thickness of 300 m, and was deposited in a tidally dominated environment on a shallow shelf (Mory & Beere, 1988). The Hart Spring is overlain abruptly by the 120 m (maximum) thick Boomerangian to Mindyallan Skewthorpe Formation, an interbedded series of oolitic and stromatolitic carbonates, and shoaling shale to sandstone cycles (Mory & Beere, 1988). The Pretlove Sandstone conformably overlies and interfingers by facies change with the Skewthorpe Formation. This 125 m thick formation was deposited in intertidal to subtidal environments (Mory & Beere, 1988) during the Mindyallan.

Deepening marine waters are indicated by the change to the glauconitic Clark Sandstone, a 320 m thick unit deposited during the Idamean to Payntonian (Late Cambrian) on an open marine shelf. The only Late Cambrian to earliest Ordovician sediments preserved form the latest Payntonian to early Arenigian Pander Greensand. This unit is thought to lie conformably upon the Clark Sandstone and reaches 120 m thickness. It was deposited in moderately deep marine waters (Mory & Beere, 1988). Later Ordovician sediments are not preserved.

4.2.4 Late Ordovician to Early Devonian

Sediments of the Early Ordovician to Middle Devonian interval are absent in the onshore Bonaparte Basin (Enclosure 4), and offshore, no wells have been drilled deep enough to penetrate any sediments of this age.

Sedimentation at this time is interpreted to have been confined to the deeper portions of the older Palaeozoic depressions. Subsequent movement of fault blocks or crustal upwelling may have resulted in the proto-Petrel Sub-basin being isolated from deeper open marine conditions to the north (Edgerly & Crist, 1974) and consequently, enabled evaporitic conditions to develop. Offshore several salt diapirs have been observed on seismic data or penetrated by drill holes (for example, Gull #1 and Sandpiper #1). Kulshill#1 was drilled on an inferred salt induced structure and penetrated Late Devonian sediments without encountering evaporites, whereas on other structures (for example Kinmore #1) salt was encountered below the Late Carboniferous Kulshill Group or the Early Carboniferous Milligans Formation (Pelican Island #1). Seismic interpretations show salt diapiric penetration of the later Palaeozoic to Tertiary section in several other locations in the Petrel Sub-basin and Malita Graben (Sections 4.3 & 6.2).

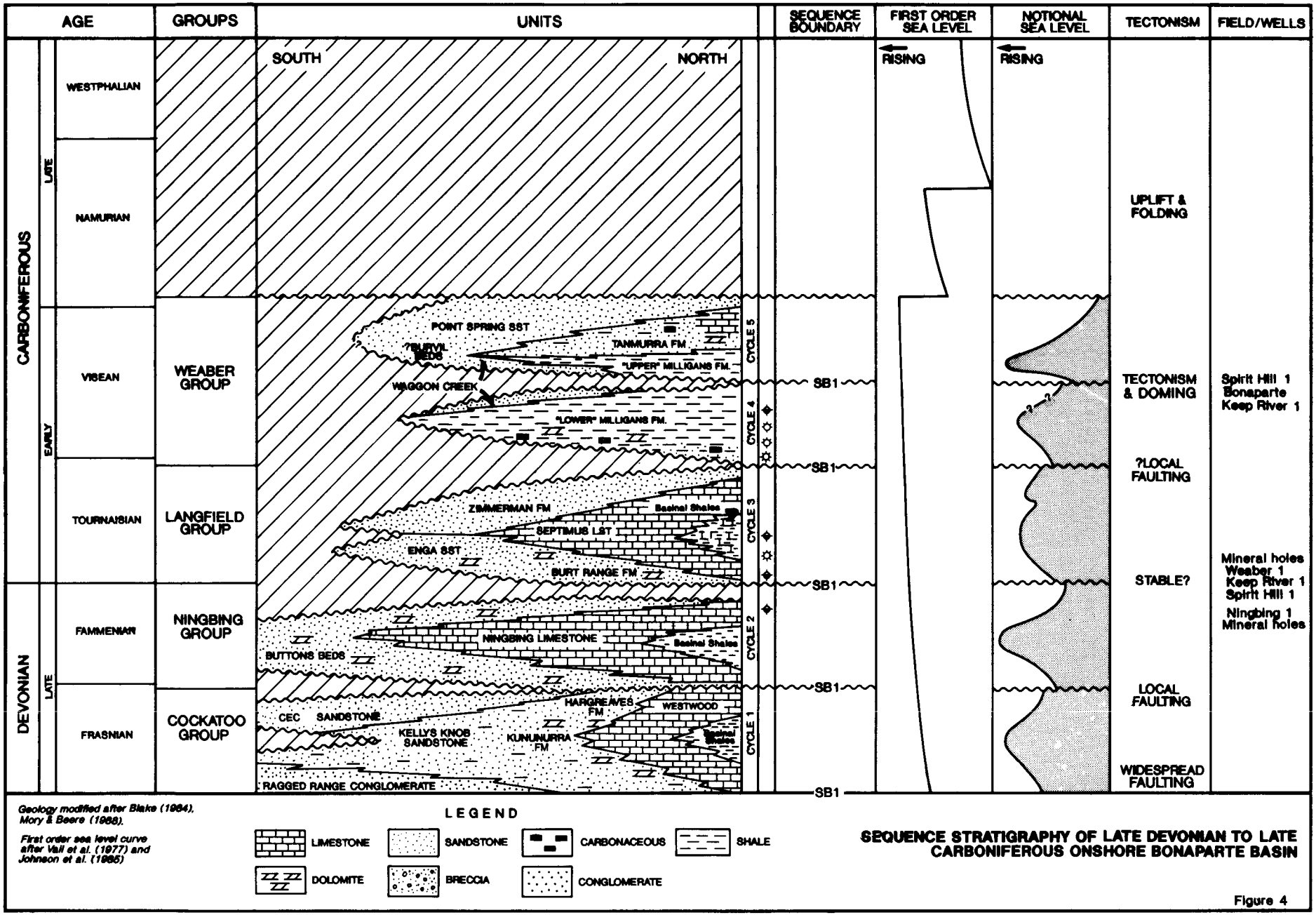
The precise stratigraphic relationships and age of the salt sequence is subject to debate. Because no direct evidence of its age within the Bonaparte Basin has been established, the age of the evaporitic sequence is inferred by Mory (1988) as Silurian to Early Devonian from comparative stratigraphic relationships with sequences in the Canning Basin. Lavering (Figure 2, 1989) also tentatively dated the evaporites as late Early Silurian to Late Silurian.

Lee & Gunn (1988) identified salt at three separate stratigraphic levels in different parts of the basin. These are pre-Late Devonian on the basin margins from the drilling results at Sandpiper #1 and Kulshill #1, "lower" Milligans Formation in the southern central tilted fault block area evidenced by seismic interpretation, and "upper" Milligans Formation in the central axial part of the basin, where Lee & Gunn interpret no older sediments to be present. The evidence for salt at the upper two levels might be considered equivocal. A Siluro-Devonian age for the evaporitic sequence is accepted in this study.

4.2.5 Late Middle Devonian to Late Carboniferous

Sedimentation during this interval was associated with a sequence of discrete transgressive/regressive cycles (Figure 4). During the first cycle up to 2700 m of the Cockatoo Group sediments were deposited (Laws, 1981; Mory & Beere, 1988). Coarse clastics are associated with the eastern and western faulted basin margins and grade basinward into marine siliciclastics. Interbeds of dolomite, marl and limestone are found along the western margin. The sediments become more marine to the northwest.

Sedimentation commenced during the early Frasnian with alluvial fan deposits accumulating along active fault scarps. Broad braided rivers flowed to the north and northeast. Aeolian and fluvial conditions prevailing during the middle Frasnian changed basinwards into



Geology modified after Blake (1984), Mory & Beere (1988).

First order sea level curve after Vail et al. (1977) and Johnson et al. (1985)

SEQUENCE STRATIGRAPHY OF LATE DEVONIAN TO LATE CARBONIFEROUS ONSHORE BONAPARTE BASIN

Figure 4

fluvio-deltaic and tidal environments. Further north, marine environments are indicated by stromatoporoid and algal reefs during later Frasnian time. Thus, the Cockatoo Group records deposition during a marine transgression corresponding to a general eustatic sea level rise at this time. A global sea level fall occurred at the end of the Frasnian (Johnson et al., 1985) and this is reflected by regression at the end of Cockatoo Group deposition.

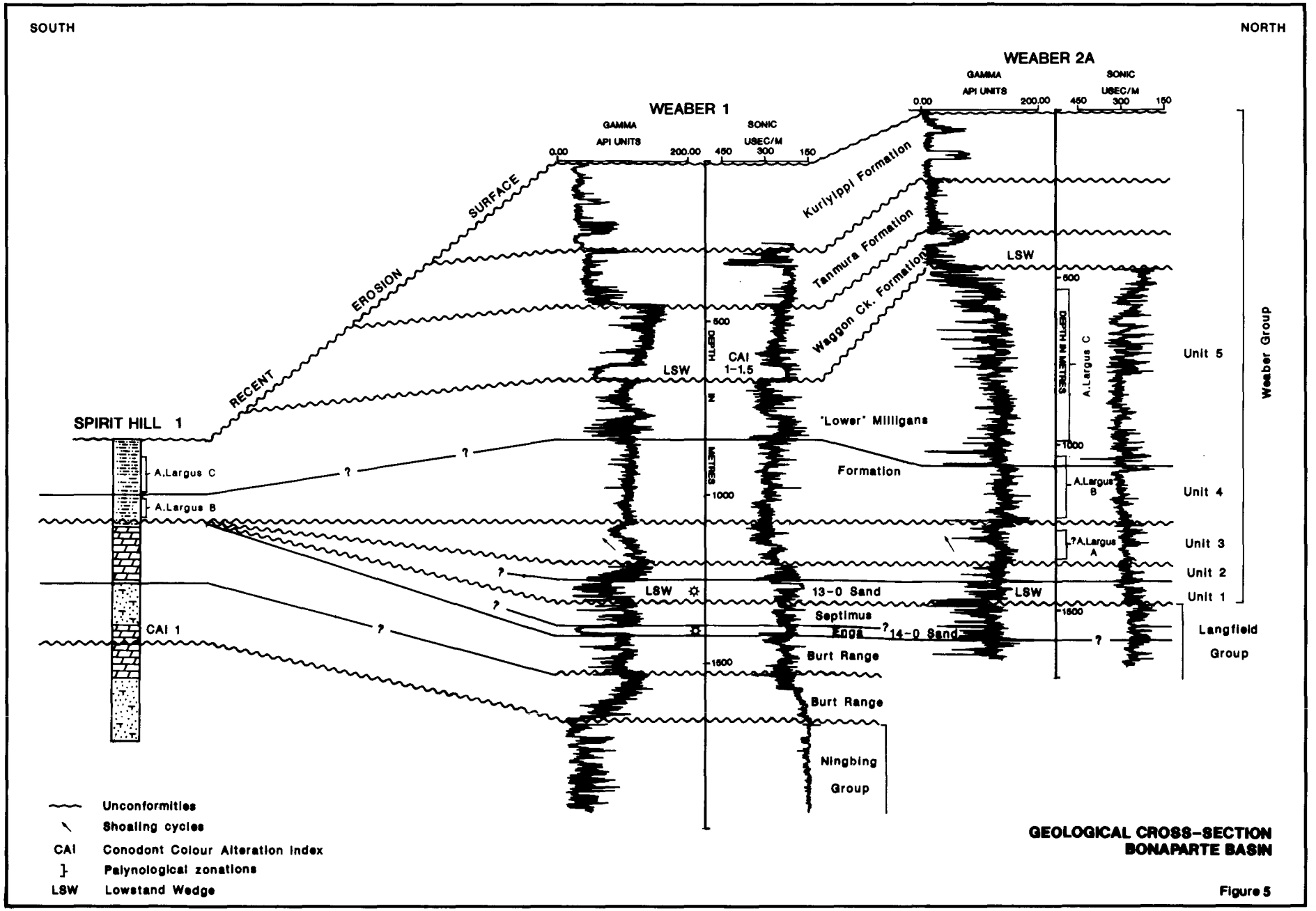
Carbonate deposition of the Famennian Ningbing Group began following a reduction of the high rate of clastic sedimentation of the Cockatoo Group. Carbonate deposition involved algal reef development on isolated bathymetric highs. The Famennian Ningbing Group contains reefal developments similar to those found in the northern Canning Basin, albeit much smaller in scale. A reef complex of the Ningbing Group, some 500 m (1500 ft) thick (Lee & Gunn, 1988) with associated back reef, small patch reef, and forereef facies is documented in outcrop and penetrated by wells drilled onshore. Reef growth may have been directly influenced by eustatic sea level changes. Several mineral exploration boreholes have encountered porosity developments within the reef that contain bitumen staining.

In offshore areas up to 3000 m (10 000 ft) of shallow marine shales and thin sandstones, attributed to the "Bonaparte Formation" (Mory, 1988), were deposited. Since the "Bonaparte Formation" has been variously correlated with the Frasnian Cockatoo, Famennian Ningbing, Tournaisian Langfield and younger Weaber Groups in the onshore portion of the basin (Enclosure 4), we prefer not to use this name herein. The basinal shales comprising these groups (Figure 4), therefore, have not been named in Enclosure 4. More precision in biostratigraphy will undoubtedly clarify the relationship of the "Bonaparte Formation" with these groups.

The onset of deposition of the Tournaisian Langfield Group (Keep River Group of Laws, 1981) marks the termination of reef growth, as uplift increased the supply of clastic sediments. The Langfield Group consists mostly of limestone and sandstone with minor shales (Mory & Beere, 1988) deposited in a shallow, clastic influenced shelf setting. The group comprises two carbonate to clastic sequences interpreted as representing progradation of shoreline clastics over shelf carbonates (Mory & Beere, 1988). Significant quantities of gas were encountered in the Enga Sandstone of the Langfield Group at Weaber #1.

The Weaber Group unconformably overlies the Langfield Group. The Weaber Group is composed of a basal shale, referred to as the "lower" Milligans Formation, the sandstone dominated Waggon Creek Formation, the "upper" Milligans Formation, a sandstone and carbonate unit called the Tanmurra Formation, and an upper sandstone and shale sequence, the Point Spring Sandstone (Figure 4). Significant gas flows were obtained from the Milligans Formation in Bonaparte #2 and Keep River #1.

The interpretation of the Weaber Group presented here is extensively modified from that published by Mory & Beere (1988), and somewhat different to the stratigraphic successions illustrated by Lee & Gunn (1988) and Gunn (1988). Our interpretation has followed a sequence stratigraphic analysis utilising the principles of Van Wagoner et al. (1987)



GEOLOGICAL CROSS-SECTION
BONAPARTE BASIN

Figure 5

and Vail (1987), and recognises important unconformities and depositional sequences which are tied, where possible, by palaeontology and seismic profiles. This analysis has led to the following depositional scenario.

During the Visean, in response to a period of active subsidence, the southern Bonaparte Basin received marine sediments of the "lower" Milligans Formation. The "lower" Milligans Formation in Keep River #1 is clearly correlated to Weaber #1 (Enclosure 5) and #2A, and Spirit Hill #1 (Figure 5) by logs and palynological control (Wood, 1988). Several upwards coarsening cycles are readily recognised and correlated on the gamma ray logs in these wells.

In Keep River #1 (2380 - 3450 m), five discrete units are described (Enclosure 5). The basal sandstone of unit 1 is correlated with the 13-0 sand at Weaber #1 (Garside, 1983). This sand is interpreted as the basal lowstand wedge deposit of the "lower" Milligans Formation in this area. The unit fines upwards into calcareous shales containing marine fossils and ooids, and then coarsens up to a highstand sandstone section.

Units 2 and 3 are also shoal cycles. At Weaber #2A, unit 3 questionably contains the *Anapiculatisporites largus* unit A assemblage (Wood, 1988), and thus correlates with the gas bearing zone at Bonaparte #2. Overpressured shales were reported in this interval at Weaber #1 (Garside, 1983), although a reservoir was absent. At Weaber #1, the "lower" Milligans Formation lies between 1300 and 655 m (Garside, 1983), and unit 3 shoal cycle is identified between 1206 and about 1095 m (Figure 5). The cycle coarsens upwards from carbonaceous shales to interbedded calcareous siltstones and shales.

Unit 4 is a monotonous series of interbedded shales, siltstones and thin carbonates, with some ooids reported from Keep River #1. Minor gas shows occur towards the top of this unit at Keep River #1 (Caye, 1969) and overpresurred shales occur at Weaber #1. The *A. largus* unit B assemblage is present in the unit at Weaber #2A (Wood, 1988)

At Keep River #1 the lower part of unit 5 (2771-2899 m) is a shoal cycle (Enclosure 5). This unit commences with shale, and coarsens upwards through weakly calcareous quartz siltstone with forminifera (2719 to 2771 m), to interbedded crinoidal shale and siltstone with thin beds of calcareous, medium grained, gas bearing sandstone (2646 to 2652 m) and interbedded calcareous mudstone and biosparite conglomerates. Sandstone beds up to 1.5 m thick increase upsection and consist of fine to medium grained, calcareous beds with crinoids, brachiopods and foraminiferal remains. Palaeocurrents interpreted from the dipmeter suggest a southerly source and low energy shallow water deposition (Caye, 1969).

The lower part of unit 5 lies between 775 and 825 m at Weaber #1 (Figure 5). The sandstones of unit 5 are well sorted, fine to medium grained, and occur in beds up to 2.5 m thick. The uppermost beds of unit 5 are mainly siltstones and shale with minor interbedded calcareous sandstone in beds up to 1.5 m thick. Unit 5 at Weaber #2A contains the *A. largus* unit C assemblage. (Wood, 1988).

Several unconformities are recognised within the Milligans Formation at Keep River #1 (Enclosure 5). Lee & Gunn (1988) have indicated that a sandstone interval occurs at the base of the "upper" Milligans Formation at Keep River #1 and Weaber #1, and is unconformable upon the "lower" Milligans Formation. This sandstone unit is here correlated with the Waggon Creek Formation of Mory & Beere (1988).

The basal lowstand wedge of the Waggon Creek Formation (*sensu* Mory & Beere, 1988) lies erosionally upon the "lower" Milligans Formation in this well, and log correlation to Weaber #1 suggests that these basal sands onlap to the south (Enclosure 5). Dipmeter data suggest channel sands occur between 2289 and 2377 m in Keep River #1 at the base of the Waggon Creek Formation. These sands are interpreted to form the lowstand wedge and are overlain by a flooding surface at about 2290 m, marking the base of the transgressive systems tract. Above about 2280 m is the condensed section, representing the maximum rate of flooding, after which the sequence commenced shoaling. Marine fossils, including algae, brachiopods and echinoderms occur in biosparites at 2131 m (Caye, 1969). Minor porosity occurs in the highstand systems tract, with slightly fluorescent, salty water produced from a drillstem test between 2104 - 2109 m. The upper Waggon Creek Formation may also be unconformable on the lower part of the same formation at Keep River #1.

The upper part of the Milligans in Keep River #1 ("upper" Milligans Formation of Lee & Gunn, 1988) commences with a lowstand wedge to transgressive systems tract sandstone dominated unit, here called the Upper Waggon Creek Formation, although this name is probably stratigraphically invalid. The relationships of the Waggon Creek Formation, as described by Mory & Beere (1988), are decidedly unclear. However, this basal sand facies at Keep River #1 contains "good reservoirs" (Caye, 1969) between 1963 and 1975 m. The sands are locally medium grained, poorly sorted (1809 to 1817 m) and siliceous, with rare crinoids, brachiopods, ostracods and forams noted between 1948 and 1963 m (Caye, 1969).

According to Mory & Beere (1988), the top of the Waggon Creek Formation facies lies at 1810 m in the Keep River #1 well. The "upper" Milligans Formation, which lies immediately above the abrupt top of the upper Waggon Creek Formation at Keep River #1, is a coarsening upwards cycle to about 1155 m (gamma ray log interpretation). The lower part consists of interbedded shale, poorly sorted silty shale with scour-and-fill structures, siltstone and occasionally microconglomeratic sandstone. Crinoids, forams, molluscs and ostracods occur throughout. Near the top of the shoal cycle (1262 to 1274 m), the calcareous fine grained sandstone and sandy limestones contain ooids. Above 1155 m to the unconformable base of the Tanmurra Formation at 755 m, the formation consists of micaceous silty shale, and below 994 m, clear quartzose sandstone. Plant fragments are common throughout. The upper beds contain lignitic, fine grained sandstone and thin dolomitic siltstone. The section is interpreted as a shoaling marine cycle (to 1155 m) overlain by lagoonal to lacustrine sediments of the highstand systems tract.

The rate of clastic sedimentation and subsidence declined substantially during the subsequent Tanmurra Formation deposition, which occurred

across a broad shelf. Carbonates, averaging some 300 m (1000 ft) in thickness, were developed over the mid-basin area. These carbonates grade into siliciclastic sequences to the southeast, and northwest into thicker shale sequences in the deeper parts of the basin. The siliciclastics, laterally equivalent to the carbonates, are referred to as the lower portion of the Point Spring Sandstone (Mory & Beere, 1988).

The more clastic dominated sequence, referred to as the main Point Spring Sandstone after Mory (1988), contains fluvial to shoreface facies in the onshore sections, whereas offshore the unit contains thick shales. In both the offshore and onshore areas the Point Spring Sandstone has a thickness between 200 - 400 m (650 -1300 ft), but at Kulshill #1 over 800 m (2650 ft) of section has been assigned to the sequence (Mory, 1988). This thick section suggests that the Kulshill wells were located in a subsiding sub-basin during the main period of Point Spring Sandstone deposition.

4.2.6 Late Carboniferous to Permian

A depositional hiatus occurred during Late Carboniferous time within the Bonaparte Basin (Laws, 1981) and also in the Arafura Basin. A series of transgressional and regressional cycles followed, and resulted in non-marine to marine sedimentation from the Late Carboniferous to Late Permian. Three sequences have been identified within this cycle; the Kulshill Group, Fossil Head Formation, and the Hyland Bay Formation (Kinmore Group).

4.2.7 Kulshill Group

Over 1500 m of Kulshill Group sediments are recognised in Kulshill #1 (Mory, 1988), which is the type section for the Kulshill Group and some of the constituent formations. According to Mory (1988), deposition commenced with a glacial to fluvial, coarse siliciclastic phase (Kuriyippi Formation). Recurring glacigene conditions led to the deposition of lacustrine to estuarine shales (Treachery Shale) followed by a fluvial to deltaic and marine siliciclastic sequence (Keyling Formation).

Lee & Gunn (1988) infer a depocentre that contains up to 7000 m (23 000 ft) of Kulshill Group sediments in the middle of the Petrel Sub-basin, but the reported thickness may include parts of the underlying Weaber Group (Mory, 1988). As indicated at the Moyle #1 and Berkley #1 well locations, the upper part of the Kulshill Group transgressed the basin margin faults.

Kuriyippi Formation

Mory (1988) defined the Kuriyippi Formation as a lower series of upwards fining, thick, clean sandstone overlain by siltstone and an upper part of sandstone, pebbly sandstone, conglomerate, and tillite. The upper section is characterized by relatively higher gamma ray counts than the lower part of the formation (Mory, 1988, Figure 16; see also Enclosure 6). This higher radioactivity is presumably caused by the igneous pebbles, mica and feldspar contained in sediments deposited in areas proximal to the Precambrian provenance areas. This log character is not consistent away from the Kulshill #1 area (see also Figure 3 in Lee & Gunn, 1988).

Mory (1988) suggested that the Kuriyippi Formation was deposited initially by fluvial processes (that is the upwards fining cycles present in the type section at Lesueur #1) succeeded by a glacial sequence.

However, in Kulshill #1 at least five grossly upwards coarsening cycles are present from the gamma ray and sonic log profiles (Enclosure 6) and occasional glauconite is reported from cores (Duchemin & Creevey, 1966). Fisher & Associates (1987) suggested "periglacial-marginal marine - tide dominated transgressive sequences". However, the presence of varves and plant fossils in cores, and the lack of definitive marine indicators in the numerous palynological preparations (Duchemin & Creevey, 1966; Kemp et al., 1977) argue for a non-marine environment. Furthermore, in the Kinmore #1 well, boron concentrations in the Kuriyippi Formation are consistently very low, glauconite is very rare to absent (Laws & Clerc, 1974), and no marine organisms are present in palynological preparations. All of this evidence points to a non-marine depositional environment.

The upper Kuriyippi Formation at Kulshill #1 consists of a series of upwards coarsening cycles. Depositional indicators include common glauconite in some cores, and brackish water algae (*Botryococcus* sp) in the lower part, and coaly laminae in the upper part with no associated glauconite. The sandstones are often calcitic compared to the lower part of the formation where calcareous cement is rare (Duchemin & Creevey, 1966). Fisher & Associates (1987) have ascribed a "regressive sub-tidal, fluvial-deltaic - glacial" origin to these sands. Certainly some marine influence was present during deposition.

Laws & Clerc (1974, p13) interpreted deposition of the Kuriyippi Formation to have taken place "largely in a high energy, near shore environment, including sands from beach, barrier bar and related environments, grading up to channel and natural levee deposits etc. An overall marine regression is evident throughout this sequence". Lee & Gunn (1988) suggest that the upper Kuriyippi sediments are "glacigene clastics resulting from a major glacial event associated with an eustatic lowering of sea level". Thus, they believe deposition of the uppermost Kuriyippi Formation to be a result of **increased** glaciation (lowered sea levels).

Correlations based on limited data suggest that the basal Kuriyippi thickens offshore to the Kinmore #1 location, and thence towards the Barnett #1 location. The upper Kuriyippi section thins in the same direction, and while the boundary with the overlying Treachery Shale is said to be gradational at Kinmore #1 (Laws & Clerc, 1974), a possible unconformity appears to be present below the Treachery Shale at Barnett #1. However, there appears to be no definitive change in palynoflora over this boundary at Kulshill #1 (Kemp et al., 1977).

The formation contains the *Diatomozonotriletes birkheadensis* and *Granulatisporites confluens* palynological zones, indicating a Stephanian to Asselian age.

Treachery Shale

The Treachery Shale (Mory, 1988) is defined on logs by a distinctive interval of monotonous high gamma ray values overlying the Kuriyippi Formation. In some areas the Treachery Shale overlies the Kuriyippi Formation apparently conformably, but at Barnett #1 and Turtle #1 the contact appears disconformable on seismic sections (Mory, 1988). Lee & Gunn (1988, their Figure 3) also indicate an unconformable relationship

with the Kuriyippi Formation at Lesueur #1, Cambridge #1 and Lacrosse #1, and probably at Tern Field. An unconformable contact over a veneer of Kuriyippi Formation is also suggested by these authors at Moyle #1. A dipmeter determined unconformity is present below the Treachery Shale at Kulshill #1 (Brophy, 1966) where it separates "true...tillite from the underlying microconglomeratic shale" (p 22). Thus, the base of the Treachery Shale is unconformable on the basin margins and over the central domed province (Barnett area) in the Petrel Sub-basin, and corresponds to a Type 1 sequence boundary in the terminology of Van Wagoner et al. (1987).

Mory (1988) interprets the unit to have been formed as glacial outwash in lacustrine or estuarine environments following the retreat of ice sheets on the surrounding Kimberly and Sturt blocks. The unit contains the *Graulatisporites confluens* microflora assemblage of Asselian age.

In Kulshill #1, the Treachery Shale is described as dominantly tillite (1094 to 1227 m) consisting of "common angular to subangular quartz grains and polygenic rock fragments up to five inches (12.5 cm) diameter, occasionally faceted or striated in an argillaceous or shaly matrix. The rock fragments are mainly quartz and andesite or dolerite with few sedimentary and metamorphic rocks.....Shales and siltstones ..... are slightly micaceous and pyritic" and " pure shales are commonly varved". The sandstones are "fine with common larger angular grains and small rounded pebbles, feldspathic, common lithic fragments" (Duchemin & Creevey, 1966, p26).

The Treachery Shale at Moyle #1 (Brophy, 1966) is also tillitic, with about 10% granular or pebbly grains distributed throughout a silty mudstone matrix. A lagoonal or lacustrine depositional environment is suggested by the presence of *Botryococcus* algae and rare Tasmanitid acritarchs. Varves are present in cores, with faceted and striated rafted pebbles to 8x3 cm in disturbed, laminated finer clastics.

In Kinmore #1 the Treachery Shale is less clearly defined than in wells to the southeast, but has been here placed between about 2118 and 2235 m, in a section displaying the characteristic high gamma ray values with an uncharacteristic sand sequence in the middle. Boron values are extremely low (less than 40 ppm) in this section suggesting a fresh water depositional environment, although very rare glauconite is reported from sidewall cores.

It is clear from these descriptions that the name Treachery Shale is in many instances a misnomer; the high gamma values characteristic of the unit are probably more related to the high component of exotic rock components, including feldspars and micas.

Keyling Formation

The upper unit of the Kulshill Group is the Keyling Formation (Mory, 1988), a mostly siliciclastic formation with minor limestone and coal containing the *Granulatisporites confluens* microflora of Asselian to locally early Artinskian age.

The presence of coal lenses and *Botryococcus* algae are indicative of a lagoonal to lacustrine origin for the middle part at Kulshill #1 (Duchemin

& Creevey, 1966). Chamositic ooids noted within the middle part of the unit at Kulshill #1 (Duchemin & Creevey, 1966) are suggestive of shallow brackish water to nearshore marine conditions (Core 5). Lee & Gunn (1988) indicated a marginal marine depositional environment, and Mory (1988) postulated a fluvio-deltaic setting in a post-glacial climate. Laws & Clerc (1974) interpreted a transgressive marine depositional environment at Kinmore #1.

4.2.8 Kinmore Group

The Fossil Head, Hyland Bay and Mt Goodwin Formations form the Kinmore Group (Mory, 1988).

Fossil Head Formation

Following the deposition of the Kulshill Group, Fossil Head Formation sedimentation covered the Petrel Sub-basin with silty, carbonaceous shales. The basal beds abruptly overlie the Kulshill Group (eg Tern #1, Lacrosse #1, Kulshill #1 and Kinmore #1). This formation is some 575 m (1900 ft) thick at the Tern #1 well and thins onto the basin margin areas, as at Kulshill #1, where about 200 m are preserved below the ?Tertiary weathering profile. The Fossil Head Formation contains the stage 3b to upper 4b microfloras indicating Artinskian to Kungarian age.

Dickins et al.(1972) reported Artinskian age limestones from the Kuriyippi Hills. In Flat Top #1, Mory (1988) notes a basal limestone section in the Fossil Head Formation. In the more basinal wells (eg Tern #1, Petrel #2), the basal beds are dark grey to black shales (silty, micaceous and carbonaceous), interbedded with fine to medium grained well sorted sandstone and siltstone, and biomicritic limestone stringers containing bryozoa and crinoids. Acritarchs are present in the basal beds at Kulshill #1 (Duchemin & Creevey, 1966). A marine to estuarine depositional environment for the Fossil Head Formation has been advanced by Lee & Gunn (1988).

Seven to eight shoaling cycles can be interpreted from the gamma and sonic log patterns at Petrel #2 (Enclosure 6), suggesting minor regressions or stillstands in an overall transgressive regime. Similar cycles are present at Tern #1, but cannot be directly correlated to the Petrel wells on the current data set. In the thinner sections towards the basin margins, shoaling cycles are not readily discernable. The upper part of the Fossil Head Formation is coarser grained in places with discrete sand bodies developed (e.g. Petrel #2).

Seismic profiles in the vicinity of the Petrel Field show no evidence of an angular relationship between the Fossil Head and Keyling Formation. Lee & Gunn (1988) also indicate that the base of the Fossil Head Formation is comfomable upon the Kulshill Group with no evidence of unconformity.

A high amplitude, cross-cutting seismic reflector occurs at Bougainville #1, intersecting the well base at about 6000' (1829 m), in part corresponding to a 2 m thick high gamma ray interval in an otherwise apparently sandy section. The reflector may indicate a sill, but there is no evidence of igneous rocks from the sidewall core description at this depth, and maturation profiles do not show any perturbations in gradient at this level.

Gas occurs in the upper Fossil Head sandstones at Penguin #1, immediately below the basal unnamed shale member of the Hyland Bay Formation, although in Figure 4 of Bhatia et al., (1984), this sandstone is shown lying at the base of the Basal Member of the Hyland Bay.

Hyland Bay Formation

The later Permian strata comprise the Hyland Bay Formation (Hughes, 1978; Bhatia et al., 1984), which has been split into five members (Bhatia et al., 1984) based on lithologic characteristics. Only two of these five members were formally named by Bhatia et al. (1984). These were the uppermost unit, the Tern Member, which forms the reservoir for the Tern gas field, and the middle Hay Member, which forms the bulk of the formation and hosts the gas accumulation at Petrel Field. Mory (1988) renamed the Hay Member as the Cape Hay Member. The five subunits of the Cape Hay Member, recognized by Bhatia et al. (1984) (Enclosure 6) can be correlated through several wells in the southeastern Bonaparte Basin.

The lower limestone, the Pearce Member of Mory (1988), was formerly referred to as the H5 limestone marker (Bhatia et al., 1984). Mory (1988) replaced the informal H4 Member of Bhatia et al. (1984) with the term Dombey Member. The informal Basal Member of Bhatia et al. (1984) was retained within the Hyland Bay Formation by Mory (1988), who noted that it may warrant formal treatment in the future.

Bhatia et al. (1984) published a detailed study of the depositional framework of the Hyland Bay Formation, in particular the Cape Hay Member and Tern Member siliciclastics. They interpreted the depositional environment of the Cape Hay Member as a mixed river, wave and tide-dominated delta system because of the sedimentary facies recognised from cores and lack of characteristic seismic reflection patterns. The Tern Member was interpreted as the deposits of a prograding shoreline with lateral facies changes from offshore to barrier bar and inshore lagoon-marsh and flood plain environments.

Late Permian siliciclastics outcrop along the coast in the Port Keats area (Dickins et al., 1972). The abundant marine fauna and erosional breaks with channelled surfaces and basal conglomerates, are suggestive of interfingering nearshore to non-marine environments. Correlation with the Hyland Bay Formation is suggested by the fossil content.

The Dombey and Pearce Members are biomicritic to biosparitic limestones containing abundant shell fragments, bryozoans and crinoids indicative of open marine shelf deposition. Ooids and coral debris are reported in Tern #1, suggesting turbulent conditions, possibly in a near reef or bank setting. Localization of such reefal or bank buildups probably required the presence of some bathymetric relief, such as that caused by active faulting or salt tectonics. However, no thickening on seismic sections, suggestive of reefing, has been seen although the conspicuous uplift observed across the Tern structure (Enclosure 10) may have commenced at this time.

The thick Late Permian carbonates present at Osprey #1 and other western wells suggest that the Bonaparte Basin was predominantly a site of carbonate deposition at this time. The Hyland Bay siliciclastics present

to the southeast are the result of the intrusion of a deltaic sequence into the broad carbonate shelf environment that developed along the northern margin of the continential block (MacDaniel, 1988).

Mt Goodwin Formation

Latest Permian to Early Triassic marine siltstones and shales comprise the Mount Goodwin Formation. The formation has an average thickness of 600 m (2000 ft) across the central Petrel Sub-basin and thins to the southern and eastern basin margins. Early Triassic siliciclastic sediments are exposed in the Port Keats area (Dickins et al., 1972).

MacDaniel (1988) states that the boundary with the Hyland Bay Formation is disconformable, but Mory (1988) suggests a diachronous but comformable contact as the *Triplexisporites playfordii* microflora is present in wells to the west (Osprey #1) within the upper Hyland Bay, and within the lower Mt Goodwin Formation. However, the older *Protohaploxypinus samoilovichii* zone is also present in the Mt Goodwin Formation, suggesting either miscorrelation of the upper Hyland Bay limestone in the Osprey #1 area, or poorly controlled palynofacies. Helby (1974 b) notes that the *T. playfordii* assemblages recovered from Sahul Shoals #1 were interpreted "with some difficulty" (his Figure 8) in the section equated with the Mt Goodwin Formation by Mory (1988, his Figure 19). For the Mt Goodwin in Osprey #1 (Mory's Figure 19) an early to mid Scythian age is suggested by Helby (1974b, Figure 5), who also noted a general early Scythian age for the Mt Goodwin Formation. The presence of the *P. samoilovichii* and *T. playfordii* assembleges is consistent with a mid Scythian to early Anisian age (Helby et al., 1987), and supports a disconformable lower boundary. Onshore, there appears to be structural concordance between the Late Permian and Triassic strata (Dickens et al., 1972).

However the Mt Goodwin Formation is coeval with similar shale prone units in the Canning Basin (Blina Shale), Carnarvon Basin (Locker Shale) and Perth Basin (Kockatea Shale). They were all deposited during a basal Triassic eustatic rise following the Tatarian (Tern) regressive episode. The fossils recovered from the Port Keats bores and outcrop indicate correlation to the interval 3204 to 3231 m in Petrel #1, and suggest brackish water depositional environments (Dickins et al., 1972).

The sudden introduction of this thick, fine grained siliciclastic unit has been used by Mory (1988) to infer a new phase of tectonic subsidence with a northeast trending structural grain cross-cutting the earlier northwest trend of the Petrel Sub-basin.

4.2.9 Late Permian To Late Triassic of the Sunrise - Troubadour Area

At Troubadour #1, the first recognisable sediments overlying a presumed weathered pre-Permian granite high, are recrystallized carbonates, here correlated with the Dombey Member of the Hyland Bay Formation. This interpretation is made on the basis of seismic character correlation and log correlation to the Petrel - Tern wells (Enclosures 6 & 7), and the recognition of a thin, upwards coarsening unit on the gamma ray log (3275 - 3300 m) equated to the Tern Member (Enclosure 7). The age of the Tern Member is not controlled at Troubadour #1, but a Kazanian or younger age is given by Mory (1988, his Figure 17).

Overlying the Tern Member, here interpreted as a regressive shoreline facies rather than a barrier bar (cf. Bahtia et al., 1984), are the predominantly shaly sediments of the Mt Goodwin Formation. At Troubadour #1 (3012.5 - 3275 m) these sediments are dated as Early Triassic, probably *T. playfordii* zone or older from the available spore-pollen data. The sediments are described as interbedded grey, brown and black claystones, siltstones and minor, mostly very fine grained, well sorted sandstones. A nearshore marine environment is indicated by the sediments and microflora.

The top of the Mt Goodwin Formation is taken at 3012.5 m at a change in log character (Enclosure 7) and an interpreted change in structural dip. This boundary is regarded as an unconformity (cf. Mory, 1988, p 301), and is possibly related to tectonism on the Sahul Platform.

The overlying unit (2755 - 3012.5 m) is tentatively correlated with the Challis and Benalla Formations (Mory, 1988), with which it has some lithological (limestone) and wireline log similarities. It is here referred to as the Troubadour Limestone Member. The lower part of the unit (below 2824 m) is undated. The upper section (2783 - 2803 m) is dated as Carnian to Ladinian (i.e. Mid to Late Triassic) in the well completion report.

The lower part of the unit (2950 - 3012.5 m) consists of interbedded dark grey claystones and siltstones, and lighter coloured, mostly very fine grained and fine to medium grained, well sorted, sandstones. Minor black coals and crystalline limestones are present. The gamma ray log shows a series of upwards coarsening cycles suggesting small scale regressive events in a overall transgressive marine cycle. Above 2950 m to 2935 m, limestone in beds up to 5m thick occurs interbedded with siltstones and claystones. Above 2882 m, to about 2825 m, is a thick sequence of grey, mostly cryptocrystalline limestone with fragments of bryozoans and ?corals, possibly correlative to the Benalla Formation. The possibility of reefal developments within this unit is suggested by the thick carbonate body within the section and the recent recognition of Late Triassic reefs on the Wallaby Plateau to the west, and thick carbonates of this age in the Western Timor Sea (MacDaniel, 1988).

The overlying unit (2755 to 2825 m), referred to here informally as the "Shoaling Member", consists of two fully preserved shoaling cycles apparent on the gamma ray log, and an upper, partially preserved cycle (Enclosure 7). The top is truncated below a 12 m thick sandstone section and the boundary is clear on all logs. These three cycles are interpreted as prograding coastline/barrier bar facies, although in the absence of evidence from nearby wells, it is impossible to place these cycles into a regional palaeogeography. The coals indicated by cuttings and the density log (if not caused by bad hole conditions), suggest that a paralic/lagoonal environment possibly developed behind shoaling carbonate banks.

A Carnian age is indicated by the *Samaropollenites speciosus* assemblage (2783-2803 m) in the shoaling sequences below the Malita Formation, which in the Troubadour #1 well, contains the *Corollina torosa* assemblage.

The base of the Jurassic is selected on the basis of the gamma ray log at 2755 m at the bottom of a sharp based (? erosive) sandbody. The first Jurassic ages are shown by abundant *Corollina* pollens between 2545 to 2676 m, suggesting a basal Jurassic age for at least the upper part of the redbed unit between 2755 and 2605 m. This unit is correlated with the Malita Formation of Mory (1988). The Malita Formation consists of interbedded multicoloured claystones, siltstones and sandstones, with minor coal and chamositic cement, in generally upward fining units as indicated by the gamma ray log. The gamma ray log profile, colouration of the sediments, and lack of marine indicators (the rare acritarchs may be caved) suggest a non-marine, probably fluvial, depositional environment. A change to upwards coarsening cycles in the upper part of the unit suggests a paralic influence.

An unnamed Early Jurassic unit of similar lithology is present between 2605 and 2502 m. The lithology is interbedded claystones, siltstones and sandstones, but the gamma ray log indicates most cycles within the unit are upwards coarsening. The sediments also lack chamositic cement and are generally grey in colour, suggesting a change from the oxidizing environment of the underlying red bed unit to a probable more marine influenced depositional regime. The palynology suggests a late Early Jurassic age and non-marine environment.

4.2.10 Troughton Group

The Troughton Group (Mory, 1988) consists of the Cape Londonderry, Malita and Plover Formations.

Cape Londonderry Formation
The Cape Londonderry Formation, a regressive siliciclastic Triassic sequence, was deposited over the entire Petrel Sub-basin. The Cape Londonderry Formation attains a thickness of up to 400 m (1300 ft) in the Petrel Sub-basin and thins onto the basin margins. A thickening into the Malita Graben is also postulated, although not proven on current well control. Onshore correlatives are unknown.

Helby (1974b) dated the Cape Londonderry Formation as ?Ladinian to late Scythian and noted its conformable relationship with the underlying Mt Goodwin Formation. Deposition was probably curtailed by a sharp sea level fall during the Ladinian *Staurosaccites quadrifidus* microflora) shown by eustatic sea level curves published by Haq et al. (1987).

Malita Formation
In the Petrel Sub-basin the youngest Triassic sediments are the red beds of the Malita Formation. This formation attains a thickness of approximately 300 m (1000 ft) in the Petrel wells, and thins to the basin margins to the east and south. The formation is not known in the onshore area.

Helby (1974b) has shown that the oldest known Malita Formation sediments occur at Gull #1, where the *S.quadrifidus* microflora (Anisian - Ladinian) is present. However, these sediments may be also correlated with the upper Cape Londonderry Formation. A Liassic to Early Jurassic age is indicated at Plover #1 (Helby, 1974b). Mory (1988), however, has ascribed a Carnian to Pleinsbachian age to the Malita. The red bed

character of the Malita Formation suggests a generally non-marine, possibly arid environment.

Plover Formation
Following Malita Formation deposition, an Early Jurassic transgression resulted in the deposition of fluvial to deltaic sediments of the Plover Formation (formerly Petrel Formation Member C). The section thickens from the basin margins to over 500 m (1650 ft) in the centre of the basin.

Helby (1974b) noted the presence of a marine incursion during *Callialasporites turbatus* time at Skua #1, and suggested that the Petrel "C" (Plover) Formation does not "necessarily" represent a single gradational transgressive event.

The Plover Formation and Triassic sequences of the Petrel Sub-basin area are discussed in more detail below (4.2.11).

4.2.11 Triassic and Jurassic of the Petrel and Troubadour Areas

Triassic to Early Jurassic of the Petrel Area
Dating of the Triassic section in the Petrel wells is generally poor. Log correlation to Plover #1 allows more precise aging of the upper Mt Goodwin to lower Malita Formations (Helby, 1974b). The upper Mt Goodwin Formation is dated as Scythian (lower *T. playfordii* zone) at Plover #1, as is the lower Cape Londonderry Formation. The middle Cape Londonderry Formation has a late Carnian age (upper *S. specious* zone). The Malita Formation in Plover #1 has the *Corollina torosa* microflora in the upper two thirds, suggesting a mostly Early Jurassic age.

At Petrel #1 and #2, the Mt Goodwin Formation overlies the Tern Member with a distinct lithological change clearly reflected by changes on the gamma ray and sonic logs (Enclosure 6). The formation consists of thinly interbedded siltstones, sandstones and shales. Sandstones are most common in the middle part of the unit and are mostly very fine to fine grained and tight. The shales are sometimes carbonaceous, suggesting some source rock potential. Scattered shell fragments, conchostracans, acritarchs and pyrite indicate a shallow, near shore depositional environment.

The Cape Londonderry Formation consists of two units in the Petrel wells; a lower sandstone, siltstone, shale sequence and an upper sandstone dominated unit. The base of the lower unit is rather abrupt on all logs and may reflect an unconformity. Most sedimentary cycles (from the gamma ray logs) suggest upward coarsening in this lower unit. The presence of glauconite in the grey to dark grey siltstone and shale cuttings, and pyrite in the sandstones, may be indicative of a marine depositional environment, but the distinct lack of microplankton and the abundance of carbonaceous material in the siltstones, particularly in the lower beds, suggests a lagoonal/paralic depositional setting.

The upper part of the formation consists of fine to coarse grained and occasionally pebbly sandstones with minor siltstone and shale. The base of Core #3 at Petrel #2 may represent the top of this formation. The lithology in the core is massive to angle-of-repose cross-bedded, medium

to coarse-grained and pebbly sandstone with patchy distribution of clay and shaly partings (ARCO, 1971). A non-marine, possibly braided stream origin is suggested for this thick sequence of sandstone.

The Malita Formation is a red bed sequence of predominantly fine grained clastics (Mory, 1988). The sharp log breaks in the Petrel wells suggest unconformable contacts with the confining formations. The lithology and characteristic upwards fining cycles in the lower part suggest stacked meandering fluvial channels. The mottled red shales and siltstones of the middle part of the unit and rare, upwards coarsening cycles suggest deposition in possibly lacustrine settings, although a few acritarchs in the Plover #1 well imply a weak marine influence, suggestive of transgressive conditions.

The Malita Formation is absent at Tern #1, where the basal Plover Formation containing the *C. torosa* assemblage (Helby, 1974a) unconformably overlies weathered upper Cape Londonderry Formation. The top of the Malita Formation at Bougainville #1 is also unconformable below the Plover Formation. Thus, a period of erosion preceded the onset of Plover deposition, which commenced sometime during the duration of the *Corollina* microflora assemblage.

The general upwards fining of the Malita Formation and the change to possible lacustrine sedimentation, the rare acritarchs and the presence of glauconite in the upper part at Petrel #1, suggest encroaching marine conditions. From the Haq et al. (1987) sea level curve, sea level began rising during early *C. torosa* time (Sinemurian). The basal Plover Formation lowstand deposits occur in this period of overall rising sea levels, and are placed at about the Sinemurian - Pliensbachian boundary.

Middle to Late Jurassic of the Petrel Area

Three units are distinguished in the Plover Formation at Petrel #2 (Enclosure 6).

Unit 1 consists of fine to coarse-grained kaolinitic sandstone, and quartz and quartzite pebble conglomerate. Very minor glauconite and shell fragments from near the base of the unit in Petrel #1 may be caved, as neither occur in sidewall cores from the sequence. All palaeontological samples (Petrel #1) indicate generally non-marine depositional environments as does the coal recorded from cuttings. The basal part is more calcareous than the upper, as shown by cuttings and the sonic and density logs in Petrel #1 and Petrel #2. The uppermost beds are carbonaceous shales and very fine grained sandstone, interbedded with pebbly sandstones. Similar shaly beds are intercalated throughout the two well intersections, and some may be correlative between the wells. A generally continental, perhaps braided stream origin of the unit is probable. In Petrel #1, Helby (1974a) records the *C. turbatus* assemblage at 2057 m, indicating a late Pleinsbachian to early Bajocian age for the middle of the unit.

Unit 2 is also a coarse-grained sandstone in the lower part, but glauconite and pyrite become more common about 50 m from the base of the lower pebbly sandstone. The sandstones become finer grained and better sorted with an absence of pebbles. Palynological samples from the upper part contain dinoflagellates, indicative of marine depositional

environments, but shale beds near the base of the unit in Petrel #1 (not present in Petrel #2) contain only spores and pollen, suggesting lacustrine conditions.

Thus, Unit 2 records a change from non-marine, probably braided stream and lacustrine deposition (lowstand wedge), to nearshore/paralic deposition about midway through the sequence. The upper half is shallow offshore marine in origin.

The top of the Plover Formation Unit 2 contains the *Wanaea spectabilis* microflora at Petrel #1 (reinterpreted from species list in Helby, 1974a, using range charts in Helby et al., 1987), at Flamingo #1 (cuttings 3594 - 3603m, Morgan, 1983), and in Troubadour #1 (BOC, 1974). This is coeval with the "Jabiru Sandstone", which MacDaniel (1988, his Figure 2) illustrated the *W. spectabilis* sand as part of the Flamingo Group, lying unconformably on sands with a *Corollina torosa* microflora (Early Jurassic). This relationship suggests that either the entire Plover Formation in the Petrel Sub-basin belongs to the Flamingo Group (cf. Mory, 1988), or several unrecognised unconformities are present within it, as previously suggested by the reinterpretation of the Troubadour #1 well. At Petrel #1, one such unconformity is possible at 2057 m, the sediments below the putative unconformity being dated as late Pleinsbachian to basal Bajocian (Helby, 1974a) At Petrel #2, this break occurs at 2018 m (Enclosure 6).

A distinctive upwards coarsening cycle, Unit 3, occurs at the top of the Plover Formation in Petrel #1 and #2 wells (Enclosure 6). In Petrel #1 (1820 - 1890 m), the unit commences with glauconitic silty shales with minor thin limestones, and passes gradationally upwards into pyritic sandstones interbedded with siltstones and limestones, to terminate in clear, fine and coarse grained sandstones. A very similar sequence is present in the Petrel #2 well between 1770 and 1838 m.

The age of the base of Unit 3 at Petrel #1 is constrained by sidewall cores at 1874 m and 1883 m (Helby, 1974a, his Figure 5). The upper sidewall core contains *Herendeenia pisciformis*,considered by Helby et al. (1987) as confined to the *Omatia montgomeryi* zone (late Kimmeridgian). The sidewall core (1904 m) from near the top of Unit 2 on the other hand, contains both *Wanaea digitata* and *W. spectabilis* which Helby et al. (1987) show as overlapping only in the *W. spectabilis* zone (Mid Oxfordian). Thus, either an unconformity exists between these two sidewall cores or a very condensed section is represented. Unfortunately, the sidewall core at 1883 m contains undescribed dinoflagellates (Helby, 1974a). A sidewall core at 1768 m in Petrel #1 (Kemp, in ARCO, 1969) contains the dinoflagellates *Omatia* sp. and *Cyclonephelium* cf. *areolata,* along with long ranging forms, suggesting an age about the basal Portlandian (middle Tithonian).

The sidewall core at 1646 m in Petrel #1 also contains *H. pisciformis* and a variety of other forms, including *Scriniodinium crystallinum,* consistent with an assignment to the *O.montgomeryi* zone.

Thus, Unit 3 appears to be late Kimmeridgian to Tithonian in age, and may be better included with the Frigate Shale rather than the Plover Formation (cf Mory, 1988).

This coarsening cycle is not present at Tern #1, Frigate #1, or Bougainville #1, but may have stratigraphic equivalents in the condensed sections at Sunrise #1 and Troubadour #1, and possibly Curlew #1, where the microplankton suggest assignment to the *O. montgomeryi* to *Dingodinium jurassicum* zones (data in Curlew #1 WCR) using the Helby et al. (1987) range charts.

Middle to Early Late Jurassic of the Sunrise-Troubadour Area
The major sandbody above 2502 m in Troubadour #1 (Figure 6) is interpreted as representing the basal erosional fill of the lowstand wedge of the following Middle Jurassic Plover cycle. A dipmeter change near this depth suggests structural movements took place at about this time. The lower part of the Plover Formation (2389 - 2502 m) consists of interbedded sandstones, siltstones and claystones. Upwards coarsening and fining cycles are present overlying the basal massive sandstone. The sandstone is very fine to coarse grained, moderately well sorted, with angular to sub-angular grains. Sandstones higher in the unit are mostly fine grained and well sorted, and the finer clastics are grey to black in colour. Palynology suggests a marine depositional environment in part because of the occasional presence of dinoflagellates.

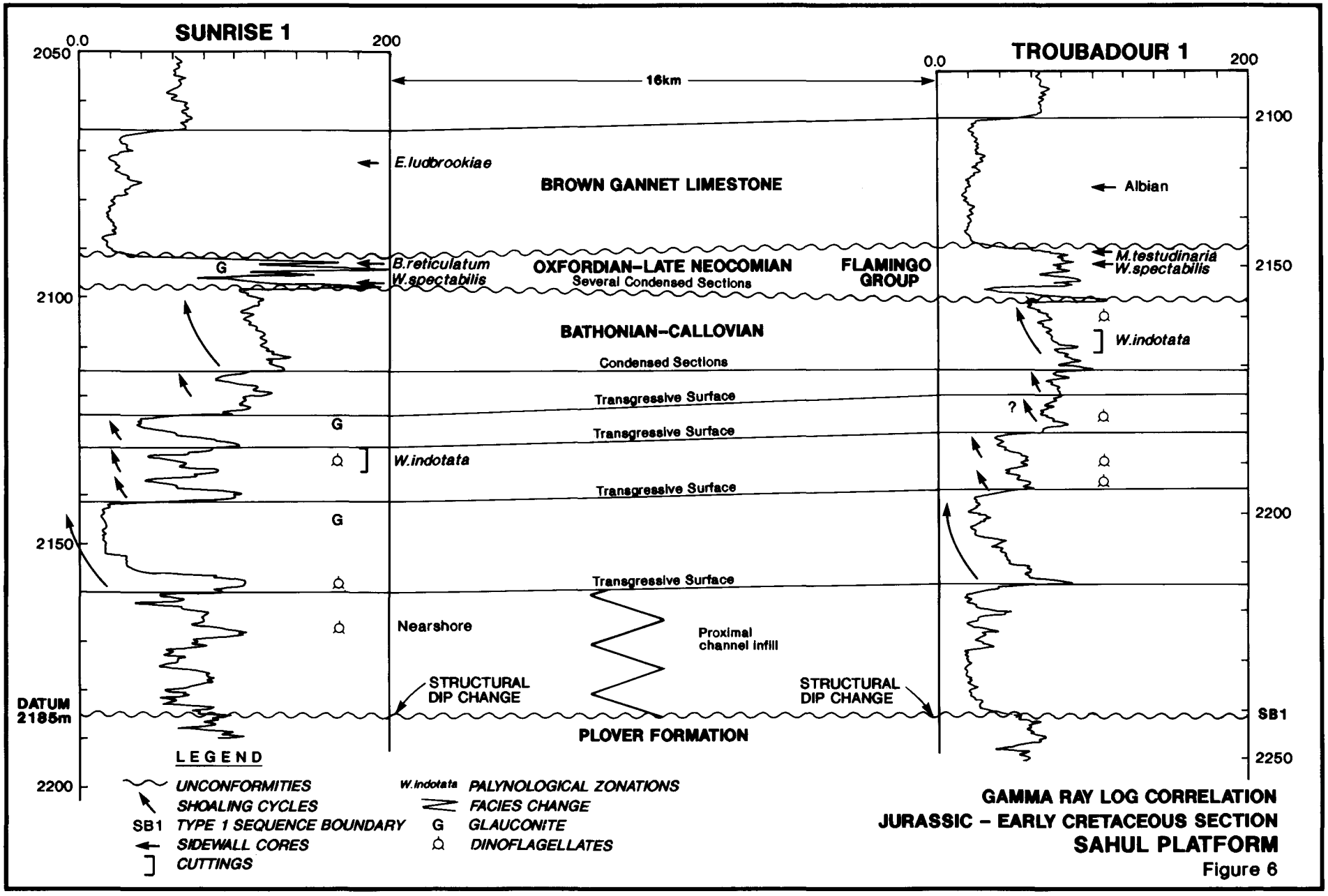
Between 2389 m and 2251 m (Figure 6), the section becomes finer grained with generally upwards coarsening clastic cycles of interbedded claystones, siltstones and sandstones. The sandstones have up to 30% dolomitic cement and traces of glauconite. The gamma ray response, presence of dinoflagellates and glauconite, and dark colour of the finer clastics suggest a nearshore marine environment with a fluctuating strandline as the spore and pollen component is high in the microflora.

4.2.12 Flamingo Group

The Flamingo Group (formerly Petrel Formation Members A and B) overlies the "Callovian" unconformity according to Mory (1988). A marine transgression resulted in deposition of the Frigate Shale in the main troughs of the Bonaparte Basin. The upper part of the Flamingo Group, the Sandpiper Sandstone, represents a fluvial to deltaic siliciclastic cycle which covers a much greater area of the Petrel Sub-basin, transgressing certain of the formerly upstanding margins not covered by the Frigate Shale. A break in slope existed in the region of the Jacaranda #1 well, and turbidites may be present in the southern Malita Graben.

Mid Jurassic to Neocomian of the Sunrise - Troubadour Area
Palaeontological data from the Sunrise #1 well (McLeod, 1975; Apthorpe, 1975; Morgan, 1983) combined with dipmeter and lithological observations (BOC, 1975) were compared with palaeontological information in Troubadour #1 (BOC, 1974; Ingram, 1974; Apthorpe, 1975; Morgan, 1983). These data, in conjunction with wireline log correlations, suggest a more complex geological history for the Sahul Platform than presented by Mory (1988). The reappraisal of the palynological information using new range charts (Helby et al., 1987), in combination with lithological, log and dipmeter data, suggests a depositional history as outlined below.

Tectonism during the Late Bathonian (*Wanaea indotata* zone) is manifested by structural discordance at Troubadour #1 (about 2250 m on



GAMMA RAY LOG CORRELATION
JURASSIC – EARLY CRETACEOUS SECTION
SAHUL PLATFORM
Figure 6

the dipmeter) and a change to a more siliceous cementation, as indicated by the density log, at 2251 m. There is also a change in the palynofacies (BOC, 1974) at this depth and a lithological change from clean, porous sandstones to interbedded siltstones and claystones with minor sandstones. These changes are interpreted to reflect an unconformity (Figure 6).

At Sunrise #1, the dipmeter log suggests an unconformity at about 2185 m, where the density log also indicates a change in cementation. Sediments above this depth are dated as Bathonian (drill cuttings between 2130 and 2135 m, Morgan, 1983). Below this depth palynomorphs are generally poorly preserved.

Log correlations between the Sunrise #1 and Troubadour #1 wells, based on log character and the palynology, indicate at least five upwards coarsening cycles are present below the highest gamma ray interval and the basal porous sand at Troubadour #1 (Figure 6). The basal Troubadour channel sand is absent at Sunrise #1, however, based on the assumption that the unconformity interpreted from the dipmeter in each well is equivalent, then it is replaced by a series of interbedded claystones and siltstones with a weak marine influence shown by palynology (McLeod, 1975). Thus, the porous sands in Troubadour #1, which produced almost 10MMCFPD on test in that well, are absent as a result of a facies change, 16 km away at Sunrise #1 (Figure 6).

Pre-Albian Sequence at Shearwater #1

Log correlation from the Sunrise - Troubadour area to Shearwater #1, 90 kms to the south, is good through the Cretaceous Bathurst Island Group succession (Enclosures 7 & 8), and is supported by foraminiferal dating. The Bathurst Island Group at Shearwater #1 contains all the subunits recognised at Troubadour #1, and confirms the regional thickening of the Group to the south (Enclosure 9). However, the basal Brown Gannet Limestone (Mory, 1988) is absent at Shearwater #1, probably because of facies change, as the time equivalent section is present.

The section below the Albian in Shearwater #1 is poorly dated with ages ranging from Late Albian to Late Bathonian cited by various authorities. The upper sequence is highly siliceous sandstones and shales, with most palaeontological samples apparently contaminated with Albian or Cenomanian microfossils. From the datings, it may appear that the uppermost tight sandstones (3054 to about 3133 m) with Late Albian ages are equivalent to the Brown Gannet Limestone, alternatively the microfossils may be caved. However, cuttings from 3136 m (Morgan, 1983) contains the *W. indotata* zone microflora of Late Bathonian age, suggesting that the overlying strata are at least this age and therefore belong to the Plover Formation.

If the section is all Late Bathonian Plover Formation, then the Shearwater structure must have been high during at least Early Neocomian time, for the late Albian (C1 -C2 foram zones) lies unconformably upon the poorly dated Plover clastics in the Shearwater # 1 well. This is supported by the available seismic data (Enclosure 9).

Below 3144 m in Shearwater #1 there is a change in the gamma ray response (Enclosure 8) indicating a downhole change to finer grained

clastics. The section contains grey to black shales, mostly fine grained siliceous and dolomitic sandstone and minor microcrystalline dolomite. Rahdon (1982) noted the presence of minor glauconite in the sandstones, and minor coal (<1%). The Plover sandstones are fine to very coarse grained and occasionally pebbly above 3127 m and mostly poorly sorted, with the presence of glauconite and dinoflagellates in the generally blocky sands (indicated by the gamma ray log). A possible proximal turbidite origin is suggested.

4.2.13 Cretaceous

A regional unconformity of Early Cretaceous (Valanginian) age interrupted sedimentation and erosion associated with uplift removed large volumes of sediment from the basin margins, Londonderry High, Sahul Platform and Darwin Shelf, but only a minor sedimentary hiatus occurred in the Petrel Sub-basin, Sahul Syncline and Malita Graben. MacDaniel (1988) interprets this break to be the result of a new seafloor spreading centre established off the west coast of Australia at this time.

The initial Bathurst Island Group deposits, the Darwin Formation, resulted from a regional marine transgression over the Valanginian unconformity. The late Valanginian to Aptian Darwin Formation is not well preserved across the Petrel Sub-basin due to subsequent erosion, probably caused by sea level fluctuations. An unnamed basal to mid Albian unit of greensand/radiolarite shale was then deposited across the northwestern Bonaparte Basin. This unit too is poorly preserved.

In the later Albian (C1-C2 foram zones), a sequence of carbonates, called the Brown Gannet Limestone, was deposited across the basin. The carbonates thin eastwards and in some areas (eg Shearwater #1 area) grade into shales. Overlying the carbonates are the thick siltstones, mudstones, shales and minor limestones of the Wangarlu Formation, which was deposited on the inner to distal shelf. The sequence is more sandy towards the basin margins and becomes more calcareous to the northwest. In excess of 2000 m (6500 ft) of this unit were deposited in the Malita Graben and Sahul Syncline thinning to the south and west over the basin margins, as well as to the north over the Sahul Platform.

Early Cretaceous marine sandstones and shales are present in the Port Keats area (Dickins et al., 1972). The precise stratigraphic equivalence of these outcrops is uncertain, but the age and abundant radiolarians reported suggest correlation with either the Darwin Formation or overlying unnamed unit.

During the Turonian sea level maximum (Haq et al., 1987), a series of eustatic events led to the deposition of shoaling cycles and incursion of the Moonkinu Sandstone member from the east. The offshore facies equivalent of the Moonkinu is the Vee Formation, which was deposited in shelf to outer shelf environments. The sequence is condensed to the northwest (Enclosure 8) where marls become the dominant lithology.

Eustatic falls in sea level during the later Cretaceous (Campanian and Maastrichtian), possibly accompanying structural movements of the basin margin to the northwest, resulted in the deposition of the marine siliciclastic sequences. The Curlew #1, Jacaranda #1 and Darwinia #1A

wells contain glauconitic sands, which become shalier basinward and are equivalent to the Turnstone Formation marls in the Sahul Platform wells. Outer shelf and slope deposits have been recognised in the top Cretaceous sequence (C12 foram zone) at Shearwater #1, based on foraminifera.

4.2.14 Cainozoic

The northward tilt of the Bonaparte Basin, established during the Cretaceous was maintained throughout the Cainozoic. Along the axis of the Petrel Sub-basin and in the Malita Graben and Sahul Syncline, Paleocene to Miocene sediments were deposited with a hiatus occurring during the Oligocene (Mory, 1988). The lower section is generally a sandy sequence grading upwards into a widespread shelfal carbonate development during Miocene time (Enclosure 8) which appears to have transgressed the palaeohighs.

4.3 STRUCTURE

4.3.1 Structural Elements

The main structural elements of the Bonaparte Basin are shown on Enclosure 3 and described as follows -

Petrel Sub-basin
The Petrel Sub-basin is a northwest trending rift containing Palaeozoic and Mesozoic sediments located mainly seaward of the onshore Bonaparte Basin. It is bounded to the southwest and northeast by marginal faults and/or hinge lines separating it from shallow Proterozoic and Early Palaeozoic shelves, platforms, and terrace areas. To the north it is separated from the Malita Graben by a northeast trending faulted hinge line, down-faulted towards the northwest. The northwest structural trends of the Petrel Sub-basin are conspicuously oblique to the northeast trends of the Malita Graben.

In cross-section the Sub-basin is 200 km wide and resembles an asymmetric half graben dipping towards the southwest. Estimates of total sediment thickness exceed 10 km. To the northeast Palaeozoic sediments of the sub-basin onlap shallowing Proterozoic basement of the Darwin Shelf.

Salt migration and vertical salt structuring are preferentially developed along major marginal fault zones in the southwest regions, and along a postulated bi-axial dyke trend (Gunn, 1988; Lee & Gunn, 1988) near the centre of the sub-basin and end near the Malita Graben boundary in the area where Gull #1 and Curlew #1 were drilled (Enclosure 3).

Berkley Platform & Lacrosse Terrace
The Berkley Platform is an offshore extension of the Kimberly Block. It is located in the Western Australian portion of the basin and comprises shallow basement unconformably overlain by thin Permian, and Jurassic to Tertiary sections.

Basement across the Lacrosse Terrace lies at intermediate depths, between the adjacent Berkley Platform and the Petrel Sub-basin. Dipping basinwards and plunging to the northwest, this terrace comprises a

thicker sequence of sediments than that across the Berkley Platform, including an early Palaeozoic to Early Carboniferous section.

Moyle Platform & Bathurst Terrace
The Moyle Platform lies on the northeast side of the Petrel Sub-basin where it coincides with a zone of shallowing basement between the Sub-basin and the structurally positive Darwin Shelf. Palaeozoic and Mesozoic sediments are progressively truncated across the Moyle Platform (Enclosures 9 & 10) which probably represents the up-dip depositional edge of the original southwest tilted half-graben located beneath the Petrel Sub-basin. In the south, the Moyle Platform is characterised by a series of en-echelon northwest trending faults which coalesce onshore and swing north-south becoming the Moyle Fault (Enclosure 3).

The Bathurst Terrace lies in a similar setting to the Moyle Platform, between the Darwin Shelf and the Malita Graben. The terrace is a depositional feature, its boundary with the Darwin Shelf taken to coincide with the pinchout edge of the Palaeozoic section.

Darwin Shelf
The Darwin Shelf is an offshore extension of the Proterozoic Pine Creek Geosyncline. It is a prominent, structurally positive, feature which has been subjected to numerous episodes of peneplanation. It is covered by thin Mesozoic and Cainozoic sedimentary sections which show a conspicuous absence of faulting. As a northwest trending embayment, projecting across the Bathurst Terrace onto the Shelf southwest of Bathurst Island, it may contain remanents of more entensive Late Palaeozoic and Early Mesozoic sediments (Enclosure 3).

Malita & Calder Grabens
The Malita Graben forms a northeast-trending depositional trough between the Sahul Platform and the Darwin Shelf and Petrel Sub-basin. Bounded by intersecting east-northeast to northeast fault trends, the graben is some 90 km wide in the southwest converging to approximately 40 km in the northeast. Largest fault displacements occur adjacent to the Sahul Platform giving it an asymmetric, southerly tilted, half-graben appearance in cross-section. Major structural development within the graben probably commenced in the Middle Jurassic (Enclosure 9). At depth it is probably underlain by a thick Palaeozoic section and total sediment thickness may exceed 8000 m.

Faulting within the graben parallels the major bounding faults and creates a series of prominent tilted blocks and terraces, the largest of which, the Heron Terrace, represents a perched, down-faulted block covering an extensive area, adjacent to the Sahul Platform.

The Calder Graben represents a northeast structural extension of the Malita Graben. Rifting here also commenced during the Middle Jurassic, although basement has been downfaulted to great depths, and basement structuring has been largely blanketed by a thick Mesozoic sediment cover (Enclosure 9). However, major faults are recognised along the eastern shelf edge (NTGS, 1989). These faults have displacements down into the basin and indicate the likelihood that the Calder Graben is a half-graben, the up-dip outer structural edge lying on the eastern slope of the Timor Trough.

Sahul Platform
Located on the western side of the Malita Graben, the Sahul Platform is a region of elevated Mesozoic and Palaeozoic sediments comprising a partially rifted fragment whose present geometry resulted during the Jurassic breakup of Gondwana. The Sahul Platform shows greatest expression adjacent to the Timor Trough and merges into broad flat platform areas to the south and east adjacent to the Malita and Calder Grabens. Consequently, the flanks are dominated by northeast to east-northeast trending normal faults showing Mesozoic displacements. Many faults, particularly on the flank adjacent to the Timor Trough, have been reactivated during the Tertiary.

The Mesozoic and Tertiary structuring overprints older Palaeozoic structural trends which, across the crestal region of the Platform, are manifest as a series of parallel, northwest-southeast trending fold axes plunging to the south. The Flamingo, Kelp and Sunrise-Troubadour structures, for example, are located on these Palaeozoic anticlinal axes (Enclosure 3).

Pincombe Inlier & Pincombe Ridge
The Pincombe Ridge and its surface expression, the Pincombe Inlier, are located onshore to the south of the Keep Inlet. During Devonian and Carboniferous times this ridge was a prominent structural feature controlling sediment deposition, forming a structural boundary between depocentres in the developing Carlton and Burt Range Sub-basins.

Carlton Sub-basin
The Carlton Sub-basin lies largely to the northwest of the Pincombe Ridge, mostly within Western Australia. It may contain over 5000 m of mostly Palaeozoic siliciclastic marine sediments, fluvio-deltaic coarse clastics, and marine carbonates, the basin margins being the sites of carbonate reef and platform development during the Famennian. The southern margin exhibits a series of northwest trending faults of pre-Late Devonian age onto which is superimposed a series of poorly defined northeasterly trending anticlines, possibly formed by movements along wrench faults (Laws, 1981) before the Late Carboniferous.

Keep Inlet & Burt Range Sub-basins
The Keep Inlet Sub-basin is an approximately northeasterly trending tensional structure that developed during the Late Devonian to Late Carboniferous in the present onshore Bonaparte Basin. Its average width is 18 km and depth to basement may be up to 4500 m (Blake, 1984). It is bordered to the east by the Cockatoo Fault and to the west by the Pincombe Ridge. The Sub-basin was a major structural feature during the Late Devonian to Late Carboniferous time and influenced the sedimentary patterns of the region. It became inactive once the Petrel Sub-basin became a major Palaeozoic depocentre.

The Burt Range Sub-basin is bounded by the Pincombe Inlier and Ridge to the west and the Halls Creek-Fitzmaurice Mobile Zone to the east. Gunn (1988) refers to the Burt Range Sub-basin as a southern extension of the Keep Inlet Sub-basin. It contains approximately 4000 m of continental and shallow marine carbonates and clastics perhaps deposited on a major platform area.

Kimberley Basin, Victoria Basin and Pine Creek Geosyncline
Structurally the Bonaparte Basin is bounded on the east by the Victoria Basin and Pine Creek Geosyncline and to the southwest by the Kimberley Basin, all of Precambrian age.

4.3.2 Offshore Structure

Introduction
The acquisition and interpretation of over 40 000 km of multifold seismic data and the drilling of 28 petroleum wells have enabled the delineation of a relatively detailed structural and stratigraphic framework of the Northern Territory portion of the Bonaparte Basin.

Bocal Pty.Ltd, Australian Aquitaine Petroleum Ltd. (AAP), Arco Ltd., Tricentrol Ltd., and Western Minning Coporation (WMC) have each independently identified and regionally mapped various Mesozoic and Palaeozoic reflections within their respective licence areas across both the onshore and offshore portions of the Bonaparte Basin (Appendix 1). Most regional mapping was conducted initially at 1:250 000 or 1:100 000 scale. More recent seismic mapping at the prospect level has been presented at either 1:50 000 or 1:25 000 scales. Because of the independent nature of company exploration efforts, horizon identifications are not harmonious. In compiling the regional maps, presented as Enclosures 11 and 12, some use has had to be made of composite horizons. Where necessary, and by reference to the seismic data, changes have been made to the contour intervals, contour style and fault patterns so as to obtain an overall consistent structural style.

The Near Top Permian Time Structure Map (Enclosure 11a & 11b) has been compiled to illustrate Palaeozoic structuring within the Petrel Sub-basin. The Near Base Cretaceous Time Structure Map (Enclosures 12a & 12b) has been compiled to show the structural development attributed largely to Gondwana pull-apart tectonism. Although not included in the report, a number of additional horizons mapped by previous operators provide detailed structural information and are of value for more comprehensive acreage evaluation. In particular, Bocal, Arco and AAP undertook detailed mapping at several key Late Palaeozoic and Mesozoic levels (Appendix 1).

Because of the thick sediment pile within the Malita Graben none of the previous explorers has regionally mapped horizons deeper than the Near Top Permian across the main depocentre (Enclosure 9). Outside of the graben successively older stratigraphic horizons have been mapped but the truncation of section has led to a lack of continuity between those horizons mapped offshore and those mapped onshore. Regional mapping onshore has particularly suffered in the past from poor data quality (Laws, 1981).

Near Top Permian Time Structure Map (Enclosure 11a & 11b)
This horizon coincides with a prominent seismic reflection which has been tied to many wells and identified as the Pearce Member (limestone) of the Hyland Bay Formation. This regional event has been mapped extensively by Arco, AAP, Bocal, and Tricentrol.

This horizon is mapped in the Petrel Sub-basin north of latitude 14°30' (Enclosure 11b) and across the Malita Graben and Sahul Platform

(Enclosure 11a). In the east the horizon is erosionally truncated along the Moyle Platform and is absent across the Darwin Shelf, the truncation edge plunging to the north from a depth of approximately 0.1 to 1.0 seconds (two-way time).

Within the Northern Territory portion of the basin, the Near Top Permian horizon defines the northern flank of the northwest plunging Petrel Sub-basin. At its deepest, adjacent to the Curlew #1 well, the horizon lies at a seismic depth of 4.2 seconds.
At this horizon level there are few basin-forming faults identified. Palaeozoic structuring, responsible for the Sub-basin's formation,is blanketed by a thick Late Palaeozoic sediment cover. However, a number of conspicuous basement ridges, plunging to the northwest are evident, and these presumably represent drape over older, Palaeozoic basement highs. They include structural noses upon which the Petrel, Bougainville, and Turtle wells have been drilled.

Deep, tilted fault blocks are observed across a regional high located in the Turtle-Barnett area. This high is attributed by Gunn (1988) to axial doming formed during lithospheric heating and uplift, prior to rift breakup. According to this theory oceanic crust should be present beneath this and much of the Petrel Sub-basin. Gunn (1988) supported this model with regional gravity and magnetic interpretations identifying the doming as confined to the offshore portions of the Petrel Sub-basin extending from Barnett in the south and splitting into two zones further northwest.

However, no well has yet penetrated sufficiently deeply to encounter the postulated oceanic crust, and doming could also be due to salt tectonics. Edgerly & Crist (1974) previously interpreted this axial gravity high as an indication that salt migrated from the centre of the basin towards the margins. Salt thicknesses of over 3000 m are inferred from seismic sections and deep continuous reflectors observed on sections across Barnett (Figure 36) suggest salt is present locally and its involvement in producing the doming cannot be discounted. Although not necessarily a true indication of original thickness, it does show that considerable quantities of evaporites were deposited within the rift setting.

Numerous salt related structures have been mapped within the Petrel Sub-basin (Crist & Hobday, 1973; Edgerley & Crist, 1974; Gunn & Ly, 1989). Locally these are associated with fault dependent and independent closures. As indicated in Section 4.2.2, salt occurs in a number of Palaeozoic basins in northwestern Western Australia with occurrences in the Bonaparte Basin being confined mainly to the Petrel Sub-basin and adjacent onshore areas (Pelican Island and Kulshill area). Seismic coverage indicates that in the sub-surface the salt takes several structural forms, with examples of simple pillow and piercement being observed within the Petrel Sub-basin.

Gunn & Ly (1989) suggest that the results of isopach studies are consistent with the Tern anticline having been created as a result of salt withdrawal towards the Sandpiper diapir to the west and a diapir towards Tern #3; that is, the anticline is a turtle-back structure. Similarly, the Petrel anticline shows anomalous isopach variations (Enclosure 10) suggesting it too may be salt related. Piercement structures, where vertical salt movement has pierced the overlying sedimentary strata (Warren, 1989)

occur at several locations including Bougainville #1 and Kinmore #1. These structures tend to be extensively faulted in the crestal areas. Peripheral synclines formed by the lateral withdrawal of salt, accompanying its vertical movement, are evident around some structures (eg. Curlew). Salt movement appears to have been protracted with some diapirs showing Late Permian movements, others moving vertically until the Early Tertiary.

Within the eastern Petrel Sub-basin most faulting at the Near Top Permian level is confined to the flank of the Moyle Platform where west-northwest normal faults provide small displacements (less than 50 msec) along an otherwise structurally undeformed depositional hingeline (Enclosure 11b). Towards the onshore areas these faults, which trend oblique to depositional strike, become laterally more coherent and probably merge with the onshore Moyle fault system.

By contrast, this horizon as mapped across the northern portions of the Bonaparte Basin (Enclosure 11a) is dominated by fault related structuring. Comparison of the structure at this level with that of the overlying Near Base Cretaceous Map (Enclosure 12 a & b) indicates that much of this faulting post-dates the Permian, and is of Mesozoic and Cainozoic age.

The Malita Graben is flanked by sinuous normal fault trends formed by the intersection of north-east and east-northeast fault sets. Displacements across these bounding faults often exceed 500 msec. Within the graben the Near Top Permian horizon plunges to the southwest and lies at its maximum depth of 6.0 seconds adjacent to the Western Australian state border. Most closures mapped at the regional scale within the Malita Graben are associated with the up-dip faulted outer edge of the Heron Terrace which, at least locally, appears to be associated with salt diapiric structuring (Figure 20; Enclosures 9 & 10).

On the Sahul Platform the Near Top Permian horizon lies at depths of between 2.0 and 3.4 seconds (TWT). Across the crestal area of the platform faulting is less intense and several northwest trending anticlinal axes, interpreted to reflect deeper Palaeozoic structural trends, are identified (Enclosure 3). These are important prospective trends as the Kelp, Flamingo, Sunrise and Troubadour structures coincide with them. Most local closures are, however, located on the intensely faulted northern flank, adjacent to the Timor Trough. These faults trend east-northeast with a sub-ordinate north-east intersecting trend resulting in highs across converging fault blocks. No salt related structures are observed across the Sahul Platform.

Near Base Cretaceous Time Structure Map (Enclosure 12)
This coincides with a prominent seismic reflection, which, when tied to several well locations, is correlated with a low stand in the Early Cretaceous, and is regionally coincident with a limestone marker around the Albian/Aptian level. In the southern areas it coincides with the Valanginian Unconformity. Considerable erosion at this time is noted across wide areas including those outside of the basin, such as the Arafura Basin (NTGS, 1989). The associated eustatic event has been attributed previously to changes in ocean basin geometry, caused by changes in the rate of seafloor spreading (MacDaniel, 1988).

The Near Base Cretaceous Time Structure Map represents a compilation of early Arco, AAP, Tricentrol and Bocal mapping, and more recent Magnet Petroleum Pty.Ltd. and WMC mapping. As shown on Enclosure 12b (South Sheet) within the Petrel Sub-basin, there is little structural complexity at this level. The horizon is identified north of 14° S latitude. Faulting is confined to a small number of local features as the surface dips relatively uniformly to the northwest, plunging from about 200 mseconds to 2.0 seconds (TWT) in the deepest portion of the Sub-basin. The horizon is draped over prominent structural noses, also evident at the deeper Near Top Permian level and associated with the Petrel, Bougainville and Turtle structures. Differential subsidence of the unconformity surface by up to 600 mseconds (TWT) within the main depocentre of the Petrel Sub-basin indicates the degree of post-Valanginian subsidence in this area. It appears to have been facilitated by sagging, maximum sag being evident around the northeastern margin adjacent to the offshore Darwin Shelf. Local faulting is associated with salt diapirs at this level.

By contrast there is considerable structural complexity at the Near Base Cretaceous level within the Malita Graben (Enclosure 12a). At its deepest level this horizon lies at approximately 3.0 seconds (two-way time). The Malita Graben is fault bound, the faulted boundaries being defined by either parallel or single northeast to east-northeast fault trends. The margins of the graben adjacent to the Sahul Platform and the Darwin Shelf are formed by multiple down-to-graben fault escarpments with intervening perched basement blocks. Many of the faults extend up to a Middle Miocene Unconformity or to the surface, and several have bathymetric expression (Enclosures 9 and 10). To the northeast the graben deepens towards the Calder Graben where faulting is less conspicuous, presumably blanketed by a thick post-breakup sediment pile.

Across the flanks of the Darwin Shelf the horizon dips montonically basinward, disrupted by minor faulting along the outer margin boundary within the Malita Graben. The fault trend is somewhat arcuate in shape, and possibly defines the contact edge of granites within the basement.

Across the Sahul Platform the Aptian/Albian Unconformity shallows to approximately 1600 msec (TWT) in the vicinity of NT/P 11. The map shows that whereas faulting along the boundary with the Malita Graben is confined to a relatively narrow zone, and involves displacements across faults which can be laterally correlated for some tens to hundreds of kilometres, the northern boundary with the Timor Trough is extensively faulted, with a series of discontinuous down-to-the trough and out-of-the-trough normal faults. Many of these faults show evidence of recent movement, some with reversed movements (Enclosure 9) indicating rejuvenation during a compressional regime.

Onshore Structure

Extensive outcrop, particularly in the Western Australian portion of the onshore Bonaparte Basin, has enabled the structural history of this part of the basin to be resolved, notwithstanding the paucity of good quality seismic data. Both normal and transcurrent faulting have been dominant influences on structure within the onshore portions of the basin. Compaction and drape over palaeohighs also have been locally important.

The onshore structure of the Bonaparte Basin is conspicuously oblique to that of the adjacent Palaeozoic Petrel Sub-basin. The Burt Range and Keep Inlet Sub-basins lie at an angle of about 110 ° to the Petrel Sub-basin, an angle typical of a triple arm aulacogen or failed arm of a rift system (Blake, 1984), although this may be coincidence.

The Keep Inlet and Burt Range Sub-basins are bounded to the east by the Cockatoo Fault, which is mapped on the surface as a number of discrete en-echelon, synthetic, strike-slip faults, with individual fault planes trending north-south (Enclosure 3). This pattern of faulting is attributed to major left-lateral wrenching along the Halls Creek-Fitzmaurice Mobile Zone (Laws, 1981; Blake, 1984). The Pincombe Ridge parallels the Cockatoo Fault trend and is intersected by east-southeast antithetic strike-slip faults, especially in the area between the Keep River #1 and Spirit Hill #1 wells (Laws, 1981). Further to the west, across the Carlton Sub-basin, north-south faults intersect outcrops of the Ningbing limestone and several northeast trending anticlinal axes, plunging into the basin, are also mapped. Much of the faulting is interpreted by Laws (1981) to be syn-depositional with many of the faults apparently terminating near the unconformity at the top of the Weaber Group.

In addition to en-echelon faulting, lateral movements appear to have induced folding, anticlinal structures being located adjacent to the major basin-forming faults. Folds associated with the north-northeasterly trending left-lateral wrench faults normally would trend northeast (Harding, 1974). The most conspicuous of these is the Spirit Hill Anticline, located on the eastern flank of the Burt Range Sub-basin (Figure 8). The axis of this fold is doubly-plunging so that several closed structures are delineated along trend (eg. Blake, 1984, his Enclosure 6).

Laws (1981) and Blake (1984) attribute major left-lateral wrenching along the Halls Creek-Fitzmaurice Fracture Zone as the causative force of this folding. Consequently, northeast trending folds and north-northeast trending faults are anticipated to extend beneath the Keep Inlet Sub-basin. In the Queens Channel region and south of Kulshill #1, a complex structural pattern probably occurs in the sub-surface, as this area coincides with the intersection of the dominant north-east Cockatoo fault trends and the dominant north-west Petrel Sub-basin trends. Here structures are most likely dominantly fault bounded blocks and fault related folds locally intruded by salt. Only a few onshore occurrences of salt are known, and that indirectly from seismic data, as at Kulshill #2.

5. BASIN HISTORY

Deposition in the proto-Bonaparte Basin was probably established in an intracratonic depression following lithospheric sag after the extrusion of the Antrim Plateau Volcanics in the Early Cambrian (Enclosure 4). Veevers et al. (1984) speculated that the Antrim Plateau Volcanics were extruded during a period of plate divergence, from about 575 to 519 Ma. These volcanics are the first indication of tensional disruption in this portion of the craton during the Early Palaeozoic. Plate divergence may have occurred in a pre-Tethyian Sea located to the north of the Indian-Australian portion of Gondwana.

The Antrim Plateau Volcanics are distributed over a wide area, from the margins of the Ord, Daly, Georgina and Wiso Basins in central Australia (Figure 1), to the Arafura Basin, South New Guinea Basin and onshore Irian Jaya in the north. Up to 1000 metres of these volcanics were emplaced in the Arafura Basin (NTGS, 1989). The extrusion of such large volumes of magma presumably initiated not only the Bonaparte Basin but also the Arafura Basin to the northeast.

Although now only preserved in outcrop along the southwestern edge of the Bonaparte Basin, initial sedimentation occurred during the Ordian transgression across an area probably much larger than that currently regarded as the Bonaparte Basin (Mory, 1988). Deposition during this Middle Cambrian marine transgression commenced with shallow to marginal marine siliciclastic and carbonate sediments of the Carlton Group. The Tarrara Formation was deposited in intertidal to shallow marine environments whereas progressive deepening and transgression resulted in the youngest unit, the Pander Greensand, being deposited in moderately deep marine waters during the Late Cambrian and Early Ordovician (Mory & Beere, 1988).

The stable platform and basinal development established during the Cambrian was interrupted during the later Ordovician. Between Early Ordovician and Late Devonian time there is a large gap in the depositional record (150 million years) as reflected by the onshore Bonaparte Basin sequences. The absence of sediments may be due to possible arching, sea withdrawal, and exposure during the Middle to Late Ordovician, a time when such events were occurring in the Arafura Basin (NTGS, 1989).

There is equivocal evidence in northern Australia of uplift at this time. For example, deposition in the Canning Basin (Carribuddy Group) was apparently in places continuous into the Silurian, but, in the Amadeus Basin tectonism during the Late Ordovician to Early Silurian is referred to as the Rodingan Movement (Wells et al., 1970). Notwithstanding the lack of definitive evidence for tectonism in the Bonaparte Basin, uplifted crustal blocks must have provided barriers blocking and/or restricting seaways through the proto-Bonaparte Basin from open marine environments to the north. In this setting, the offshore portions of the basin may have become centres of restricted circulation and arid conditions.

As indicated in Section 4.3.2, numerous salt related structures occur within the Petrel Sub-basin. Although the precise age and extent of the salt in the Bonaparte Basin are unknown at present, the effects of salt tectonics is observed under numerous structures including Kinmore and Bougainville.

Generally, it has been assumed that the salt is confined to the Petrel Sub-basin, a distribution which Gunn (1988) explained as the result of salt formation in evaporitive conditions which followed the emplacement of oceanic seafloor within the Petrel Sub-basin during "upper" Milligans (Early Carboniferous) time.

However, Paqualin #1 well, located in the Vulcan Graben to the southwest, was a test of a salt flow structure (PEX, 28 February 1989) and seismic data indicate the presence of other

diapiric structures within this graben. The occurrence of these salt structures indicates that evaporitic conditions were not confined to the Petrel Sub-basin. Indeed, regional seismic profiles across the Malita Graben suggest salt flowage beneath the Heron structure and to the southwest (Figure 20 & Enclosure 9). Thus, the Vulcan, Petrel, Malita and Calder depocentres may have been partially connected, shallow depressions, precursors to a series of aulacogens which developed during the subsequent Tethyian rift phase. These depressions are interpreted as the sites of restricted marine circulation and evaporitic deposition during the Silurian and possibly Early Devonian. This view is consistent with that of Veevers (1976), who considered that the initiation of both the Canning and Bonaparte Basins was related to the failed arms of the fracture system which gave rise to the Tethys Ocean. The age of the Bonaparte Basin evaporitic sequence is inferred to be Silurian to Early Devonian by Mory (1988) on the basis of stratigraphic comparisons with the evaporitic Carribuddy Formation of the Canning Basin.

Extensive sedimentation in the Bonaparte Basin recommenced in the Late Devonian (Frasnian) (Figure 4). This deposition was accompanied by structural activity involving tensional movements initially dominated by incipient northwest trending down-faulting and sag. As the outer structural barriers foundered, a series of transgressions occurred, the first involving initial deposition onto a marked regional unconformity. Onshore structural movements, associated with wrenching along the Halls Creek-Fitzmaurice Mobile Zone induced folding and uplift including the Pincombe Ridge, which developed at this time as a high separating the Carlton Sub-basin from the Keep Inlet and Burt Range Sub-basins. Wrenching along this mobile zone resulted in synthetic faulting along the Cockatoo Fault Zone (Laws, 1981) and led to the deposition of conglomerates and other coarse clastics in alluvial fans and deltaic sequences along the eastern margin of the onshore basin.

Three transgressive-regressive depositional cycles dominated the Late Devonian to Early Carboniferous interval; the Cockatoo, Ningbing and Langfield Groups. Each was characterised onshore by initial deposition of coarse clastics (Figure 4) shed from active fault escarpments bounding the adjacent southern and western basin margins. The Cockatoo Group exceeds a thickness of 2700 m. Basinward, these clastics merged with marginal marine sediments, basinal shales, and carbonates, which around emergent structures, such as the Pincombe Ridge, formed reef complexes. In the distal regions of the offshore basin up to 3000 m of shallow marine shales and thin sandstones, correlatives of the onshore clastic cycles, were deposited. Reef growth was terminated following uplift and the onset of increased sediment supply of the Tournaisian Langfield Group. Devonian and Early Carboniferous sediments thinned, onlapped, and were draped across the Pincombe Ridge (Laws, 1981).

The onset of sedimentation in the Bonaparte Basin in the Late Devonian approximately coincides with the onset of renewed sedimentation in the Arafura Graben to the north (NTGS, 1989) and widespread tensional tectonism. By the Late Tournaisian to early Visean, down-faulting and subsidence significantly increased giving rise to the rapid sedimentation of the Milligans Formation of the Weaber Group in the newly established Petrel Sub-basin. Onshore, these structural movements resulted in the Weaber Group unconformably overlying the Langfield Group. These structural movements also coincide with an extended period of non-deposition and erosion in the Arafura Basin to the north.

Offshore, thick sequences of marine sediments comprising the "lower" Milligans Formation were deposited as the Petrel Sub-basin quickly subsided, with rapid thickening of this unit from the margin into the Petrel Sub-basin. This subsidence was penecontemporaneous with large scale, down-to-graben normal faulting which also occurred in the Arafura Graben (NTGS, 1989) and may have represented the progressive development southward of a rift arm, or aulacogen complex, associated with Tethyian rifting to the north of the Australian craton. If so, the Petrel Sub-basin may have been a failed arm of a triple junction whose other

arms paralleled the present coastline, presumably coincident with zones of earlier Early Palaeozoic sag, and attendent evaporite development. They are now blanketed by thick Mesozoic sediments within the Malita Graben, Calder Graben and Vulcan Sub-basin.

Rapid subsidence and deposition of the Weaber Group was abruptly interrupted during the Visean by uplift and erosion in the Petrel Sub-basin. This break coincides with the boundary between the "upper" and "lower" Milligans Formations (Section 4.2.5). Mid-rift doming initiated erosion which scoured the "lower" Milligans Formation (Lee & Gunn, 1988) and in part provided the sediment source for the "upper" Milligans Formation. As shown in Figure 4, the Waggon Creek Formation represents deposition of a coarse grained clastic sequence in an otherwise fine grained dominated marine environment. The Waggon Creek is interpreted as the sedimentary result of this Visean event.

Gunn (1988) interpreted the Late Devonian to Early Carboniferous sediments of the Cockatoo, Ningbing and Langfield Groups as pre-rift sediments deposited in a sag basin caused by lithospheric stretching and associated crustal thinning along the axis of the basin. Continued crustal thinning caused a collapse of the basin floor resulting in the rift morphology and subsequent syn-rift "lower" Milligans Formation deposition. Subsequently, a medial axial dyke of oceanic crust was injected into the crust, arching the syn-rift and pre-rift blocks, effectively forming two separate depocentres of "upper" Milligans Formation located towards either flank of the developing Petrel Sub-basin.

The rate of sedimentation and subsidence decreased towards the end of the Visean, and shallow marine carbonates of the Tanmurra Formation and its partial equivalent the fluvio-deltaic Point Spring Sandstone were deposited in the southern area. Offshore clastics, perhaps including turbidites, were deposited in the south. In the Kulshill area these later Visean sediments attained thicknesses in excess of 800m. The termination of Tanmurra deposition coincided with a marked regression and climatic cooling with the onset of glaciation during the Namurian (Enclosure 4).

Widespread erosion and non-deposition, attributed in part to the effects of glaciation, continued during the Westphalian. This coincides with the stratigraphic position of an interpreted Type 1 sequence boundary in the Arafura Basin, where the Torres Anticline was formed (NTGS, 1989). Movements at this time coincide with marked compression in central and eastern Australia (Alice Springs Orogeny), and Central Europe and Spain (Variscan Orogeny), movements which Peck & Soulhoul (1986) attribute to the closing of the Tethyian Sea. More locally these movements had the effect of isolating the Bonaparte Basin from major marine influences during the Late Carboniferous.

Late Carboniferous to Early Permian deposition consisted predominantly of clastics of the Kulshill Group. The lower unit, the Kuriyippi Formation, exhibits a strong glacial influence, whereas the overlying Treachery Shale contains lacustrine to estuarine deposits onshore, formed following the retreat of the ice sheet to the adjacent hinterland (Mory, 1988). Changes in sediment provenance and structural movements produced a disconformity with the underlying Kuriyippi Formation. Offshore, marine to deltaic siliciclastic sequences of the Treachery Shale preceded the deposition of an upper unit, the Keyling Formation, comprising marginal marine sands and shales, with minor limestones and coals.

Reported thicknesses of over 7000 m of Kulshill Group sediments (Lee & Gunn 1988) imply a new phase of rapid basin subsidence and perhaps renewed rifting. However, Mory (1988) notes that this reported thickness may include Weaber Group sediments. In the Arafura Basin the Kuriyippi Formation is a thick sequence deposited during active down-faulting, which occurred at about the same time as the Kulka dolerite was intruded (NTGS, 1989), suggesting that a period of tensional tectonism may have occurred during the latest Carboniferous. Bradshaw et al. (1988) envisage this tectonism as the inception of the outer

northeast-southwest Westralian Superbasin, a connection of basins parallelling the present northwest coastline of Australia. However, based on the evidence in the Arafura Basin, where faulting was distinctly northwest oriented and involved the pre-existing Devonian faults, northeast trending down-faulting must be considered highly speculative at this time.

A rise in sea level in the late Early Permian resulted in estuarine to marine deposition with a possible conformable superposition of predominantly siltstones and sandstones of the Fossil Head Formation. A series of abrupt transgressive-regressive cycles during the Late Permian may have been responsible for the upper part of the Fossil Head Formation being eroded in the southern portion of the Petrel Sub-basin, but generally the Hyland Bay Formation overlies it conformably within the basin proper. Subsequent to the transgression of the near basal Pearce Member of the Hyland Bay Formation, the Tartarian regressive episode resulted in the deposition of a thick northwest prograding deltaic clastic unit, the Cape Hay Member. With the waning of clastic input the Dombey Member carbonates were deposited. The overlying Tern Member sandstones marked the regressive phase at the end of the upper Hyland Bay Formation time. Environments were predominantly marine and the region was experiencing sub-tropical climatic conditions, with a broad carbonate shelf environment developed along the northern margin of the continental block (MacDaniel, 1988).

The Latest Permian to Middle Jurassic was a period marked by the change from older northwest trending Palaeozoic structuring to the dominant northeast Mesozoic structuring associated with the rifting of Gondwana. MacDaniel (1988) envisaged initially broad regional sags which became major depocentres in the Late Triassic. As rifting progressed, true rift basins developed with down-faulting along northeast trends. Being nearly orthogonal to the Palaeozoic trends Mesozoic structuring did not necessarily reactivate the older northwest trends, which penetrated the craton in the Petrel Sub-basin, Arafura Basin and Fitzroy Graben (Canning Basin).

Basin subsidence associated with this tectonism resulted in transgression during the Early Triassic, and deposition of the shale sequences of the Mt Goodwin Formation unconformably upon the Hyland Bay Formation (Section 4.2.8). The Mt Goodwin Formation is coeval with shale prone units in the Canning Basin (Blina Shale), Carnarvon Basin (Locker Shale) and the Perth Basin (Kockatea Shale).

Marine conditions continued to dominate during the Middle Triassic with deposition of the Cape Londonderry Formation within the Malita Graben and Petrel Sub-basin, and shallow marine, carbonate dominated conditions across the Sahul Platform, as evidenced by the carbonates penetrated in Troubadour #1 (Section 4.2.9). In the later part of the Triassic, regressive siliciclastics were deposited over the Petrel Sub-basin and Sahul Platform. Regression culiminated with red bed deposition of the Malita Formation in the Late Triassic to Early Jurassic in an arid continental environment. Subsequent transgression in the Middle Jurassic resulted in the deposition of thick fluvial to deltaic sediments of the Plover Formation, including the important reservoir sands on the Sahul Platform.

The deposition of thick sequences during this time probably initiated and reactivated salt movement. In the western part of the Petrel Sub-basin over the Tern Structure, for example, salt movement was probably responsible for erosion and non-deposition of the Malita Formation.

During the Late Jurassic the region tilted to the northwest and the Malita Graben subsided with local uplift and erosion along fault blocks, such as the Late Bathonian movements in the vicinity of Troubadour #1. The Flamingo Group represents a prominent Late Jurassic marine transgression during which the Frigate Shale was deposited throughout the main troughs of the Bonaparte Basin. The upper part of the Flamingo Group, the Sandpiper Sandstone,

represents a fluvial to deltaic siliciclastic cycle which covers a much greater area of the Petrel Sub-basin, transgressing the basin margins not covered by the Frigate Shale. Turbidites may be present in the southern Malita Graben at this time. The regional Valanginian Unconformity resulted in considerable erosion across structural highs of the Bonaparte Basin.

The onset of more rapid basin subsidence following the Valanginian event resulted in the submergence of the Sahul Platform, and enhancement of the Malita and Vulcan Grabens as important depocentres. Continued tilting to the west resulted in a regional marine transgression with the deposition of the Bathurst Island Group across the Darwin Shelf to the east, and Arafura Platform to the north.

Rapid eustatic fluctuations resulted in poor preservation of the post-Valanginian to Aptian marine sequences. In the late Albian the Brown Gannet carbonates were deposited and buried beneath a younger thick sequence of siltstones, mudstones, and shales of the Wangarlu Formation. Sediments became progressively more open marine towards the Turonian sea level maximum, prior to a series of sea level falls during the Late Cretaceous. Falls in sea level resulted in strandline sequences of the Late Maastrichtian Puffin Formation being deposited around the basin margins and shoreline sandstones of Cenomanian age on the eastern side of the Petrel Sub-basin, indicate the emergence of the Darwin Shelf at this time. On the Sahul Platform deposition was more distal, finer grained and included marls.

The open shelf marine conditions in the Malita Graben and shallower shelf conditions in the Petrel Sub-basin continued throughout the Cainozoic, with the onshore areas the site of non-deposition and erosion. The Early Tertiary section is sandy and grades upwards into shelfal carbonate development with a hiatus occurring in the Oligocene. Structuring involving reactivated down-faulting across the flanks of the Sahul Platform and tilting of the Malita Graben westwards appears to have continued during the Tertiary, some faults having present day bathymetric expression. Bathymetric deeps adjacent to fault escarpments of the Heron Terrace suggest that sedimentation has not kept pace with recent down-faulting.

Reactivation of some faults in the middle Miocene, at about 15 Ma may reflect the collision of the outer Australian continental margin with the Southeast Asian plate. This convergence resulted in a large sinistral shear which progressively resulted in the formation of a large drag fold culminating with the Inner Banda Arc system converging with Timor at about 5 Ma. Except for perhaps some minor reverse faulting, structuring on the Sahul Platform does not appear to be characterized by compressional tectonics, although more detailed mapping may prove otherwise. Compression and/or continued sediment loading has also reactivated several salt structures during the Cainozoic, faulting and continued local uplift being locally observed across some diapiric structures.

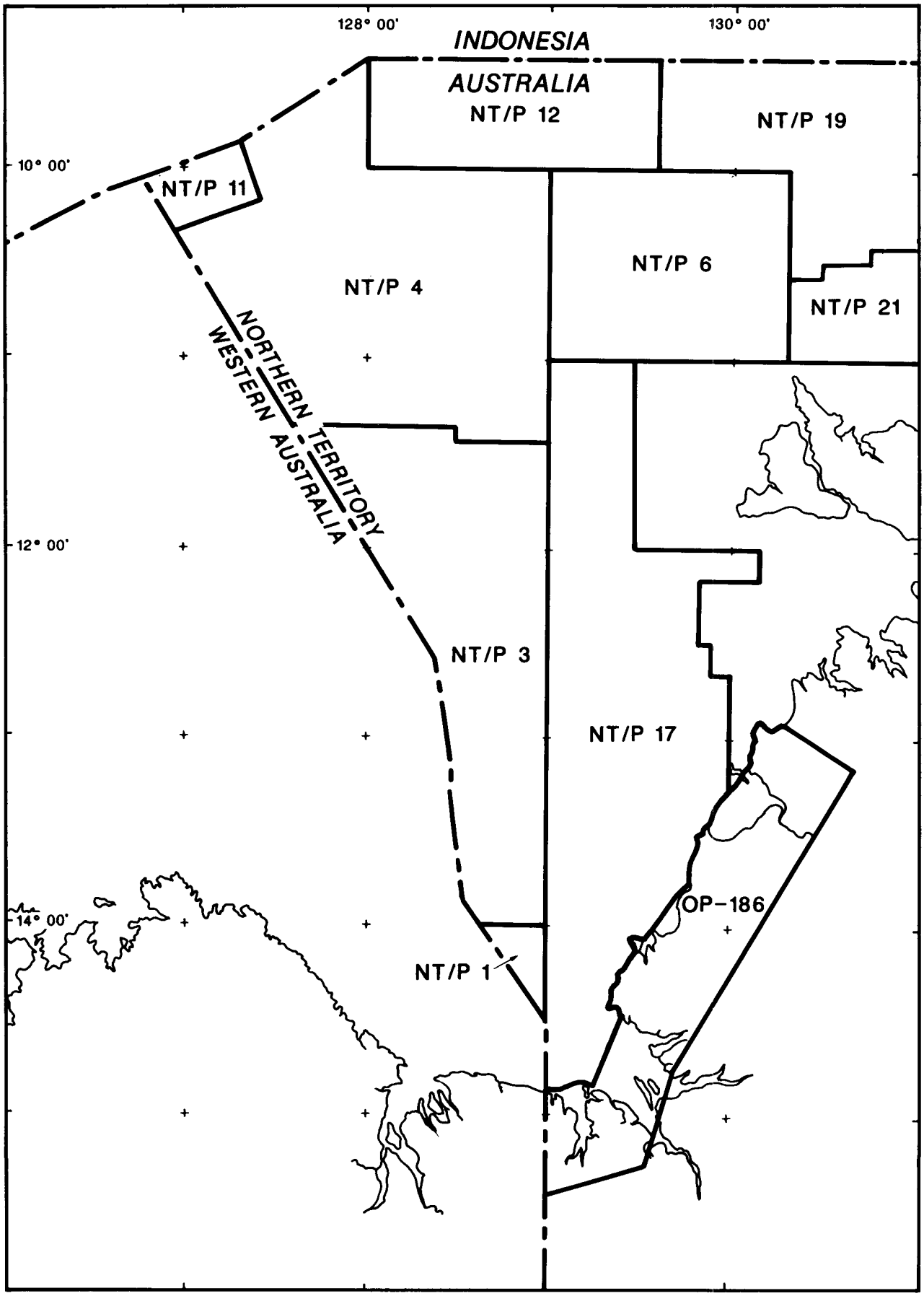


FIGURE 7 Previous Permit Boundaries Circa 1970

0 60
kilometres
1:3,000,000

6. PREVIOUS EXPLORATION HISTORY

6.1 SUMMARY

In 1839 during Commander Stokes' exploration of the coasts and rivers of Northern Australia, the crew of HMS Beagle found bitumen in a well dug for water at Holdfast Reach in the Victoria River estuary. By the turn of the 20th century several coal bores had been drilled along the coast of the Joseph Bonaparte Gulf between Port Keats and Cliff Head. The deepest, Port Keats #4 and Anson Bay #2, reached approximately 460 m (1500 ft) terminating in the Permian (Fossil Head Formation). Cliff Head #1 penetrated granite basement at 211 m (728 ft). Prior to 1963 the only oil well drilled in the basin was Spirit Hill #1, located in the north-eastern Burt Range Sub-basin. The first deep exploration well drilled in the basin was Bonaparte #1, drilled in 1963 by Alliance Oil Development (AOD) to a depth of 3210 m (10 530 ft).

The first systematic reconnaissance geological studies in the Ord Basin (Figure 1) and southern onshore Bonaparte Basin regions were conducted for the Western Australian Geological Survey during 1948 (Matheson & Teichert, 1948). Shortly thereafter, between 1949 and 1955, geological mapping was conducted in the Northern Territory portion of the onshore Bonaparte Basin by D.M. Traves on behalf of the Bureau of Mineral Resources (BMR) and Commonwealth Scientific & Industrial Research Organisation (CSIRO) (Traves, 1955). Two field parties sent by the BMR and Australian Aquitaine Petroleum (AAP) revised and extended the stratigraphy and tectonics. The results of these field studies were published during the late 1960s and early 1970s as a series of 1:250 000 geological map sheets covering the onshore Bonaparte Basin (eg Roberts & Veevers, 1973). More recently, Laws & Brown (1976) and Laws (1981) have published summaries of the petroleum geology of the onshore Bonaparte Basin utilising the results of petroleum wells drilled within the region.

Because of the relatively independent nature of petroleum and mineral exploration activities in the Bonaparte Basin, only recently has a reworked and standardised stratigraphic nomenclature been published (Mory, 1988; Mory & Beere, 1988). This stratigraphy includes many of the informal names given by petroleum companies and has enabled a more comprehensive and consistent analysis of those previous studies (Section 4).

The first reconnaissance geophysical studies involved gravity and aeromagnetic surveys (Appendices 2 & 3). During the period 1956 to 1967 the BMR, combined with various permit holders, covered the entire onshore and offshore Bonaparte Basin with a reconnaissance gravity network. The most extensive surveys were the 1965 and 1967 marine surveys (Jones, 1969) and the 1967 reconnaissance helicopter survey extending from Arnhem Land to the Kimberleys (Whitworth, 1969).

Free-air and Bouguer gravity maps were published by the BMR at a scale of 1:250 000 for the offshore areas and 1:253 440 for the onshore areas. The latest published BMR regional map incorporating the earlier results with later surveys is the 1976 1:5 000 000 scale Gravity Map of Australia.

During the 1960s subsidised aeromagnetic surveys were conducted by Arco in the offshore Northern Territory portion of the Bonaparte Basin. A summary of these surveys together with other petroleum company surveys conducted in the offshore Western Australian portion of the basin is given by Jones (1969). A depth to basement map at a scale of 1:506 880, covering both onshore and offshore parts of the Bonaparte Basin, was published by the BMR in 1966.

The gravity and magnetic surveys confirmed that a deep northwesterly plunging sedimentary basin continued offshore surrounded by relatively shallow basement of the Darwin Shelf. Structural elements such as the Sahul Platform, Ashmore Platform and Londonderry Arch were also defined at this time. As a result of these studies virtually all of the Bonaparte Basin acreage was covered by petroleum exploration leases by 1970 (Figure 7).

The first seismic survey in the basin was an experimental survey conducted by the BMR in the Carlton Sub-basin and Keep Inlet Sub-basin regions in 1956. The first use of the seismic method in the Bonaparte Basin for petroleum exploration began in 1960 with a reflection survey of over 100 km length conducted by Austral Geoprospectors for Westralian Oil Company near Spirit Hill (Enclosure 2b; Appendix 1). This was closely followed in 1961 by the first marine seismic survey of 297.7 km conducted for Associated Australian Oilfields (AAO) in the Port Keats region (Annotated as Lines 1 to 7 on Enclosure 2b). A further 80 km of reflection and 77 km of refraction seismic were recorded for AAO in the Port Keats area in 1962 (Keep River Seismic Survey) and Compagnie Générale de Géophysique (CGG) acquired 118 km of reflection and 60 km of refraction seismic for AAP in 1963 (Pearce Point Survey). During 1964 the Kulshill Seismic and Gravity Survey defined the Kulshill structure. In 1965 when Kulshill #1 was drilled, it was then the deepest well in the basin.

The good gas flow from Bonaparte #2 and encouraging shows of oil in Kulshill #1 resulted in a number of seismic surveys being recorded between 1965 and 1969 and in the subsequent drilling of several wells, including Kulshill #2, Moyle #1 and Keep River #1, in the onshore Northern Territory portion of the basin.

After 1973 interest began to wane in onshore exploration, a factor Laws (1981) partially attributes to disillusionment at the consistently poor seismic data quality recorded in the area. Renewed interest in this area followed the discovery of biodegraded oil in vuggy porosity in mineral bore holes drilled into the Ningbing Reef complex. Seismic exploration recommenced in 1980 and continued until 1984, resulting in the drilling of another well, Weaber #1 (1982). The most recent phase of exploration in the region began in 1987 with Santos conducting a number of surveys using state of the art seismic field and processing techniques including 60% CDP coverage (GES, 1988). This has improved the quality of the recorded data quite dramatically although the data quality is still far inferior to that acquired offshore (e.g. Figure 27). Weaber #2 and 2A were drilled on the basis of these results.

The first marine seismic survey was the 1961 survey by Associated Australian Oilfields Ltd. (AAO) along the east coast of Joseph Bonaparte Gulf, Port Keats and Keep Inlet areas. In 1964 AAP conducted two marine surveys in the northern and southern parts of the east coast region of the Gulf near Flat Top and Queens Channel. Results of these surveys were good enough to show that between 2000 and 3000 m of sediments existed in a basin thickening to the northwest.

In 1965 the BMR conducted an extensive sparker and gravity survey totalling nearly 6000 km of east-west oriented lines, 16 km apart, and covering an area east of 127° longitude and south of 12° latitude (Jones, 1967). This survey confirmed the presence of a thick Phanerozoic sedimentary sequence beneath the Joseph Bonaparte Gulf. Diapiric structures were noted within the sedimentary section.

Following the delineation of the offshore extent of the basin, petroleum company interest increased with the Arco and AAP consortium undertaking numerous marine surveys. Initially seismic was acquired using either sparker or dynamite sources recorded with mainly three or six fold coverage on short, 24 channel, streamers. The

presence of water bottom reverberations, short period multiples, and lack of multiplicity of recording often restricted penetration to within the shallower Mesozoic section. These data still provide the main source of regional reconnaissance lines across much of the basin (Enclosures 2a & 2b). Reprocessing of these data using modern techniques has dramatically improved data quality.

During the decade spanning the 1970s the introduction of longer cables, more channels and higher fold coverage (24 and 48 fold), and the replacement of dynamite and sparker source with airgun arrays, led to significant improvements in data quality. During this period several detailed prospect surveys were acquired in the southern offshore area, resulting in wells being drilled at Flat Top, Petrel, Bougainville and Kinmore. Since 1980 the recording techniques have been refined with marine surveys commonly recording 48 fold data on 96 or more channels. Tricentrol recorded an extensive programme in NT/P27 (Lines annotated T81, T83 and T84 on Enclosure 2a) resulting in the drilling of two wells, Jacaranda and Darwinia.

In contrast, seismic acquisition across the northwestern offshore Bonaparte Basin was subdued during this period in part because of the undefined international boundary. Seismic coverage across much of the Sahul Platform is still of a reconnaissance or semi-reconnaissance nature, the data being mainly late 1960s and early 1970s vintages (Enclosure 2a).

The most recent offshore exploration well is Evans Shoal #1 drilled by Western Mining Corporation (WMC). Drilled in 1988 on a location within the northern portion of the central Malita Graben, it recovered gas on a wireline test. It was one of several prospects mapped following the Maria and Gloria Seismic Surveys (Annotated 85MA and 86G on Enclosure 2a). Recently, attention has turned again to the southeast portion of the Petrel Sub-basin, following significant oil discoveries at Turtle #2 and Barnett #2, where detailed seismic grids have been recorded (Enclosure 2b).

A listing of all seismic surveys is included as Appendix 1.

TABLE 1

EXPLORATION AND APPRAISAL DRILLING NORTHERN TERRITORY BONAPARTE BASIN

The most active explorers in the Bonaparte Basin to date, have been Australian Aquitaine Petroleum (A.A.P.) and Arco. Following is a chronological list of wells drilled to date in this study area.

WELL NAME	YEAR	OPERATOR	WD (M)	TD (M)	OBJECTIVE	STRUCTURAL OBJECTIVE	RESULTS
Spirit Hill 1	1959	WEST.OIL	-	915.0	Burt Range Fm	Anticline	Tr. residual oil in Milligans, Burt Range and Buttons Fms not in Stratigraphy
Kulshill 1	1965-1966	A.A.P.	-	4394.0	Kulshill Gp Milligans Fm	Salt Diapir	Tr. of oil in Kulshill Gp
Kulshill 2	1966	A.A.P.	-	1961.0	Kulshill Gp Milligans Fm	Salt Diapir	Tr. of oil and gas in Kulshill Gp
Moyle 1	1966	A.A.P.	-	539.0	Permian & Carboniferous	Basin Margin Fault Block	No shows
Keep River 1	1968-1969	A.A.P.	-	4762.0	Burt Range Fm and Ningbing Lst	Reef	D.S.T. 4 (Lower Milligans Fm) 3400 m^3/D gas which declined rapidly
Newby 1	1969	A.A.P.	74.7	1148.0	Mesozoic	Stratigraphic Pinchout	No shows
Petrel 1	1969	ARCO	99.9	3980.0	Permian	Drape Anticline	Gas Blowout from Upper Fossil Head Fm
Flat Top 1	1970	A.A.P	41.1	2173.0	Mesozoic & Permian	Stratigraphic Pinchout	No shows
Petrel 1A	1970	ARCO	100.0	4089.0	Petrel 1 Relief Well	Drape Anticline	No tests
Petrel 2	1970-1971	ARCO	97.0	4725.0	Hyland Bay and Fossil Head Fm	Drape Anticline	D.S.T. 2 (Cape Hay Mbr) 186 000- 411 000 m^3/D gas on a 1.27cm choke
Flamingo 1	1971	ARCO	96	3700.0	Jurassic Antilcine	Faulted	Tr. gas Sandpiper Sst
Heron 1	1971	ARCO	38	4208.0	Mesozoic	Rift Related Half Graben	Tr. gas in Plover Fm and Bathurst Island Group
Bougainville 1	1972	A.A.P.	36.0	2676.0	Hyland Bay Fm Kulshill Gp	Salt Diapir	No shows
Lynedoch 1	1973	SHELL	236	3967.0	Early Cretaceous to Jurassic	Anticline	Gas shows in Early Cretaceous and Sandpiper Sst
Troubadour 1	1974	BOCAL	.97	3459.0	Jurassic	Faulted Anticline	Suspended gas well, tested 279 000 cu. m/D gas and 35.66 cu. m/D condensate from Plover Fm
Curlew 1	1974	ARCO	78	2035.0	Jurassic	Salt Diapir	Tr. gas in Plover Fm
Shearwater 1	1974	ARCO	70	3177.0	Jurassic	Faulted Anticline	Minor dead oil staining in Plover Fm
Kinmore 1	1974	A.A.P.	28.5	3250.0	Kulshill Gp	Salt Diapir	No shows

WELL NAME	YEAR	OPERATOR	WD (M)	T.D. (M)	OBJECTIVE	STRUCTURAL OBJECTIVE	RESULTS
Sunrise 1	1974	BOCAL	159	2341.0	Jurassic	Faulted Anticline	Suspended gas well, tested 2.536 m^3 gas and 545 cc condensate from the Plover Fm.
Petrel 3	1981-1982	A.A.P.	94.5	3970.0	Cape Hay Mbr	Drape Anticline	D.S.T. 1 (Cape Hay Mbr) 622 000 m^3/D gas on a 1.9 cm choke, 31.8 m^3/D. D.S.T. 2 (Cape Hay Mbr) 208 000 m^3/D gas on a 2.54 cm choke, 9.2 m^3/D. D.S.T. 3 (Cape Hay Mbr) 302 900 m^3/D gas on a 1.27 cm choke
Weaber 1	1982	A.A.P.	-	1950.0	Ningbing Lst	Carbonate Bank	D.S.T. 4 (Enga Sst) 127 000 m^3/D gas on a 1.27 cm choke
Barnett 1	1985	A.A.P.	36.0	2350.0	Kulshill Gp	Drape Anticline	Tr. of oil Kulshill Gp
Jacaranda 1	1984	TRICENT	78.4	3783.0	Jurassic	Anticline	Tr. gas Plover Fm
Darwinia 1A	1985	TRICENT	85.0	2426.0	Cretaceous	Faulted Anticline	No shows
Petrel 4	1988	A.A.P.	94.0	3975.0	Hyland Bay Fm	Drape Anticline	Capped suspended gas well 792 000 m^3/D
Weaber 2A	1988	SANTOS	-	1657.0	Enga Sst	Stratigraphic	
Evans Shoal 1	1988	BHP	110	3712.0	Jurassic	Anticline	12.9 m^3 gas on wireline at 3554m
Barnett 2	1989	A.A.P.	32.0	2480.0	Kulshill Gp	Anticline	D.ST. 4 (1491 m to 1497 m and 1500.5 m to 1506.5 m) 145.8 m^3/D

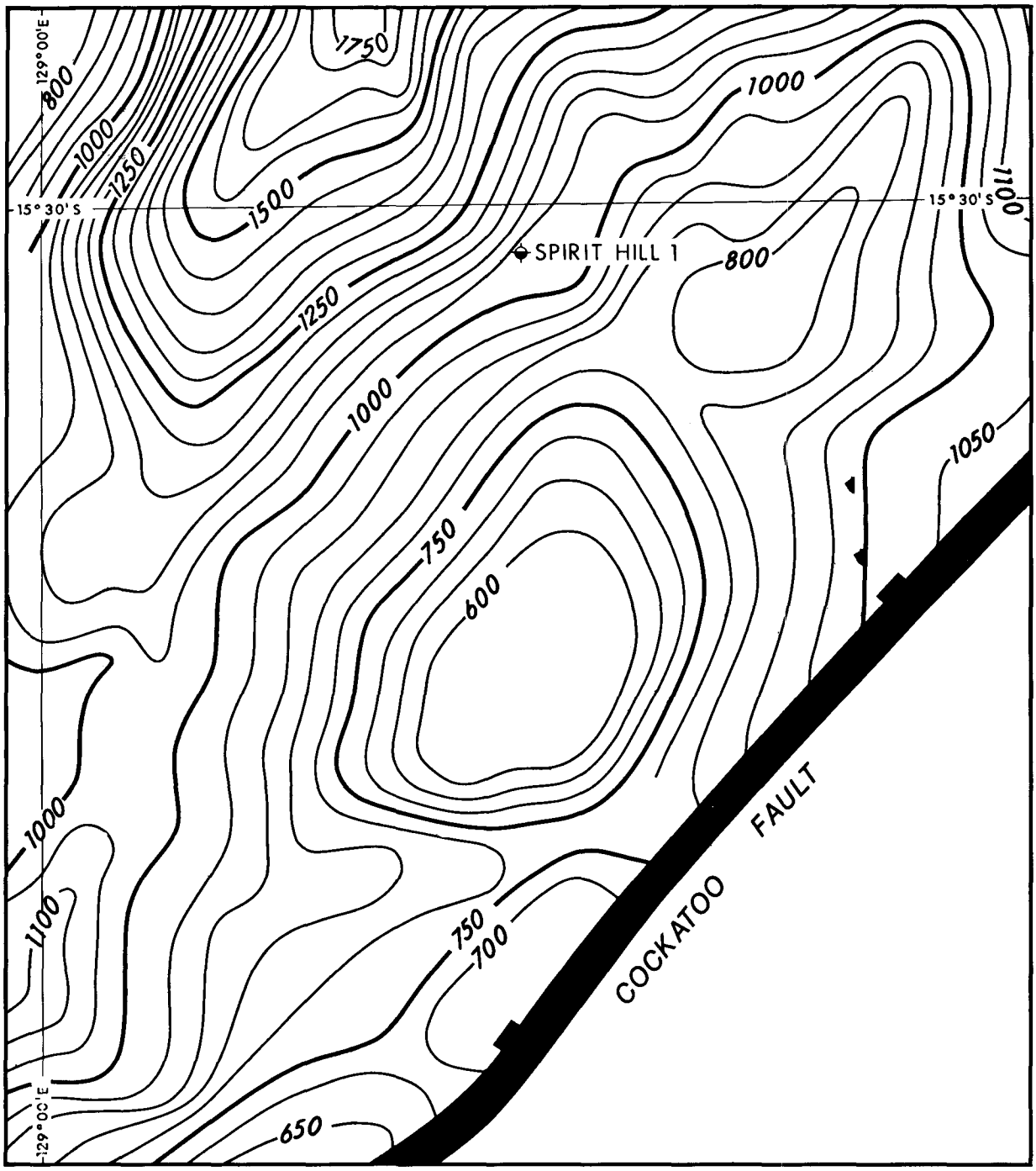


FIGURE 8 Spirit Hill Depth Structure Map

Near Top Cockatoo Group (late Devonian)

(After Lennard Oil, Burt Range Seismic Survey, PR71/008)

0 2
kilometres

Contour Interval: 25 metres

6.2 PETROLEUM EXPLORATION DRILLING

Brief summaries of petroleum exploration wells drilled within the Northern Territory portion of the Bonaparte Basin are presented below. Pertinent aspects of these activities are shown in Table 1.

6.2.1 Spirit Hill #1

This, the first petroleum well drilled in the Bonaparte Basin, was a continuously cored diamond drill hole by Westralian Oil Limited in 1959 and deepened by Oil Development N.L. (subsequently AOD). The objectives of this well were to determine the subsurface stratigraphic sequence on the Spirit Hill Anticline and the prospectivity of the Burt Range Formation located adjacent to the Burt Range Sub-basin. Slight traces of residual oil were encountered in the Milligans and Burt Range Formations. Subsequent seismic survey and field mapping indicated that the well was located at least 4 km down-dip of a sub-crestal culmination and some 6 km down-dip of the regional anticlinal crest (Figure 8). The well was plugged and abandoned at a total depth of 915 m (3003 ft).

6.2.2 Kulshill #1 & 2

Kulshill #1 and 2 were drilled by AAP in 1965-66 for the purpose of investigating the Palaeozoic stratigraphy and prospectivity of the Kulshill structure (Figure 9). This structure was delineated from refraction and surface mapping as a highly faulted dome or horst. Both oil and gas shows were encountered in the Early Permian and upper part of the Early Carboniferous sediments. Only gas was recorded below the Tanmurra Formation (Enclosure 6). DSTs produced only water and gas cut mud. The well was plugged and abandoned at a total depth of 4394 m (14 416 ft).

Kulshill #2 was drilled up-dip on another fault bound compartment of the Kulshill structure and 5 km from Kulshill #1 (Figure 9). Oil and gas shows were encountered over a much more restricted interval than in Kulshill #1, being confined to the Milligans Formation. The well was plugged and abandoned at a total depth of 1961 m (6432 ft).

6.2.3 Moyle #1

Moyle #1 was drilled on the southernmost extent of the Moyle Platform in OP 2 by AAP in 1966, primarily as a stratigraphic test to ascertain the thickness of Palaeozoic sediments in this portion of the basin. There were no gas or oil shows in any of the sedimentary formations penetrated by Moyle #1. However, the well did establish that the deepest seismic reflection recorded in this region coincided with the top of Proterozoic crystalline basement. The well was plugged and abandoned at a total depth of 539 m (1767 ft) (Enclosure 5).

6.2.4 Keep River #1

Keep River #1 was drilled by AAP in 1968-69 on the western flank of the Pincombe Ridge in OP 162. The well was designed to test a partially fault dependent closure at Palaeozoic levels along a structural high trend separating the Carlton and Burt Range Sub-basins (Enclosure 3). The nature of the up-dip closure to the southwest was obscured by poor quality

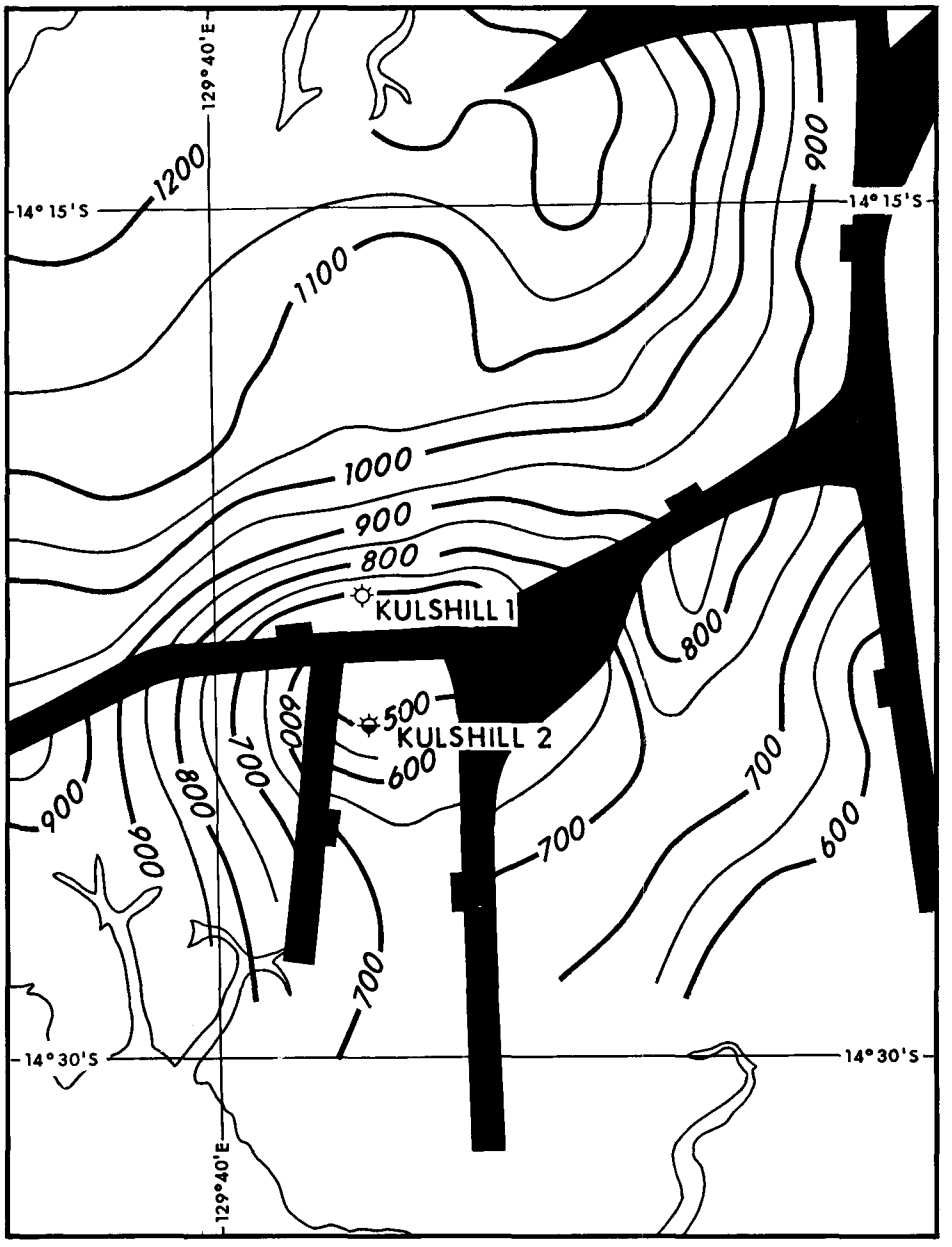


FIGURE 9 Kulshill Time Structure Map

Base Treachery Shale (Lower Permian)

(After Aquitaine, Moyle River Seismic and Gravity Survey, PR66/006)

0 5
kilometres

Contour Interval: 50 msec TWT

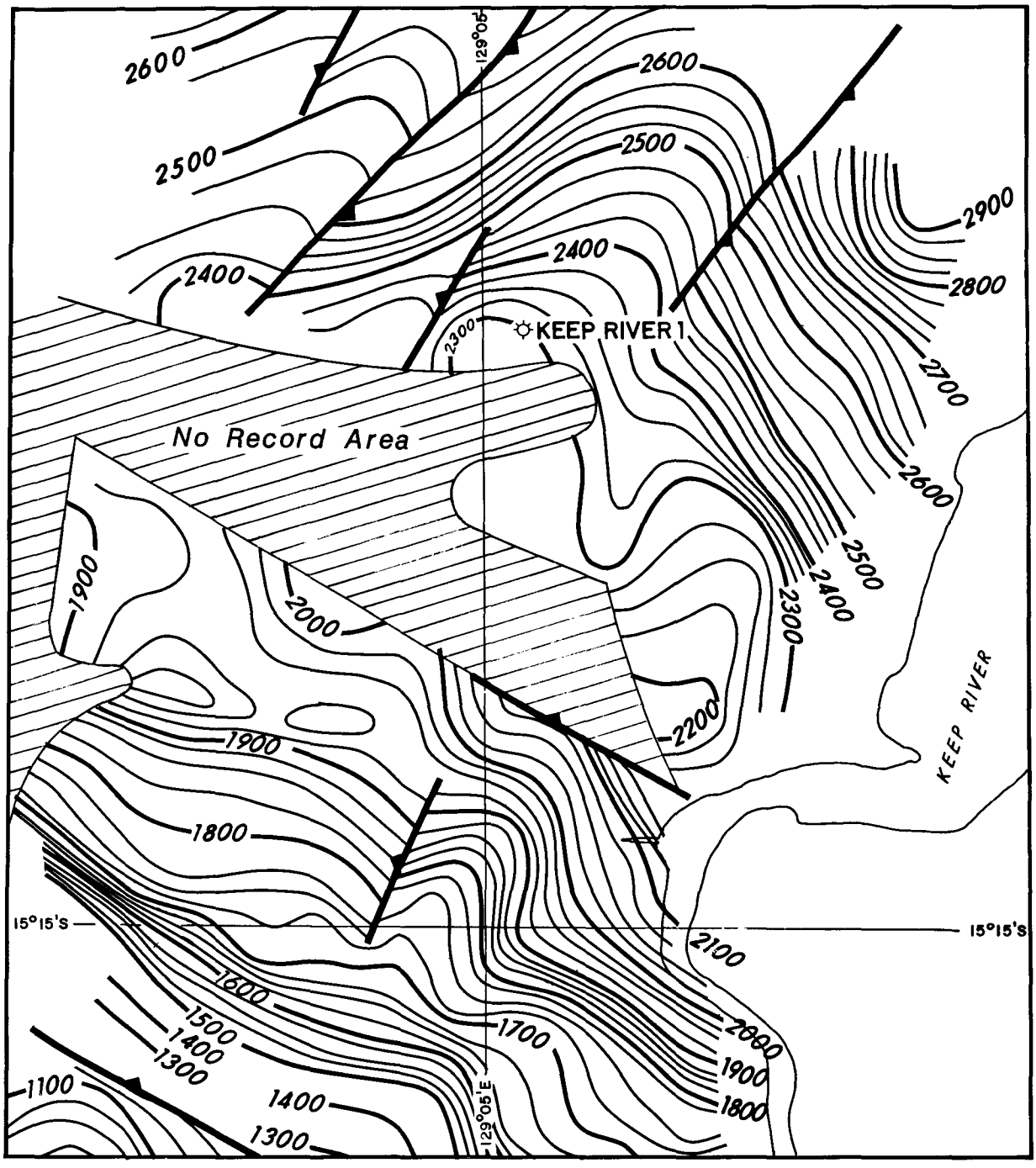


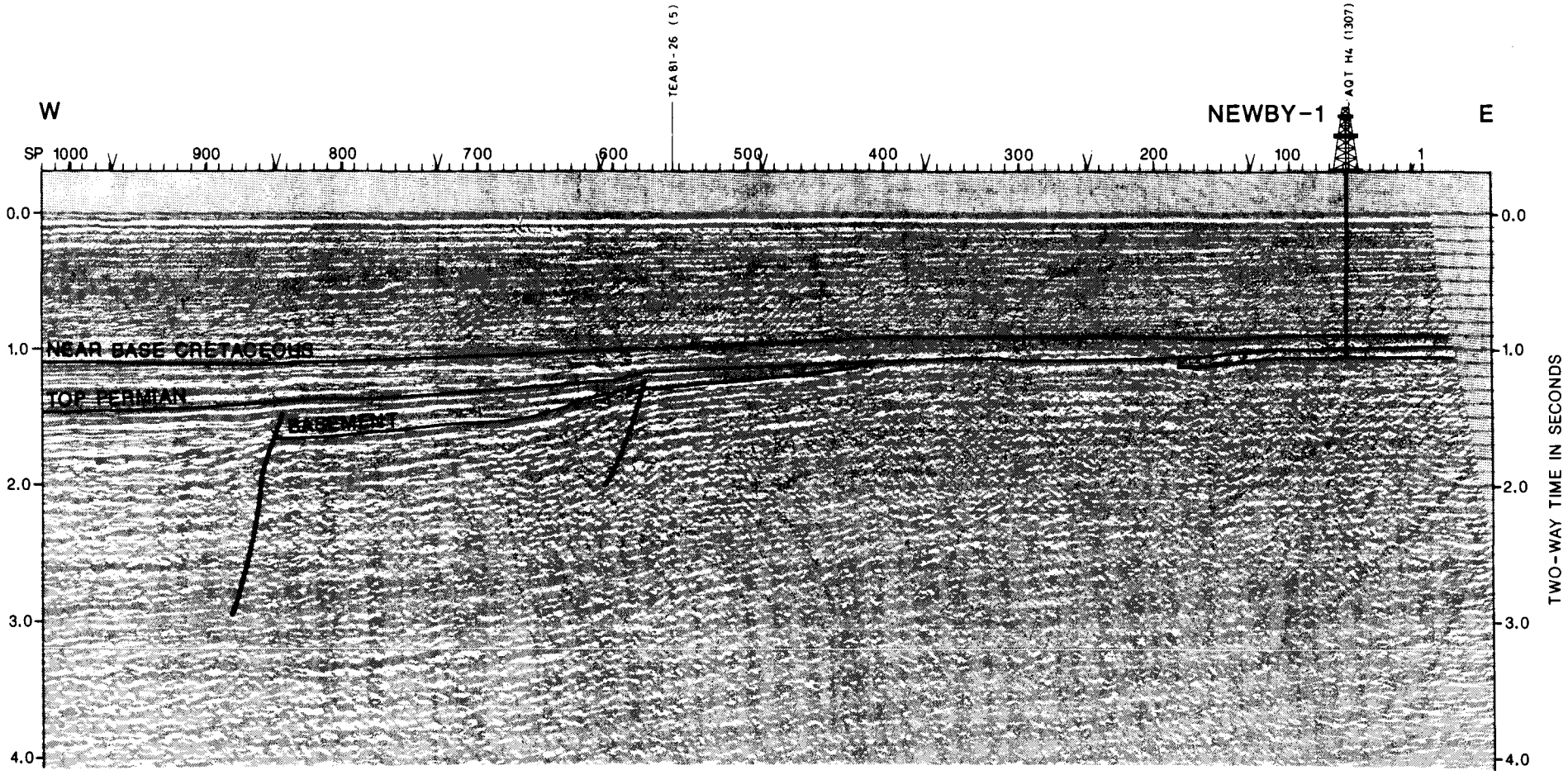
FIGURE 10 Keep River-1 Time Structure Map

Near Top Cockatoo Group (Late Devonian)

(After Aquitaine, Border Creek Seismic Survey, PR72/002)

0 2
kilometres

Contour Interval: 25 msec TWT



0 3km

FIGURE 11 Interpreted portion of Seismic Line TEA81-23 across the Newby-1 location

seismic data (Figure 10). Northwest trending, down to the basin, cross-faults may provide the critical counter-dip closure. A thicker than expected Palaeozoic section was encountered with gas shows throughout the Lower Caboniferous and from fractures within the Upper Devonian (Enclosure 5). Eight DST's produced up to 3 MMCFPD. The well was subsequently plugged and abandoned at a total depth of 4762 m (15 623 ft) in probable Devonian sediments.

6.2.5 Newby #1

Newby #1 was drilled by AAP in 1969 in NT/P 17 to explore the stratigraphy and hydrocarbon potential of erosional pinchouts on the Moyle Platform (Figure 11 and Enclosure 10). A Mesozoic section unconformably overlying Proterozoic basement established the presence of a Palaeozoic pinchout to the west, however, no hydrocarbon shows were encountered. The well was plugged and abandoned at a total depth of 1148 m (3150 ft).

6.2.6 Petrel #1

Petrel #1 was drilled by Arco-AAP in NT/P 3 in the offshore portion of the Petrel Sub-basin. Drilled in 1969, Petrel #1 was only the second offshore well (Lacrosse #1 being the first) and the first to be drilled in the offshore Northern Territory portion of the Bonaparte Basin. Drilled in 100 m of water, the well was designed to test a large northwest trending anticline (Figures 12 and 13 and Enclosure 10). Areal closure is greater than 119 km^2 and vertical closure exceeds 83 m (Lavering & Ozimic, 1989).

The well reached a total depth of 3980 m without encountering any hydrocarbon indications except for the final 2 m interval in which high pressure gas was intersected. Owing to a series of mechanical failures, a blow-out occurred and the drillhole was lost. No tests were conducted. The following year a relief well, Petrel #1A, was drilled. The Petrel #2 confirmation well was drilled in 1970/71, and was followed by the drilling of Petrel #3 in 1981 and Petrel #4 in 1988. The accumulation is currently being assessed for commercial development with gas reserves estimated at between 190×10^9 and 440×10^9 m^3 (Section 3).

6.2.7 Flat Top #1

Flat Top #1 was drilled in NT/P 17 by AAP in 1971 as a follow-up to Newby #1, to evaluate further the potential of pinchouts associated with the northeastern edge of the Bonaparte Basin. Flat Top #1 penetrated some 1200 m of Permo-Triassic sediments unconformably overlying basement. Although good reservoirs were penetrated only minor traces of gas were encountered. The well was plugged and abandoned at a total depth of 2173 m (7131 ft).

6.2.8 Bougainville #1

Drilled by AAP in 1972, Bougainville #1 tested a diapiric structure. The structure trends north-west and the crestal region is extensively modified by associated normal faulting (Figures 14 and 15). The well was located slightly off the crest, and slight traces of fluorescence were noted towards the base of the Fossil Head Formation. However, log analysis revealed all

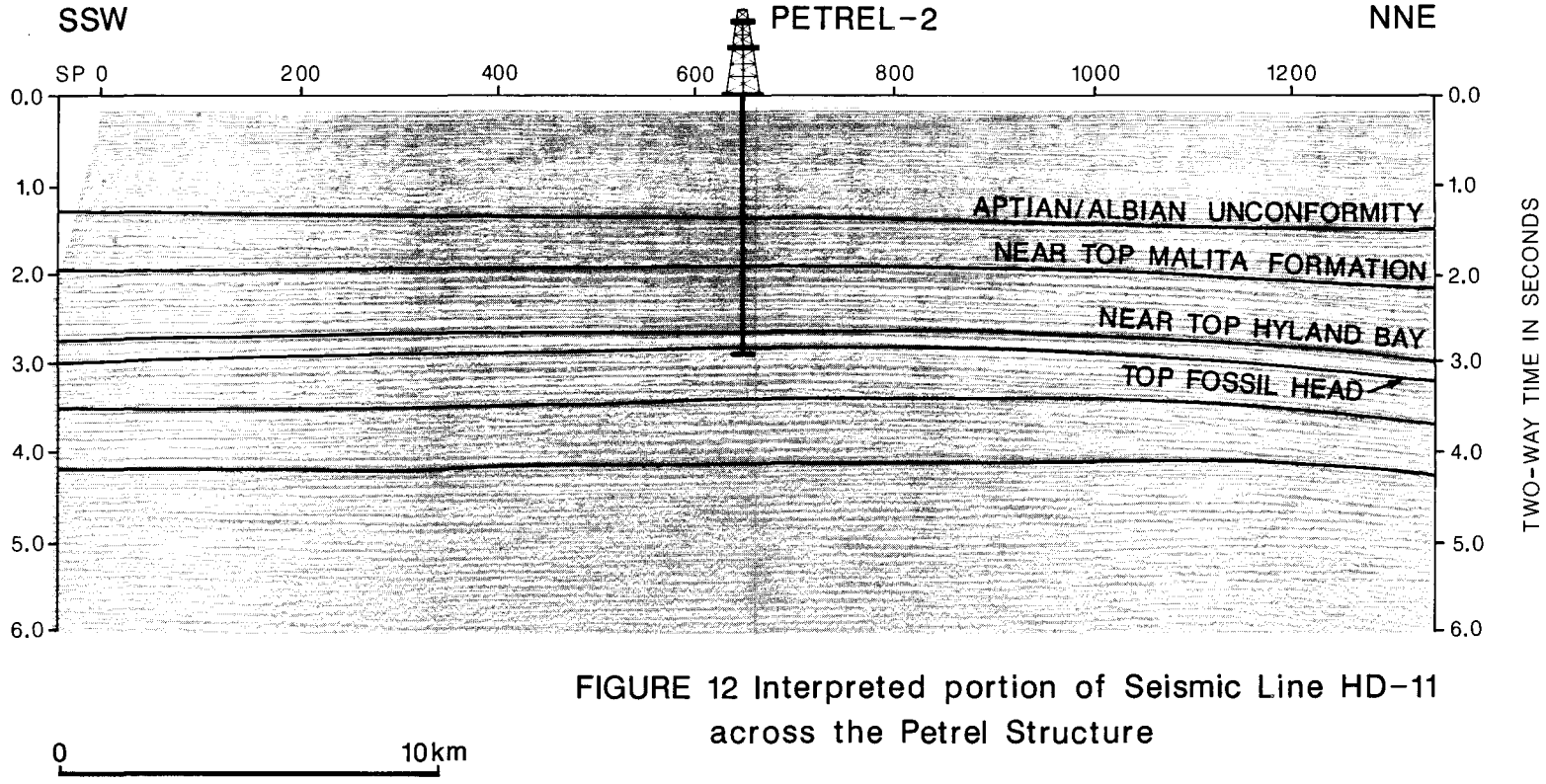


FIGURE 12 Interpreted portion of Seismic Line HD-11 across the Petrel Structure

0 10km

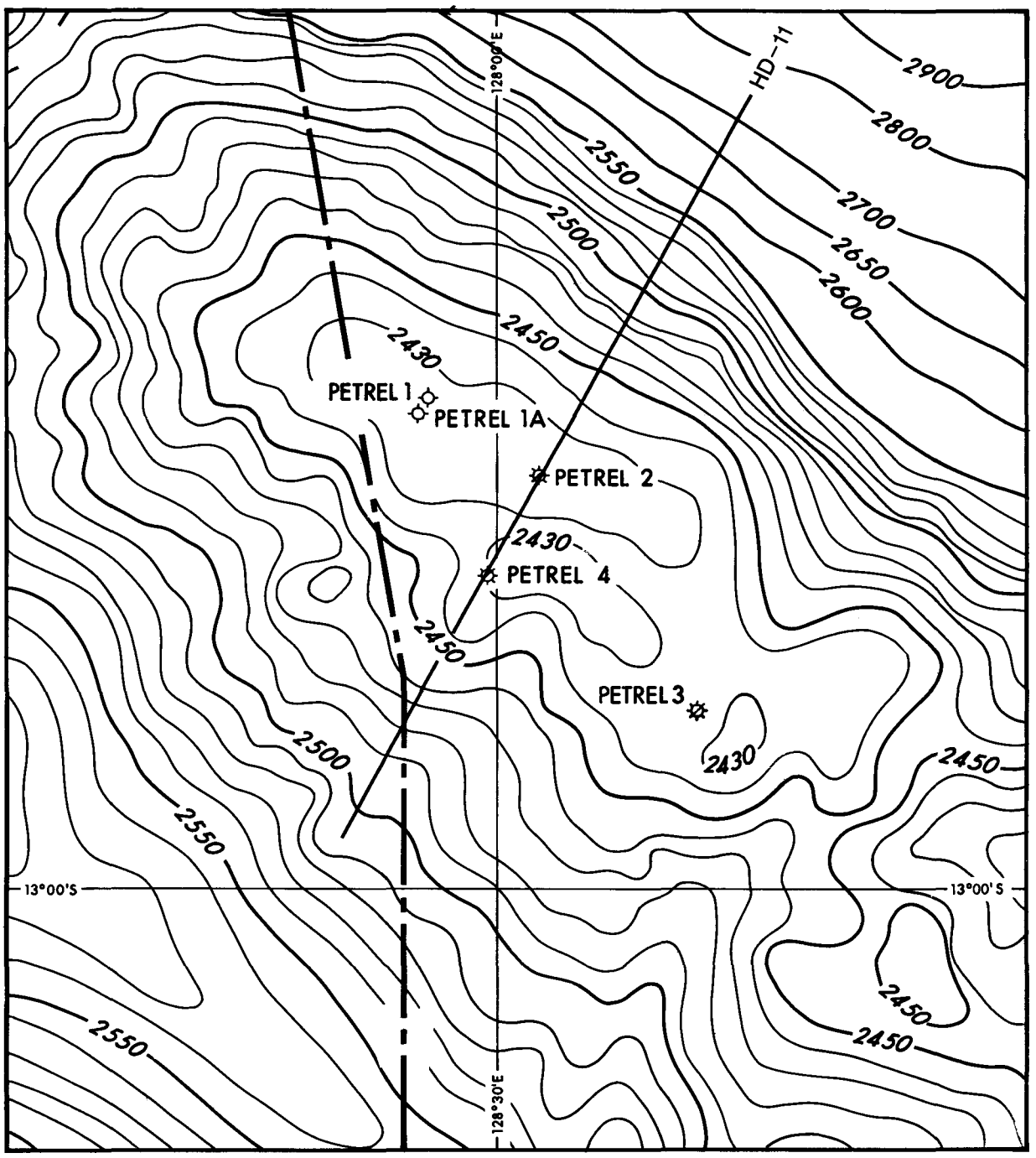


FIGURE 13 Petrel Field Time Structure Map
Near Top Hyland Bay Formation (Upper Permian)

0 5
kilometres

Contour Interval: 10 and 50 msec TWT

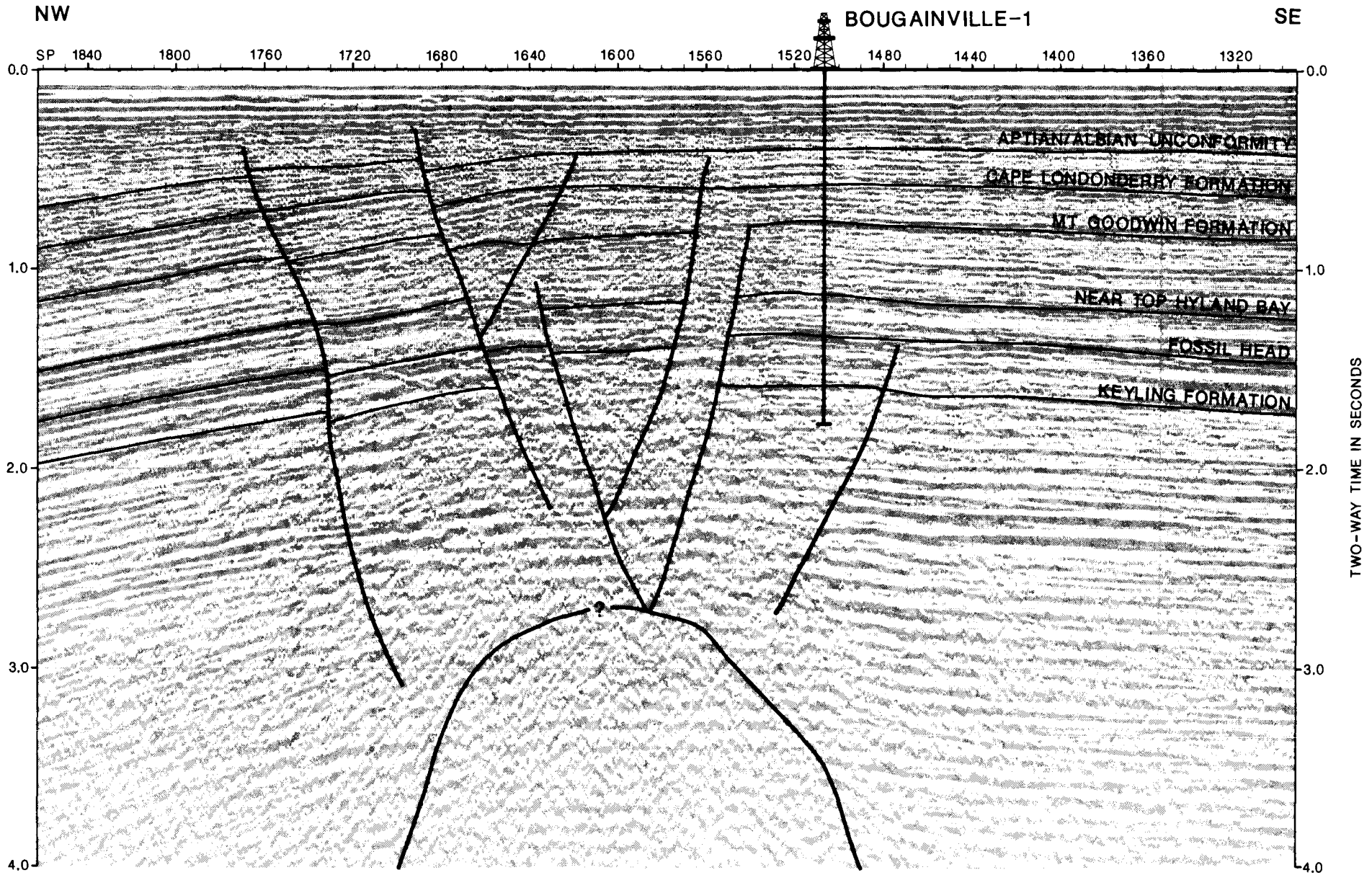


FIGURE 14 Interpreted portion of Seismic Line HD-12 across the Bougainville Structure

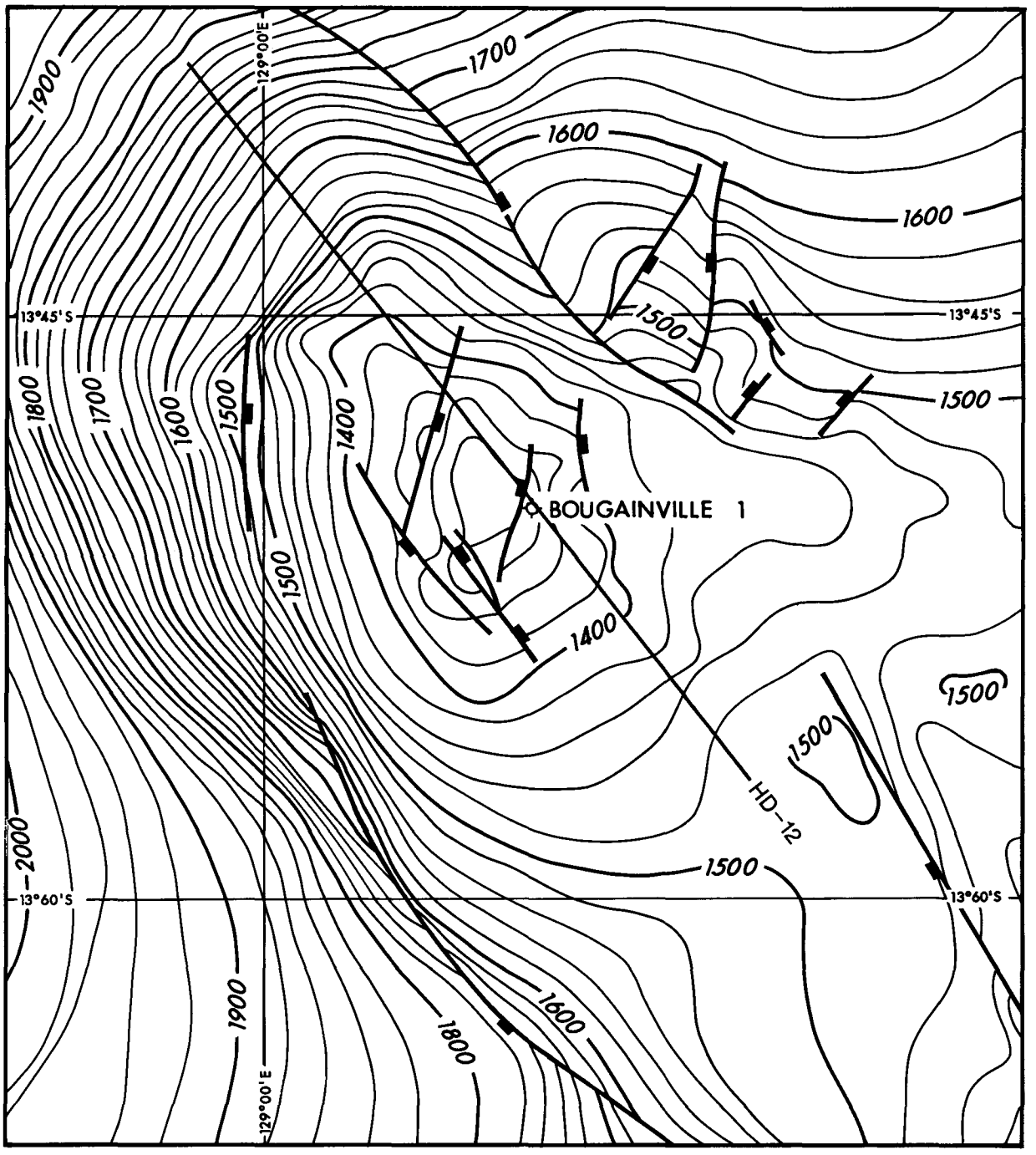


FIGURE 15 Bougainville Time Structure
Near Base Hyland Bay Formation (Upper Permian)
(After Aquitaine, Cape Scott Survey, PR 71/011)

0 2
kilometres

Contour Interval: 20 msec TWT

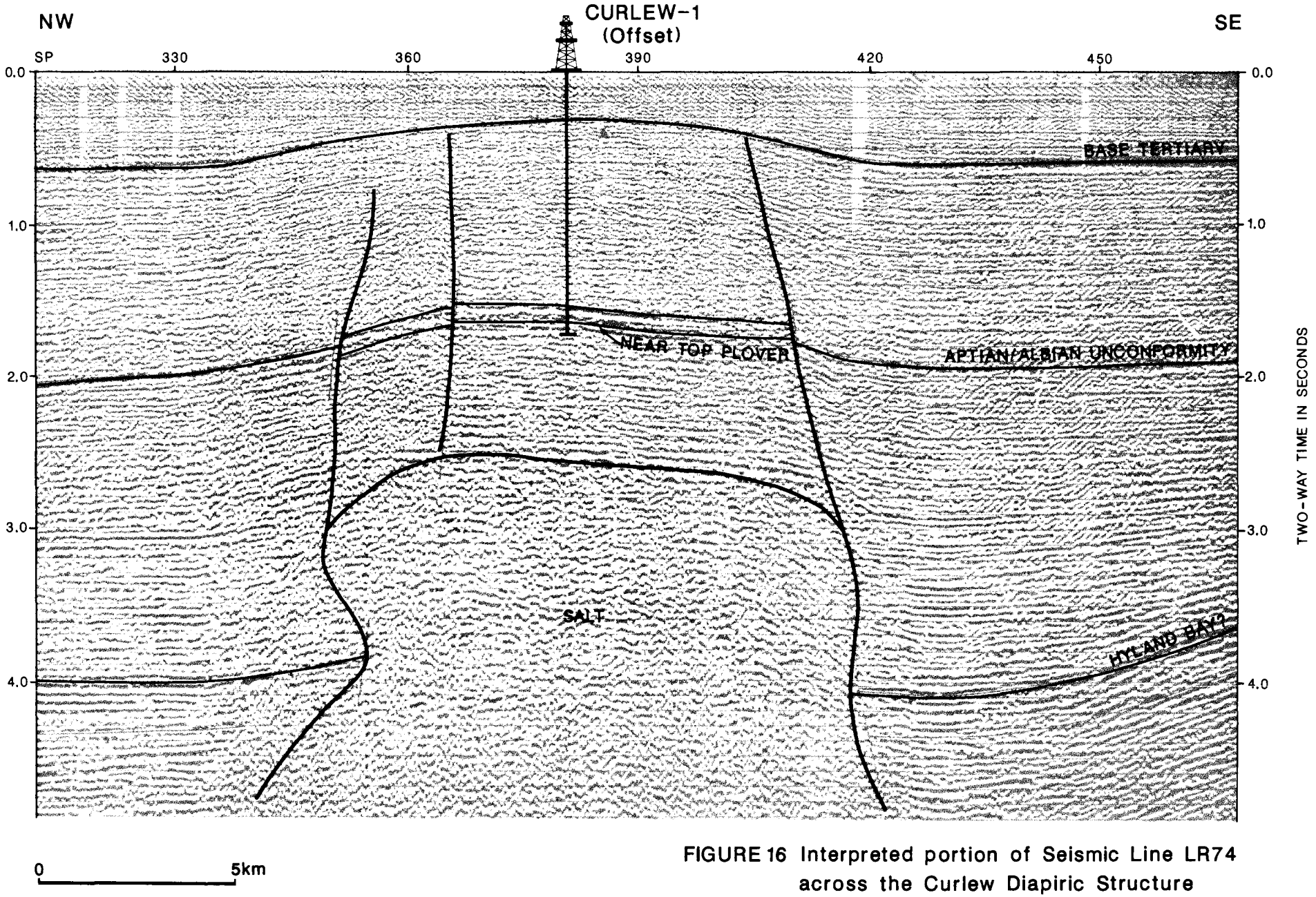


FIGURE 16 Interpreted portion of Seismic Line LR74 across the Curlew Diapiric Structure

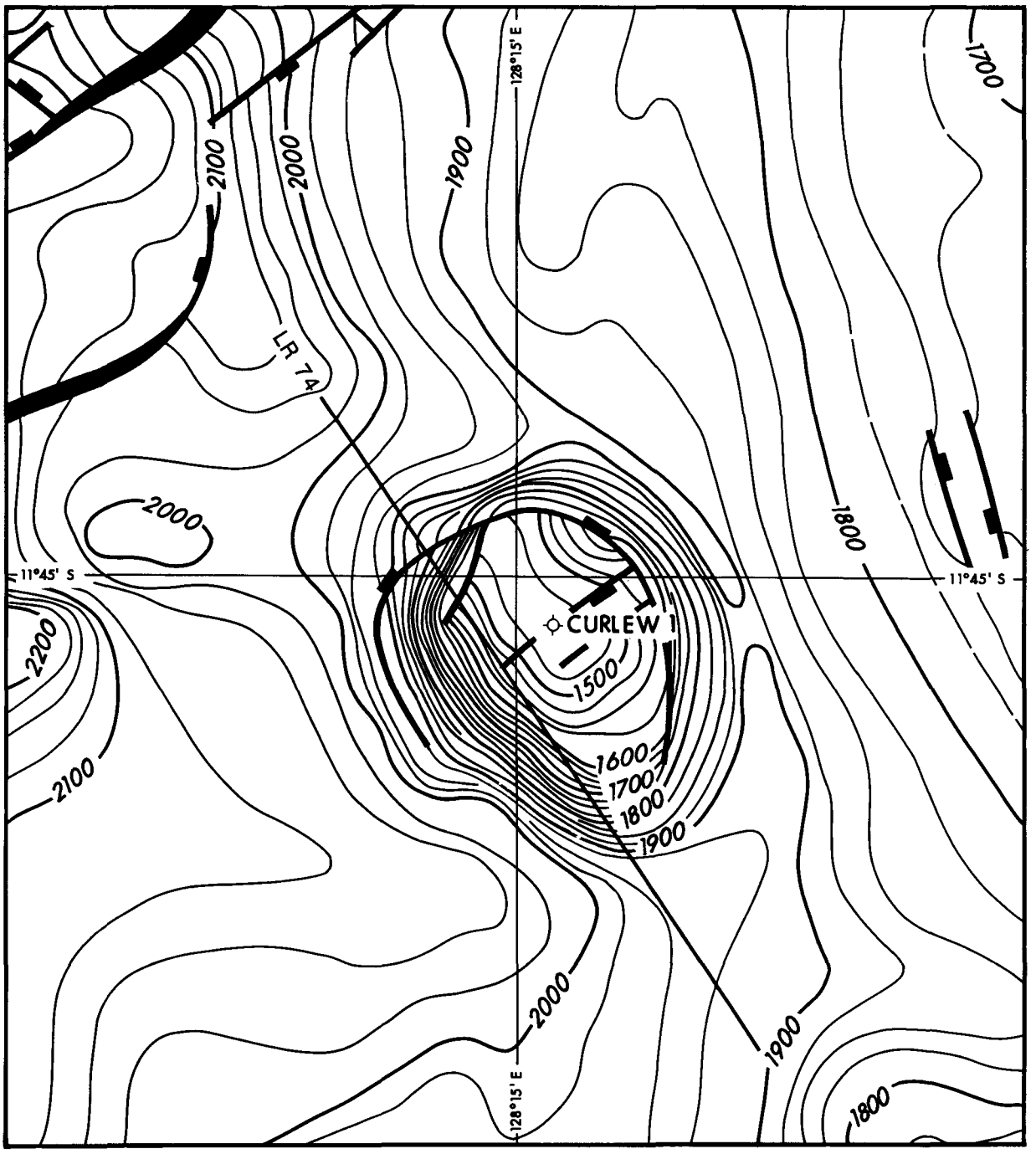


FIGURE 17 **Curlew Time Structure Map**
Near Base Bathurst Island Group (Cretaceous)
(After Tricentrol, NT/P33 Seismic Survey, PR82/031)

0 5
kilometres

Contour Interval: 25 msec TWT

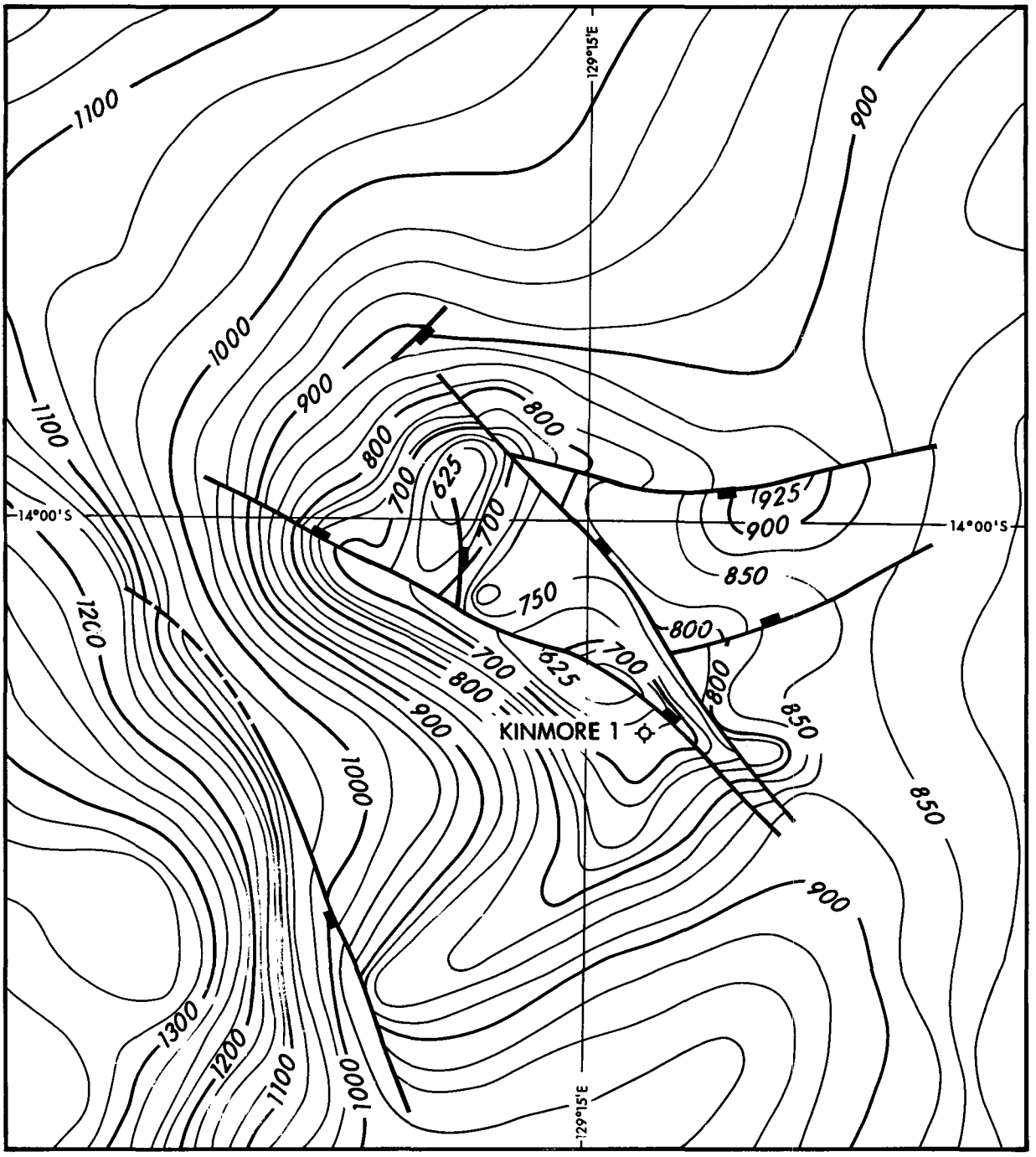


FIGURE 18 **Kinmore Time Structure Map**
Near Top Hyland Bay Formation (Upper Permian)

0 2
kilometres

Contour Interval: 25 msec TWT

reservoirs to be water saturated. Variations in salinity indicated flushing of at least some reservoirs, presumably by water migrating along the adjacent fault planes. The well was plugged and abandoned at a total depth of 2676 m (8780 ft) (Enclosure 6).

6.2.9 Curlew #1

Curlew #1 was drilled by Arco in 1974 to test a domal closure over an apparent deep seated salt piercement feature on the eastern flank of the Petrel Sub-basin (Figure 16). The structure is closed at the near-base Tertiary level, but structural closure at the near base Upper Cretaceous level is fault dependent (Figure 17). Seismic interpretation indicates diapiric growth with the development of prominent rim synclines during the Permian to Tertiary period. The structure is very similar to one tested by the Gull #1 well some 43 km to southwest in the Western Australian portion of the Basin, although at Curlew #1 structural growth ceased at an earlier stage in the Tertiary as evidenced by onlap of the near top Bathurst Island Group sediments (Figure 16).

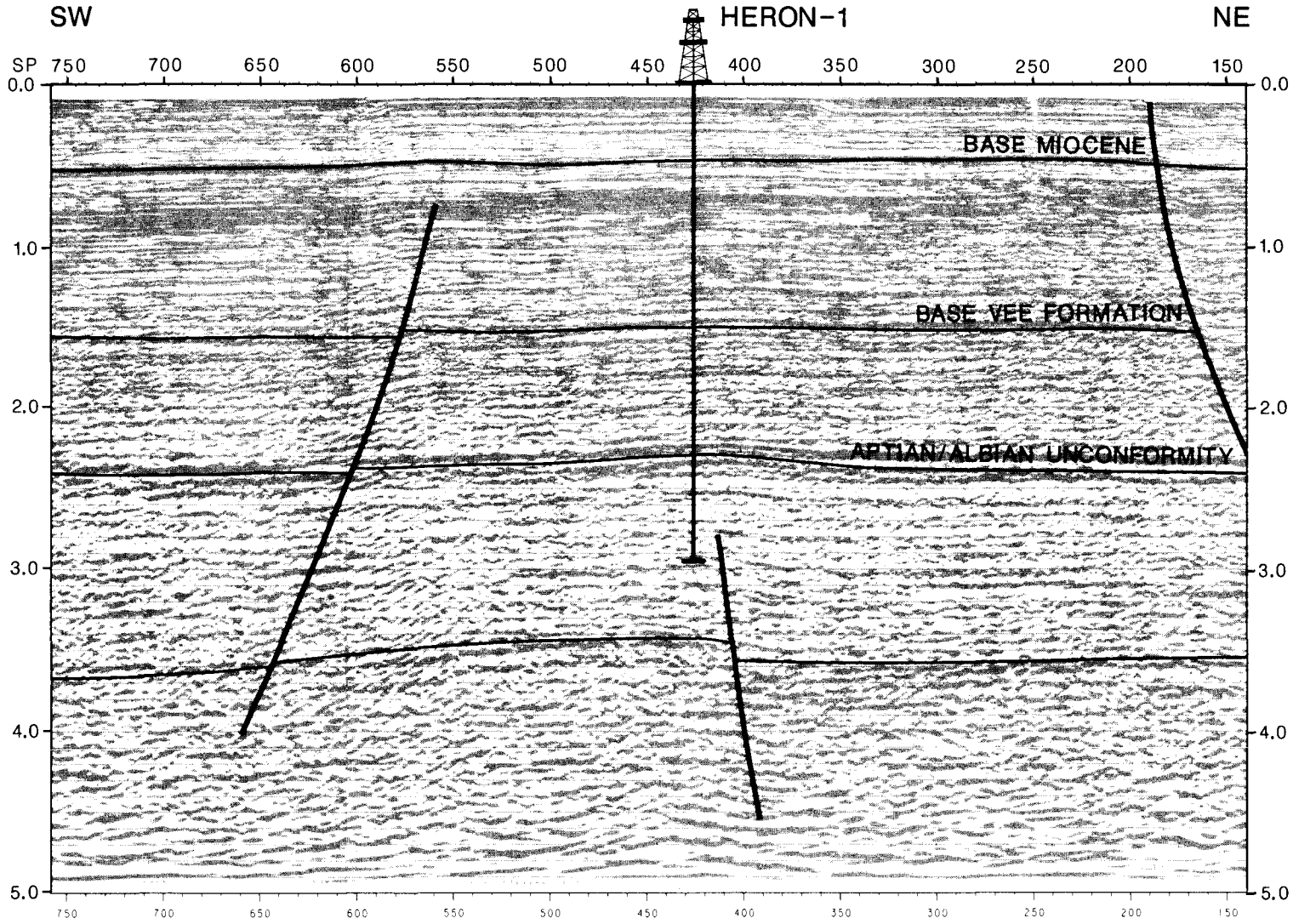
The primary objectives of the well were Jurassic sandstones. Minor gas shows were observed through the Jurassic Flamingo Group and Plover Formation although tests recovered only filtrate and salt water (Enclosure 7). The well was plugged and abandoned at a total depth of 2035 m in the Plover Formation.

6.2.10 Kinmore #1

Drilled by AAP in 1974, Kinmore #1 was located down-dip from the crest of a diapiric structure (Enclosure 10). The well intersected sequences on the southeastern flank of the intrusive, which is interpreted to have grown relatively continuously since the late Early Permian. Structural closure is mapped over an area exceeding 55 km^2 although, as shown on Figure 18, the structure is disrupted by a series of major normal faults upon which critical closure is dependent. Only minor traces of gas were encountered notwithstanding that adequate reservoir and cap rocks were penetrated. The well was plugged and abandoned at 3259 m total depth.

6.2.11 Heron #1

Heron #1 was drilled by Arco in 1971/72 to test a large, northeast-southwest trending anticline overlying a deeply buried high on the edge of the Heron Terrace within the central Malita Graben (Enclosure 3). The structure is fault bounded with fault dependent closure existing at the near base Tertiary and near- base Cretaceous levels (Figure 21). The subtle faulted nature of the structure is seen on seismic line 85 MA-19 (Figure 19). However, a dip oriented line 85 MA-4A (Figure 20) is interpreted to show this faulting to be related to underlying intrusive salt structuring. The upturned nature of the deep reflectors near 4.0 seconds on the flanks of the structure are similar in character to those intrusives observed elsewhere in the basin, and in which salt has been directly encountered.



0 5km

FIGURE 19 Interpreted portion of Seismic Line 85MA-19/19A across the Heron Structure

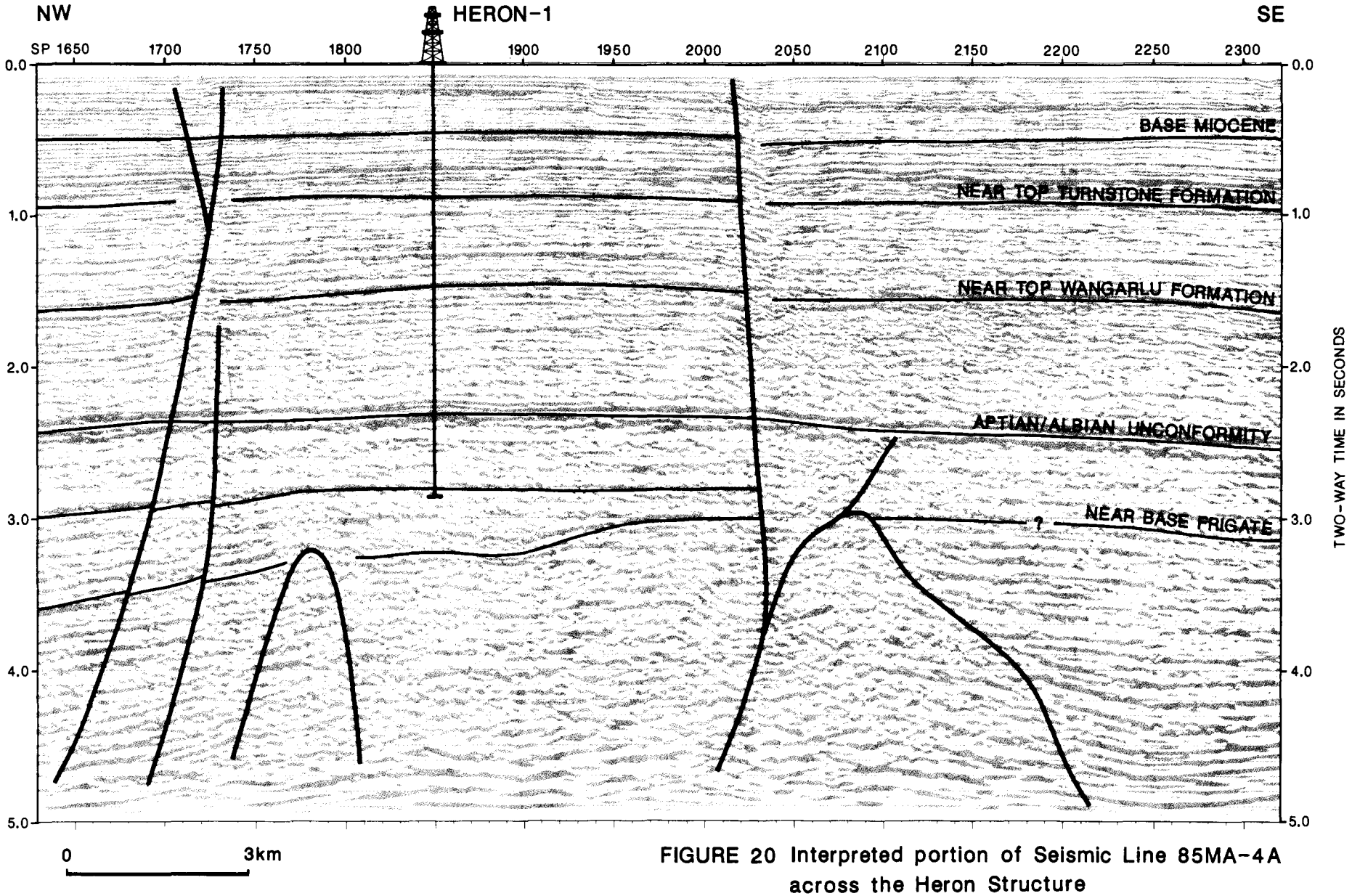


FIGURE 20 Interpreted portion of Seismic Line 85MA-4A across the Heron Structure

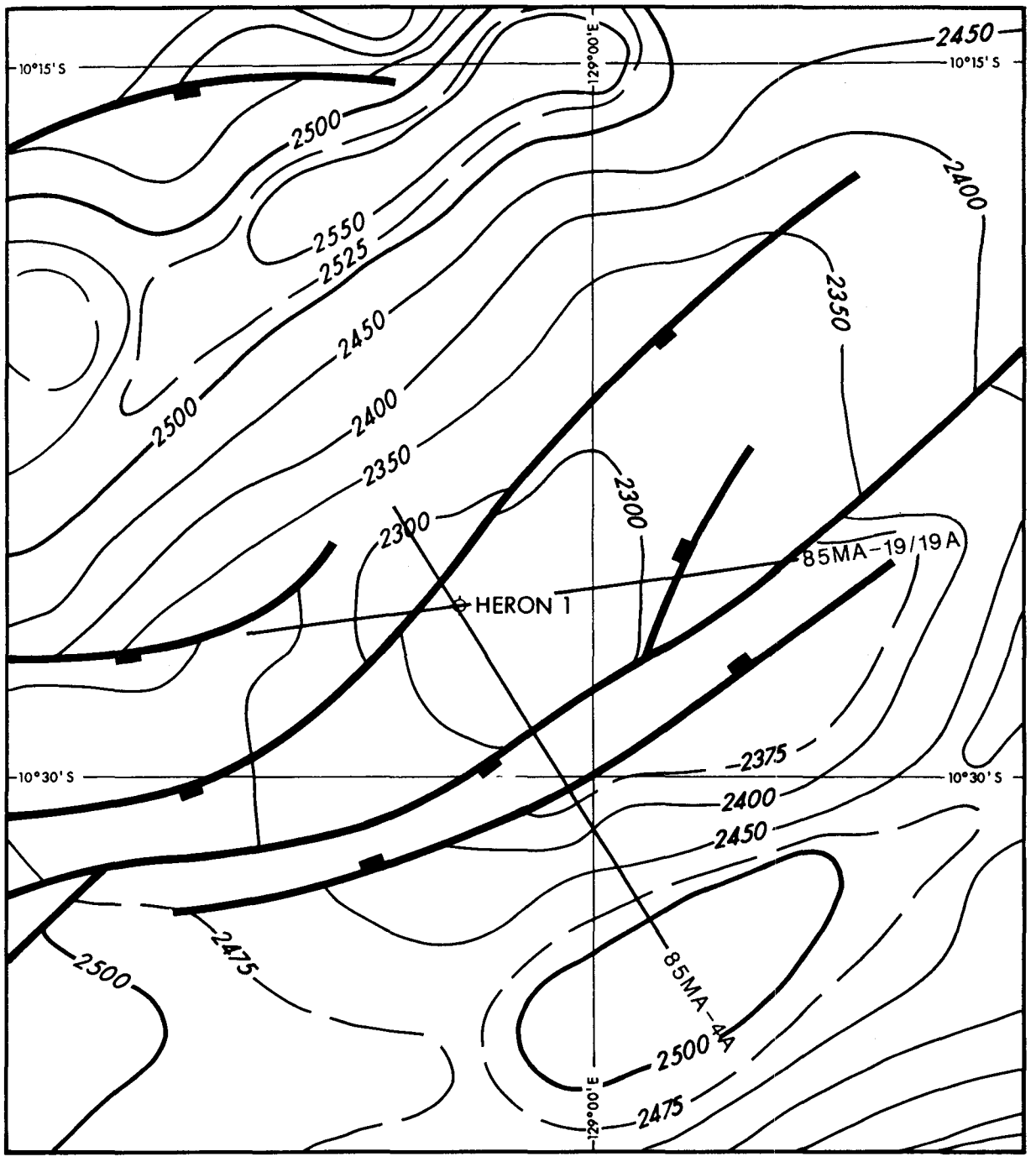


FIGURE 21 **Heron Time Structure Map**
Near Base Bathurst Island Group (Cretaceous)

0 5
kilometres

Contour Interval: 50 msec TWT

The objectives of the well were Cretaceous to Jurassic sandstones with several gas shows observed in these sections during drilling (Enclosure 8). Testing was not conducted owing to the absence of a suitable reservoir (all sandstones were silicified) and the well was plugged and abandoned at a TD of 4208 m (13 808 ft).

6.2.12 Lynedoch #1

Lynedoch #1, located near the junction of the Calder and Malita Grabens, was drilled by Shell in 1973 in NT/P 19. The well was designed to test a large broad anticlinal structure of some 150 km^2 mapped at the top intra Early Cretaceous level (NTGS, 1989). A thin hydrocarbon, bearing zone probably gas, was encountered within an Early Cretaceous carbonate but it was not tested (Enclosure 8). Log analyses indicated a further zone of possible gas saturation within sandstones at the top Jurassic level. Although drilled within structural closure the seismic grid was such that Lynedoch #1 was not a crestal test (NTGS, 1989). Furthermore, high water saturations indicate that the closure mapped at the "P" horizon carbonate level may not have been present, possibly because of velocity distortions. The well was plugged and abandoned at a total depth of 3967 m in the Jurassic.

6.2.13 Troubadour #1

Troubadour #1 was drilled by Bocal in 1974 to test a northeast-southwest trending faulted anticline on the northern side of the Sahul Platform (Figure 22). The structure is closed and fault dependent at the near-base Tertiary, near base Late Cretaceous (Figure 23) and near Top Permian levels. Closure of the structure is controlled by drape over a topographic high, coincident with an old igneous high, and by compaction and drape folding. Lavering & Ozimic (1989) estimate closure at the reservoir level to be 17.5 km^2 with 41m of vertical relief.

The primary objectives of the well were Jurassic reservoirs. Late Cretaceous calcarenites and sandstones were found to be porous but water-wet, whereas Triassic sandstones were tight and water-wet. A reservoir section was found in the Jurassic Plover Formation and DSTs recovered significant amounts of gas and condensate (Enclosure 7). However, other Jurassic sandstones were tight as indicated by the presence of immovable oil on logs and residues of oil in fractures in core. The well was plugged and suspended as a gas well at a TD of 3459 m (11 349 ft).

6.2.14 Sunrise #1

Sunrise #1 was drilled by Bocal in 1974 to test a large northeast-southwest trending faulted anticline on the northern margin of the Sahul Platform (Figure 23). The structure is closed and fault dependent at the near base Cretaceous level. The termination of the bounding fault at the Aptian/ Albian Unconformity is clearly seen on the seismic sections in Figure 24. Lavering & Ozimic (1989) estimate closure at the reservoir level to exceed 44 km^2 and vertical closure to exceed 66m.

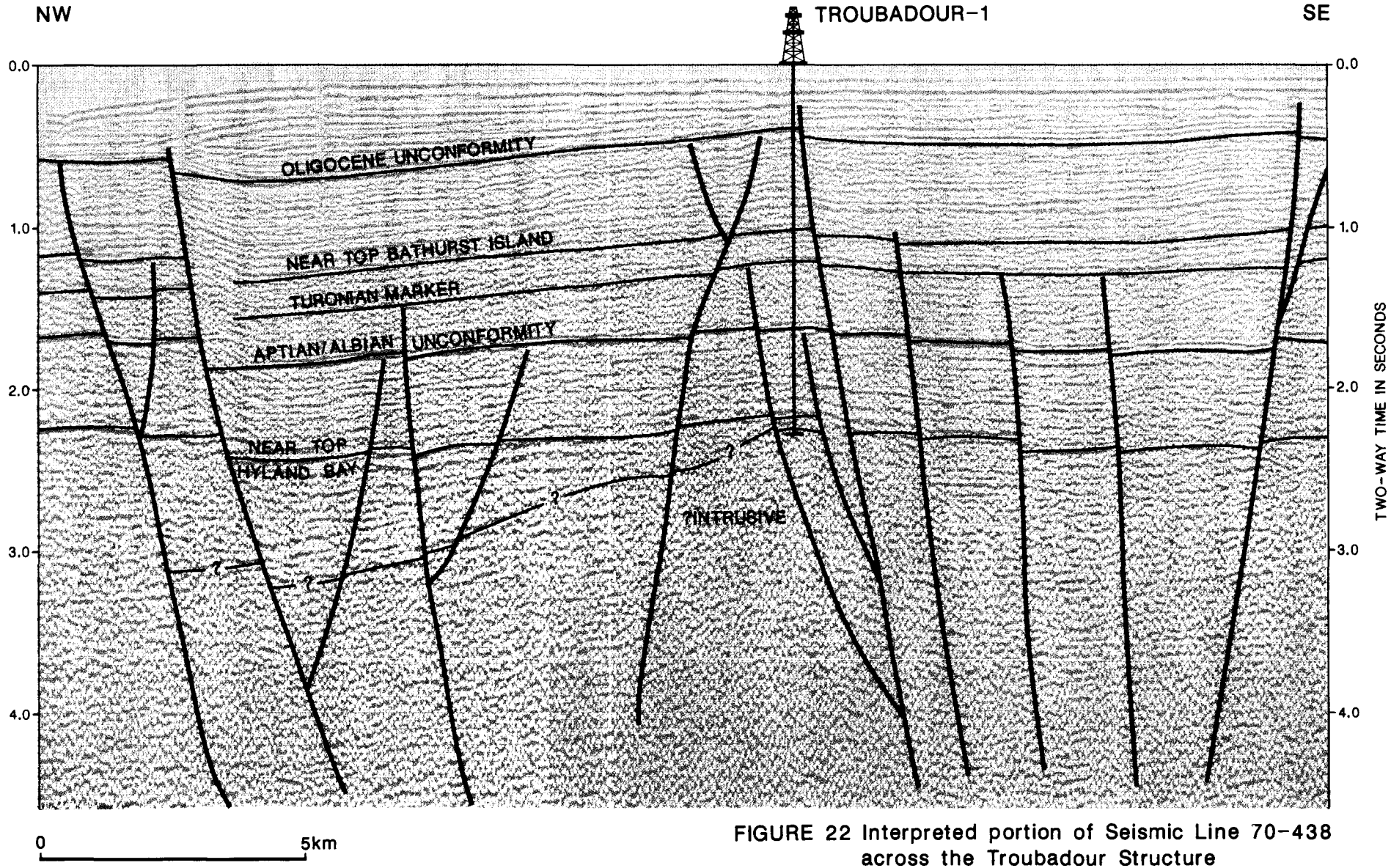


FIGURE 22 Interpreted portion of Seismic Line 70-438 across the Troubadour Structure

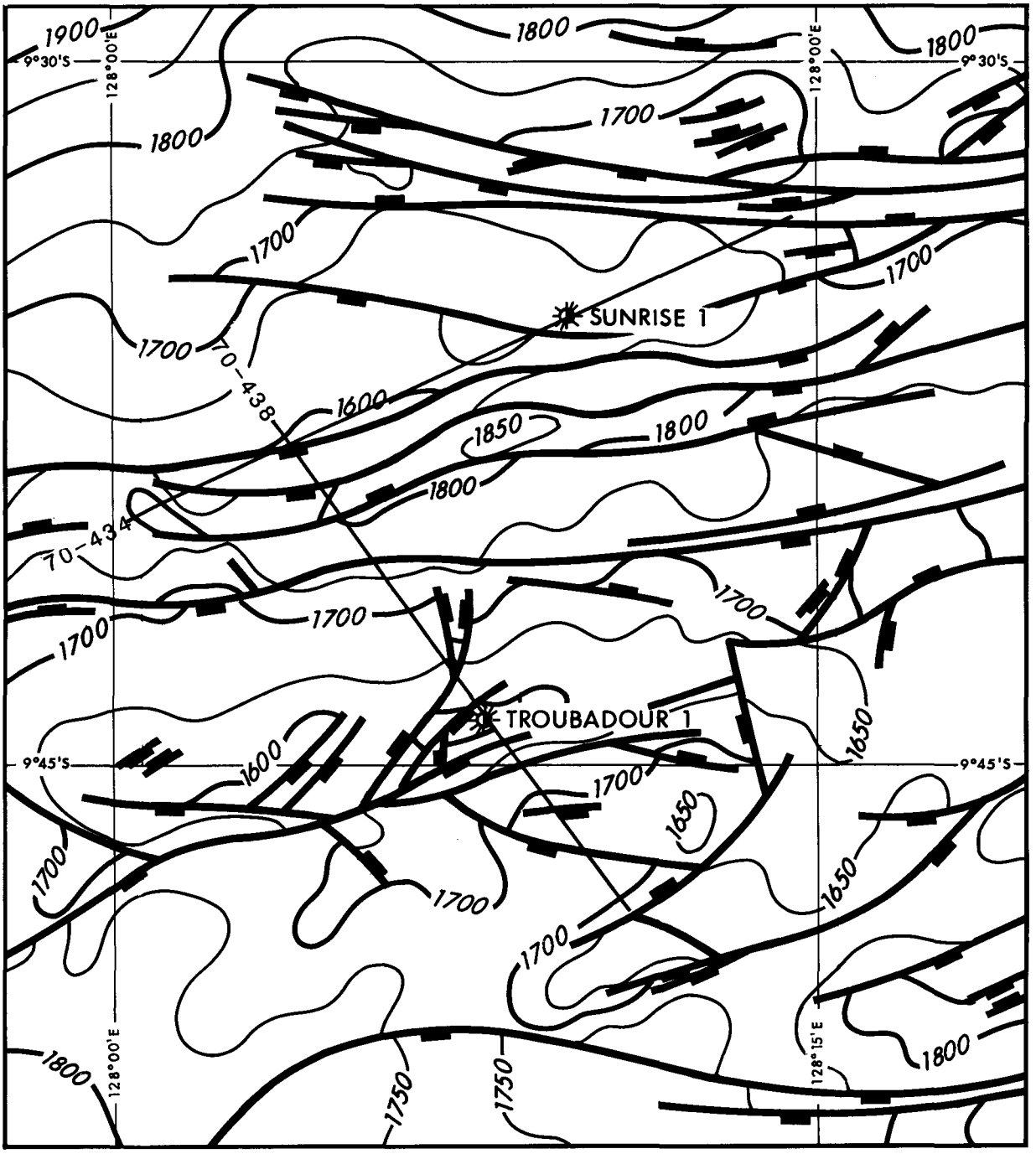
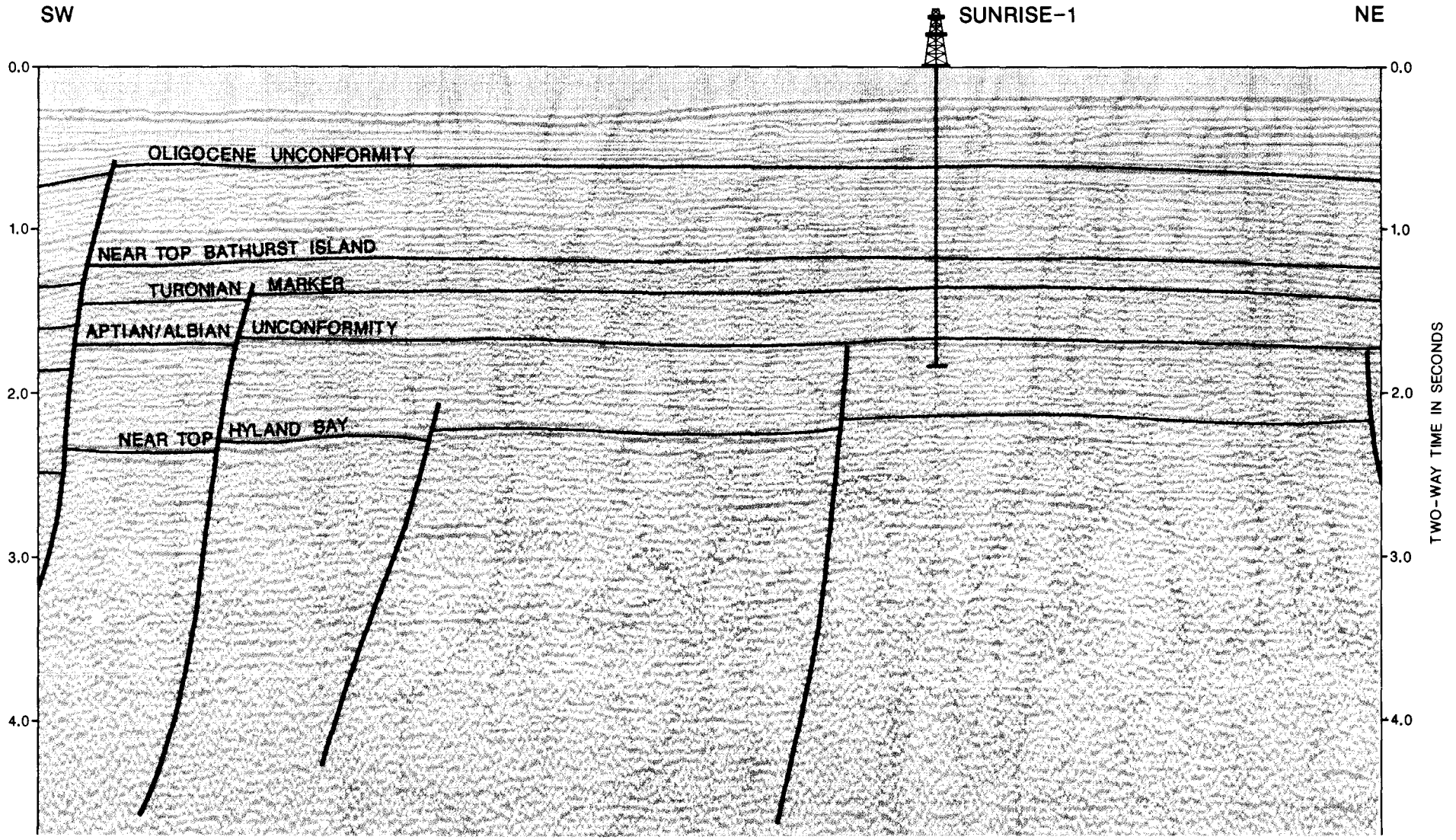


FIGURE 23 **Troubadour Time Structure Map**
Near Base Bathurst Island Group (Cretaceous)

0 5
kilometres

Contour Interval: 50 msec TWT



0 5km

FIGURE 24 Interpreted portion of Seismic Line 70-434 across the Sunrise Structure

The primary objectives of the well were Jurassic sediments. A reservoir section consisting of two sandstone intervals in the Jurassic Plover Formation were evaluated with FITs and recovered gas and condensate (Enclosure 7). The well was plugged and suspended as a gas well at a TD of 2341 m (7681 ft) in the Plover Formation.

6.2.15 Shearwater #1

Shearwater #1 was drilled by Arco in 1974 to test a northeast-southwest trending faulted anticline located along a hingeline between the Sahul Platform and the Malita Graben. The structure is fault bound to the southeast, fault independent closure being mapped at the near-Base Bathurst Island Group (Figure 26). In other directions low dipping structural attitude provides closure. The Shearwater fault has been active in post-Oligocene times (Figure 25) and a protracted period of fault movement may have breached effective seal.

The primary objectives of the well were Jurassic sandstones and minor dead oil staining was observed in cores from the Plover Formation (Enclosure 8). No tests were conducted as the Jurassic sandstones were silicified and the well was plugged and abandoned at a TD of 3177 m (10 425 ft) in the Jurassic.

6.2.16 Weaber #1

Weaber #1 was drilled in 1982 in O.P. 186 on a structural closure interpreted as a possible Famennian carbonate bank, a lateral equivalent of the Ningbing reef limestones encountered in Keep River #1 (Figure 28). A second objective was the Langfield Group. The following case history is paraphrased from Willink (1989).

No indications of live oil were detected during drilling, although minor gas detector anomalies were observed in two Early Carboniferous sandstones above the Tournaisian unconformity. Fluorescence with cut was recorded in the Enga Sandstone between 1395 m and 1415 m, but was attributed to pipe-dope contamination. Logs showed the primary objective Ningbing limestones to be tight. Fair porosities, high resistivities and high SP deflections were recorded over the Enga Sandstone and an overlying thin Carboniferous sandstone between 1300 m and 1304 m. Although recognising the potential presence of probable gas in these sands, Aquitaine interpreted them to be fresh water filled. As a result, no tests were carried out and the well was abandoned.

Northern Territory Mines Department personnel inspected the abandoned Weaber #1 location in 1984 and found gas bubbling through water inside the surface casing. Santos, the new operator of the permit, re-evaluated the logs and concluded that the two Carboniferous sandstone intervals were gas bearing. As a result, Weaber #1 was re-entered in 1985 and DST #1 over the interval 1281-1313 m flowed dry gas at 56 600 m^3/d, while DST #4 over the interval 1273-1421 m flowed dry gas at a maximum of 127 400 m^3/d. Later analysis of pressure data revealed that formation damage may have impaired the test results and that flow rates as high as 480 000 m^3/d could be achieved from the Enga Sandstone.

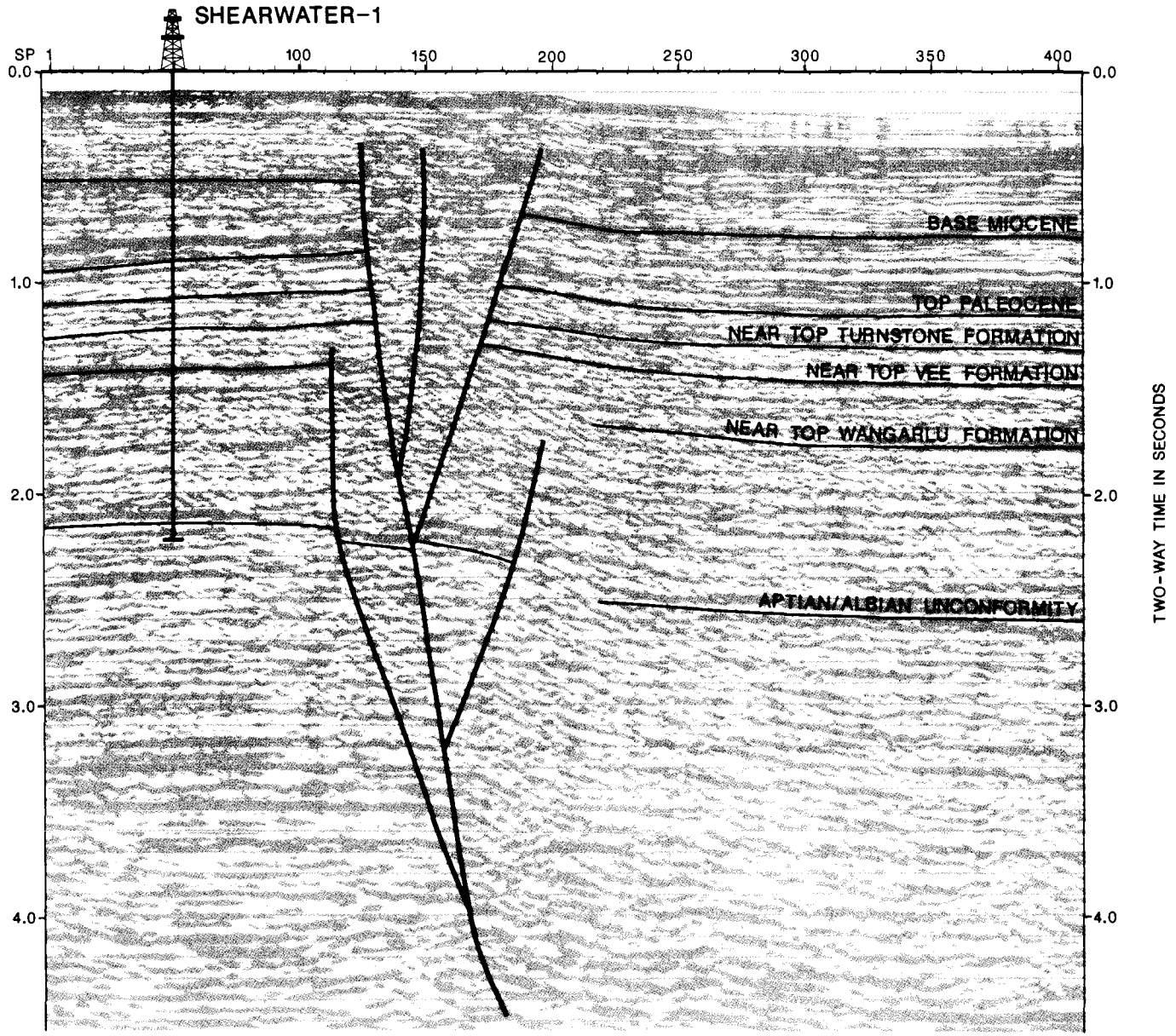


FIGURE 25 Interpreted portion of Seismic Line 85MA-1 across the Shearwater Structure

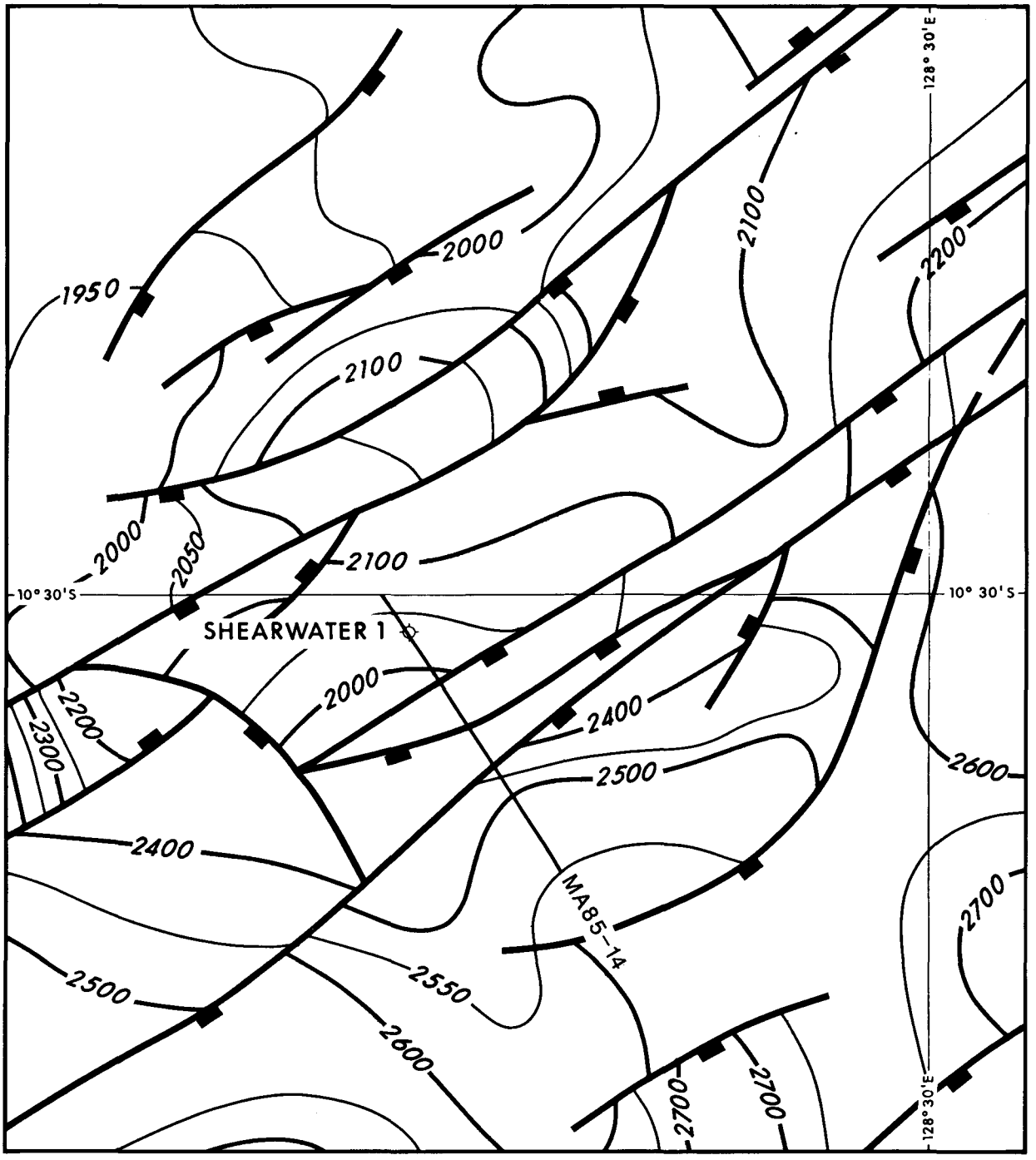


FIGURE 26 Shearwater 1 Time Structure Map
Near Base Bathurst Island Group (Cretaceous)

0 5
kilometres

Contour Interval: 50msec TWT

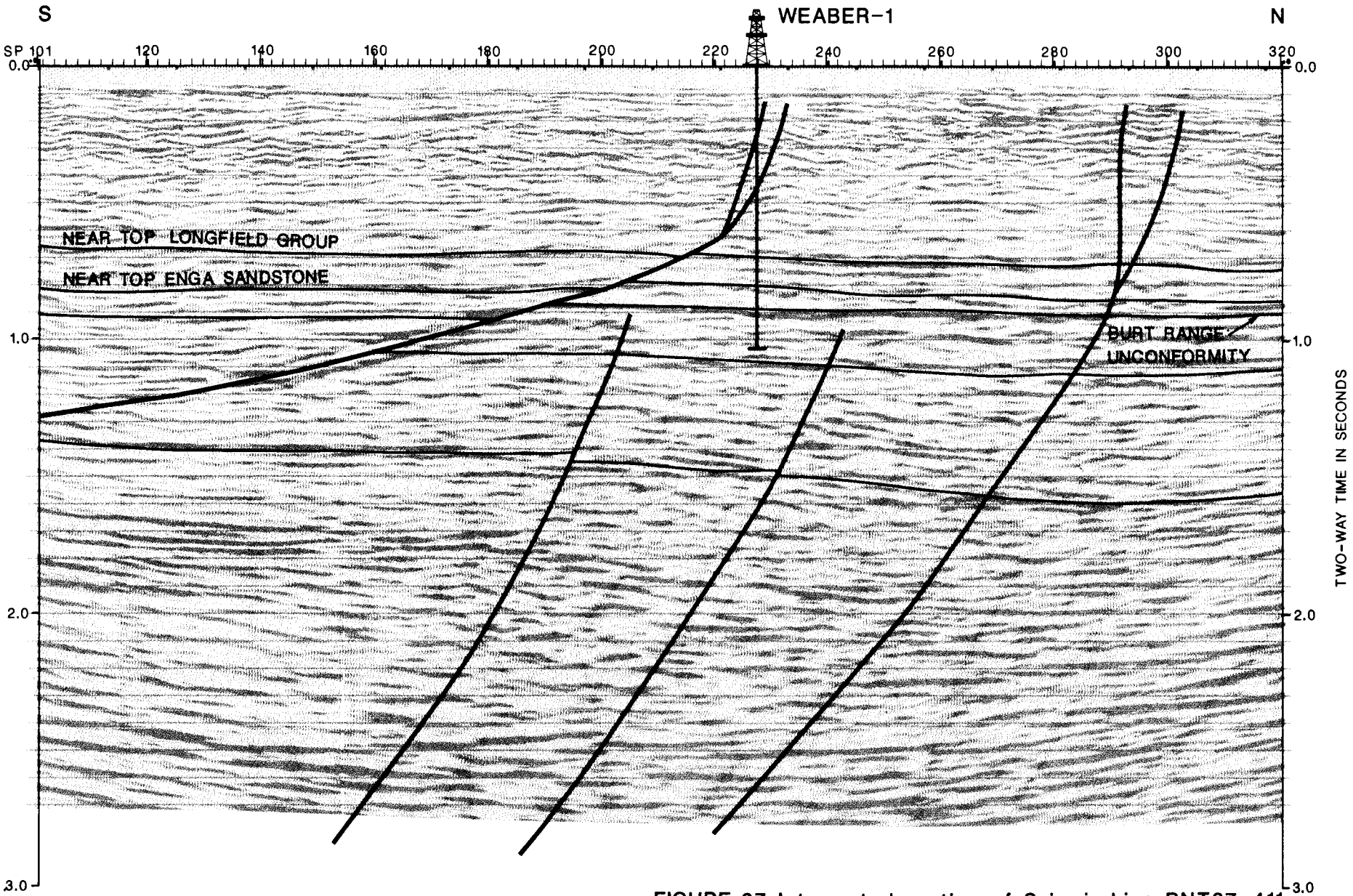


FIGURE 27 Interpreted portion of Seismic Line BNT87-411 across the Weaber Structure (Santos, 1988)

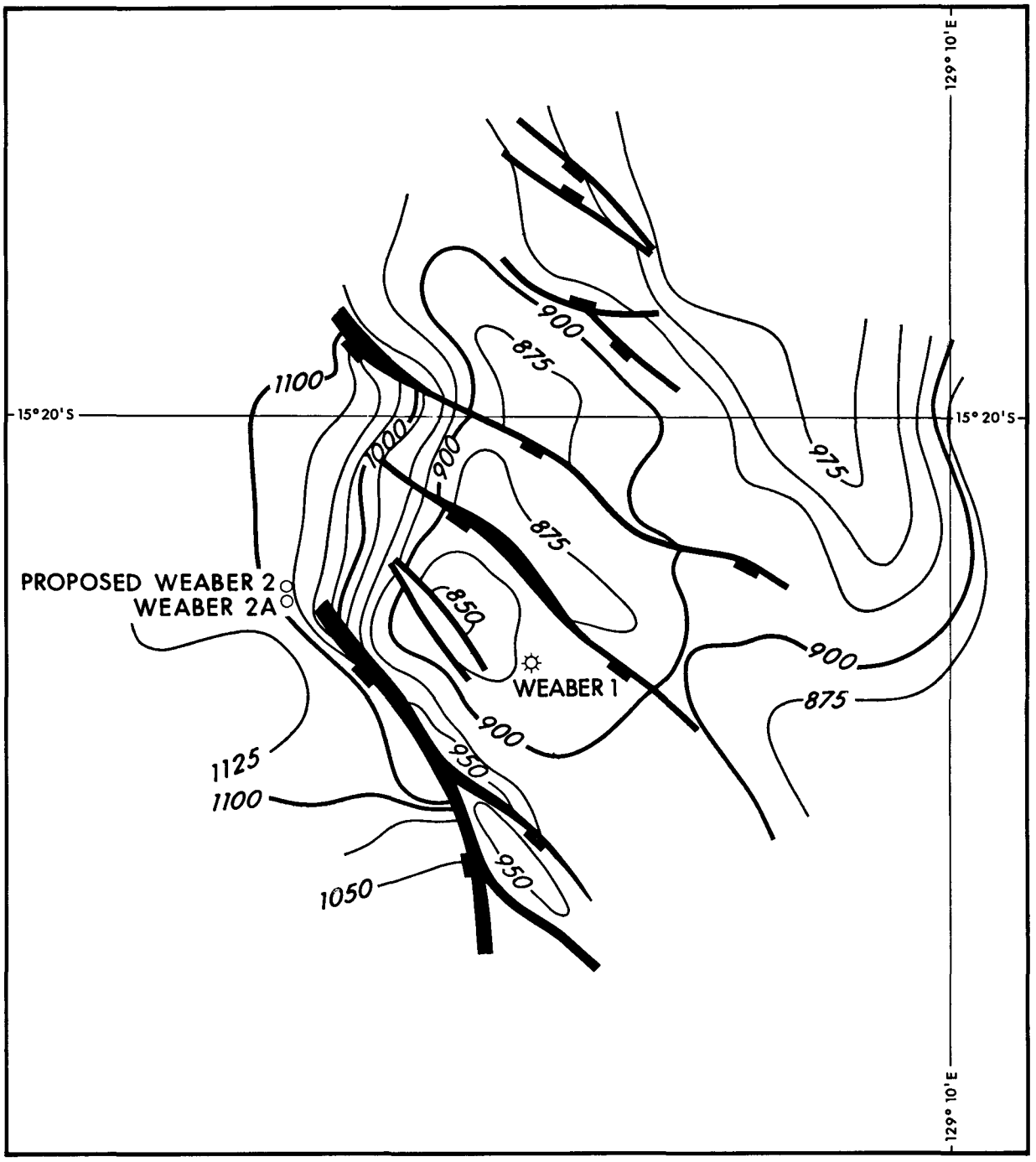


FIGURE 28 Weaber Field Time Structure Map

Mid Burt Range Unconformity (after Santos, 1988)

0 2
kilometres

Contour Interval: 25msec TWT

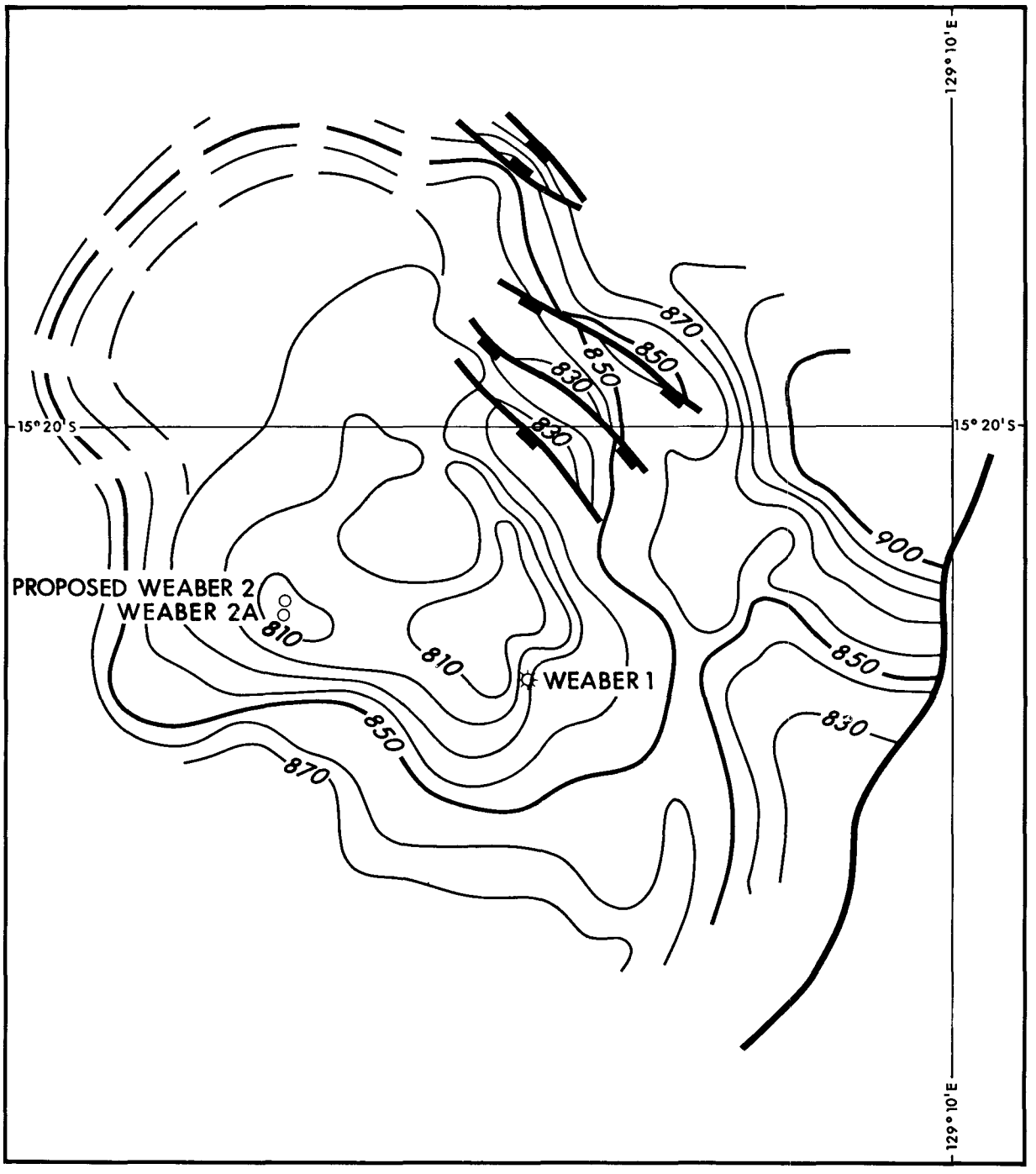


FIGURE 29 Weaber Field Time Structure Map

Enga Sandstone (after Santos, 1988)

0 2
kilometres

Contour Interval: 10msec TWT

A denser grid of 60-fold seismic data was acquired over the Weaber prospect in 1987. A much larger time closure was interpreted to be present, and Weaber #1 was interpreted to have been drilled down-flank on this structure (Figure 28). Weaber #2A was spudded in 1988 on the crest of the time high some 2.3 km west-northwest of Weaber #1 and unexpectedly found the objective Enga Sandstone some 100 m deeper than in Weaber #1 (Figure 29). The seismic data had been intrepreted to show strong erosional relief at the Burt Range Unconformity level. Alternatively, shallow faults may sole out at this level and be effectively unrelated to deeper structuring (Figure 27). The immature nature of the reservoir sequences (Figure 45) indicates that the gas migrated into place.

6.2.17 Jacaranda #1

Jacaranda #1 was drilled by Tricentrol in 1984 to test a four-way dip closure and fault dependent structure on the downthrown side of the fault zone flanking the Malita Graben (Figure 31). No closure exists at the near-base Tertiary level, however, fault dependent closure exists at the near-base Late Cretaceous level (Figure 30). Seismic sections show the structure to be intensely faulted and up-dip closure fault controlled. The arched nature of the structure at the Aptian/Albian unconformity level and below, together with a thickening sediment pile off the flanks of the structure, are suggestive of an association with a deep seated salt pillow or diapiric structure.

The primary objectives of the well were Jurassic sandstones (Enclosure 7), however, these sediments were found to be tight and water-wet. Late Cretaceous sandstones with good reservoir characteristics were encountered, but outside of mapped closure. The well was plugged and abandoned at a TD of 3783 m (12 412 ft) in the Plover Formation.

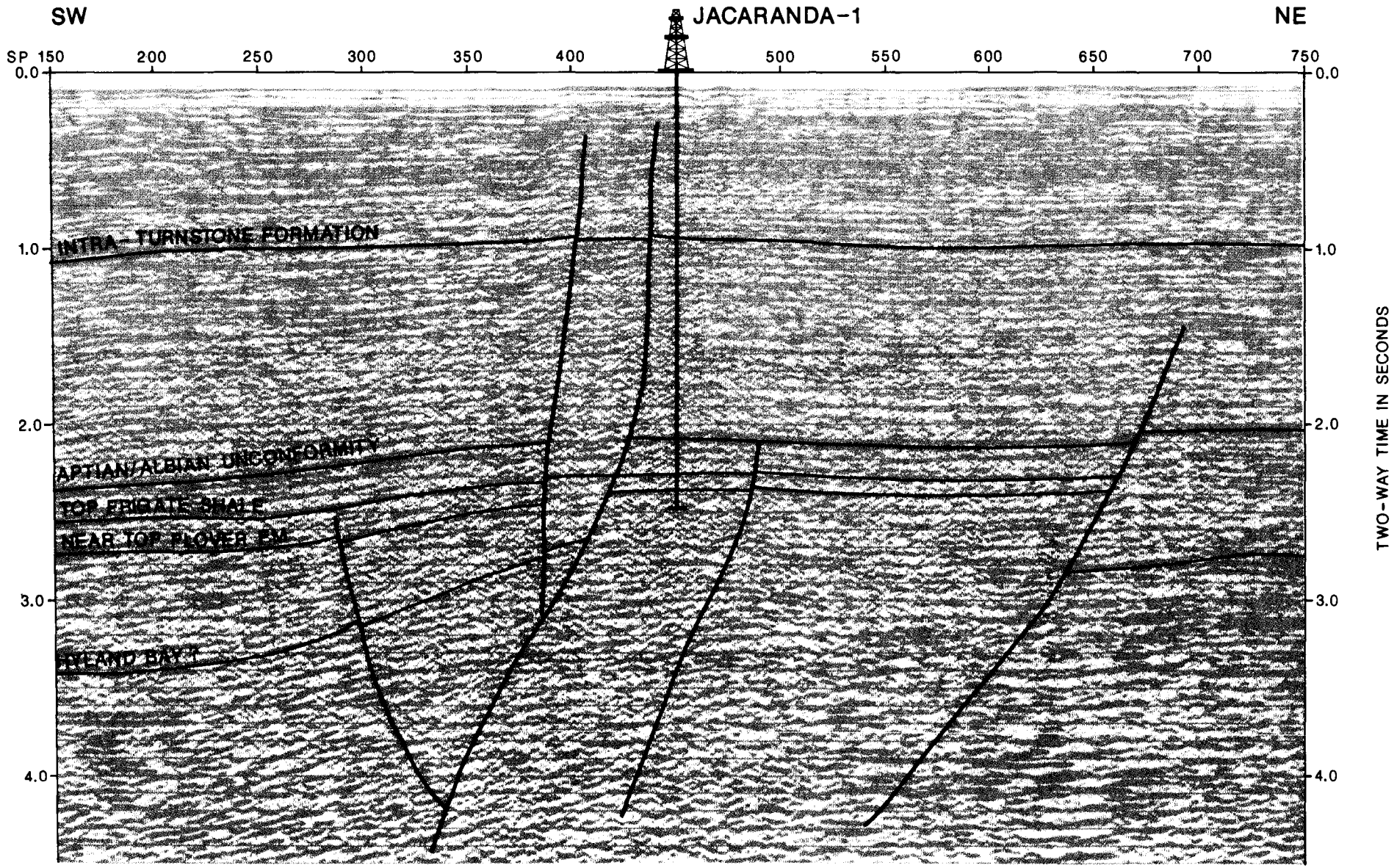
6.2.18 Darwinia #1A

Darwinia #1A, a shallow follow-up well to Jacaranda #1, was drilled by Tricentrol in 1985 to test a small four-way dip closure and a much larger fault dependent area in the central Malita Graben. The structure was interpreted to be closed and fault bound at the near-base Tertiary and near-base Late Cretaceous levels (Figure 32). The bounding fault of this structure is a major antithetic fault to the south-bounding fault zone of the Malita Graben. In this setting the structure has a broad low relief, similar to that at Evans Shoal #1 (Figure 34).

The primary objectives of the well were Upper Cretaceous sandstones because Jurassic sandstones were known to be tight and water-wet from the results of Jacaranda #1. The objective sandstones were encountered with good porosity and permeability but were water-wet. The well was plugged and abandoned at a TD of 2426 m (7960 ft) in the Bathurst Island Group.

6.2.19 Evans Shoal #1

Evans Shoal #1 was drilled by BHP in 1988 to test a large low relief anticline overlying an earlier faulted structure on the terraced flank of the Malita Graben. The structure is closed at the near-base Late Cretaceous level



0 3km

FIGURE 30 Interpreted portion of Seismic Line 83-103 across the Jacaranda Structure

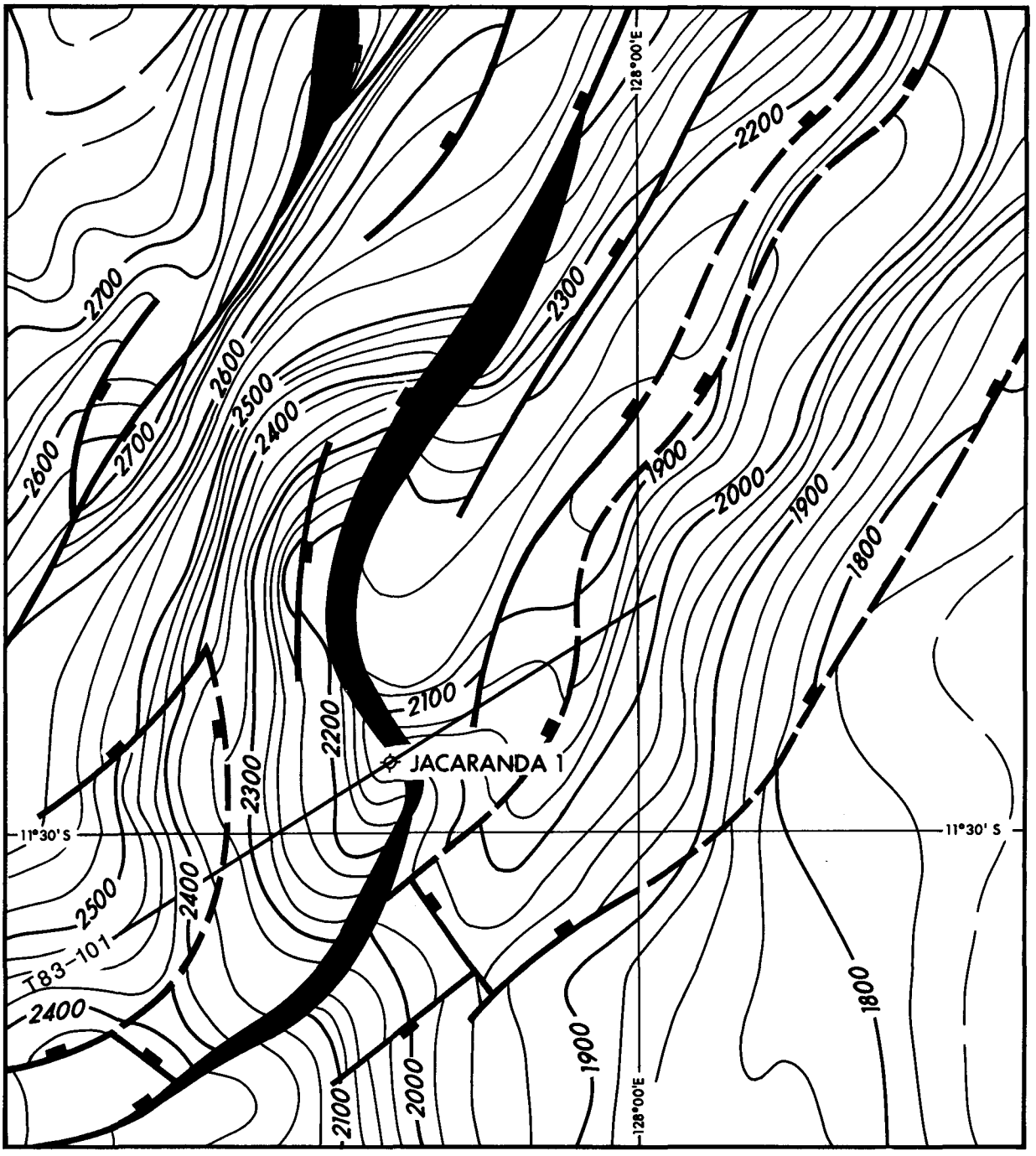


FIGURE 31 **Jacaranda Time Structure Map**
Near Base Bathurst Island Group (Cretaceous)

0 5
kilometres

Contour Interval: 25 msec TWT

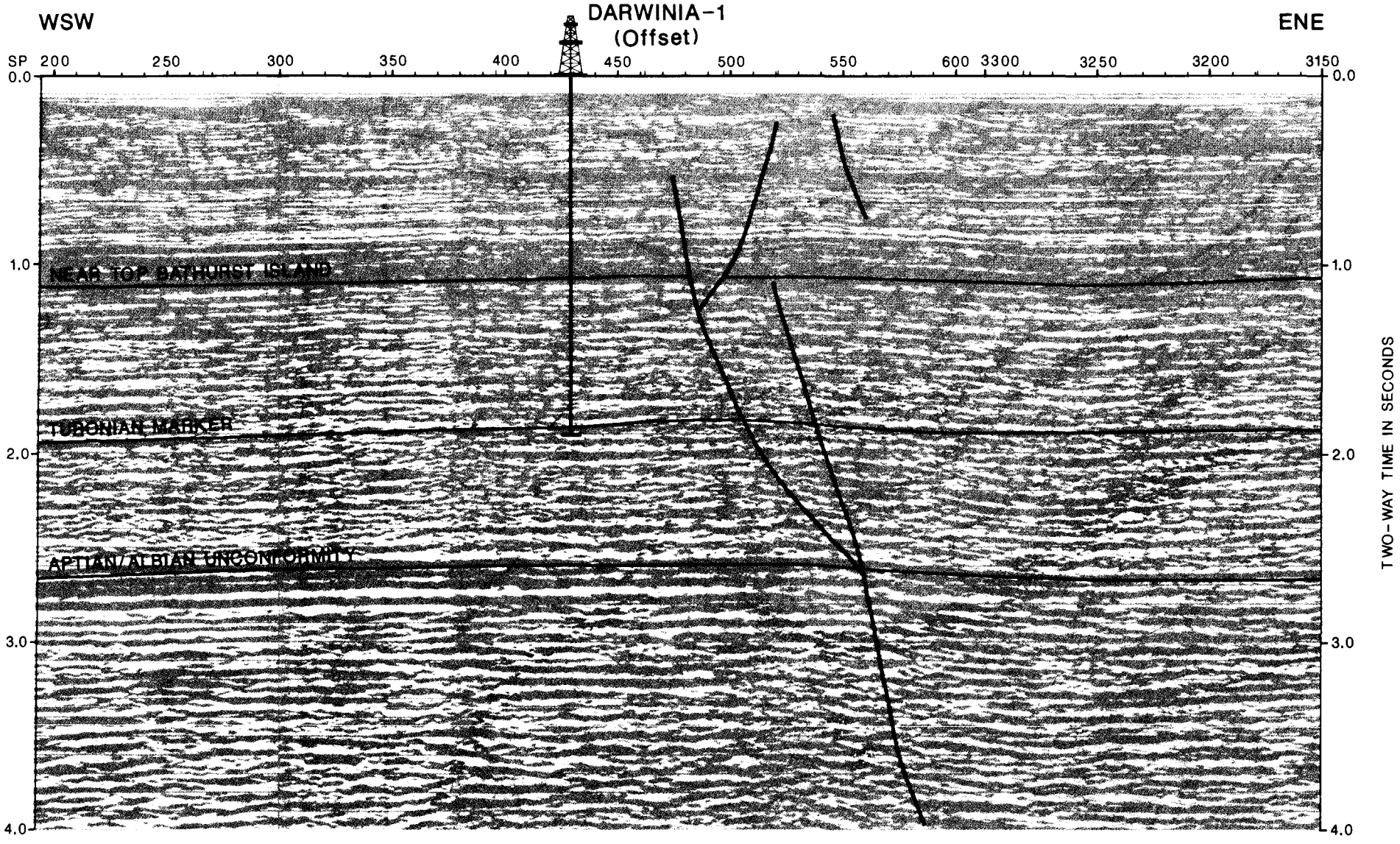


FIGURE 32 Interpreted portion of Seismic Line TEA84-1125 across the Darwinia Structure

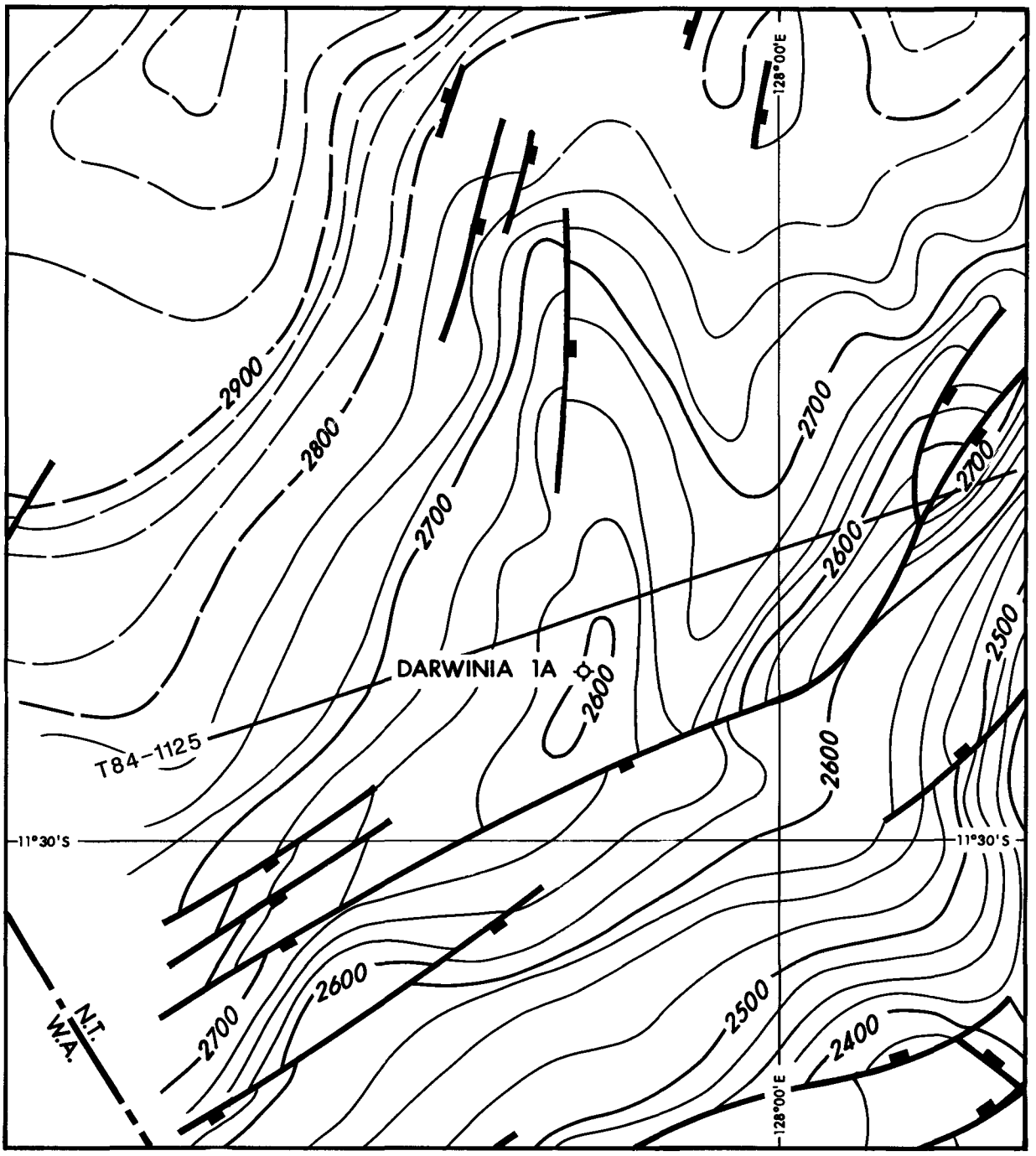


FIGURE 33 **Darwinia Time Structure Map**
Near Base Bathurst Island Group (Cretaceous)

0 5
kilometres

Contour Interval: 25 msec TWT

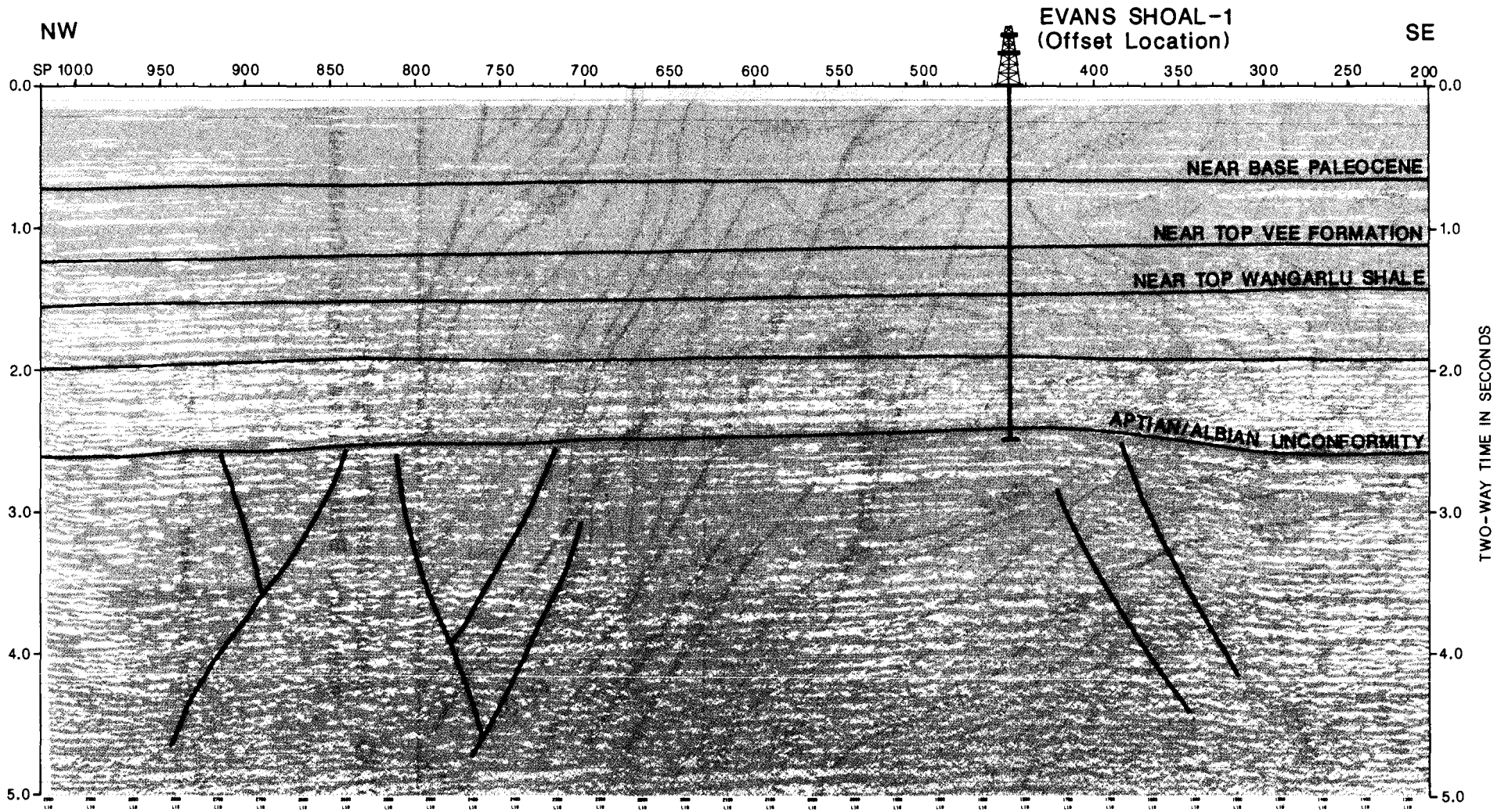


FIGURE 34 Interpreted portion of Seismic Line 86GL-18 across the Evans Shoal Structure

0 5km

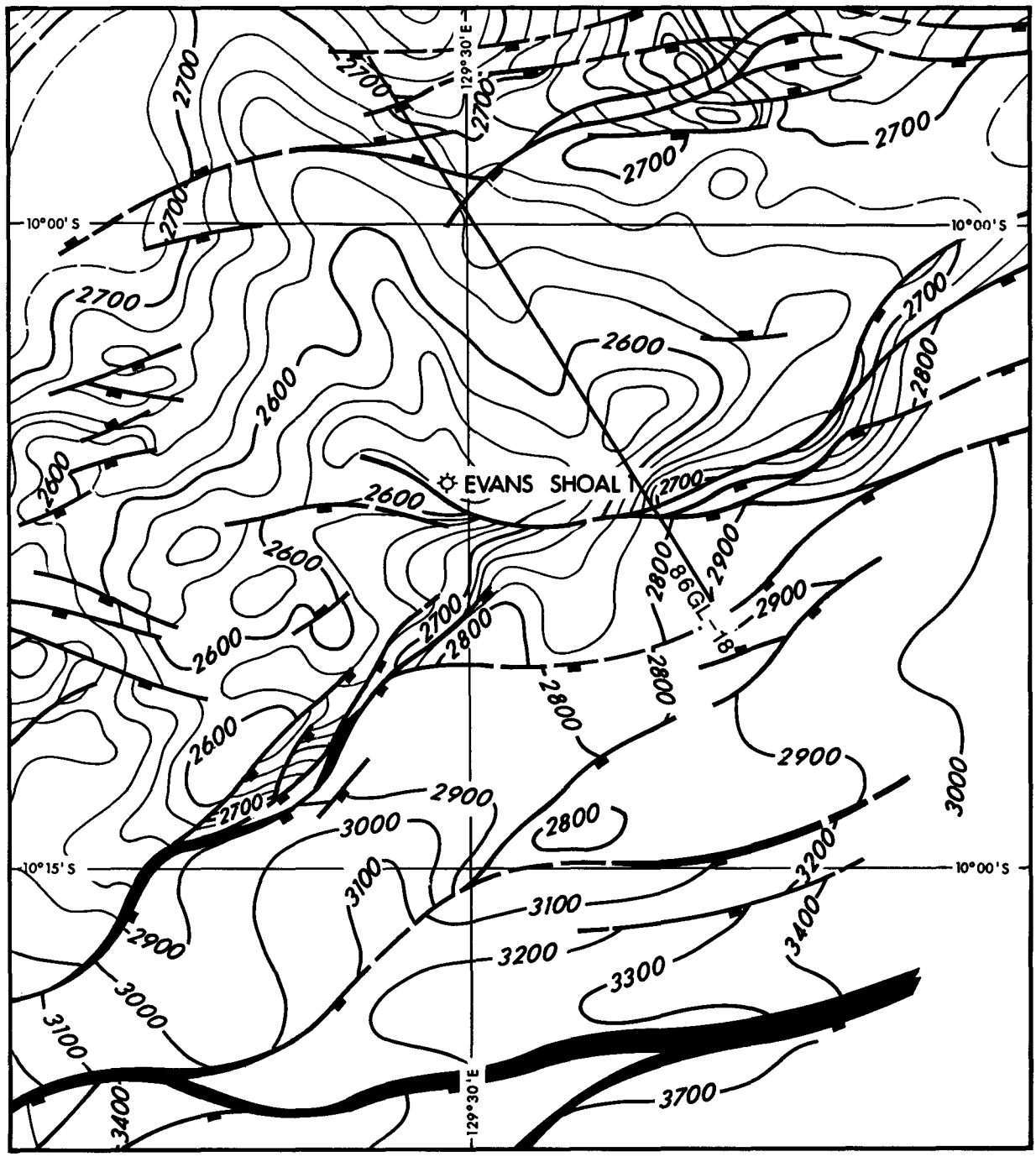


FIGURE 35 **Evans Shoal Time Structure Map Near Top Plover Formation (Middle Jurassic)**

0 5
kilometres

Contour Interval: 20 msec TWT

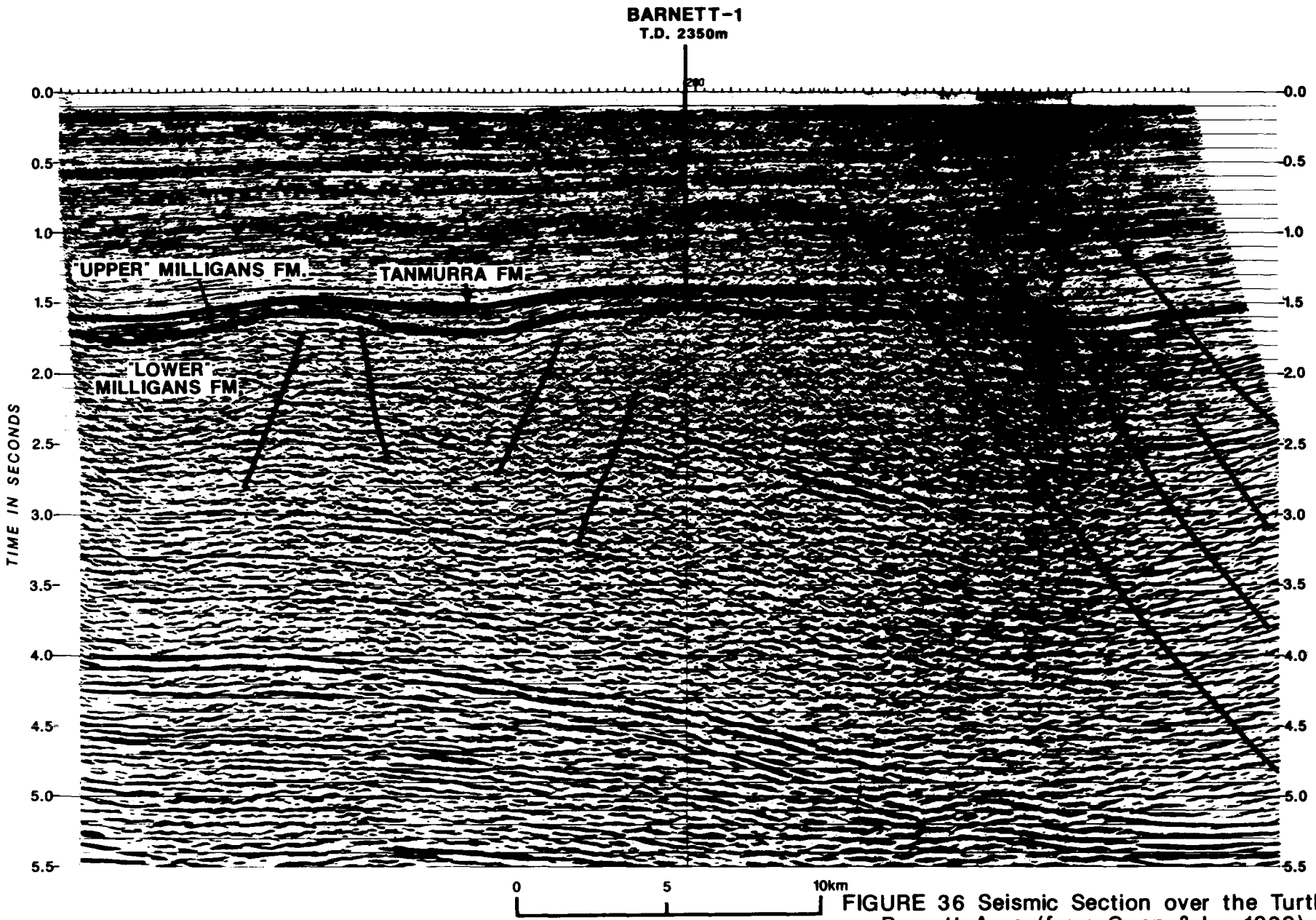


FIGURE 36 Seismic Section over the Turtle - Barnett Area (from Gunn & Ly, 1989)

with fault dependence on the southeastern flank (Figure 35). Closure below this level is also fault dependent as the intensity of faulting increases with major throw existing at the Jurassic level into the Malita Graben (Figure 34). The broad low relief nature of this structure is well defined on seismic profiles.

The primary objectives of the well were Jurassic sandstones and gas shows were recorded in a low porosity sandstone whilst drilling this section. The recovery of gas from wireline formation tests of the Jurassic is potentially significant as a larger volume of gas was recovered during testing in this well than in Sunrise #1. The well was plugged at a TD of 3712 m (12 179 ft) in the Plover Formation.

6.2.20 Barnett #1 & 2

Only basic data are available for Barnett #1 and Barnett #2 as at the time of writing this report these wells remain on closed file. Barnett #1 was drilled in 1985 by Aquitaine in NT/P 28 on a domal structure which Gunn & Ly (1989) interpreted as part of the axial dome formed by the injection of oceanic material during "upper" Milligans Formation time (Figure 36). Drape across the erosional relief provides closures for the Tanmurra and younger formations, including the Kulshill Group. A similar structural setting is likely for the nearby Turtle #1 well, which had good oil shows within the Kulshill Group. Turtle #2, drilled slightly off the crest to intersect potential stratigraphic pinchouts below the Tanmurra Formation, flowed oil from a depth of 2635 m (probably from the basal "upper" Milligans Formation).

Barnett #1 had significant oil shows in the Permo-Carboniferous Kulshill Group and Stirling Petroleum N.L. (Annual Report, 1989) indicated that Barnett #2 was intended to test the Kulshill Group in a slightly up-dip position as a secondary target. The primary target was the previously undrilled deeper section in the "upper" Milligans Formation which produced oil at Turtle #2.

Drilled late in 1989, DSTs in Barnett#2 produced a flow of 917 BOPD from the interval between 1491 and 1506 m in the Kulshill Group. The well reached TD within the "upper" Milligans Formation at a depth in excess of 2800 m and was cased as a suspended oil producer. A Barnett #3 appraisal well is planned for May to June, 1990.

7.0 HYDROCARBON POTENTIAL

The presence of gas and condensate in Sunrise #1 and Troubadour #1 on the Sahul Platform, gas in the Malita Graben at Evans Shoal #1, oil in Turtle #2 and Barnett #2, gas in the Petrel and Tern structures in the Petrel Sub-basin, and gas in Weaber #1 onshore, indicate that considerable quantities of hydrocarbons are reservoired in a wide range of geological settings within the Bonaparte Basin. An inventory of significant shows is given below in Section 7.1, and Sections 7.2, 7.3, 7.4 and 7.5 deal with source, maturity, geothermal gradients and reservoir properties of the Bonaparte Basin sequences.

7.1 HYDROCARBON SHOWS

The results of numerous hydrocarbon shows reported in a number of wells drilled within the Northern Territory portion of the Bonaparte Basin are outlined below and are specified in more detail in Appendix 5.

7.1.1 Barnett #1

Barnett #1, drilled in 1985, had significant oil shows within the Kulshill Group. Oil was recovered from an RFT (Repeat Formation Test) between 2095.5 and 2036 m at the top of the Point Spring Sandstone, and several gas peaks occurred between 2195 m to 2245 m.

7.1.2 Barnett #2

DST #1 was run through perforated tubing over the intervals 2393 to 2408 m and 2413.5 to 2421 m. This test flowed gas at 90 MCFPD and a small quantity of oil was recovered from the test string. DST #2 was conducted over the interval 1929 to 1935 m. No results have been published. Drillstem test #3 (1491 to 1497 m) flowed 550 BOPD of 39° API oil. DST #4 (1491 to 1497 m and 1500.5 to 1506.5 m) flowed 917 BOPD in a three hour test.

7.1.3 Bougainville #1

Traces of methane (C_1) were observed by the mud loggers over the Mount Goodwin, Fossil Head and Keyling Formations, as well as traces of fluorescence and cut towards the base of the Fossil Head Formation and the top of the Keyling Formation (Enclosure 6).

7.1.4 Curlew #1

Five formation interval tests (FITs) and three drillstem tests (DSTs) were run over the Jurassic Flamingo Group and Plover Formation (Enclosure 6) after shows of gas were observed while drilling; all recovered filtrate and salt water with no indications of hydrocarbons.

7.1.5 Evans Shoal #1

Significant gas shows were recorded in low porosity sandstones below the Valanginian Unconformity in the Plover Formation. Two wireline formation tests were reported (PEX, September, 1988); one run at 3678 m in the Plover Formation, recovered 78.8 ft^3 of gas and the second at 3554 m in the "Flamingo Shale" (the Frigate Shale), recovered 456.1 ft^3 of gas.

7.1.6 Flamingo #1

A FIT was undertaken over a section of the Jurassic Sandpiper Sandstone after encouraging hydrocarbon indications from a core. The test recovered only 0.13 m^3 of gas which indicated the zone to be tight (Enclosure 8). A very minor show was reported from the Jurassic Plover Formation whilst drilling.

7.1.7 Flat Top #1

Good quality sandstone reservoirs were encountered over the Permian to Cretaceous sections with porosities ranging from 15 to 30% and permeabilities ranging from fair to good. However, a FIT run at 1,473 m over the upper Fossil Head Formation yielded a trace of C_2 together with formation water (37 000 ppm NaCl).

7.1.8 Heron #1

Several gas shows were observed while drilling the Cretaceous and Jurassic sections of the well (Enclosure 8).

The more notable gas shows (methane to pentane) occurred over the following intervals, although none were tested.

2824 - 2926 m (9265 - 9600 ft)
3109 - 3155 m (10 200 - 10 350 ft)
3688 - 3703 m (12 100 - 12 150 ft)
3703 - 3828 m (12 150 - 12 560 ft)
4191 - 4208 m (13 750 - 13 808 ft)

7.1.9 Kulshill #1

Oil staining was observed while drilling through the Kulshill Group. Six DSTs were run over the Kulshill Group to evaluate these shows, but only small recoveries of fresh water and/or drilling mud were obtained (Enclosure 6). Gas shows were also encountered over the same interval and within the older Carboniferous and Devonian sections.

7.1.10 Kulshill #2

The well encountered fluorescence in the Treachery Shale and fair to good oil shows in the Point Spring Sandstone. Numerous gas shows were also noted.

7.1.11 Lynedoch #1

Lynedoch #1 encountered a thin hydrocarbon bearing zone (10 m thick and probably gas) within an Early Cretaceous interval between 3674 m and 3715 m, (Enclosure 8), but poor hole conditions prevented proper evaluation (Shell, 1973). Gas shows were also present in the Plover Formation.

7.1.12 Petrel #2

Petrel #2 was drilled as a follow-up to the initial gas discovery well Petrel #1. Late Permian sands of the Cape Hay Member located between 3653

to 3671 m (11 982 - 12 040 ft) tested dry gas at a rate of 186 000 - 411 000 m^3/day (6.6 - 14.5 MMCFPD) on a 1.27 cm (1/2") choke (DST #6) (Enclosure 6). The Petrel Field is currently shut-in awaiting development (Section 3).

7.1.13 Shearwater #1

Minor dead oil staining was encountered in the Jurassic Plover Formation (Enclosure 8), however, no tests were conducted.

7.1.14 Sunrise #1

Fluorescence and an increase in gas readings were observed at the top of the Jurassic Plover Formation. Two zones of interest were identified and evaluated with FITs #2 and #4, both yielding recoveries of gas and condensate (Enclosure 7).

FIT	Interval	Recovery
#2	2,303 m	2.563 m^3 (90.5 ft^3) gas, 545 cm^3 condensate and 365 cm^3 mud/condensate emulsion
#4	2,144 m	4.15 m^3 (146.6 ft^3) gas, 800 cm^3 condensate and 800 cm^3 mud

7.1.15 Troubadour #1

Two DSTs were conducted over the Jurassic Plover Formation, both recovering gas and condensate (Enclosure 7).

DST #2 2228 - 2244 m (7310 - 7363 ft) rec. gas to surface at 279 000 m^3 /day (9.85 MMCFPD) and 35.66 m^3/day condensate (224.3 BCPD) with a trace of water

DST #3 2206 - 2211m (7238 - 7254 ft) rec. gas to surface at 41 500 m^3 /day (1.447 MMCFPD) and 2.08 m^3 /day condensate (13.1 BCPD) and 0.49 m ^{3}/day water (3.1 BWPD)

7.1.16 Weaber #1

Weaber #1 was drilled by Australian Aquitaine in 1982 to a total depth of 195 m. Maximum gas shows of 3.12% and 4.2% were recorded at 1400 m and 1463 m but no DSTs were run and the well was plugged and abandoned. Subsequently, Weaber #1 was found to be leaking gas to the surface. Re-analysis of the electric logs showed that there might be considerable gas accumulation at least within two sandstone beds in intervals 1300 to 1305 m and 1396 to 1414 m.

After re-entry of Weaber #1 in 1985, four DSTs were run. DST #1 was a valid test of the interval 1281 to 1313 m. Gas flowed to surface after 12 minutes, and flowed steadily after 34 minutes at the rate of 2.0 MMCFPD through a 1/2" choke with stabilised surface pressure of 321 psi. No fluid recovery was reported.

DST #2 was an invalid test of the interval 1357 to 1421 m and DST #3 was also invalid test of interval 1372 to 1421 m. DST #4, a valid test of interval

Age		Stratigraphic Units		Lithology	Shows	Environment	Hydrocarbon Potential				
							source	reservoir	seal	maturat'n	other
Permian		Keep Inlet Formation				fan delta and glaciomarine	poor to moderate	good	moderate	immature	
Carboniferous	Namurian	Weaber Group				fluvio-deltaic to shelf	poor	good	poor	weakly mature	fresh-water flushed
Carboniferous	Visean	Milligans Formation			☼ ☼	offshore marine	good (TOC up to 2%)	good (minor)	very good	mature	small oil shows in Spirit Hill 1
Carboniferous	Tournaisian	Langfield Group	Bonaparte Formation		●	shoreface to shelf	very poor	good	poor	mature	bitumen shows in mineral drill holes
Late Devonian	Famennian	Ningbing Group	Bonaparte Formation		●	reef complex	moderate (TOC up to 1.3%)	moderate to poor	poor to good	mature	bitumen shows in mineral drill holes
Late Devonian	Frasnian	Cockatoo Group	Bonaparte Formation			shallow marine, tidal, fluvial, alluvial and eolian	very poor	very good	very poor	mature	? fresh-water flushed
Early Ordovician-Cambrian		Carlton Group				intertidal to shallow marine	?	good	?	over mature	
		Antrim Plateau Volc.				continental					
Proterozoic		undifferentiated									

(From Mory and Beere, 1988)

GSWA 23396

GENERALISED STRATIGRAPHIC HYDROCARBON POTENTIAL

Figure 37

1273 to 1421 m KB, tested both upper and lower sandstone beds in an open hole test below the 9$^{5/8"}$ casing. Gas flowed to surface after 9 minutes. Gas flowed during two flow periods as follows:

1st flow period: Gas flowed at a rate of 3.6 MMSCFPD through a 1/2" choke at an average surface pressure of 585 psi.

2nd flow period: Gas flowed at a rate of 4.5 MMSCFPD through a 1/2" choke at an average surface pressure of 735 psi. No fluid recovery was reported.

7.1.17 Weaber #2

Significant gas shows were recorded through two sands in the Early Carboniferous Milligans Formation. Two drillstem tests were run over the sands at Weaber #2. DST #1, run over the interval 1016 -1044 m, was a misrun due to tool plugging during the flow period. DST #2, run after electric logging over the interval 1020 - 1037 m, flowed gas at a rate of 0.134 MMCFPD through a 13 mm (1/2") top choke. 59 m (1.4 BBLS) of slightly gas cut muddy filtrate (Rw = 0.344 @ 25°) and mud were recovered.

7.2 SOURCE POTENTIAL

The review of source rocks in this section is based on published reports and available open file data. Appendix 5 contains a tabulation of data sources as well as the criteria employed to relate quantitive source rock measurements to the qualitative descriptions applied herein.

7.2.1 Source Rock Quality (Richness)

The amount of total organic carbon (TOC) contained within a rock is the prime determinant of its source potential. In clastic rocks 0.5% TOC is generally accepted as the minimum requirement to constitute a viable, hydrocarbon source rock, although as little as 0.2% may be adequate for carbonates (Tissot & Welte, 1978). The average TOC values for selected formations, calculated by averaging all measured TOC contents for a particular well, are plotted on Figure 37. Maximum measured TOC values are tabulated in Table 2.

As indicated in Section 7.1, the presence of hydrocarbons, in the form of oil recoveries from Sunrise #1 and Turtle #2 and Barnett #2, gas and condensate from Troubadour #1, gas at Weaber #1, and the substantial gas reserves in the Petrel structure indicate that the Northern Territory portion of the Bonaparte Basin has generated considerable quantities of hydrocarbons.

Cambro-Ordovician

No source rock studies have been carried out on rocks of this age in the Bonaparte Basin. However, the presence of oil shows in vesicular basalts of the Antrim Plateau Volcanics in the Ord Basin (Wade, 1924) indicates that potential oil sources may occur in these sediments. Wade (1924) suggested such source beds occur in the overlying marine Cambrian sediments. Mory & Beere (1988) note that the Early Palaeozoic in the Bonaparte Basin has no prospectivity since it is overmature, being buried

TABLE 2

WELLS CONTAINING SIGNIFICANT SOURCE ROCK SECTIONS

Well Name	Depth of Section (M)	Formation Sampled	Lithology	%Ro	Maximum measured	Oil/gas generative TOC - %
Bougainville #1	2561 - 2570	Keyling Formation	mudstone	.55	6.12	Oil & Gas
Flat Top #1	899 - 906	Flamingo Group	blk.lignite	.42	1.75	Oil & Gas
	1287 - 1299	Hyland Bay Formation	mudstone	.55	1.11	Gas
	1659 - 1671	Keyling Formation	mudstone	.57	3.17	Oil
	1921 - 1936	Keyling Formation	mudstone with trace limestone	.63	2.5	Oil
Kinmore #1	1470 - 1500	Keyling Formation	mudstone/ coal	.52	17.58/ 65.8	Oil
	1796 - 1820	Keyling Formation	mudstone/ coal	.57	6.96/ 51.1	Oil
Kulshill #1	1332	Kuriyippi Formation	mudstone/ siltstone	.67	22.3	Oil & Gas
Darwinia #1A	2380 - 2391	Bathurst Island Group	carbonaceous	.6	4.0	Oil
Gull #1	2073 - 2088	Bathurst Island Group	Mudstone	.47	1.03	Gas
	2210 (core)	Plover Formation	Mudstone	.56	2.19	Oil
Lynedoch #1	2033 - 2036	Bathurst Island Group	Mudstone	.46	3.43	Oil & Gas
Flamingo #1	2990	Darwin Formation	Mudstone	.4+	3.10	Oil
Sunrise #1	2100	-	Shale	.60	0.95	?Gas
Troubadour #1	2207.2 (Core)	Plover Formation	Mudstone	.57	2.70	Gas
Heron #1	3842 - 3857	Frigate Shale	Mudstone	2.26	5.39	Gas
	4162 - 4131	Frigate Shale	Siltstone	indet	25.67	Gas

to greater than 3.5 kms. However, this observation does not negate potential hydrocarbon generation at earlier periods of the basin's history, or in less deeply buried areas.

Siluro - Devonian

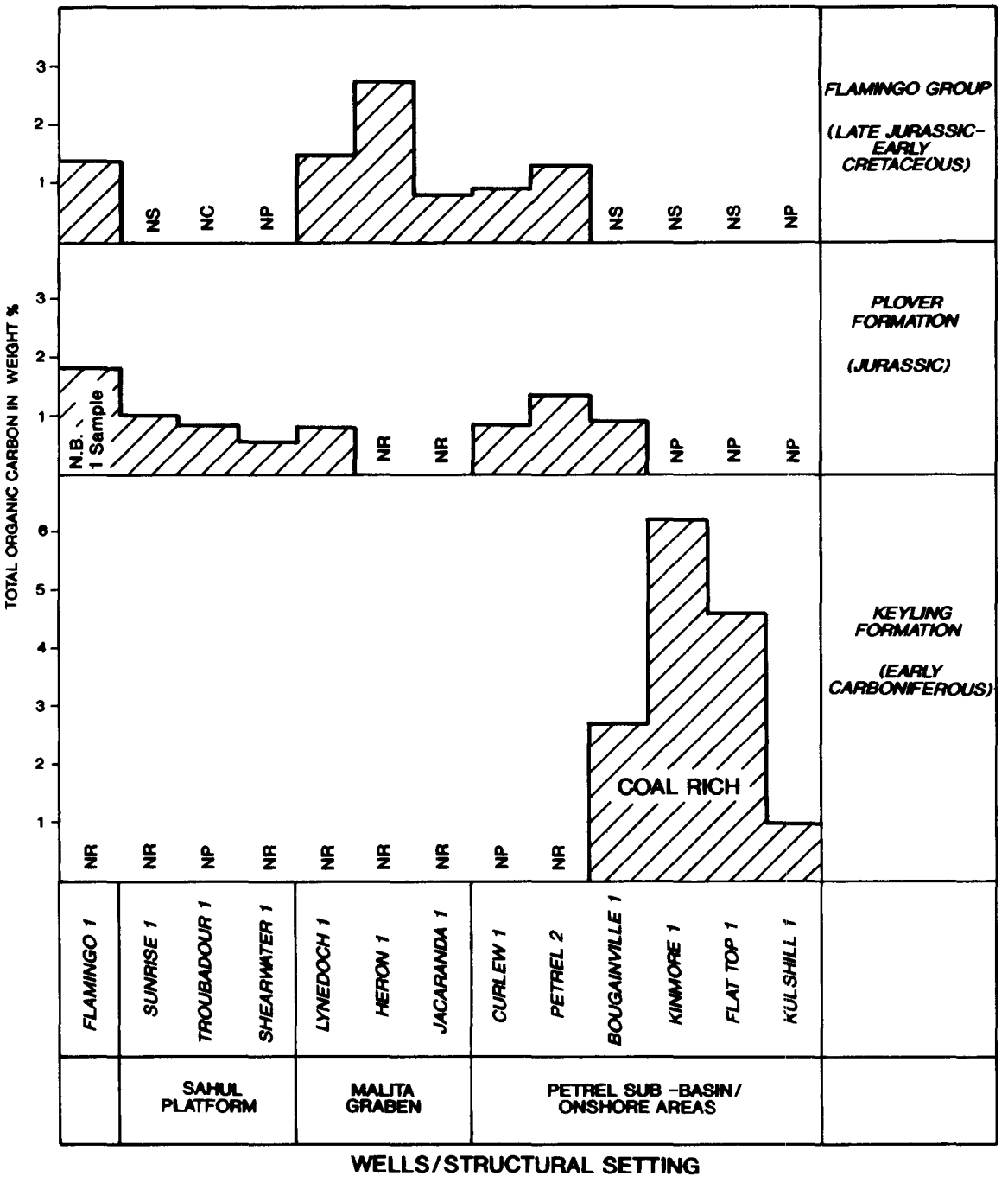
As the nature of sediments deposited in this time interval remains speculative, little can be said about their source potential. However, evaporitic sequences, while generally regarded unfavourably as potential sources for hydrocarbons, can contain appreciable amounts of organic matter and constitute potential source rock sequences.

Middle Devonian to Early Carboniferous

Mory & Beere (1988) noted that the Cockatoo Group sediments had generally poor source rock characteristics (Figure 37), a conclusion in keeping with the generally non-marine to tidal depositional environments of these Mid Palaeozoic deposits in the present onshore area.

In the onshore Bonaparte Basin, indications of oil staining in the vuggy Ningbing Group carbonates, the Enga Sandstone and Septimus Limestone, led Laws (1981) to infer that the source of this oil was the overlying basal Bonaparte Formation (that is, Milligans Formation). However, a more basinward sampling of this section by Analabs (1985a) at Kulshill #1 indicated the section to be a gas generative section. Mory & Beere (1988) noted that the shows occurring in shallow mineral holes in the Ningbing and Langfield Groups have chromatographic signatures similar to oil from shales in the Milligans Formation, suggesting that the Milligans may be the source. However, McKirdy (in Garside, 1983) noted that the undegraded oil show within the Kamilili Formation (Ningbing Group) in Ningbing #1 was derived from intraformational, organic rich, micritic limestones.

Mory & Beere (1988) reported up to 2% TOC in the Milligans Formation of the Weaber Group (Figure 37). Jefferies (1988), in his analysis of the oil recovered in Turtle #1, suggests, but does not firmly establish, that the source of oil found in the upper Kuriyippi Formation sands was the underlying marine shales of the Milligans Formation, a section not sampled at that location. The gas recovered from the Enga Sandstone (Langfield Group) at Weaber #1 (McKirdy in Garside, 1983) may have been generated off-structure from exinitic and vitrinitic kerogens of the Milligans Formation. However, and in contrast, Lavering (1989) stated that oil-prone organic matter is present in the Milligans Formation in areas near the basin margin, and away from the basin margins the Milligans Formation is mainly gas-prone. The Tanmurra Formation also may have some source potential.



NS Not Sampled
NP Not Present
NR Not Reached
NC Not Computed

AVERAGE TOTAL ORGANIC CARBON VERSUS FORMATION

Figure 38

Late Carboniferous to Early Permian
The Kuriyippi Formation contains live oil staining in several wells within or near the Northern Territory portion of the Bonaparte Basin (e.g. Lacrosse #1, Kulshill #1 and Turtle #1). Coaly beds within the non-marine Kuriyippi at Kulshill #1 contain up to 22% TOC with mixed oil and gas generative ability, as shown by Rock-Eval pyrolysis (Analabs, 1985a), suggesting that the Kuriyippi itself may be the source for at least some of these shows (cf. Jefferies, 1988).

The Keyling Formation, which exhibits a more marine influence than the other formations of the Kulshill Group, contains organic-rich sections in several wells sampled to date. The organic matter is dominantly humic and associated with coals. TOC values of up to 13.6% were measured at Flat Top #1 (Analabs, 1985a) with up to 65.8% recorded at Kinmore #1 (Robertson Research, 1979). Generally lower values occur at Kulshill #1 (maximum TOC 4.56%) and Bougainville #1 (maximum TOC 6.12%). Average total organic carbon values are shown for several wells in Figure 38.

The Fossil Head Formation is not generally regarded as a potential hydrocarbon source despite its partial marine origin and TOC as high as 2.99% at both Bougainville #1 and Kinmore #1 (Robertson Research, 1979). These good source rock richness values occur in the lower part of the formation. Poorer sources are indicated at Flat Top #1, Kulshill #1 and Petrel #2, where maximum TOC content seldom exceeds 2%.

Late Permian to Late Triassic
The marine to deltaic (Bahtia et al., 1984) Hyland Bay Formation contains generally poor source rocks despite TOC values of 1.63% at Petrel #2, 9.95% at Bougainville #1 and 2.97% at Kinmore #1. Lee & Gunn (1988) point to the underlying marine shales as the probable source sequences for the Hyland Bay Formation hydrocarbons, but do not state the formation of origin.

The Mt Goodwin Formation contains less than 1.0% TOC at Petrel #2, Bougainville #1, Flat Top #1 and Troubadour #1, indicating poor source rock potential. Similar conclusions are drawn for the sand dominated Cape Londonderry Formation and the red bed lithologies of the Malita Formation.

Jurassic
The Plover Formation contains potentially fair to good oil source rocks. TOC values extend up to 2.85% at Petrel #2 (average 1.37%, 19 values, Robertson Research, 1979; Analabs, 1985a), 2.70% at Troubadour #1 (average 0.81%, 27 values, Robertson Research, 1979; Analabs, 1985a; BP, 1984), 1.36% at Bougainville #1 (average 0.90%, 6 values, Analabs, 1985a), 0.81% at Shearwater #1 (average 0.53%, 7 values, Analabs, 1985a; BP, 1984), 1.11% at Curlew #1 (average 0.83%, 2 values, Analabs, 1985a), 1.80% at Flamingo #1 (one value, BP, 1984), and 0.95% at Sunrise #1 (average 0.71%, 6 values, BP, 1984). Based on these data the best source beds, in terms of TOC, occur in the Petrel Sub-basin in the Petrel area (Figure 38).

Within the Malita Graben two samples were collected from the Plover Formation at Lynedoch #1 (average 0.76%, Analabs, 1985a).

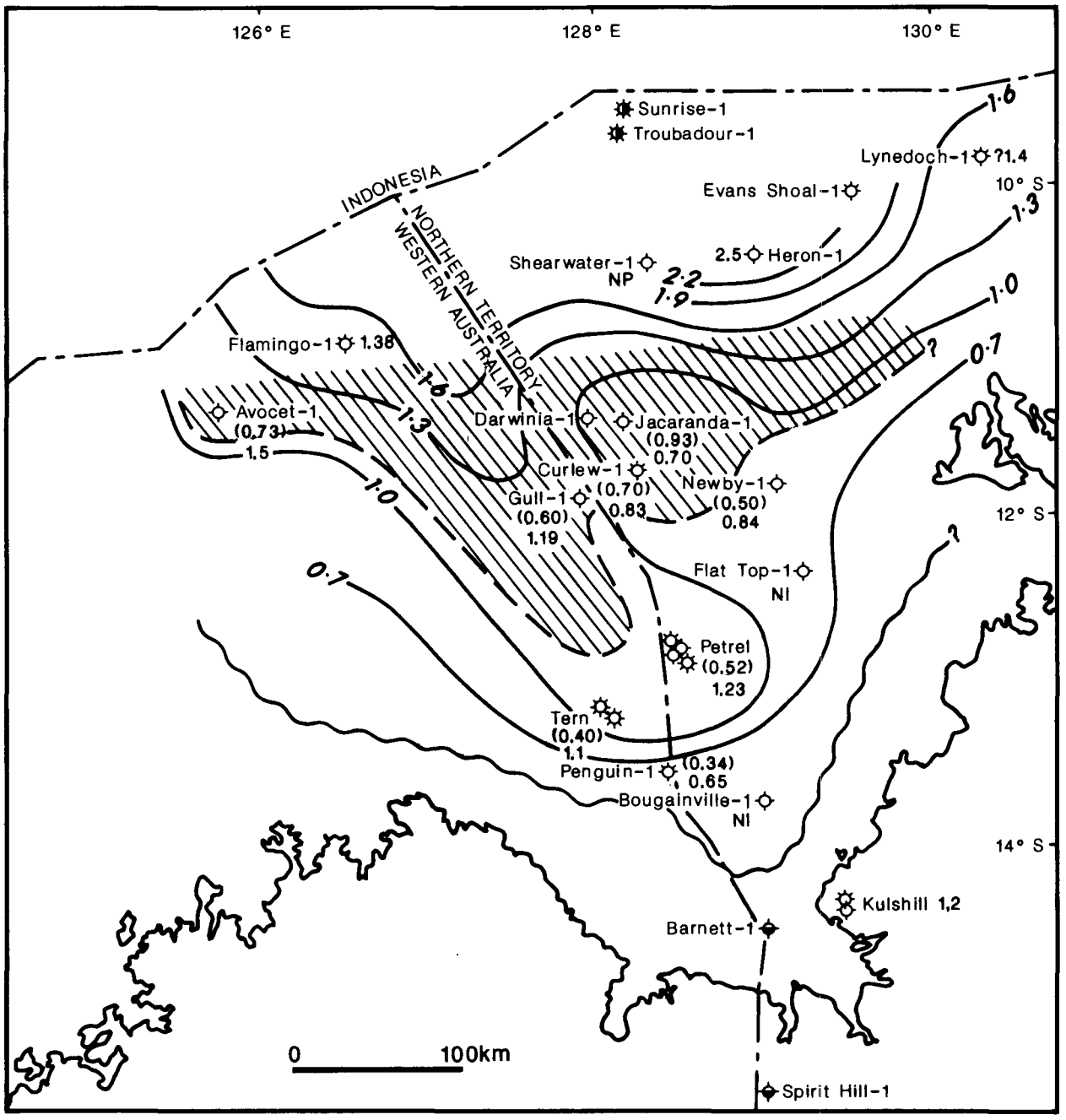


FIGURE 39 Source Rock Potential (TOC) and Maturity, Flamingo Group

LEGEND

~~	Erosional/Depositional Limit
NI	No Information
(0.52)	Average % Ro
1.1	Average TOC
	% Ro = 0.6, Onset of Oil Generation

In Evans Shoal #1 TOC content of the Plover Formation (from 3541 m to T.D.) was variable, values ranging from 0.34 to 3.60%, reflecting the variable, and generally sandy nature of this section. Selected claystones in the core at T.D. yielded TOCs of 2.00 - 3.60%. Generally the source potential of the Middle Jurassic claystones could be considered to be moderate to very good in the Malita Graben.

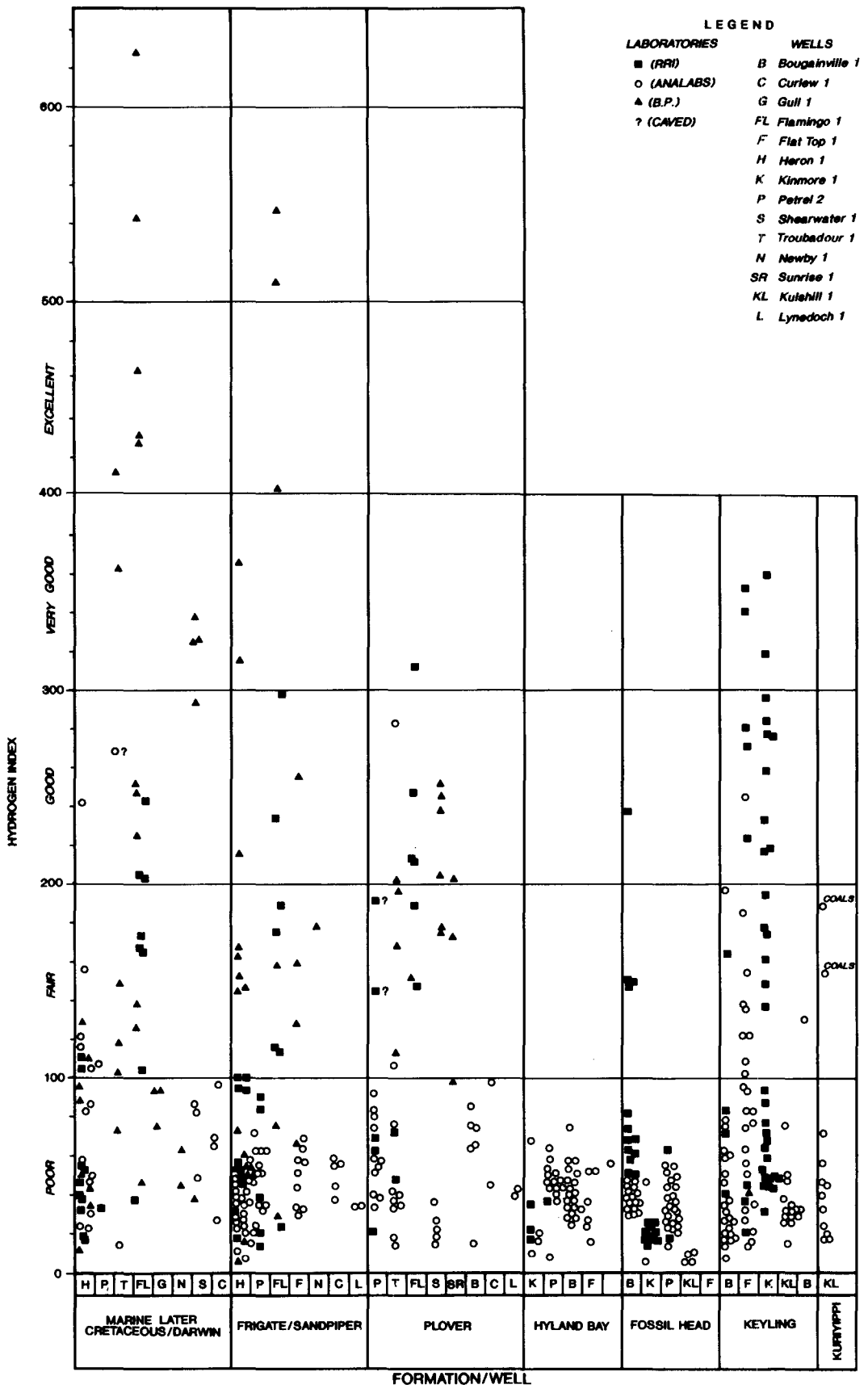
Late Jurassic - Early Cretaceous (Flamingo Group)
The thick siltstones and shales of the Frigate Shale and parts of the Sandpiper Sandstone have good to excellent source potential.

At Heron #1 in the Malita Graben, TOC values range as high as 26.49% (picked cuttings, Robertson Research, 1979), with an average TOC of 2.5% (78 samples) or 1.91% if the two highest picked values are excluded. At Lynedoch #1 an average TOC of 1.4% for two samples is present in the ?Frigate Shale (Analabs, 1985a). At Jacaranda #1, the combined Frigate - Sandpiper interval has a maximum TOC of over 2% and an average of about 0.70%. While based on only 3 wells, the greater TOC in the Heron location and the decrease in sand content is consistent with a more offshore depositional environment in the Malita Graben (Figure 38). In Evans Shoal #1 the interval 3462 - 3541 m (Darwin Formation or Frigate Shale) is rich in TOC with values ranging from 0.81 - 2.29%. A sidewall core of definite Oxfordian age at 3540.9 m has a TOC of 1.49% (BHP, 1988).

In the Petrel Sub-basin only the Frigate Shale has been analysed. A maximum TOC of 1.86% was measured at Petrel #2 with an average of 1.23% (19 samples, Robertson Research, 1979; Analabs, 1985a). At Tern #1, only 1 sample was analysed, with a TOC of 1.1% recorded. In the Curlew #1 well, a maximum of 1.0% TOC was reported (Analabs, 1985a) with an average of 0.83% TOC (9 samples). In the Flamingo #1 well a maximum of 2.71% TOC with an average of 1.38% (24 samples) was recorded in the Frigate Shale.

From Figures 38 and 39, it can be seen that the best source beds in this interval are concentrated in the Petrel Sub-basin and Malita Graben, both probable centres of active downwarping at this time.

Later Cretaceous
In the inshore area, the Mid to Late Cretaceous Bathurst Island Group generally has poor to fair source potential as indicated by TOC values, and where contents are sufficiently rich, the organic matter appear to be gas-prone. However, in Flamingo #1, the hand picked BP samples indicate TOC values as high as 1.3%. Similarly, at Lynedoch #1 up to 3.43% TOC was measured in the Campanian to Maastrichtian section. In the Heron #1 area, TOCs as high as 1.79% have been reported (Robertson Research, 1979) in picked samples from the lower Turnstone Formation, and 1.35% from cuttings in the Vee Formation (Analabs, 1985a). In the Petrel Sub-basin, BP reported 5.5% TOC from picked cuttings in the Wangarlu Formation, and 1.26% was measured in the Wangarlu Formation at Petrel #2.



SOURCE ROCK QUALITY VERSUS STRATIGRAPHY AND LABORATORIES

Figure 40

7.2.2 Source Rock Quality

Figure 40 shows a comparison at present day maturation states of the source rock quality as measured by the Rock Eval Hydrogen Index (HI) for selected potential source rock-bearing formations. Also shown for comparison are the measured values from three different laboratories. It is noticeable that, in some cases, the BP data indicate superior source rock richness compared to Robertson Research and Analabs data for comparable sample intervals. This discrepancy may be due to a variety of factors, including different pyrolysis machines, operators, pyrolysis temperatures etc. Where analyses from two sources are in agreement for a specific formation in a well, these data have been taken as the preferred measure of source rock richness (at the current maturation state), ignoring other sources of error (see Peters, 1986; Foster et al., 1986). Statistically, in properly sampled wells, median values will outweigh aberrant values. It is apparent from BP's data that only hand picked samples were used, thus biasing the sample to the visually more source prone lithologies. Robertson Research values were derived from both bulk cuttings and hand picked data and are thus more representative of the average source potential of each formation.

The Robertson Research and Analabs data sets are remarkably consistent given the types of samples used for analyses, generally cuttings collected in some cases up to 15 years beforehand with unknown drying techniques used, possible mud additive contamination, and unknown degrees of reworking or caving. Thus, values from these two sources have been preferred. Generally the BP data has been used cautiously, and in wells for which other information is lacking.

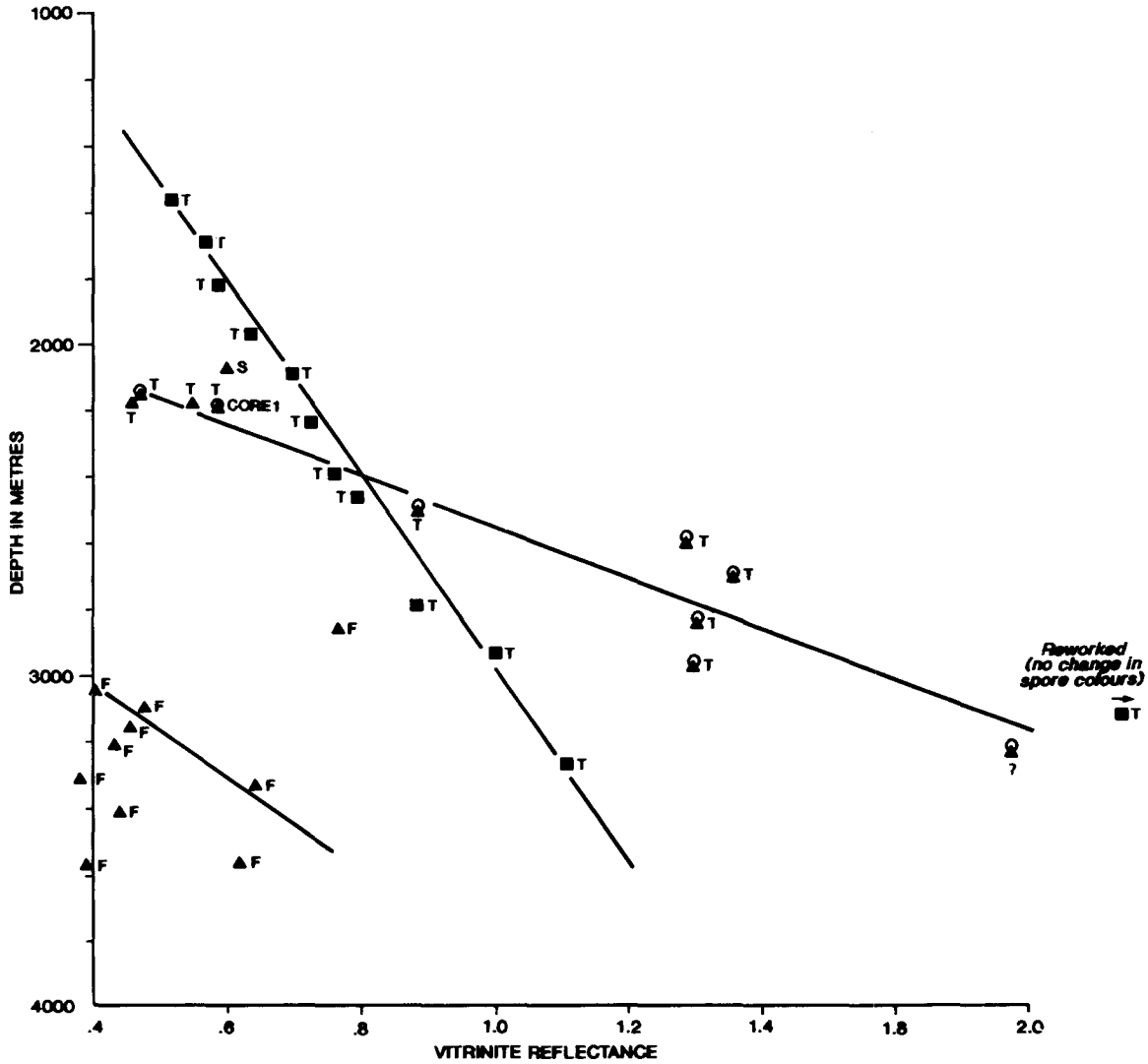
From Figure 40 it is clear that the best oil potential source beds at current maturation states lie in the Keyling Formation, in coals within the Kuriyippi Formation (2 values only), the Fossil Head Formation at Bougainville #1, and the Plover Formation in the Troubadour - Flamingo area.

For the Frigate - Sandpiper interval, overmaturity in wells in and around the Malita Graben may have resulted in lowered HI values due to migration of hydrocarbons, as is strongly suggested by HI values of less than 20 in relatively TOC rich units at T.D. in Evans Shoal #1 where the vitrinite reflectance is approximately 2.2%. Data from the lower maturity areas (eg Petrel #2 well) also suggest generally low HI and poor to fair gas-prone source facies.

7.3 MATURATION

7.3.1 Vitrinite Reflectance

Vitrinite reflectance data ($R_o$max %) for individual wells in four structural/geographic provinces are plotted against depth (KB) in Figures 41 to 45. The measurements come from Robertson Research (1979), Shell (1977), Analabs (1984, 1985a), CSIRO (Martin & Saxby, 1980) and BP (Heffernan & Mason, 1984). Because different laboratories often give disparate measurements, the data from different sources have been identified on the plots. Where the values are compatable between



LEGEND

■T *TROUBADOUR 1 (RRI)*

OT *TROUBADOUR 1 (ANALABS)*

▲T *TROUBADOUR 1 (B.P.)*

▲F *FLAMINGO 1 (B.P.)*

▲S *SUNRISE 1 (B.P.)*

VITRINITE REFLECTANCE VERSUS DEPTH

SAHUL PLATFORM

Figure 41

laboratories, a line of "best fit" has been drawn. The most notable disagreements occur between Analabs (1985a) and Robertson Research (1979) at Troubadour #1 (Figure 41), and, to a lesser degree, at Petrel #2 (Figure 42). The BP (1984) values are remarkable for their wide scatter and often do not show any consistent increase in reflectivity with increasing depth.

Data reliability is questioned when samples occur with less than 10 measurements (if the number of measurements was available), if associated spore colouration suggests maturation state of the vitrinite is too high (eg Robertson Research data), if caving is suggested by associated palynology (eg at Jacaranda #1, Analabs, 1984), or poor hole conditions are indicated by logs which may lead to downhole contamination. A description of maturity in each of the main basin regions follows.

Sahul Platform Area

Troubadour #1 is the only adequately sampled well on the Sahul Platform (Figure 41). Of the four different laboratories that sampled this well, three laboratories (BP, CSIRO and Analabs) have values in relatively close agreement, but Robertson Research data show a much lower maturity trend. The few values available from Sunrise #1 tend to parallel the high maturity trend for Troubadour #1 (Figure 41).

Malita Graben

Heron #1 is the sole well located within the Malita Graben for which $R_o$max data is available. The $R_o$max vs depth plot shows a clear break in slope about the Albian - Aptian boundary (that is, near base of the Bathurst Island Group) on the Robertson Research measurements (Figure 43). All sediments below this break are presently mature for late stage wet gas and dry gas generation. Above the break, the top of the oil maturity window lies at about 1600 m (ie $R_o$max 0.65%) with all sediments below this depth to about 3200 m being presently in the phase of main oil generation. It is reported (BHP, 1988) that a similar vitrinite reflectance verses depth relationship was obtained in Evans Shoal #1, where the maximum maturity as recorded at T.D. is $R_o$max of 2.2%.

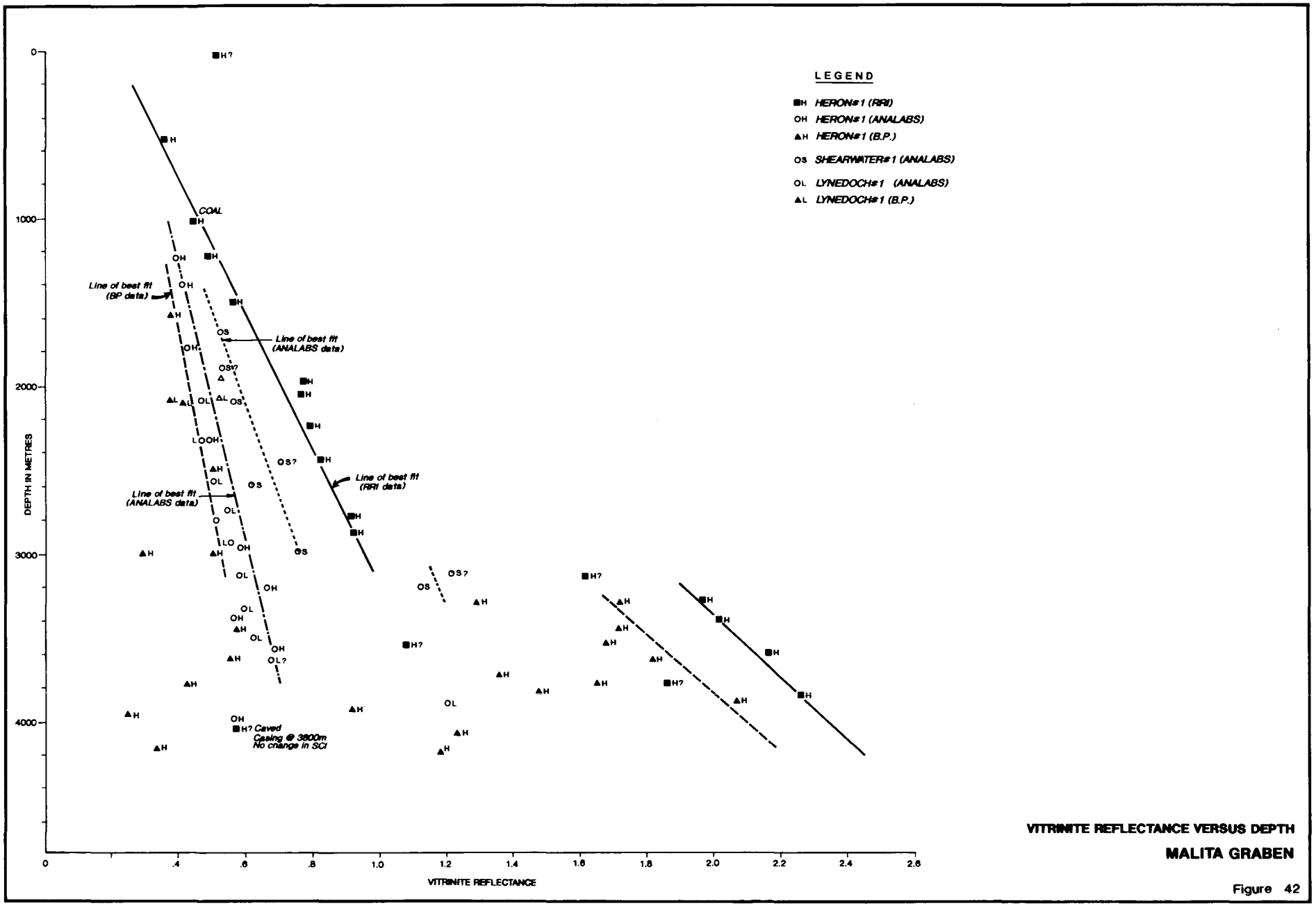
Conversely, the Analabs data set from the same well (Figure 42) shows that the sediments enter the main oil window (0.65%) at about 3000 m and are still within this at total depth. The Analabs data are rejected for the following reasons:

a) High geothermal gradient reported in the well is inconsistent with these maturation values, unless the increased gradient is very recent (ie within last 100 000 years).

b) Spores and pollens throughout the section were reported as carbonized and often unrecognisable.

c) Only dry gas occurrences are recorded on the hot wire gas detector and there is a lack of fluorescence.

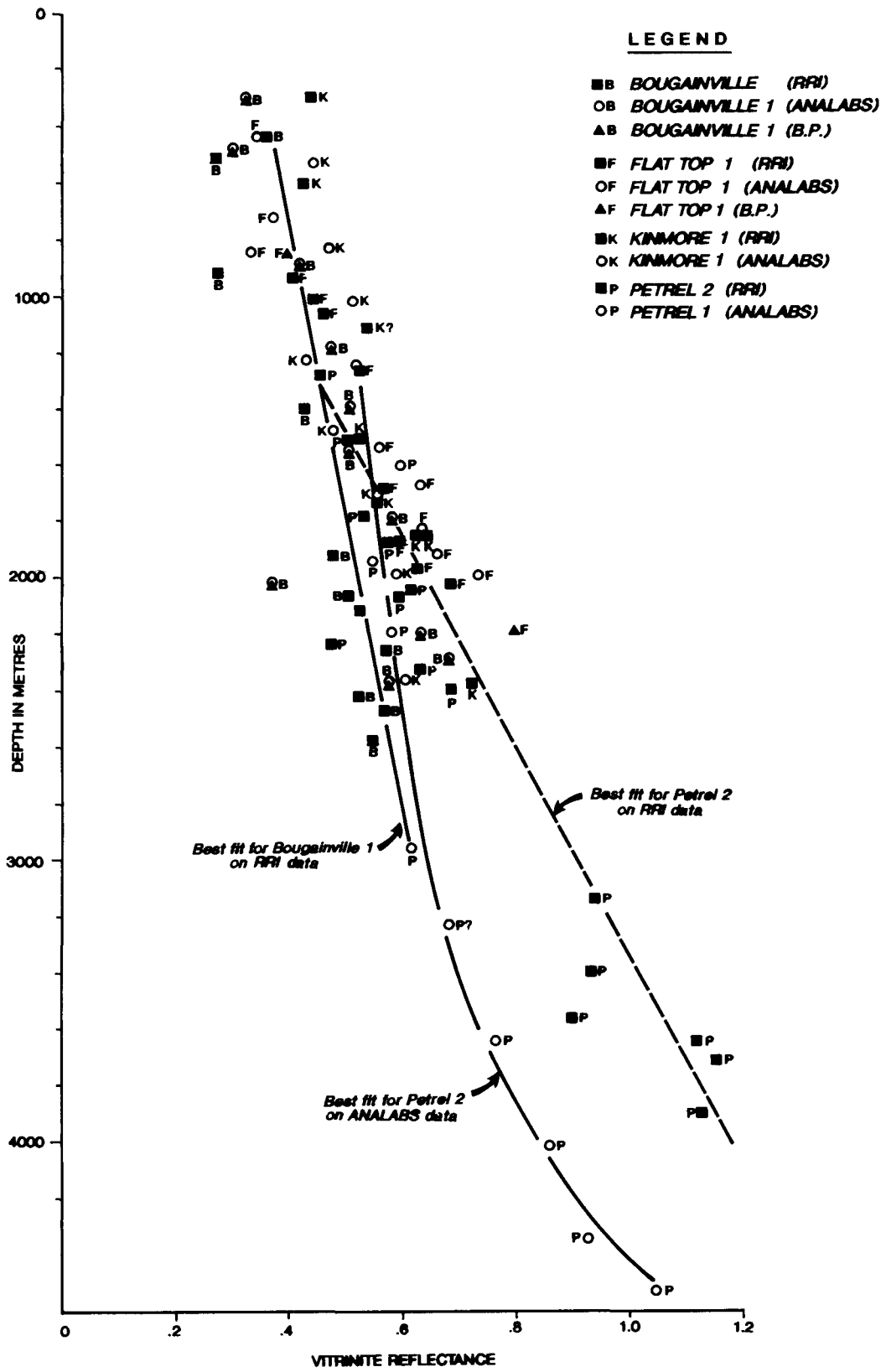
Furthermore, many of the BP measurements in the lower part of the hole, although widely scattered (Figure 43), support the Robertson Research values.



VITRINITE REFLECTANCE VERSUS DEPTH

MALITA GRABEN

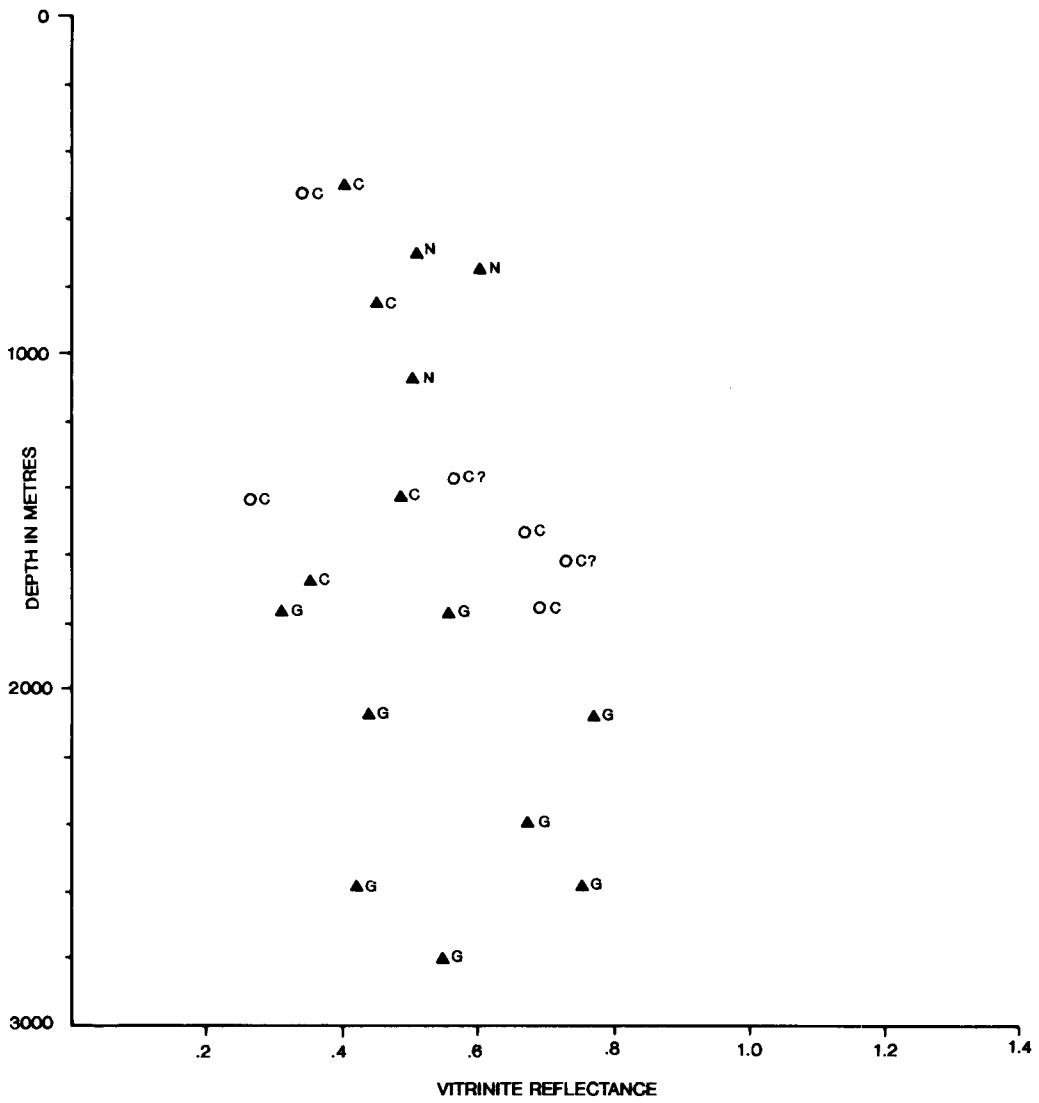
Figure 42



VITRINITE REFLECTANCE VERSUS DEPTH

PETREL SUB-BASIN

Figure 43



LEGEND

- OC *CURLEW 1 (ANALABS)*
- ▲C *CURLEW 1 (B.P.)*
- ▲N *NEWBY 1 (B.P.)*
- ▲G *GULL 1 (B.P.)*

VITRINITE REFLECTANCE VERSUS DEPTH

SALT RELATED STRUCTURES

Figure 44

Lynedoch #1 also shows a maturity break at the Albian-Aptian boundary. The top of the main oil zone is barely achieved at 3625 m, with the upper late oil stage occurring at about 3870 m (Figure 43). Thus, the information supports a maturation break at about the Albian-Aptian boundary in the Malita - Calder Grabens.

Shearwater #1 (Figure 43), on the flank of the Malita Graben, has a poorly controlled maturity profile, but a marked break can be interpreted between 2900 and 3155 m, roughly corresponding to boundary between the Albian and older strata.

In conclusion, there appears to have been a marked change in heating of the sedimentary section about the end of the Aptian in Heron #1, irrespective of the present high heat flow on the well. This sudden break in maturation profiles for wells immediately adjacent to and in the Malita Graben may be associated with the transfer of rifting from this area westwards, and the break up and inception of seafloor spreading to the north of the Sahul Platform.

Darwin Shelf and Petrel Sub-basin

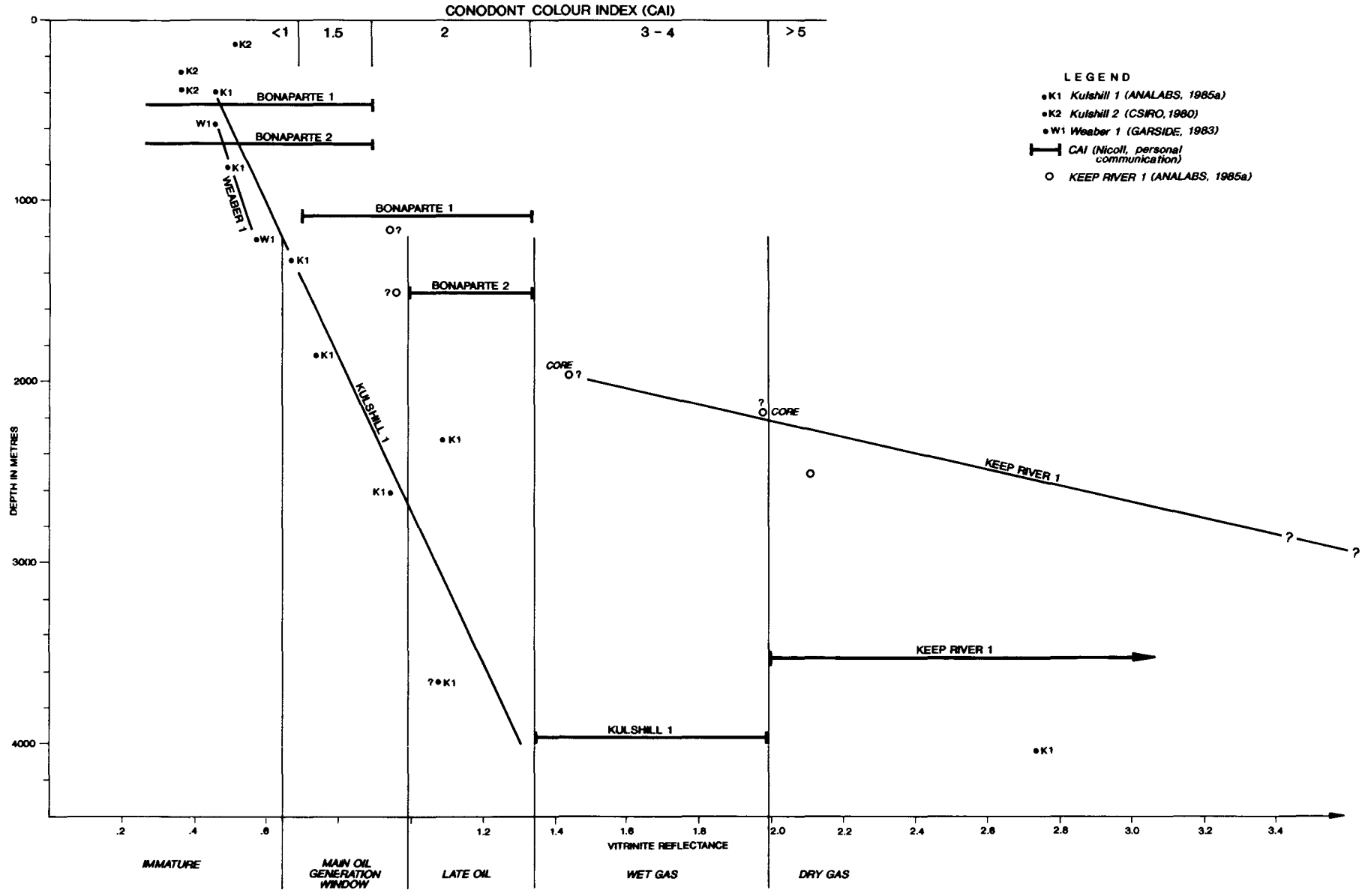
At Bougainville #1, the $R_o$max data show a steady increase in maturation with depth. The top of the main oil generation window is at about 2800 m with the sediments at total depth only just achieving this level (Robertson Research values). Values from other wells are scattered (Figure 43), but no maturation levels higher than that of the main oil zone is achieved by any of the wells sampled. The Curlew #1 samples (4 data points) may indicate a slightly higher maturation curve, possibly related to the quite recent uplift of the structure, as evidenced on seismic profiles. Scattered high maturity values from Flat Top #1 may be the result of reworking of older vitrinites into younger sediments in this near basin-margin well.

The best sampled well is Petrel #2 (Figure 42). On the Robertson Research data, sediments at a depth of about 1850 m are currently in the phase of main oil generation, with the onset of the late oil generation stage occurring at a depth of about 3350 m. Measurements from Analabs would support a much lower maturity gradient in this well with the main oil zone between about 2400 m and 4400 m. Other wells (Figure 42 and 44) show a scatter of $R_o$max data points with depth and no clear trends.

Onshore Areas

There is a paucity of maturation values for the onshore area of the Bonaparte Basin (Figure 45). However, data for Weaber #1, Kulshill #1 and #2 suggest a relatively steady maturity gradient, with the onset of the main oil generating zone at about 1200 m. The base of the oil zone is not well constrained but is projected at about 4000 m. The gas in Weaber #1 was generated at depth and migrated into the structure (Section 7.2.1.3).

The data from Keep River #1 indicate a very different maturity profile from that at Kulshill #1, and show a very steep gradient (Figure 45) and a rapid passage through the oil generation zone (about 2000 m). This is discussed further in 7.3.3.



CONODONT COLOUR INDICIES AND VITRINITE REFLECTANCE VERSUS DEPTH
ONSHORE BONAPARTE BASIN

Figure 45

7.3.2 Pristane to Phytane Ratios and Derivatives

A plot of pristane/n C_{17} against phytane/n C_{18} (Connan & Cassou, 1980) can give information regarding the origin of the kerogen and the maturation stage reached. Available data have been plotted for several source rocks horizons (Figure 46 a-d).

Kuriyippi Formation kerogens (Figure 46a) from Kulshill #1 plot as humic sources with moderate maturity. This maturity is consistent with the $R_o$max at 1332 m of 0.67%, that is, early mature. The pristane/phytane values are high (3.9 to 4.26) confirming the low maturity, and suggest a peat-swamp depositional environment (Lijmbach, 1975).

Similarly, kerogens for the Keyling Formation at Flat Top #1 (Figure 46a) exhibit low to moderate maturity and are derived from humic sources, consistent with the fluvio-deltaic origin of the Keyling (Mory, 1988). $R_o$max values range from 0.63 to 0.84% in the well in line with the indicated maturity. The pristane/phytane values (2.53 - 4.23) are also consistent with a peat-swamp environment (Lijmbach, 1975). At Kinmore #1, the Keyling has similar attributes, but an algal/bacterial source character is also present suggesting possible bacterial degradation of the original humic source material. Low maturity is suggested by $R_o$max values between 0.48 and 0.56%.

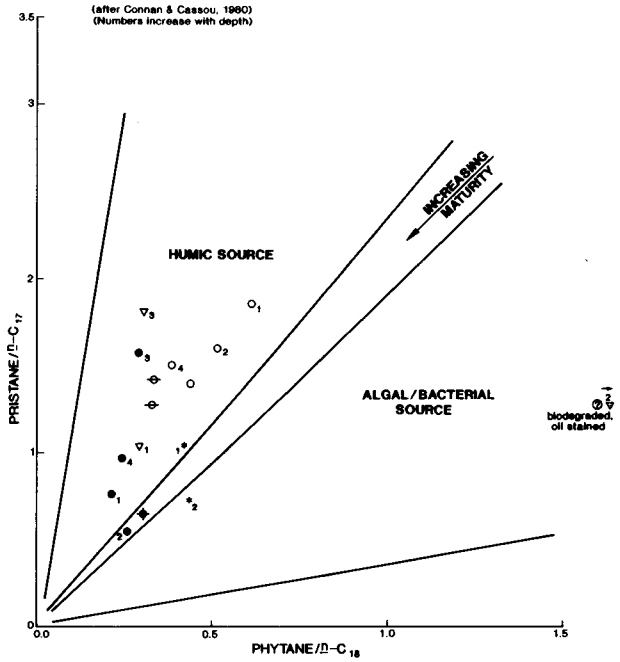
By contrast, all Plover Formation samples plot as early mature algal/ bacterial sources (Figure 46b). At Petrel #2 this is confirmed by low pristane/phytane values (0.83 to 1.85) and $R_o$max in the range 0.55 to 0.58%.

At Troubadour #1, the pristane/phytane value of 1.28 at 2210-2215 m is consistent with the marginal maturity shown by vitrinite (0.57%), but the value at 2595 - 2600 m (1.29) is at odds with the high maturity shown by vitrinite (1.29%) according to the Analabs data. However, Robertson Research (1979) show a reflectivity range of 0.8% at 2470 -2485 m to 0.89% at 2790 - 2800 m, more consistent with the other geochemical data suggesting lower maturity. Consequently, the Robertson Research $R_o$max data has been used for the maturity assessment in this area.

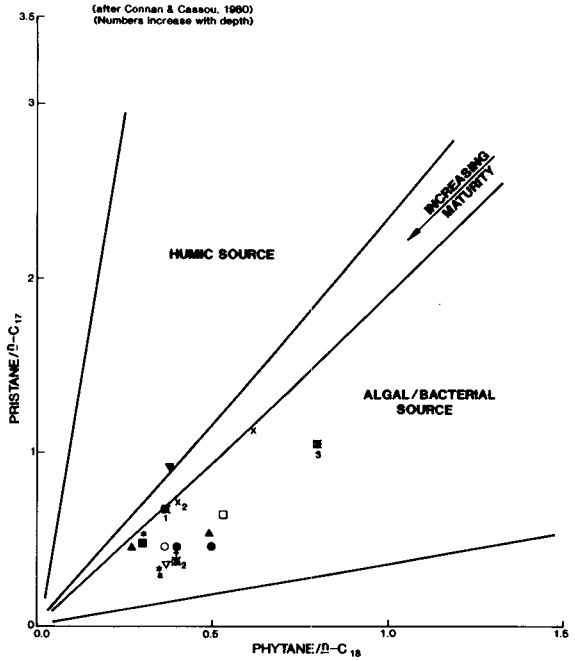
The Shearwater #1 well sample (Figure 46b) also plots as an algal/bacterial source of low maturity (BP data), but vitrinite reflectivity data from Analabs (1985a) indicates high maturities from this level (1.17% $R_o$max). Since the BP derived data was obtained from picked cuttings, it may be biased towards caved material from the overlying Cretaceous as the Jurassic section is sand-prone. Caving from higher levels is apparent from cuttings description in this well.

Flamingo Group kerogens plot as mostly algal/bacterial sources (Figure 46c), except when the facies is distinctly sandy (Sandpiper Sandstone), when they plot as mixed algal/bacterial and humic sources (Flamingo #1, Flat Top #1), probably reflecting a greater input of land plant derived organic matter.

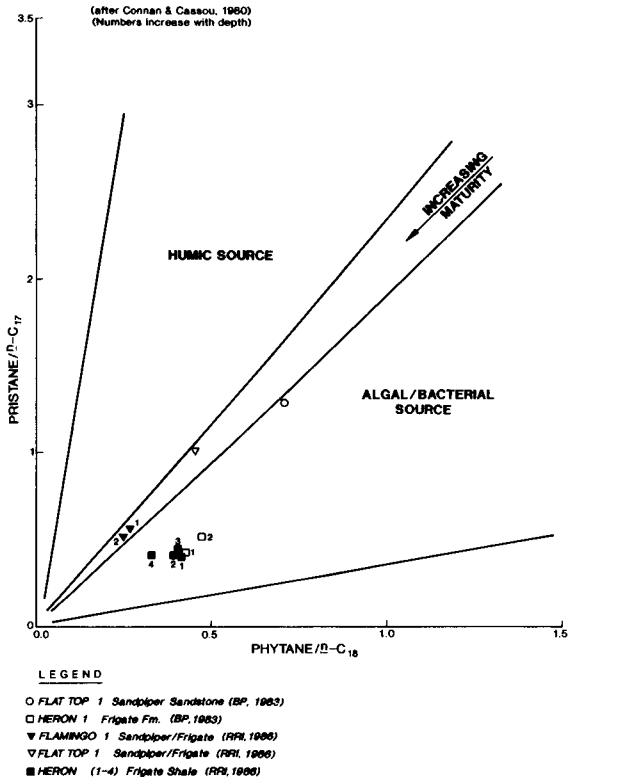
Later Cretaceous kerogens (Figure 46d) show a wide scatter of source affinities. Most are of algal/bacterial type, as expected from the predominantly shelfal depositional environments.



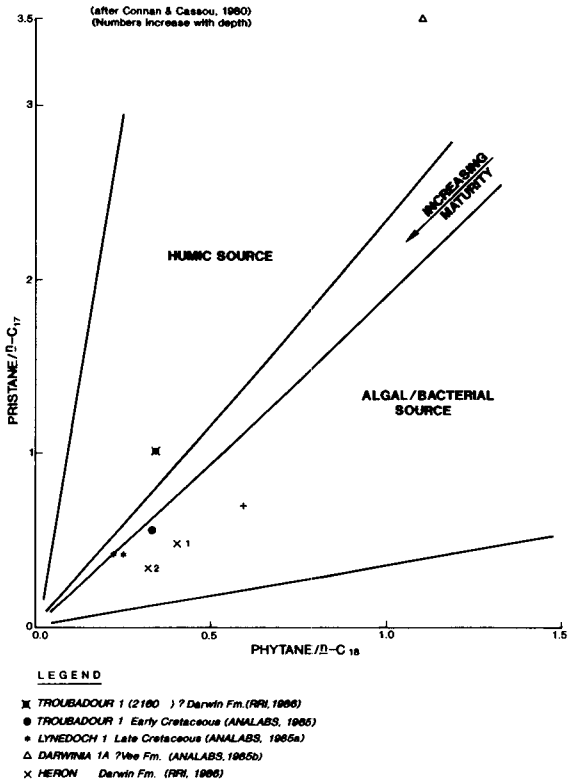
(a) KEYLING & KURIYIPPI FORMATIONS



(b) PLOVER FORMATION



(c) SANDPIPER SANDSTONE & FRIGATE SHALE



(d) CRETACEOUS

ORIGIN AND MATURITY OF EXTRACTED HYDROCARBONS

Figure 46

7.3.3 Conodont Colour Alteration Index

Conodont colour alteration indices (CAI, Epstein et al., 1977) are available for several onshore wells (Weaber #1, Spirit Hill #1, Kulshill #1, Keep River #1, Bonaparte #1 and #2), several shallow mineral exploration holes and outcrop. In general, CAIs from outcrop and shallow boreholes are CAI 1 (Nicoll, personal communication), whereas those from the deeper wells are indicative of higher maturation (Ref. Table 3).

In addition, a single conodont recovered from cuttings between 560 and 590 m in Weaber #1 (Figure 5) has a CAI of 1 to 1.5 (Jones & Nicoll, 1983, in Garside, 1983), indicating prime oil maturity in the Waggon Creek Formation of that well (Appendix 5).

A comparison of the CAI measurements with more conventional palaeothermal indicators (e.g. vitrinite) is shown in Appendix 5. From this chart, it is clear that all sediments sampled are at least mature for oil generation. Post-oil maturity is shown by the Famennian-aged sediments at about 3970 m in Kulshill #1 and the Late Devonian section at Keep River #1 (Figure 45).

7.3.4 Discussion

Low maturation in the Milligans Beds is shown by vitrinite reflectance data (Lacrampe et al., 1981) from between 76 and 147 m in a series of shallow mineral exploration holes near the Bonaparte wells, and north and northeast of Spirit Hill #1, where the highest $R_o$max is only 0.68% and most values are less than 0.5%. Conodont colour indices from outcrop and shallow boreholes in the same areas support this immaturity for the surficial sediments, irrespective of age of the formation sampled. In general, sediments do not enter the main phase of oil generation until about 1200 m.

The notable exception to this generalization is at Keep River #1, where both vitrinite and CAI indicate a very high maturity gradient with depth (Figure 45). These high vitrinite values may be related to several factors.

a) Proximity to igneous intrusions (although not known in the basin).

b) Reworked vitrinites from an older terrain (unlikely unless of Cambro-Ordovician age and therefore not vitrinite).

c) Misidentification of organic macerals as vitrinite (possible although unlikely).

d) Carbonization of cutting samples by heating on well site (possible but unlikely to be of long enough duration).

e) Proximity to mineralizing fluids causing locally enhanced thermal maturation.

TABLE 3

CONODONT COLOUR ALTERATION INDEX IN THE BONAPARTE BASIN

Well	Depth (m)	No. of elements	Species	CAI
Spirit Hill #1	61-588	-	-	1-1.5
Bonaparte #1	477 (Core 5)	2	Gnathodus sp.	1-1.5
Bonaparte #1	1062.7 (Core 12)	1	Gnathodus sp.	1.5-2
Bonaparte #1	1064.6 (Core 12)	2	Gnathodus sp.	1.5-2
Bonaparte #2	661.8-662.4 (Core 3)	1	Gnathodus sp.	1-1.5
Bonaparte #2	1503 (Core 11)	2	Mestognathus beckmanni indet. element	2
Kulshill #1	3969.7	6 fragments	-	3-4
Kulshill #1	3970.0	2		3-4
Kulshill #1	3969.1	26	Palmatolepis gracilis	3-4
Keep River #1	3496.4-3497.9	1	Polygnathus sp.	5
Keep River #1	3494.8-3496.5	5	Polygnathus sp. Ozarkodina sp.	5
Keep River #1	3493.6-3495	1 fragment	-	5

The CAI data from the Keep River #1 well are extremely high. While CAI is known to be influenced by epithermal mineralization, there is no alteration of the conodonts at Keep River #1 (Nicoll, personal communication). Futhermore, no mineralization is reported from the well (Caye, 1969). The reason for these high maturities remains uncertain, but may be related simply to the depth of burial. It is possible that the shallower $R_o$max readings may be affected by mineralization, but no conodonts have been examined from these depths. Alternatively, salt intrusion into the area corresponding to the no record seismic zone to the south of the well is a possibility, with enhanced maturation due to the proximity of the salt stock. The highest maturity in Kulshill #1 occurs at the base of the well where the sediments may be in closest contact with the underlying diapiric core.

Maturity data from the onshore Bonaparte Basin and Petrel Sub-basin do not support any marked change in maturity gradients in this area, at least in rocks younger than the Late Carboniferous. However, wells in the Malita and Calder Grabens, and on the immediate flanks of these structural features, show a marked change in maturity gradients at about the Albian - Aptian boundary. It has been suggested above that this change reflects the relatively sudden cessation of rifting in the grabens and relocation of the heat source elsewhere, probably to the north and west of the Sahul Platform, sometime in the Early Cretaceous. This event is approximately coincident with the initiation of new oceanic floor in the mid Valanginian, and it is tempting to consider the two are related.

The high geothermal gradient apparent at Heron #1 is difficult to explain under this scenario, although it may be related to increased heating due to tensional tectonics in later Tertiary times. The high Heron #1 geothermal gradient has been noted by several authorities (eg George, 1972), who attributed it to proximity to volcanic activity. However, there is no supporting evidence for a volcanic source in the vicinity. Alternatively it may be an artifact of extremely high thermal conductivity associated with salt intrusion (Section 4.3) as suggested for Keep River #1. Local anomalously high heat flows, perhaps more than double the ambient level, are well documented around salt piercement structures (Warren, 1989).

7.3.5 Conclusions

The discrete structural bounded provinces of the Bonaparte Basin considered above have undergone substantially different geothermal histories and consequently display characteristic and different thermal maturation profiles.

The onshore portions of the basin show no evidence for excessive or changing geothermal heating, and a virtual straight line maturity gradient can be assumed except around salt cored features. As indicated in the Kulshill area the oil floor may also be as deep as 4000 m. Marked changes in gradients may be caused by mineralising fluids, probably of the Mississippi Valley type, and this may be an alternative explanation of the anomalous Keep River #1 maturity profile.

In the Petrel Sub-basin, there is no compelling evidence to suggest changes in the heat flow. However, if Gunn's axial igneous intrusion model for the formation of the Petrel Sub-basin (Bonaparte Rift) is valid, it follows that enhanced heating occurred in rocks of "lower" Milligans and older age in the rift centre.

The Malita and Calder Grabens, and immediately adjacent areas (e.g. at Shearwater #1) were subjected to a higher geothermal gradient due to incipient rifting which probably ceased about mid-Valanginian time. Subsequently a normally decaying geothermal gradient was established. Thus, pre-Valanginian aged source rocks in this area (e.g. Frigate Shale) attained thermal maturity for oil relatively soon after burial and traps involving similar aged reservoirs must have been formed prior to or during this time in order to receive any migrating hydrocarbons.

Based on the current geochemical data set the geothermal history of the Sahul Platform is ambiguous. However, most maturity profiles show a relatively narrow oil generation window, perhaps related to a granitic basement (e.g. Troubadour #1) or another heat source at depth. Lack of data prevents more specific elaboration as to when maturity for oil was achieved for individual source beds.

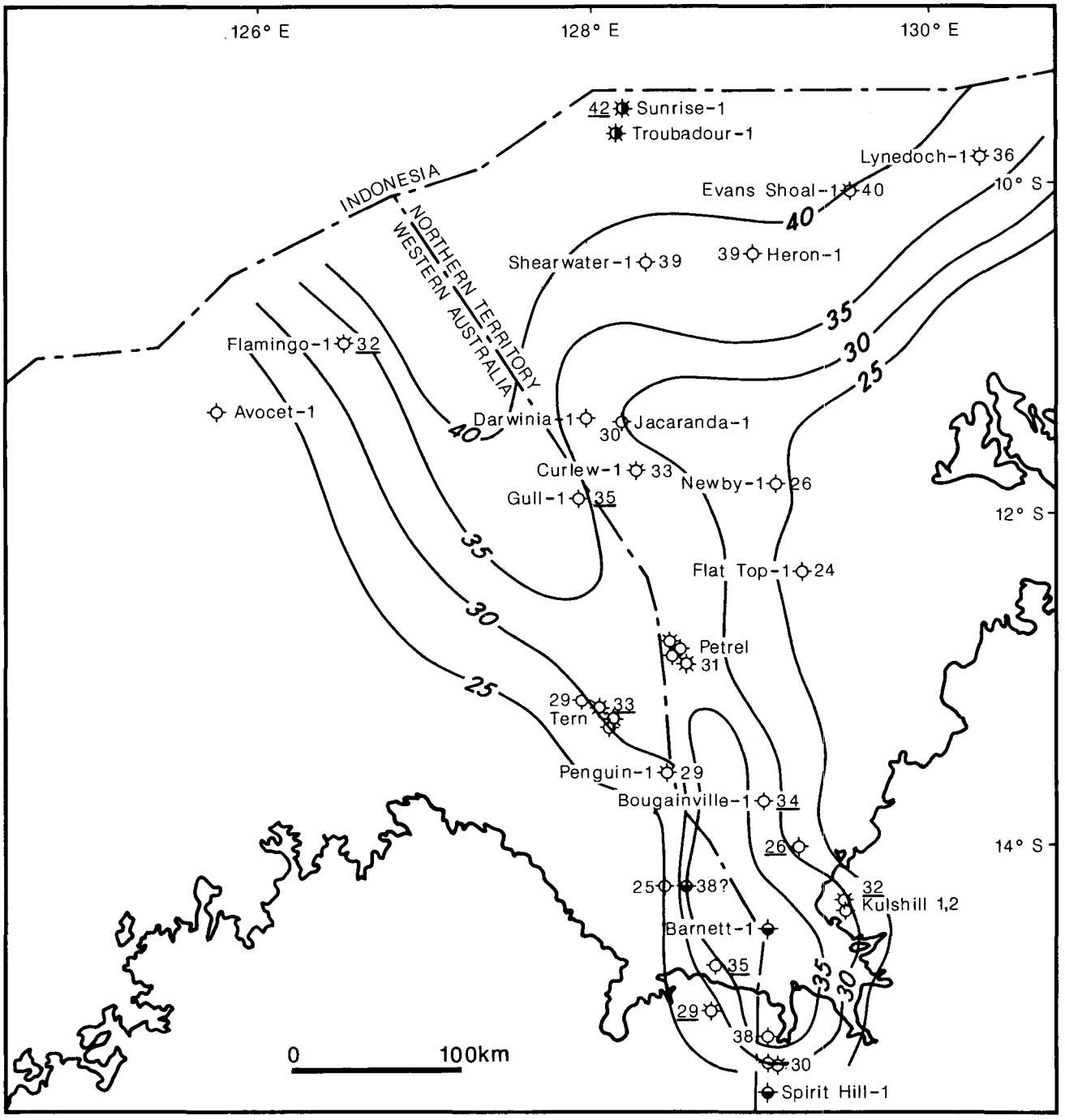


FIGURE 47 Present-day Geothermal Gradient

LEGEND

29: From Horstman, 1988

39: Calculated this Study

25 Contour 25°C/km

7.4 GEOTHERMAL GRADIENTS

Geothermal gradients were determined using maximum bottom-hole temperatures recorded on the logging runs and adding an arbitrary 10% to compensate for the inequilibrium of the circulating mud and surrounding formation, and a surface intercept temperature of 25° C, following Horstman (1988). Horstman's published figures have been used to provide additional temperature information for several wells within the Western Australian portion of the Bonaparte Basin.

In compiling these data, it was observed that in several older wells inconsistencies were noted in the bottom hole temperatures recorded on the log headers, and often the period since circulation had stopped was not recorded. It is also noted that several wells either bottomed within, or adjacent to evaporites, which may give spuriously high geothermal gradients depending on the heat conductivity of the salt (Warren, 1989). Similarly, as outlined above, the basin may have been subjected to several heating events, which in some regions may still be manifest as high ambient heat flow levels.

Figure 47 shows temperature gradients contoured at 5°C/km interval. A region of high geothermal gradient occurs in the southern Petrel Sub-basin, and another is associated with the Malita Graben and Sahul Platform (see also Horstman, 1988; his Figure 3). The high gradient in the southern Petrel Sub-basin may be due to the presence of thick evaporitic sequences beneath the basin. The reason for the increasing gradient on the Sahul Platform and Malita Graben is unknown, but may be related to Tertiary tectonism.

7.5 RESERVOIRS

A variety of reservoir types are present in the Bonaparte Basin. These include primary and secondary sandstone reservoirs, primary and secondary (vugs, karstic etc) carbonate reservoirs and fracture porosity. Comparative formation porosities are shown in Table 4.

7.5.1 Cambro-Ordovician

Little is known about the subsurface reservoir characteristics of the Antrim Plateau Volcanics or of the Carlton Group sediments. Vuggy porosity has, however, been noted in the Antrim Plateau Volcanics in the Ord Basin. The presence of feldspars and other labile grains within the sandstones of the Carlton Group gives rise to speculation that secondary porosity development does occur in these rocks, and the oolitic carbonates of the Skewthorpe Formation may have potential for secondary reservoir enhancement. Fracturing of these carbonates may have also led to the formation of extensive networks of permeability, and allowed percolation of fluids resulting in the creation, or enlargement, of pore spaces. Mory & Beere (1988) have indicated "good" reservoir potential in these sediments (Figure 37).

7.5.2 Late Devonian - Early Carboniferous

Laws (1981) commented on the reservoir potential of the Cockatoo, Ningbing, Langfield and Weaber Groups in the onshore Bonaparte Basin. Mory & Beere (1988) echoed many of these comments (Figure 37). The following review draws on the work of Laws (1981) and more recent information, particularly from the Weaber #1 and #2A wells.

Cockatoo Group

The clastic and carbonate reservoirs of the Cockatoo Group have not been petroleum targets since the mid 1960s following the disappointing results of the inital drilling phase within the onshore basin. Nevertheless, fair to good reservoir and source beds, juxtaposed with sealing shales in tilted fault blocks and stratigraphic pinchouts, could form viable exploration plays. Recognition herein that the source beds are oil mature to depths of about 1500 m, and gas mature under deeper burial, suggests that rocks of this age should not be discounted as viable petroleum targets. However, the long time between deposition of the potential reservoirs, several episodes of faulting, and the relatively late-stage attainment of oil maturity, suggests exploration for such targets will not be straightforward. Positive factors are the relative ease of access and proximity to transport, and shallowness of objectives.

Mory & Beere (1988) noted "excellent (reservoir) characteristics" in outcrops of this group. The presence of arkosic sands and carbonates within the Cockatoo Group suggests that secondary porosity may be developed. Back reef facies within the Cockatoo Group (Gunn & Ly, 1989) suggests that reef complexes and associated carbonates could also provide petroleum reservoirs.

Ningbing Group

Laws (1981) drew analogies with the productive Late Devonian reef trends in Alberta, and suggested similar exploration plays could occur in the Bonaparte Basin. To date, most exploration in rocks of this age has been aimed at reef complex targets, including pinnacle and platform reefs. Laws (1981) noted that porosity is very rarely observed in outcrops of the Ningbing limestones because any primary or secondary porosity present was probably infilled during recent subaerial weathering. Furthermore, the barrier margin and reefal facies of the Ningbing Group is algal in origin, and its original porosity was probably poor. In the petroleum exploration wells which intersected this unit (Keep River #1, Ningbing #1 and Weaber #1), porosities and permeabilities have been negligible (Mory & Beere, 1988). However, in Weaber #1 Garside (1983) noted the presence of calcite rhombs below 1793 m within the Ningbing limestones indicating fractures or vuggy porosity. Several gas shows appeared to be associated with microfractures and a 3 m interval 1880.5 - 1883.5 m) was said to have "very good" permeability (Underdown & Whitehouse, in Garside, 1983).

In Keep River #1, drillstem tests of the Ningbing Group below 3720 m revealed very low permeabilities although log interpretation had indicated fair porosity in 2 to 5 m thick intervals (Caye, 1969). In contrast, cores from shallow mineral exploration holes have shown that secondary porosity is widely developed below the contact with the overlying transgressive Langfield Group. Vuggy porosity is common, intercrystalline and fracture porosity is subsidiary. Porosities of up to 20 percent are not unusual, with the average around 7 percent (Laws, 1981).

In these shallow wells, secondary porosity extends down more than 100 m from the contact with the overlying shales and is not confined to any one facies. Porosity has been encountered in the barrier margin and marginal slope sediments of the Ningbing Group, as well as the back reef and lagoonal carbonates of the Burt Range Formation and Septimus Limestone (Langfield Group). The porosity is largely due to dolomitization which probably took place in the Late Carboniferous after the deposition of the overlying Milligans Formation (Laws, 1981; Mory & Beere, 1988).

Possible sub-surface extensions of the reef trend may occur along the northeastern extension of the Pincombe Ridge and along the eastern basin margin (Gunn & Ly, 1989), and eustatic sea level changes through the later Devonian (Famennian) may have led to the development of basin-floor fans and of karstic porosity within limestone exposed during sea level falls.

In Kulshill # 1 (Duchemin & Creevey, 1966), the Ningbing Group Equivalent sandstones are well consolidated and strongly silicified with silicification increasing towards the base of the well. Porosity is generally less than 1% (maximum 6.5%) and permeability practically nil. Log interpretation indicates minor porosity at 4206 m which is possibly due to fracturing.

Langfield Group

Horsts and tilted fault blocks and channel-like features seen on seismic lines may form traps (Gunn & Ly, 1989). As noted by Gunn & Ly (1989), the Langfield Group lies below the potential regional source and seal of the "lower" Milligans Formation.

Carbonates in the Langfield Group probably have similar reservoir characteristics to the Ningbing Group. In Weaber #1, limestones within the lower Burt Range Formation were generally tight (Garside, 1983) and similar poor porosity was noted in Keep River #1 (Caye, 1969). Some fractured calcareous sandstones showed small gas peaks while drilling. Ooid shoals may provide porous intervals within the carbonate complexes, although extensive reef growth is unlikely in this group (R.S. Nicoll, personal communication)

Sands of the Enga Sandstone have already proven gas productive at Weaber #1. Laws (1981) noted a single analysis available from a mineral exploration core hole gave a porosity of 22 percent in a sample of Enga Sandstone at 230 m, and thought it doubtful that porosities of this level could be maintained deeper in the Keep Inlet Sub-basin. Furthermore, at Kulshill #1 (Duchemin & Creevey, 1966), the Langfield Group (? Burt Range Formation) is shaly and contains no reservoirs. However, the Enga Sandstone encountered at Weaber #1 (14.0 sand) had fair porosity where medium grained, but cuttings showed most of the sandstone to be dolomite cemented and tight. The good gas flows tested from this sand (Willink, 1989) may be due to fracture enhanced permeability. In the Keep River #1 well, the correlative unit is tight, suggesting that the increased overburden pressure has kept closed any similar fractures.

Weaber Group

Sandstone intervals within the Weaber Group are apparently rare, but thick developments are sometimes present. A good example is the Waggon Creek Sandstone at Keep River # 1. This sandstone is a multiphase unit and may have developed in channels cut during sea level falls such as the Waggon Creek channel. Such turbidite sands, including basin-floor fans and related slope fan features, may have developed during the complex structural history of the Weaber Group. A variety of plays, associated with halokinesis slumping, doming and syndepositional structuring (Gunn & Ly, 1989), combined with sea level fluctuations, provide several potential reservoir targets, many of which will have the added attraction of being encased in Milligans Formation source beds.

The Tanmurra Formation and Point Spring Sandstone at the top of the Weaber Group generally display good reservoir parameters. Gunn and Ly (1989) have suggested deltaic and turbidite plays based on the interpretation of seismic profiles offshore. Carbonates within the Tanmurra Formation may have fracture porosity, and some secondary porosity associated with ooid shoals is possible.

In Bonaparte #2, 43m of net sandstone was penetrated in the "Bonaparte" (Milligans) Formation between 1384 m and 1970 m (Laws, 1981). The sandstones are fine to occasionally very coarse-grained and reported to be of poor to fair porosity. One core analysis at 1387 m gave a porosity of 16 percent and a permeability of 16 md (LeBlanc, 1965), while porosities derived from the sonic log ranged from 16 percent down to 9 percent. At Keep River #1 this interval is tight, but numerous shows of gas were present (Caye, 1969).

However, shallow core hole data from the Milligans Formation along the basin margin have shown that a considerable increase in porosity and sandstone percentage occurs in this area. Porosities of 25 percent, and permeabilities of 500 md, have been measured in these core holes. Thus, reservoir quality can be expected to be better developed to the south where sediments are coarser grained and at shallower depths of burial.

Oil shows have been reported in the "lower" Milligans Formation at Turtle #2 (Section 7.1). The well kicked at 2635 m in this formation with the influx of gas and minor oil into the borehole. Subsequently, two drillstem tests recovered oil from this zone indicating porosity and permeability is possible in this formation at depth.

At Weaber #1, the basal sand of the "lower" Milligans Formation (13.0 sand) has generally tight to fair porosity in cuttings (Garside, 1983) but flowed gas on drillstem test. However, at Weaber #2A, the same interval proved tight due to carbonate cementation (Turner & Badcock, 1989). This was also the case at Keep River #1 (Caye, 1969).

The basal sandstones of the Weaber Group at Kulshill #1 (Duchemin & Creevey, 1966) are tight with porosities less than 50% and permeabilities below 0.1 md. The best reservoir interval (3328 - 3362 m) has up to 6% porosity but is tight due to silicification resulting in interlocking quartz grains. Poikilitic dolomitic cements further reduced porosity. Feldspathic sands are rare and potential secondary porosity developments at this level are discounted.

The middle Weaber Group Waggon Creek Formation lowstand deposits also have reservoir potential. At Weaber #1 visual porosity was described as good (Garside, 1983) but no porosity was described from cuttings in the correlative section at Weaber #2A (Turner & Badcock, 1989). At Keep River #1 these sands are tight due to calcareous cementation (Caye, 1969). Fractures in similar calcareous sandstones higher in the Waggon Creek Formation in this well produced 15.5 m^3 of slightly flourescent water (Caye, 1969). The upper Waggon Creek Formation at Keep River #1 is tight due to silica cement. Gas shows in the interval are probably due to fractures.

The basal Waggon Creek sandstones are tight due to silicification and/or calcite cementation at Kulshill # 1 (Duchemin & Creevey, 1966). Minor ferruginous cement and clay matrix also downgrade the reservoir potential, but the presence of labile potassium feldspar grains suggest the potential for secondary porosity development under suitable conditions. In the "upper" Milligans Formation of this well, the hard dolomitic limestones have measured 1-2% core porosities and only fracture permeability.

In Keep River #1, the Tanmurra Formation is a good reservoir (Caye, 1969) with little cementation or matrix reported from the sandstone. Core porosities range from 1.4 to 17.5% with patchy development of up to 285 md of permeability. Permeability is more consistent in the lower part of the formation (Core #2) with 35 to 145 md measured, and a porosity range of 11.6 to 16.6%. Better porosity is also reported from cuttings in the lower Tanmurra at Weaber #1 (Garside, 1983) where cuttings have fair to good visual porosity compared to tight to fair in the upper part. The same phenomenon occurs at Weaber #2A (Turner & Badcock, 1989), although some good inferred porosity occurs at shallow depth, possibly due to decalcification of cement.

The Tanmurra Formation (*sensu* Mory, 1988) at Kulshill #1 (Duchemin & Creevey, 1966) has 2-3% core derived porosity and very low permeabilities. Log derived porosity values range from 5-7% over the same interval.

Oil shows occurred in the Tanmurra Formation and Point Spring Sandstone at Turtle #1 (Jefferies, 1988), although these were not tested. Shows were also encountered at Turtle #2. Oil and gas shows were reported from the Tanmurra Formation at Barnett #1, with a small quantity gas recovered on DST at Barnett #2 from 2413.5 to 2421 m.

The Point Spring Sandstone at Kulshill #1 contains generally argillaceous or calcareous sandstones with free oil reported (Duchemin & Creevey, 1966). Silicification is generally poorly developed. Reservoir quality sandstones occur between 2012 and 2044 m with an average 25% porosity derived from sonic and neutron logs, and cores, with permeabilities up to 20 md. Despite the apparent low permeability, FIT #1 (2015 m) and DST #4 (2008 - 2045 m) produced good flows of gas-cut salt water. An upper reservoir, between 1864 to 2012 m and consisting of sandstone interbedded with shale, has sonic log-derived porosities of 10-15%, but drillstem testing (DST #5) showed the interval to be tight. The sandstones are generally very fine with variable amounts of clay matrix and calcareous cement; silicification is minor. Oil was noted in non-reservoir lithologies between 1859 and 1890 m in this well.

The Point Spring Sandstone in Kulshill #2 contains several reservoir sands. Although the sandstones of this interval are fine grained and commonly interbedded with shales and siltstones, they are moderately porous and permeable (Creevey, 1966). Core porosities range up to 20% but permeabilities are generally lower than 3.7 md. However, a good flow of salt water was obtained from DST #3 (1660 - 1680 m). As noted by Creevey (1966), the salinity of the water recovered from this DST (14 178 ppm NaCl equivalent) is in strong contrast to the 40 970 ppm measured for water from DST #4 at the equivalent level in Kulshill #1. These disparate salinity results indicate a probable fault barrier between the reservoir in the two Kulshill wells.

Porosity and permeability in this formation is also present in offshore wells. The Point Spring Sandstone reportedly had oil shows in the Turtle #1 well (Jefferies, 1988). In the Lacrosse #1 well, this section is very fine grained, grading to very coarse quartz sandstones, in part calcareous, and interbedded with siltstones and shales. The lower portion of the section contained sand units which showed 9 - 12% sonic log-derived porosities, with an upper sand displaying up to 20% porosity.

Kulshill Group

The lower Kuriyippi Formation in Kulshill #1 has an average sonic log derived porosity of 10%, but core porosities up to 15% have been measured (Duchemin & Creevey, 1966). All the potential sandstone reservoirs are partly silicified and permeability is generally low. The best reservoir was tested by DST #2 (1444 - 1463 m) and produced a good flow of salt water. Core 15 cut at this level had porosities of 15.9% and permeabilities from 100 md to one darcy. In Kulshill #2 (Creevey, 1966), DST #1 (1269 - 1284 m) produced a moderate flow of salty water from this interval, indicating permeability.

In Kinmore #1 (Laws & Clerc, 1974) average log-derived porosity in the lower part of the Kuriyippi Formation is 6.5% for a net 29 m of reservoir, defined by zones of filter cake build-up and microlog separation. No tests were run. Up to 15% porosity was calculated in parts of the upper Kuriyippi Formation of this well.

A fair sandstone reservoir was encountered in the upper Kuriyippi Formation between 1227 and 1237 m in Kulshill #1 (Duchemin & Creevey, 1966). Core #13 from this interval had oil impregnations over 15 cm and porosity ranging from 4.9 to 19.1% with permeabilities of 0.02 to 113 md. However, these values, while moderate, were considered by the well operator to be too low and variable to give possible oil production. Furthermore, DST #1 (1215 to 1233.5 m) gave no flow. Calculated formation fluid salinities of 6000 ppm NaCl equivalent suggest only residual oil saturation.

Potential flushing by meteoric waters of shallow Kuriyippi Formation reservoirs is thus of concern, however, the discontinuous nature of the sediments may have left unflushed sands effectively sealed by intraformational shales. On the other hand, the 5.2 m^3 (32.7 bbls) of oil recovered from an upper Kuriyippi Formation sand at Turtle #1 was reportedly biodegraded (Jefferies, 1988). This particular reservoir sandstone exhibits up to 20% neutron density log-calculated porosity. Bacteria were presumably introduced by percolating groundwaters.

The Keyling Formation has good to excellent porosity and permeability in Kulshill #1. Porosity up to 38% is present, reducing with depth to about 26% in Core #8 near the base of the formation. Permeabilities are variable, however, and appear to be related to the feldspar or argillaceous content of the sandstone, but range up to 900 md. Over 400 m of reservoir quality sandstone is present in this well. Drillstem testing of the interval (DST #6, 262 - 315 m) recovered only drilling mud suggesting extensive contamination and invasion by the drilling fluid. Fair to good porosities are also present in the Keyling Formation at Kulshill #2 (Creevey, 1966) and permeability is good due to the general lack of clay matrix.

In Kinmore #1, Laws & Clerc (1974) calculated over 230 m of reservoir with 19% porosity and permeability, indicated by mud cake and micrologs. At Moyle #1, very high visual porosity and permeability estimates were confirmed by cores and logs (Brophy, 1966). The porosity averages 30% in the upper part (Cores #1 and 2) with 2.9 to 180 md measured, and decreases with depth to an average of 20% (Core #3) at 313 m with permeability varying from 0.03 to 14.8 md. A trace of oil was recovered in a Repeat Formation Test (RFT) of an upper Keyling Formation sand in the Turtle #1 well (Jefferies, 1988). Log derived porosities of up to 30% have been calculated in this well.

At Bougainville #1, where the Keyling Formation consists of very fine grained sandstones, there is little porosity due to silica cementation and argillaceous matrix. Where the sands are clean, pressure solution has considerably reduced the permeability. Core #1 from the top of the formation (2380 m), however, has 13.3 to 20.3% porosity and 1.1 to 234 md permeability indicating fair oil reservoir characteristics. Horizontal permeability is considerably better than vertical permeability in this core.

Kinmore Group

The uppermost section of the Fossil Head Formation in the middle of the Petrel Sub-basin, in the Penguin #1, Tern #1 and Petrel #2 wells, contains calcareous sands and interbeds of hard limestone and appears to grade into very calcareous sequences in certain wells, for example, Flat Top #1. This zone tested gas in Penguin #1. The operator of that well commented that the zone is permeable with 8.5 m (28 ft) of net pay, but sub-commercial. Sonic log-derived porosity for this sand at the Penguin #1 well was in excess of 30%, with reported horizontal permeabilities varying from 0.1 to 18 md. Porosities of 22% are calculated for the Fossil Head in Kinmore #1 (Laws & Clerc, 1974), between 847 and 1321m. Twelve metres of sandstone near the top of the formation of Bougainville #1 display good log porosity, with the more argillaceous sands showing generally poor porosity but some permeability.

The Hyland Bay Formation contains two regionally extensive reservoir units developed over the Petrel Sub-basin; the Cape Hay Member, reservoir to the Petrel Gas accumulation, and the Tern Member, reservoir to the Tern Gas Field. Bhatia et al. (1984) discussed the depositional and diagenetic alterations to the reservoirs of these two large accumulations.

The Petrel wells encountered the Cape Hay Member pay zones at depths of around 3500 m (11 500 ft). Porosities range from 6 to 23%, the value depending very much on the respective depositional facies and degree of diagenesis. The Cape Hay Member in the Petrel structure is interpreted

TABLE 4

COMPARATIVE FORMATION POROSITIES

FORMATION	WELL NAME	LOG INTERVAL (M)	POROSITY	PERMEABILITY	TESTS
Kuriyippi Formation	Turtle 1	1,620 - 1,630	20% Neutron/ Density	No data	D.S.T. -5 rec. 5.2 m^3. (32.7 bbls) of 33_API oil (Jef feries, 1988)
Keyling Formation	Turtle 1	950 - 955	30% Neutron/ Density	No data	R.F.T. - rec. lcc. oil (Jefferies, 1988)
Fossil Head Formation	Kinmore #1	847 - 1,321	22% Sonic	No data	No tests
Cape Hay Member	Petrel 2	3,664 - 3,570	21% Sonic	No data	D.S.T. 6 - rec. GTS - 186,000 to 411,000 m^3/ D (6.6-14.5 MMCF/D)
Tern Member	Tern 1	2,730 - 2,545	24% Sonic	No data	D.S.T. 2 - rec GTS - 215,000 m^3/D (7.6 MMCF/D)
Malita Formation	Petrel 2	2,316 - 2,321	20% Sonic	No data	No tests
Sandpiper Sandstone	Petrel 2	1,295 - 1,326	26% Sonic	No data	No tests
Turnstone Formation	Jacaranda 1	1,095 - 1,105	33% Sonic	No data	Chromatograph l ogged gas, 6% C 1

Note: Log derived porosities can be optimistic, caused by enlarged well bore sizes, shale contents which have not been corrected for and presence of gas.

as deltaic. Silicification of sandstones formed in the high energy depositional environments of the delta have substantially reduced the porosity of this section, whereas the shalier facies of the delta have retained their near original porosities owing to clay coating on the quartz grains inhibiting silicification. Other forms of diagenesis, including calcite cementation, also acted to reduce the primary porosity of the reservoir.

The Tern Member reservoirs in the Tern structure lie at 2500 m (8000 ft). The porosity of the Tern Member reservoir ranges from 1 to 24%, depending on the facies and degree of diagenesis. Diagenetic effects include carbonate cementation and the growth of clay minerals, both of which have reduced primary porosity. In the finer grained facies the clay fraction has inhibited calcite cementation.

The Hyland Bay Formation at Kinmore #1 has an average calculated porosity of 31% (505 - 847m) according to Laws & Clerc (1974). Good reservoir characteristics are also present in the formation at Bougainville #1, as shown by the very coarse sands in sidewall cores. These clean sands constitute about 36% of the formation and have an average porosity of 24%. Formation tests showed good permeability at 1344m.

Troughton Group

The Middle to Late Triassic Cape Londonderry Formation is laterally equivalent to the reservoir section encountered in the Challis Oil Field of the Vulcan Graben (Figure 4). The unit is widespread over the southeastern Petrel Sub-basin and locally has a massive sand development containing 13-21% sonic- derived porosity values in the basin centre (Petrel #2) with slightly higher porosity values in the thinner basin margin areas, such as at Flat Top #1, where a sonic porosity of 25% was calculated. Cores in the interval at Petrel #2 had up to 165 md of vertical permeability and 59 md of horizontal permeability.

The Early Jurassic Malita Formation contains very fine to coarse grained sandstones with sonic derived porosities of between 12-22%. This range is comparable to core porosities, measured at Petrel #2, of 13.2 to 21.7%. A maximum 1480 md of horizontal permeability was measured in this well at 2550 m.

The Plover Formation, a thick sand dominated unit, has been the subject of several investigations of reservoir quality. As with the Permian Hyland Bay Formation reservoirs, the degree of diagenesis is a big factor in determining the reservoir quality of the Plover Formation. The shallower the section, the better the chances of encountering porous sandstones. In some wells, the Plover sands are of excellent reservoir quality (eg Petrel #2), but in other wells (eg Shearwater #1), they are tight. The Plover Formation could prove to be a significant hydrocarbon-bearing reservoir for the northern Bonaparte Basin where it is buried at depths shallower than 3000 m (10 000 ft) and has log-derived porosity values of between 15% and 30%. Good reservoir characteristics are shown by the upper Plover Formation at Petrel #1, where cores have 14.3 to 24.3% porosity and vertical and horizontal permeabilities in medium grained sandstones at 1970m of 377 to 567 md, and 359 to 943 md, respectively. Calcareous cementing leads to erratic porosity development in the lower part of the Formation.

Conversely, at Shearwater #1, the Plover Formation sands are tight. Arco (1975) calculated average porosities in this section of 2-8%, with stringers reaching a maximum 14% porosity, but effective permeability is very low. Why this is so has been investigated by several workers, including Rahdon (1982), who noted the following diagenetic sequence; quartz overgrowth, dolomite cement, and later shearing of the interlocked quartz mozaic. A similar diagenetic history was proposed by Steveson (1983), with later stages of calcite and siderite cementation noted as well.

Diagenesis of the basal sandstones at Shearwater #1 was apparently by remobilization of quartz (possibly early), and introduction of dolomite into the remaining pore space, probably following stress-induced shearing and formation of strain lamellae. The stress may be related to the proximity of the Shearwater Fault, part of the bounding northern fault zone of the Malita Graben, suggesting a wrench component to the tectonic regime. A high heat flow in this area prior to the Valanginian has been suggested above, and this undoubtedly contributed to diagenesis.

Rahdon (1982) concluded that the Plover "sandstones with exceptionally good depositional features (very coarse, well sorted clean quartz sandstones) retain primary porosities up to 18% even to a depth of 3600 m

(Flamingo #1)", but some fine and medium grained sandstones "lose their porosities and permeabilities already at 1800 m" (Rahdon, 1982, his Table V). The poorly sorted and argillaceous Plover Formation sandstones at Shearwater #1, using the same rationale, may have undergone diagenesis under comparatively little burial (that is, less than 1800 m).

The lower Plover Formation at Sunrise #1 exhibited poor visual porosity in cuttings with log-derived porosities in the range 12 to 16%, but the upper, gas-condensate sands had trace to good porosity and log derived porosities of between 17 and 22%. Minor silicification of these upper sands is apparent in cuttings, with silicification and minor calcite cementation downgrading porosity in the lower section.

The increase in silicification towards and surrounding the Malita Graben suggests that the graben forming processes themselves may have contributed significantly to the mechanisms of porosity reduction in this area. Perhaps the interpreted high geothermal gradient of the region is the main contributing factor. However, it should be stressed that Plover Formation sands have only been intersected within the graben at Evans Shoal #1 where average log derived porosities are 8%. Hydrocarbons reservoired in this structure apparently have not prevented diagenetic destruction of the primary porosity through quartz overgrowths and minor pyrite and spar calcite development. Reasonable reservoir may still be expected, particularly along the southern margin where a contribution of coarse grained sediment from the Darwin shelf may be assumed and burial has not been as severe.

The same general observations can be made for the Sandpiper Sandstone, although the unit is absent in the northern Malita Graben and on the Sahul Platform. Log-calculated porosities varied from 20-30% in basin margin locations (Tamar #1) to 15% in the mid-basin areas (Curlew #1). This northwards reduction in porosity is the result of diagenesis through increased depth of burial, although the lower portions of the section, as described in the Tamar #1 well, contain kaolin, silica and calcareous components, which contribute to a reduction in porosity through cementation and diagenesis. At Petrel #1, however, the Sandpiper Sandstone has very good visual porosity in fine to coarse grained sandstones having log-derived porosities from 9 to 27%, supported by core porosity measurements of 10 to 26%. Permeabilities from the core could not be measured owing to the unconsolidated nature of the sediment. At Flat Top #1, Steveson (1983) noted a depth-dependent change from minor diagenesis to higher degrees of quartz authigenesis with increasing burial of the Sandpiper Sandstone. However, the degree of diagenesis is low enough that cementation has not significantly reduced primary porosity. It is possible that the high silicification noted by Steveson from cuttings in the lower part of the section may be derived from quartzitic pebbles. Log derived porosities range between 25 to 30% and a FIT indicated a permeability of 450 md.

Campanian glauconitic sandstones, and Maastrichtian sands of the Puffin Formation, encountered in the northern portions of the Petrel Sub-basin are time equivalent to the oil-bearing sands tested in the Puffin wells in the Vulcan Graben. The sands and sandstones are mainly medium to very coarse grained with mild burial induced diagenesis and some calcareous cementation (Rahdon, 1982). Some sideritic cementation is noted by Steveson (1983) at Curlew #1.

The Campanian sands in Jacaranda #1 are friable, fine to medium grained and occasionally coarse, sub-rounded grains. The average sonic log-derived porosity for these sands is 35%. The Maastrichtian sands at Jacaranda #1 are very friable, fine, to in part coarse grained with slightly higher average sonic log-derived porosities of 38%.

Maastrichtian sands were encountered at Darwinia #1A, where they are medium to coarse grained and of good reservoir quality. Porosities up to 29% are calculated. Sands occur in the Santonian of the Bathurst Island Group at Darwinia #1A with log-derived porosities of about 24.4%. These sands are very fine to fine grained and glauconitic. At Heron #1, the later Cretaceous section contains very fine to coarse, generally friable, slightly argillaceous, locally calcareous sandstone with moderately high visible porosity. Sonic log-derived porosities through this section range from 20 to 33 percent.

A thick section of later Cretaceous inner neritic to coastal plain sandstones at Lynedoch #1 represents a possibly attractive reservoir target, with sea level changes during this time implying a multiplicity of sandstone depositional cycles, including offshore bar to fluvio-deltaic sands. At Evans Shoal #1 Late Cretaceous fine to coarse grained sandstones, grading to very fine to fine sandstones between 1287-1983 m, have good visual porosity and permeability. Log porosities range from 19 - 32% with individual sand units attaining a thickness of over 80 m (e.g. 1615 - 1696 m). These correspond to the "Puffin Sands" encountered at Lynedoch #1 (Enclosure 8).

Reservoir characteristics of the Cretaceous and Tertiary limestones have not been investigated in this study, but fracture and secondary diagenetic reservoirs are possible within this section. Glauconitic sandstones within the Paleocene and Eocene may also constitute viable reservoirs if suitable sealing lithologies are present. Paleocene sands at Darwinia #1A have core derived porosities of 17.7 to 19.5%, but low permeabilities (4.7 to9 md).

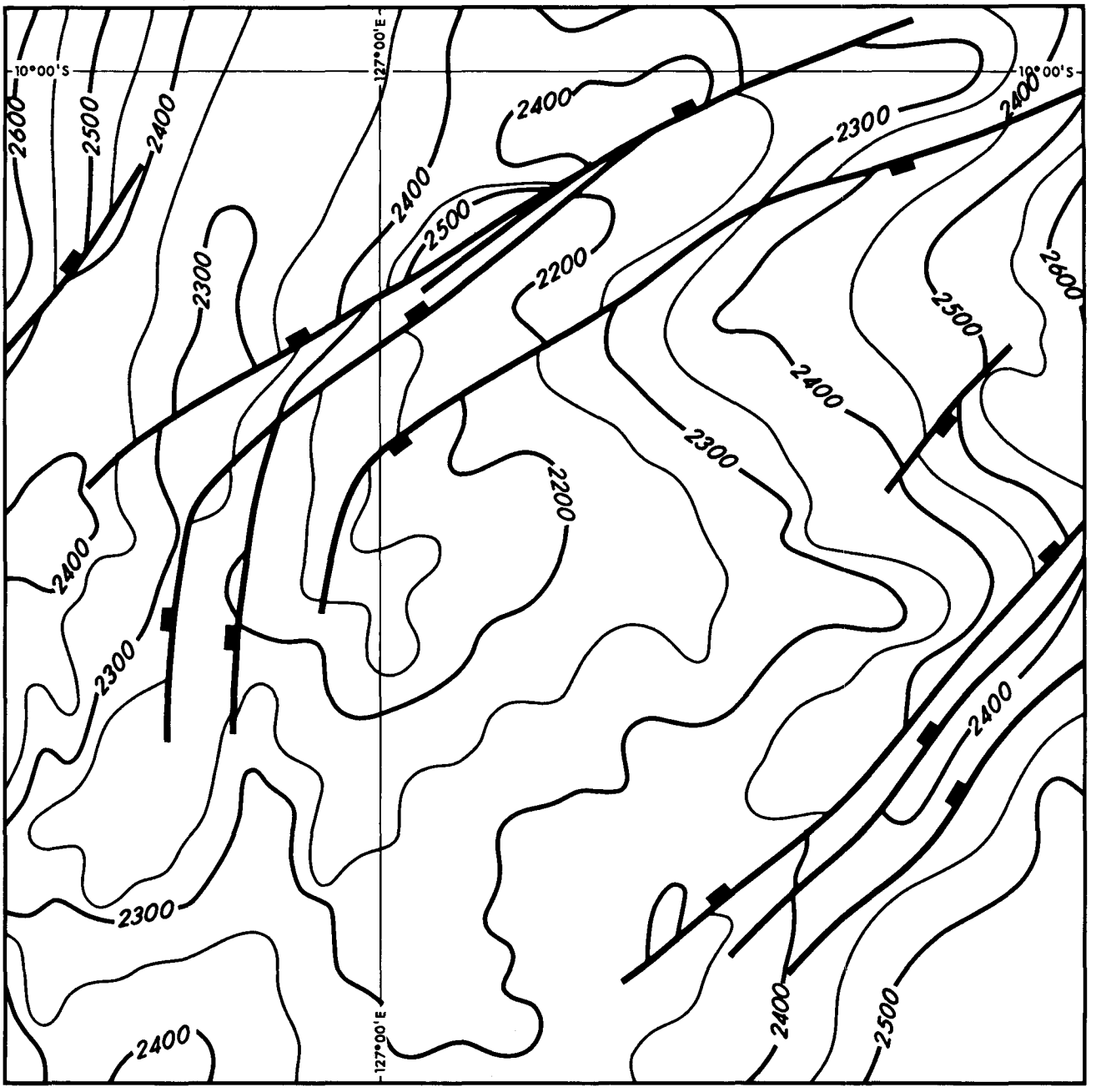


FIGURE 48 Kelp Prospect Depth Structure Map
Near Base Upper Cretaceous (After Bocal, 1974)

0 5
kilometres

Contour Interval: 50m

8. HYDROCARBON PLAYS

The hydrocarbon plays within the Northern Territory portion of the Bonaparte Basin, identified on the basis of integration of material presented in the preceding chapters is described below in terms of regional geological setting.

8.1 SAHUL PLATFORM

The Sahul Platform covers an area of more than 30,000 km^2. Much of it has only been lightly explored, mainly with reconnaissance seismic coverage (Enclosure 2a). Only two wells, Troubadour #1 and Sunrise #1, drilled in 1974 and 1975 respectively, are located on the Platform. Both wells encountered significant amounts of gas-condensate. Elf Aquitaine and Woodside (then Bocal), operators of NT/P4, and NT/P11 and 12, respectively, were hampered in further exploration by uncertainties concerning administrative jurisdiction of the Timor Gap region.

Nevertheless, the limited amount of seismic data acquired up until that time enabled approximately fourteen structural targets, prospects and leads, to be identified on the Sahul Platform (Enclosure 13). These structural traps involve mainly antithetic fault blocks, or horsts, bounded by normal faults, trending east-west or east-northeast and formed during the breakup of Gondwana (Section 4.3). Drape related four-way dip closures are present at some levels, however, for most, critial updip closure is provided by bounding faults. Lateral closures are provided by either intersecting normal faults or closing contours. Fault structures are particularly prevalent on the northwestern flank, and in the Troubadour and Sunrise localities, several additional fault related closures have been identified (Figure 24; Enclosure 13). Displacements on some faults, such as at Troubadour (Figure 23), which extend through to the water bottom or terminate within the Tertiary section, indicate a protracted history of movement.

In a broader sense these Mesozoic trends appear to overprint subtle north-west Palaeozoic trends which are more evident across the western half of the Sahul Platform. The Palaeozoic trends, manifest as a series of parallel anticlinal-synclinal axes, produce regional highs upon which the Flamingo, Kelp, Sunrise and Troubadour structures are located.

Individual structural closures are significant. At Troubadour maximum vertical closure is approximately 40 m and areal closure 18 km^2; at Sunrise maximum vertical closure is approximately 66m and areal closure is 44 km^2 (Lavering & Ozimic, 1988). The largest untested structure, Kelp, was mapped by Bocal at the Near Base Upper Cretaceous level as having a closure of approximately 680 km^2 and a maximum vertical relief of in excess of 150 m (Figure 48). It lies within NT/P11 and is delineated by seismic data recorded during the late 1960s and early 1970s.

Based on the results of the two wells drilled to date, the main objectives in the identified structures on the Sahul Platform are sands of the Plover Formation, the reservoir of the gas-condensate in the Sunrise #1 and Troubadour #1 wells. As indicated on Enclosure 13 the Plover Formation is expected to contain reservoir quality sands at effective depths across the entire Sahul Platform, excluding areas adjacent to active bounding faults where shearing may reduce porosity (Section 7.5.2). As was evident in the Sunrise #1 and Troubadour #1 wells, individual Plover Formation sands may not be laterally continuous across the entire structure, although a multiplicity of upward coarsening cycles and channel fill sequences provide

adequate reservoir development beneath intraformational seals (Figure 6; Section 4.2.12.1).

Other potentially prospective reservoir targets include sands in the underlying Malita Formation and "Shoaling Cycle" (Section 4.2.9.1), a lateral equivalent to the Middle to Late Triassic Cape Londonderry Formation, the reservoir section in the Challis Oil Field in the Vulcan Graben. Sands of the Tern Member, the deepest stratigraphic sequence penetrated on the Sahul Platform, also provide potential reservoir targets. Although the Tern Member is located at much greater depths of burial across the Sahul Platform than at Tern, appraisal drilling there highlights the significant variability in reservoir properties (Section 7.5.2.4). The poor reservoir properties encountered in this unit at Troubadour therefore may not be indicative. Similarly, the granite into which Troubadour #1 bottomed suggests that arkosic sediments may have been shed from the Troubadour high region and that these may form fans and deltaic basal sequences with local reservoir quality, perhaps enhanced by diagenesis.

Additional, non-clastic, potential reservoir objectives may be associated with the Troubadour carbonate unit, either as reef related porosity, or karst porosity developed following exposure during sea level falls. Sequences above the Aptian/Albian Unconformity generally lack reservoir potential (Section 7.5.2).

Intraformational shales provide seal for the objective Plover reservoir sands. The thick (>500 m) shale unit comprising the Wangarlu Formation would be expected to provide regional seal. This seal is unlikely to have been breached even during Tertiary reactivation, as demonstrated by the results of Sunrise #1 and Troubadour #1 where displacements of faults did not compromise overall trap integrity.

The Plover Formation reservoirs in the Sunrise and Troubadour wells lie at depths of burial incompatible with gas and condensate maturities implying that the source of these hydrocarbons lies deeper within the section. Regionally, the Hyland Bay and Fossil Head Formations could be expected to source gas and condensate across the Sahul Platform. Oil mature source rock sequences are confined to shallower levels, either shale units within the Plover Formation itself, or alternatively, in the lower part of the Wangarlu Formation. These potentially more oil-prone source-rock sequences may require up-dip fault access into the reservoir sands of the Plover Formation. The absence of oil in the two wells drilled to date may also reflect the gas mature nature of the Late Palaeozoic source rock sequences, coupled with later gas pooling and displacement of previously trapped liquids. There is also the possibility that maturity levels in the Troubadour and Sunrise areas may be anomalously elevated due to the presence of a granite body. If this is the case then lower maturities, more compatible with the preservation of liquid hydrocarbons, could be expected at similar depths elsewhere across the platform.

Traps adjacent to the Malita Graben may be exposed to hydrocarbons generated from within the Frigate Shale sequence, which is either not present, or very thin, across the Sahul Platform.

8.2 MALITA GRABEN & BATHURST TERRACE

The Malita Graben, within the Northern Territory portion of the basin, covers an area of more than 15,000 km^2. Only two wells, Heron #1 and Evans Shoal #1, have been drilled within the graben proper, the latter encountering gas. Lynedoch #1, located further to the north, in the adjacent Calder Graben also encountered gas. Darwinia #1A and Jacaranda #1 located on the southern margin did not encounter significant shows.

The gaseous nature of the hydrocarbon occurrences reflects in part the great depth of burial of potential source beds beneath the thick Tertiary, Bathurst Island and Flamingo Group sequences deposited within the graben. The maturity of the gas-prone Frigate Shale, the main regional source within the graben, is presently at $R_o$max levels greater than 1.0. However, Wangarlu shales and carbonates could also provide potential sources at lower levels of maturity, as suggested by gas shows in the Brown Gannett Limestone at Lynedoch #1.

Based on the mapping of previous operators, more than twenty structural targets have been identified within the graben (Enclosure 13). Several of the identified structures are large, some with significant fault independent rollovers, involving drape compaction over deep seated structures,such as Evans Shoals (Section 6.2.19). Several other antithetic fault related traps have been identified in the area including an Evans Shoal Up-dip, Martin Shoals, and Melville, prospects, the latter located to the south of Lynedoch #1. Melville, as mapped at the Base Upper Cretaceous level by Magnet Oil (Figure 49), is a fault independent closed structure having an areal extent of 60 km^2, and vertical closure in excess of 125 msec. It lies on trend with the northward plunging Bathurst Terrace, a trend upon which there may be several other fault related structures.

The Martin Shoals prospect lies within the Malita Graben, northeast of the plunging Sahul Platform. Coincident with a reef anomaly, WMC have depth mapped this prospect at the Near Base Bathurst Island Group (Near Base Cretaceous), showing it as a drape closure over a crestal fault-bound horst. Maximum vertical relief is 75m, and areal closure is approximately 30 km^2 (Figure 50).

The prospectivity for many of the structures located within the depocentre and distal portions of the Malita Graben is discounted because known regional reservoirs lie beyond their effective depths. In these areas reservoir potential is confined to the less predictable post - Aptian/Albian sequences, which tend to be carbonate prone and lack porosity development.

However, across the eastern flank of the Malita Graben, and the adjacent Bathurst Terrace, several reservoir objectives are envisaged for traps mainly recognised along the downside of a major fault bounding the graben (Enclosure 13). Such down-thrown fault related traps have not been adequately tested, Jacaranda #1 being the only test to date.

The fault escarpment coincides with the palaeo-shelf break and fluvio-deltaic sheet sands of the Sandpiper Sandstone probably merge basinward into marine channel sands and turbidite sands. For example Cretaceous delta front sequences have been identified on Line BB-30, prograding from the adjacent Moyle Platform into the Petrel Sub-basin. Turbidite fan deposits basinward of the escarpment may provide reservoir targets across roll-over structures, located on the down-faulted side of the escarpment or form significant stratigraphic traps in their own right. Based on the geochemical control at Flat Top #1 (Figure 40) oil-prone source rocks of the Keyling Formation could be expected to be present and mature at least across the outer flank of the terrace.

Sands within the Plover Formation are also expected to lie at effective reservoir depths across the Bathurst Terrace (Enclosure 13) as too are shallow marine and paralic sands within the Campanian to Maastrichtian "Puffin Sands". At Lynedoch #1,

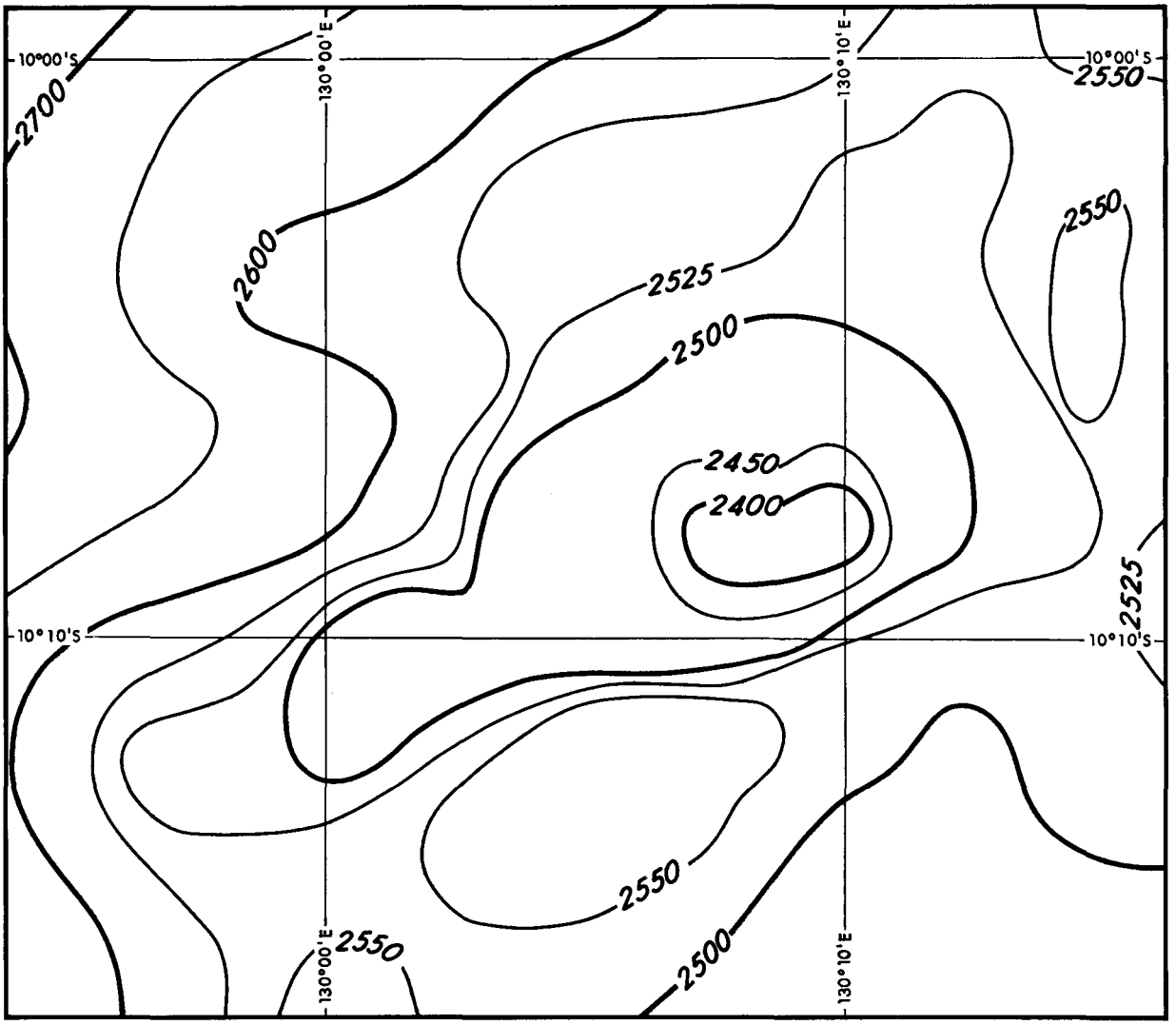


FIGURE 49 Melville Prospect Time Structure Map
Base Upper Cretaceous (After Magnet, 1981)

0 2
kilometres

Contour Interval: 50msec TWT

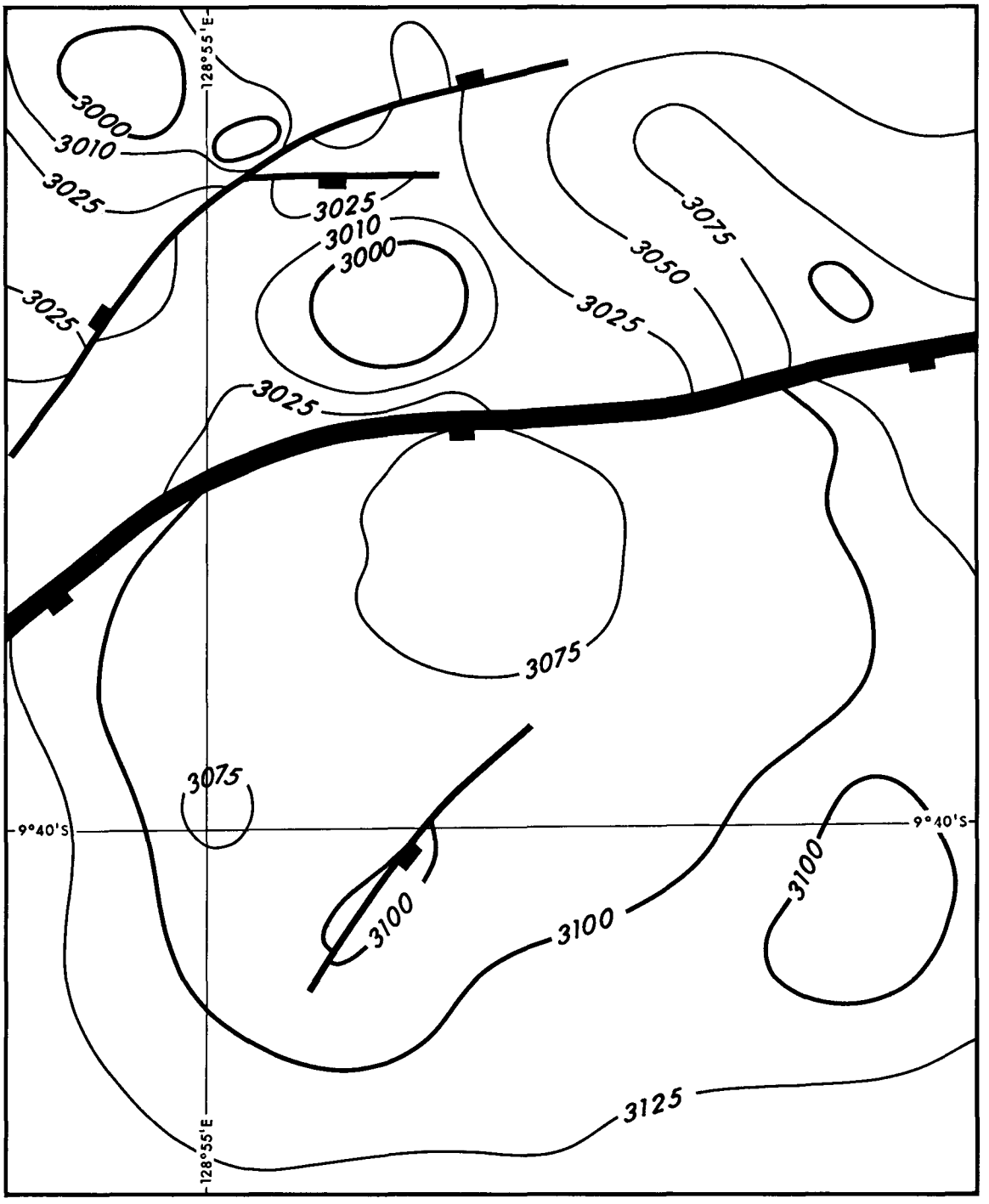


FIGURE 50 Martin Shoals Prospect Depth Structure Map
Near Base Bathurst Island Group (After WMC, 1987)

0 1
kilometre

Contour Interval: 50m

coastal plain sands of the same age comprise a 600 m thick unit. Located on the Bathurst Terrace proper is an embayment (Enclosures 3 & 11a) which may contain thickened Jurassic and Triassic sequences. Although seismic coverage across this region is only of a reconnaissance nature (Enclosure 2a), this northwest trending structure may reflect older Palaeozoic structural trends. If this is a Palaeozoic depression, then it may also contain Permian reservoir targets and possibly Permo-Carboniferous targets as well as source rock sequences, such as the Keyling Formation (Enclosure 13). Local reservoir sequences may also be present in the form of deltaic sequences containing arkosic sands shed from the adjacent Darwin Rise. In this setting the sediments would not have been deeply buried so that the preservation of good reservoir quality could be anticipated. However, based on maturity levels at Newby #1 and Flat Top #1, which are in similar settings, traps within the embayment may be migration dependent, with hydrocarbons migrating out of the adjacent Malita Graben. One structural target has been identified from the limited seismic coverage, and several basement highs may provide additional drape related closures. Up-dip pinchout edges within the Sandpiper Sandstone or Plover Formation, if present beneath the Cretaceous and Tertiary marine shale and carbonate sequences, may potentially form large stratigraphic traps within the embayment.

8.3 PETREL SUB-BASIN & MOYLE PLATFORM

To date, exploration results have indicated that hydrocarbons in the Petrel Sub-basin are mainly reservoired within the Late Carboniferous - Early Permian sandstones of the Kulshill Group (Turtle and Barnett oil discoveries) or the Late Permian sandstones of the Hyland Bay Formation (Petrel and Tern gas fields). These occurrences indicate that very substantial quantites of hydrocarbons have been generated within the Petrel Sub-basin. Furthermore, combined with the Western Australian drilling results, the Petrel Sub-basin is identified as a hydrocarbon habitat which is gas-prone in the north and oil-prone in the south. Rather than reflecting source rock trends, this probably more reflects regional maturity trends, the result of the regional north-westerly plunge of the Sub-basin and increased depth of burial of the regional source rock sequences towards the Malita Graben. Diagenesis associated with this increased depth of burial is also a controlling factor on the effective depth of reservoir targets.

The Tern and Cape Hay Members of the Hyland Bay Formation are key objectives in the central portion of the Sub-basin where wave and tide reworking of sands in nearshore environments has enhanced their reservoir potential (Enclosure 12). Intraformational shales and the capping limestone of the Dombey Member contribute to sealing the Cape Hay Member, whereas the Early Triassic Mount Goodwin Formation provides a regional seal for the Late Permian across the Sub-basin. The Middle to Late Triassic Cape Londonderry Formation contains good reservoirs at Petrel #2, and is a slightly better reservoir in Flat Top #1. Additional later Triassic reservoir objectives are anticipated within the Malita Formation, which contains sandstone units up to 50 m thick interspersed with intraformational shales of similar thickness, which act as seals.

As indicated on Enclosure 13, the Jurassic Plover Formation is expected to be an effective oil reservoir across much of the Petrel Sub-basin, particularly where it is located at depths of less than 3000 m. Better reservoir quality is anticipated in the south where the sands are removed from the marine carbonate cementation which reduces porosity to the north. The Plover Formation is sealed by the overlying Frigate shales, except around the basin margins where onlap or erosional truncation has removed or reduced the effectiveness of this seal. The Plover Formation also contains thick shale sequences which could provide intraformational seal as well as source. The

Plover Formation sands are well placed to be charged by hydrocarbons expelled from such source beds.

Reservoirs may be also located within the Sandpiper Sandstone, a fluvio-deltaic to nearshore siliciclastic unit with high porosities around the Sub-basin margins analogous to that anticipated across the Bathurst Terrace. The basinward extent of the Sandpiper Sandstone as an effective reservoir is, however, controlled by the degree to which kaolinitic, silicic and calcareous cements have contributed to a reduction in porosity. Generally, and in the absence of intraformational shales, vertical seal for this unit would be the Bathurst Island Group.

In the central portions of the Sub-basin, the post-Aptian transgressive sequences contain poorly developed glauconitic sandstone reservoirs. Around the margins of the Sub-basin, reservoir quality facies may exist associated with fluvio-deltaic to strand-line deposits, such as the Campanian and Maastrichtian "Puffin" sands, similar to that envisaged across the Bathurst Terrace.

Reservoirs are probably sourced from a variety of sequences. The Kuriyippi Formation probably sourced, in situ, the shows in Kulshill #1, Lacrosse #1 and Turtle #1. The overlying Keyling Formation is regionally a very rich source rock interval, which within the deeper portions of the Sub-basin is in the gas generating window. The Hyland Bay Formation is both a gas and oil source, and lies within the oil generating window across much of the depocentre. At Petrel #2, for example, the maturity of the source beds as indicated by vitrinite reflectance data was 1.06%, indicating late oil generation. The Plover Formation contains oil-prone source rocks, which in the Flat Top area are marginally mature, whereas the overlying Frigate Shale contains oil and gas-prone source rocks at maturities of 0.93% at Jacaranda #1 and 0.7% at Curlew #1. It is only marginally mature over the Petrel Anticline, but maturity increases towards the Malita Graben. The Cretaceous Bathurst Island Group sediments are considered immature across the Petrel Sub-basin.

Most drilling targets identified within the Petrel Sub-basin are salt related structures. This is particularly the case in the deeper portions of the basin, where basement related structuring is virtually absent, being masked by a thick sediment cover, and exacerbated by the northerly plunge of the Sub-basin. This plunge imposes a strong northwards regional dip making it difficult to obtain critical counterdip closure, particularly across original, basement related structures. Only structural traps with the greatest relief, such as the salt diapirs, have the potential to form present day structural hydrocarbon traps.

Salt structures produce a wide diversity of play types in both carbonate and clastic sequences (Warren, 1989) (Figure 51). Piercement diapirs have been unsuccessfully tested in crestal positions by the Bougainville #1 and Curlew #1 wells, and on the flanks by Kinmore #1 well. Similar tests have been made in the Western Australian side of the basin by Sandpiper #1, Pelican Island #1, Gull #1, Tern #3 and Matilda #1 wells (Gunn & Ly, 1989). However, these wells have only tested a few of the possible salt related plays (Figure 51). Edgerly & Crist (1974) considered that the distribution of salt diapirs is structurally controlled, with piercements preferentially forming along the faulted margin trends. The Kinmore, Bougainville and Petrel structures lie along a north-west trending, northerly plunging nose which may define one such trend. Similar parallel trends occur to the south and coincide with the Penguin, Turtle and Barnett structures (Enclosure 13).

Salt pillows, which involve non-intrusive upwelling of overlying strata, are implicated in the formation of the Petrel Anticline and Heron structure. Other structures formed

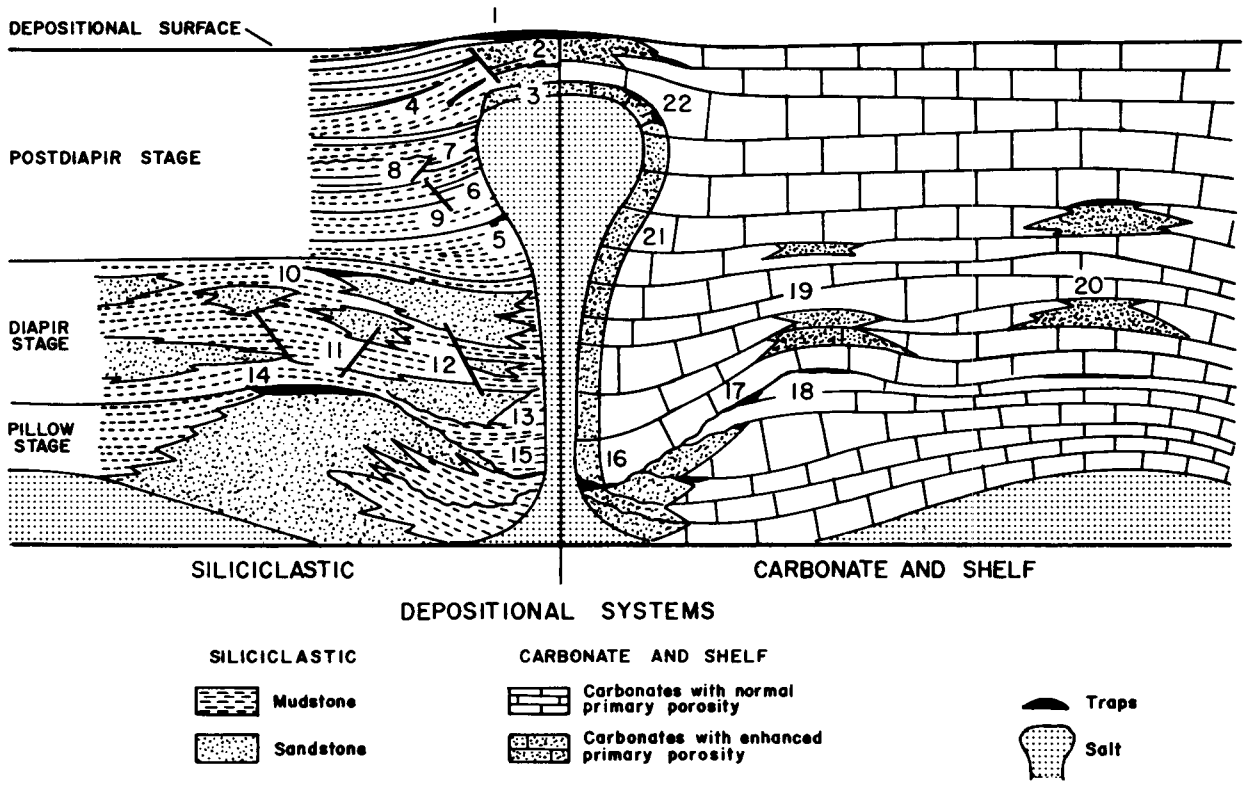


Figure 4 — Schematic diagram of the distribution of potential reservoirs in carbonates (right-hand side of figure) and siliciclastics (left-hand side of figure) during the three stages of salt structure growth (from Warren 1989, after Seni & Jackson 1983c). The trapping mechanisms: 1, combination trap in sand in anticline over crest of dome; 2, graben fault trap over dome; 3, porous caprock; 4, stratigraphic trap in flank sand pinchout; 5, structural trap beneath overhang; 6, structural trap uplifted and buttressed against salt stock; 7, unconformity trap; 8, fault trap downthrown away from salt stock; 9, fault trap downthrown toward salt stock; 10, combination trap in sand from up-dip pinchout of porous facies in sink; 11, fault trap in sand over turtle structure; 12, fault trap in sand in peripheral sink; 13, stratigraphic trap in sand from domeward pinchout of porous facies in sink; 14, combination trap in sand at crest of turtle structure; 15, unconformity trap in sand over crest and flanks of precursor pillow; 16, unconformity trap in carbonates from enhanced porosity over crest and flanks of pillow; 17, combination trap in carbonates from pinchout of enhanced porosity zone on distal flanks of precursor pillow; 18, structural trap in carbonates over crest of turtle structure; 19, combination trap in carbonates from enhanced porosity due to palaeotopography over raised saddle between peripheral sinks; 21, combination trap in carbonates from enhanced porosity near dome due to palaeotopography and buttressing against salt stock; 22, combination trap in carbonates over crest of salt stock from enhanced porosity due to palaeotopography.

(from Warren, 1989)

SALT STRUCTURE RELATED PLAYS

Figure 51

by salt withdrawing from the surrounding strata during diapir formation, such as turtle-back anticlines, provide alternative primary targets. For example, Gunn & Ly (1989) interpret the Tern Anticline as a turtle-back formed by withdrawal of salt into the stock of the Sandpiper diapir and a diapir located south of the Tern #3 well location. Salt withdrawal is also attributed to causing rollover southwest of Frigate #1, induced by listric collapse into the peripheral syncline surrounding the diapir at Sandpiper #1 (Gunn & Ly, 1989; their Figure 15b). A fault related, and as yet untested, structural high situated between Gull #1 and Curlew #1 (Enclosure 11a) may also be attributable to salt withdrawal into the salt stocks located beneath both wells.

The general lack of exploration success associated with drilling salt-related structures in the Bonaparte Basin, can, according to Gunn & Ly (1989), be attributed to, firstly, incompatible timing of structural development and hydrocarbon generation and migration. Whereas some structures show that the main growth occurred during the Tertiary, after the major period of hydrocarbon maturation and migration, others (Tern for example) developed much earlier, that is, during the Permian (Gunn & Ly, 1989). Since these salt related structures have a complex history of growth, it would be advantageous to know the timing of structural development vis-a-vis maturation and migration. Secondly, extensive crestal faulting associated with salt piercement has possibly disrupted the cap seals enabling the escape of hydrocarbons. Gunn & Ly (1989) concluded that fault-free salt closures are the preferred target. In this regard it is noted that the gas productive Tern and Petrel structures are simple, unfaulted anticlinal structures at the reservoir levels (Lavering & Ozimic, 1989).

Conversely, the absence of faulting in these structures may mean that potential reservoirs are not in communication with underlying mature source units. At Petrel for example, excellent reservoirs within closure at the Plover Formation level contained no hydrocarbons. These reservoirs have effective maturities of R_o max 0.6% indicating that intraformational Plover Formation source rock sequences are immature in this region.

An additional factor which is likely to have contributed to the lack of success in exploring salt structures is that several past well tests (eg. Kulshill #1 and Kinmore #1) were sited on structurally complex locations without the benefits afforded by modern, high-fold, closely spaced seismic control. The validity of these older tests is therefore questionable and a careful reassessment is warranted.

Future exploration efforts should be directed towards isopaching regions with known diapir and piercement development, as such analyses may provide not only controls on the timing of critical structural closure, vis-a-vis maturation and migration history, but also highlight the presence of associated passive structures such as peripheral rim synclines, fault-related roll-overs, and turtle-backs. Diapiric structures with Late Cretaceous movements and sited proximal to palaeo-shelf breaks should be evaluated for possible preferential reservoir development of Campanian and Maastrichtian sands across the crest and surrounding flanks.

Older Palaeozoic reservoirs lie at effective depths and form potential exploration targets across structures in the southern portion of the Sub-basin and across the adjacent Moyle Platform (Enclosure 13). In the Turtle and Barnett area, the Hyland Bay Formation, Fossil Head Formation, Kulshill Group and Point Spring Sandstone of the Weaber Group are the key reservoir units. Within the Kulshill Group the best reservoirs are generally restricted to the upper part of the sequence. Barnett #2 flowed oil at a rate of 917 BOPD (Section 6.2.20) from the Kulshill, and at Turtle #1, 5.2 m^3 (32.7 bbls) of biodegraded oil was recovered from an upper Kuriyippi Formation sandstone exhibiting up to 20% log-derived porosity. The glacigene, coarse

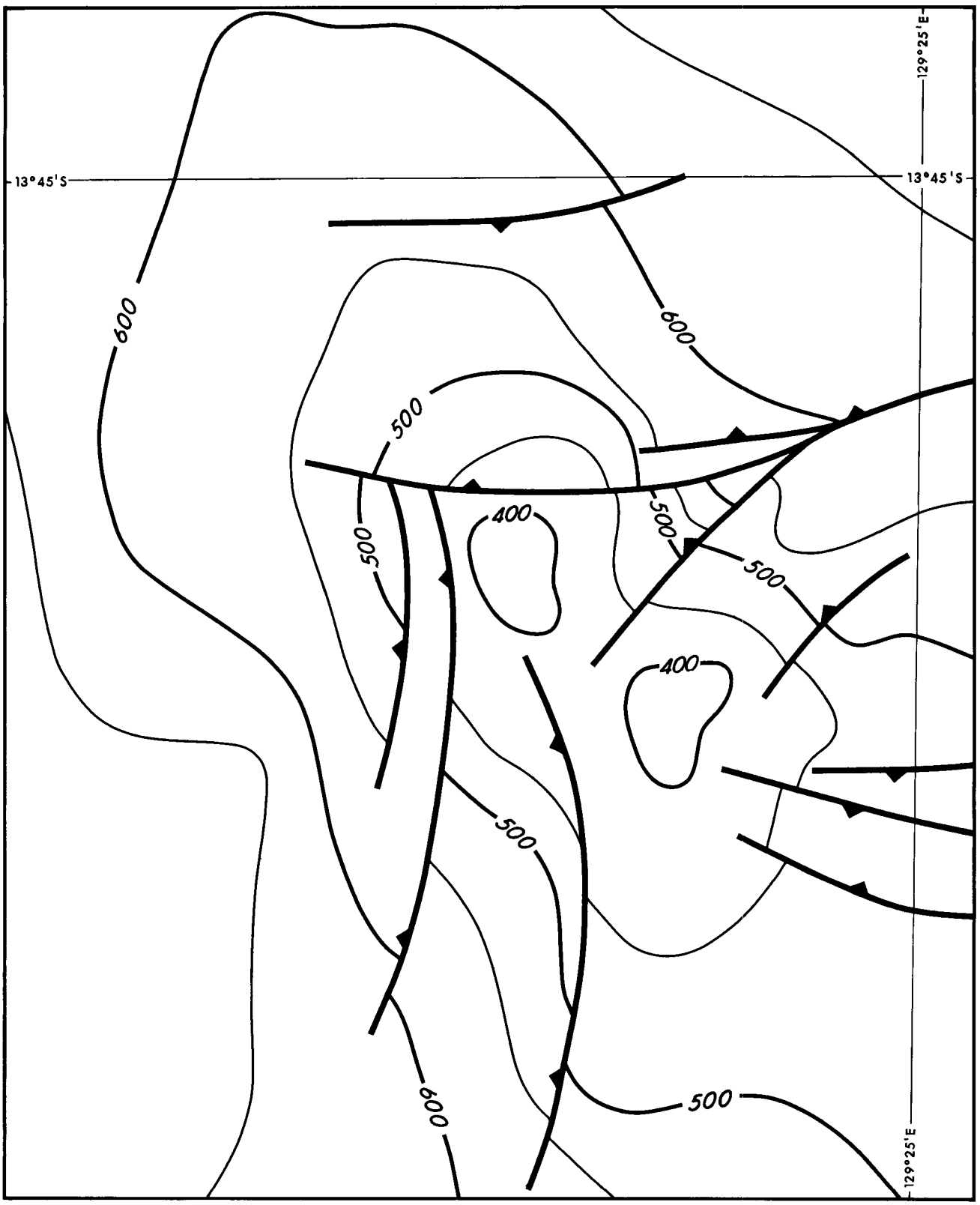


FIGURE 52 Structure E Time Structure Map
Near Top of Upper Permian (After AAP, 1973)

0 1
kilometre

Contour Interval: 50msec TWT

siliciclastic sediments of the Kuriyippi Formation provide potential discontinuous and laterally variable reservoirs, with oil staining reported in this formation within the Lacrosse #1 and Kulshill #1 wells.

The many intraformational shales within the Kulshill Group are considered sufficiently continuous and extensive to provide reliable seal. The regionally extensive shales and silts of the Fossil Head Formation provide a basinwide seal to the Keyling Formation sandstone.

Source intervals within the southern Petrel Sub-basin are expected within the Kuriyippi Formation and the Keyling Formation, which contains rich generally oil-prone source rock sections at Bougainville #1, Kinmore #1 and Flat Top #1 (Section 7.2.1.). The Hyland Bay Formation is not mature within the southern portion of the Sub-basin although it probably contains some source beds.

Palaeozoic reservoirs are the objective targets in many structures in the southern Petrel Sub-basin in which a variety of structural and combined structural-stratigraphic trapping mechanisms are formed by truncation at several unconformity levels. In Enclosure 13, a number of untested salt related structures are shown in the area between the Cretaceous and Permian pinchout edges. Figure 52 shows in detail one such typical structure ("E"). As mapped by AAP at the Near Top Upper Permian, fault independent and dependent closure of approximately 13 km^2 and 75 msec of vertical relief is indicated about a north-west trending, diapiric structure. Reservoirs within the Hyland Bay and Fossil Head Formations form key targets across this structure.

Structuring associated with the formation of the "axial dome" of Gunn (1988) may have contributed to the formation of fault related traps within the Weaber Group. Infill and drape by overlying reservoir units of the "upper" Milligans and Tanmurra Formations across these faulted blocks provide the trapping mechanism in the Turtle and Barnett areas. Large slump related rollovers have been identified along the eastern portion of the Petrel Sub-basin (Gunn & Ly, 1989; their Figure 12) formed by detachment of the "upper" Milligans Formation across the overpressured shales and evaporites of underlying sequences. Similar structures may also be located to the east within the Northern Territory portion of the basin.

Around the margins of the Petrel Sub-basin, regional stratigraphic pinchout plays have been explored without success. Pinchout of the Plover and Londonderry Formations has been evaluated in the Western Australian portion of the basin at Plover #1 and Peewit #1. Flat Top #1 was drilled unsuccessfully on the eastern margin of the Sub-basin to evaluate sub-Aptian/Albian unconformity stratigraphic pinchouts towards the Darwin Shelf. Sand-prone sequences and lack of vertical seal are likely causes for the absence of hydrocarbons in these pinchout plays. However, no wells have been drilled to test possible deltaic, turbidite fan and mound deposits adjacent to and across the flanks of the Moyle Terrace or to test possible intra-Carboniferous stratigraphic and structural traps. As indicated in Section 8.2, thick deltaic sequences within the Cretaceous sequence have been recognised infilling towards the Petrel Sub-basin, suggesting the likelihood that clastic reservoir deposits occur along the margin and could be charged from the oil prone Keyling Formation by hydrocarbons migrating up margin faults. Wells drilled along this margin pre-date high resolution seismic data acquisition and the development of sophisticated seismo-stratigraphic techniques incorporating sea level changes (Van Wagoner et al. 1987).

8.4 ONSHORE PLAYS

To date, the major onshore target has been the Ningbing Reef Complex, which has been compared to the reef systems of the Canning Basin (Blina Oil Field) and the prolifically producing Devonian reef systems of Alberta (Laws, 1981). These reefal sediments occur in the Famennian Ningbing Group.

However, the older sediments of the basin also have hydrocarbon potential. Little is known of the hydrocarbon characteristics of the Early Palaeozoic Carlton Group, but adequate fault controlled structures are undoubtedly present (Enclosure 13). Reservoir quality sandstones are documented by Mory & Beere (1988) and potential carbonate reservoirs exist, but source bed assessments have not been carried out. The downgrading features of the sediments of the Carlton Group are the lack of documented source beds, their perceived over-maturity, the numerous post-depositional structuring episodes and presumed long period of exposure to weathering prior to deposition of younger units. In more basinal areas, evaporites could provide a regional seal to the Carlton Group.

Coarse clastics and carbonates of the Devonian Cockatoo Group deposited in the initial tensional down-faulting stages of basin formation could provide reservoirs in classical fault block traps with fault dependent closures and drape. The outcrop of back reef facies on the northwestern basin margin suggests that a reef complex may exist in this older Devonian sequence and could sub-parallel the Ningbing Reef outcrops. These carbonates may form a similar reef complex on the eastern basin margin, although this margin is structurally controlled.

Notwithstanding the lack of success to date, the Ningbing Group is still a viable exploration target for both carbonate and clastic reservoirs. Exploration problems have been to locate this reef, its platform atolls or pinnacle reef equivalents, in localities where the porous carbonate units have been sourced and sealed by shales of the "upper" and "lower" Milligans Formation. The Keep River #1, Ningbing#1, and Skull #1 wells were drilled for such targets. True reef facies was encountered only in Keep River #1, where porosities were low, but back-reef facies with some porosity was intersected in Ningbing #1 and Weaber #1 wells. Traces of oil were noted in the Ningbing limestones at Keep River #1 and Ningbing #1.

Although the Ningbing limestones lacked effective primary porosity in Keep River #1, Ningbing #1, and Weaber #1, each well was relatively basinwards in terms of the palaeogeography. In more marginal areas, secondary porosity may have developed due to exposure to fresh waters prior to deposition of the Burt Range or Milligans Formations. Secondary porosity may also have developed near the basin margins due to dolomitisation in lagoonal or sabkha environments soon after deposition. Blake (1984) claims that the vuggy porosity seen in the dolomites in Spirit Hill #1 is due to such early diagenesis. Porosity in the Burt Range Formation and Septimus Limestone (Langfield Group) is largely due to dolomitization, which probably took place in the Late Carboniferous after the deposition of the overlying Milligans Formation (Laws, 1981; Mory & Beere, 1988). In Section 7.4.2. it was noted that such secondary porosity extends down to 100 m below the contact of the overlying Langfield Group. Fracture porosity was noted in Weaber #1 in the Ningbing limestones (Section 7.4.2.), and several gas shows were associated with these microfractures. Fracture porosity may be extensively developed along the eastern structural margin, and could host substantial gas reserves.

Other play concepts identified by Laws (1981) within the Ningbing Group involve either a combination of clastic reservoirs and structural traps close to the basin

margins, or pinnacle reefs and platform atolls in the region of the Pincombe High and along the western basin flank. However, reefal limestones may not be well developed along the eastern margin of the onshore Bonaparte Basin because it is a structural, as opposed to a depositional, margin. Block faulting may have led to the formation of quite deep water palaeoenvironments in this area, where the potential exists for fan-type deposits (Enclosure 13). The Ningbing, Langfield and Weaber Groups would provide both the source and seal for both clastic and carbonate objectives.

The area up-dip and slightly basinwards of Keep River #1 along the Pincombe Ridge axis is considered an ideal location for secondary porosity to be preserved in stratigraphic traps, such as platform atolls and pinnacle reefs. Platform atoll development over areas of pre-existing topographic highs, for example on the seaward flank of the Pincombe Ridge, would result in compaction by drape and suggests the possibilility of a dual play involving sands developed in the overlying Milligans Formation. Although no pinnacle reefs have been identified to date in the Bonaparte Basin, they are known in the contemporaneous deposits of the Canning Basin. Because of their small extent, the exploration for pinnacle reefs normally entails a dense seismic grid and good quality seismic reflection data. This is generally not yet available in the onshore Bonaparte Basin, but such reefs may be confined to the region of the Pincombe Ridge and a narrow band sub-parallelling the Ningbing reef complexes.

Possible sub-surface extensions of the Ningbing reef and back-reef limestone east of the Ningbing Range and along the western edge of the Pincombe Ridge may also be possible (Enclosure 13). Gunn & Ly (1989) predicted that additional Ningbing reef development may exist along the eastern basin margin and northwest of the outcrops of the Ningbing Range.

Gunn & Ly (1989) note that the numerous occurrences of oil staining in Langfield Group sediments are usually located immediately beneath the Milligans Formation seals (e.g. at Spirit Hill #1). Langfield Group reservoirs may form valid traps across horsts and tilted blocks draped by intra-Milligans Formation sources and seals. Major channelling interpreted from drilling and seismic sections, suggests that stratigraphic elements may provide important trapping mechanisms.

Despite the fact that the Langfield Group lies immediately beneath potential regional sources and seals, only four exploration wells have tested this level. Furthermore, given the probability of facies variations, this objective can not be regarded as having been fully investigated. The Enga Sandstone of the Weaber Group provides the gas reservoir in the Weaber #1 well, and Laws (1981) indicated that the Enga had a porosity of 22% in a diamond drill hole. Keep River #1 and Kulshill #1 encountered tight sandstones in the Enga, indicating that good porosities are likely only around the basin margins. However, the zone updip from the Weaber #1 gas discovery southward along strike of the Pincombe Ridge has potential for other small to medium sized gas discoveries (eg. additional closures along Spirit Hill Anticline, Figure 8). East-southeasterly trending faults, which are known in this area, could provide counter regional closure to the southwest.

Carbonates of the Langfield Group probably have similar reservoir characteristics to the Ningbing Group, and similar, untested plays are possible. However, massive reefal limestones are unlikely in these Early Carboniferous sediments.

Several plays exist within the Weaber Group. Gunn & Ly (1989) refer to seismic expressions of fans along the margins formed of coarse clastics, such as the Waggon Creek Formation. While the more basinal sequence is dominated by marine shales,

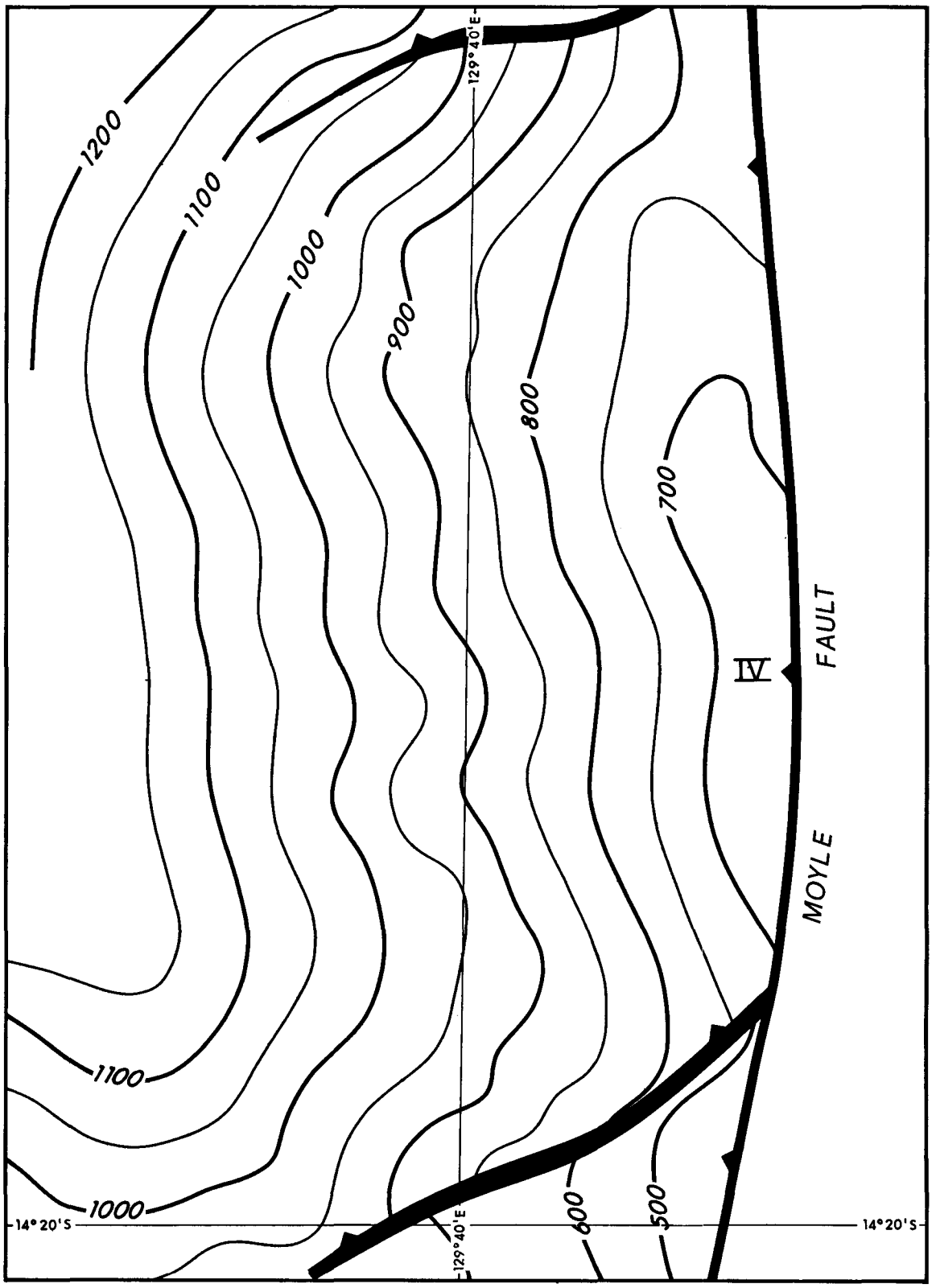


FIGURE 53 Structure IV Time Structure Map
Base Treachery Shale (Lower Permian) (After AAP, 1973)

0 2
kilometres

Contour Interval: 50msec TWT

gas flows from the Bonaparte #2 and Keep River #1 wells show reservoir intervals do occur. Additional traps include the more traditional drape and compaction over fault blocks, with drape over erosional relief possible, particularly at the top of the "lower" Milligans Formation. Laws (1981) identified a major palaeo-channel west of the Pincombe Ridge, called the Waggon Channel. This, and possibly similar channels cut into the platform further to the east, probably provided clastic detritus for fans, channel sands and turbidite deposits shed into the basin and which may now provide reservoir targets (Enclosure 13) around the basin margins, an area in which Lavering (1989) states that the Milligans Formation contains oil-prone organic matter.

In Enclosure 13 several salt diapirs are indicated in the near-shore and onshore areas indicating that salt structuring of the Weaber Group and Langfield Group occurs at relatively shallow depths. On the basis of gravity data, such structures may extend onshore in the vicinity of the Bonaparte #1 (Laws, 1981) and Kulshill #1 wells. Structures may also be located in the Queens Channel area which to date has proved difficult to explore.

Australian Oil Development Ltd. identified the eastern flank of the Burt Range Sub-basin (Legune Terrace of Blake, 1984) as a key region where left lateral faulting along en-echelon segments of the Cockatoo Fault system has produced a series of folds and faulted drape folds. The main objectives are secondary porosity in carbonate reservoirs of the Langfield Group (Keep River Group of Laws, 1981) or the Ningbing limestones. Additional plays along this faulted margin involve either primary or dolomitic secondary porosity in fore-reef and back reef environments, fractured carbonate porosity, as well as clastic reservoir in Permo-Carboniferous sequences. Adjacent to larger faults rollovers have been mapped which involve closures within the Permo-Carboniferous sequences. Figure 53 shows such a typical structure identified in this area by AAP during the Quinns Seismic Survey. Critical closure is provided by fault seal on the down-thrown side of the Moyle Fault. Lateral closure is by closing contours. The areal extent of closure is approximately 37 km^2 and vertical relief is 100 msec at the mapped Treachery Shale level (Figure 53).

The upper Weaber Group sediments (Point Spring Sandstone and Tanmurra Formation) are generally too shallow and lack the required seal to constitute exploration targets onshore.

8.5 DISCUSSION

In reviewing the play concepts in the preceding sections it is apparent that notwithstanding the paucity of exploration data a large number of plays and specific targets have already been identified in a wide variety of geological settings. Clearly with further exploration there is considerable scope for identifying many additional play types and targets.

Equally, in currently evaluating the potential of the basin, there is the danger of dismissing large areas of it as immature and unprospective, or over-mature and gas-prone, on the basis of perhaps one or two well results. The recent oil recoveries from the Turtle and Barnett wells should serve as a caution in applying such results too broadly. To date many of the well tests have been biased towards the deeper, and hence more mature, portions of the basin where sequences are likely to have gas prone affinities.

Future exploration efforts directed in offshore areas towards shallower Cretaceous reservoirs and reservoirs located in structurally shallower basinal positions may yield

results which readdress the apparent gas-prone nature of the Petrel Sub-basin and Malita Graben. Onshore, detailed seismic coverage should enable far superior definition of structural and stratigraphic traps located in what are now established oil and gas bearing sequences.

As described in Sections 8.1, 8.2, 8.3 and 8.4, all four basin provinces have the necessary prerequisites to contain significant oil and gas accumulations. Given that the success to date has come from very limited testing of the more obvious targets one can only be optimistic about the Northern Territory portion of the Bonaparte Basin becoming an important hydrocarbon province in the future. The existing acreage opportunities within the basin warrant the close scrutiny of all serious explorers.

9. CURRENT EXPLORATION OPPORTUNITIES

9.1 EXISTING PERMITS AND INTERESTS

Enclosure 1 shows the status of petroleum acreage holdings in the Northern Territory portion of the Bonaparte Basin. Acreage interests for these holdings are listed in Table 5.

Most existing acreage holdings cover the Sahul Platform, northern part of the Malita Graben, and shallower portions of the Petrel Sub-basin, including onshore areas currently under application. The largest tracts of vacant acreage are located offshore across the Darwin Shelf, across the southwestern portion of the Sahul Platform and Malita Graben and south of the Petrel Field in the Petrel Sub-basin. Targets across the Darwin Shelf could be expected at relatively shallow depths, and in terms of maturity, the prospective section would be within the oil window. This region has not been subjected to modern seismic coverage. Seismo-stratigraphic analysis using modern high resolution seismic tied to available well control could provide considerable up-side potential for identifying new play concepts as well as delineating as yet unknown structural targets in this area. The vacant region south of Petrel must be considered prospective for both oil and gas in view of its proximity to the Turtle - Barnett area. To date only reconnaissance seismic control covers most of this acreage, which includes the basement high trend extending from Bougainville to Petrel. In addition to untested salt related targets, there may be more subtle salt related features within this acreage at stratigraphic levels which only detailed isopach mapping would reveal.

The vacant acreage to the south of NT/P4 (Enclosure 1) includes potential structures located along the Shearwater Fault trend. On the structural high side of this trend potential for Troubadour/Sunrise features exists. Targets also exist for Cretaceous plays on the flank of the Malita Graben in the Curlew - Jacaranda area.

A smaller vacant acreage opportunity exists in an area across the Sahul Platform adjacent to the Kelp structure.

Both NT/P28 and 40 are due to expire during 1991 and renewal of each would be subject to a compulsory relinquishment of 25% of the current area if the respective co-venturers decide to apply for such renewals.

Opportunities may also exist whereby existing co-ventures may wish to farm-out all or part of their equities in particular blocks, particularly in light of some of the more recent corporate rationalisations.

Further information or enquiries regarding vacant areas and data availability should be directed to the Director of Energy, Northern Territory Department of Mines & Energy, Darwin.

TABLE 5 EXISTING PERMITS, NORTHERN TERRITORY BONAPARTE BASIN

Permit	Expiry Date	No. of Blocks	Interest Holders
NT/P4	Pending	111	Elf Aquitaine Exploration Australia
NT/P11	Pending	29	Woodside Petroleum Development Woodside Oil Ltd Mid Eastern Oil Ltd Shell Development (Australia) P/L BHP Petroleum P/L B.P. Petroleum Development Australia
NT/P12	Pending	70	Woodside Petroleum Development Woodside Oil Ltd Mid Eastern Oil Ltd Shell Development (Australia) P/L BHP Petroleum P/L B.P. Petroleum Development Australia
NT/P28 NT/CPI	20/02/91 20/02/91	183 36	Elf Aquitaine Exploration Lenoco (Northern Territory) P/L Gulf Resources N.L Southern Cross Exploration N.L. Petroz N.L. Alliance Minerals Australia N.L. CSX Oil & Gas (Australia) Corp Cornwell Petroleum Corp N.L.
NT/P40	16/06/91	284	Tricentrol Exploration Overseas Western Mining Corporation Ltd P & O Energy
NT/P41	02/06/94	385	BHP Petroleum P/L B.P. Petroleum Development Ltd
NT/P43 NT/CP2	07/03/95 07/03/95	41 38	CNW (Explorations) P/L Cultus Petroleum NL Stirling Petroleum NL Coachwood Resources Ltd. Metana Energy NL
NT/P44	18/01/96	155	BP Petroleum Development Ltd.
NT/P45	18/01/96	152	BP Petroleum Development Ltd.
EP31	17/07/94	20	Alliance Petroleum International Ltd. Vamagas Ltd.
EP 32	01/05/95	60	E.I.E. Exploration P/L
RL 1	07/02/95	6	Alliance Petroleum International Ltd. Vamgas Ltd.
OPA 246	Application	7320 km^2	Canada Northwest Aust. Oil NL Crusader Oil NL Texas International Company Minora Resources NL Cultus Pacific NL

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APPENDIX 1

SEISMIC SURVEYS

A.1.1. MARINE SURVEYS

Survey: Marine Reflection Seismography in the Port Keats Area
Year: 1961
Permit: O.P. 2
Operator: Associated Australian Oilfields
Contractor: Mines Administration
Length: 185 miles
Source: Dynamite
Fold: Single
Line ID: Line 1-7
Reference: Northern Territory Geological Survey Reference Number PR 62/003

Survey: Flat Top Bank Marine Seismic Survey
Year: 1964
Permit: O.P. 83
Operator: Australian Aquitaine
Contractor: Western Geophysical
Length: 294 km (182.5 miles)
Source: Dynamite (39.8 lbs)
Fold: 100 & 300%
Line ID: Prefix FB
Reference: Northern Territory Geological Survey Reference Number PR 64/022

Survey: Timor Sea Seismic Survey
Year: 1965
Permit: P.E. 221 H, O.P. 100 (1) & O.P. 100 (2), O.P. 83
Operator: ARCO Australia & Australian Aquitaine
Contractor: Geophysical Associates
Length: 2306 km (1437 miles)
Source: Sparker
Fold: Single
Line ID: B, C, D, E, F, G, H, L, M, N, P
Reference: Northern Territory Geological Survey Reference Number PR 65/008

Survey: Montebello-Mermaid Shoal Area Marine Seismic Survey
Year: 1965
Permit: P.E. 213H, O.P. 90 CD, O.P. 90 (2), O.P. 92 (2)
Operator: B.O.C. of Australia
Contractor: Western Geophysical Company
Length: 3191 miles (213 H), 106 miles (O.P. 92(1)), 223 miles (O.P. 90(2)), 245 miles (O.P. 92 (2))
Fold: 200% and 300%, Refraction
Line ID: Prefix 65
Reference: Northern Territory Geological Survey Reference Number PR 66/014

Survey: Sahul Shelf Marine Seismic Survey
Year: 1966
Permit: P.E. 221H, O.P. 151
Operator: ARCO Australia & Australian Aquitaine
Contractor: Compagnie General De Geophysique
Length: 12 050 km (7500 miles)
Source: Sparker
Fold:
Line ID: Prefix TS
Reference: Northern Territory Geological Survey Reference Number PR 66/033

Survey: Rankin-Troubadour Area North-West Australian Marine Seismic Survey
Year: 1966
Permit: O.P. 90(2), O.P. 92(1), O.P. 92(2), O.P. 108, O.P. 132(1), O.P. 132(2), O.P. 141, P.E. 213H
Operator: B.O.C. of Australia Limited
Contractor: Western Geophysical
Length: 1715.5 miles
Source: Dynamite
Fold: 200 & 300%
Line ID: Prefix 66
Reference: Northern Territory Geological Survey Reference Number PR 66/015

Survey: Cape Hay - Cape Ford Marine Seismic Survey
Year: 1966
Permit: O.P. 2 and O.P. 83
Operator: Australian Aquitaine
Contractor: Company Generale De Geophysique
Length: 391 km (100% OP2), 835 km (300% OP2), 31 km (100% OP 83), 733 km (300% OP83)
Source: Flexotir & Sparker
Fold: 100 & 300%
Line ID: Prefix CH, Prefix CF
Reference: Northern Territory Geological Survey Reference Number PR 66/012

Survey: Marine Seismograph Survey, Offshore Northern Territory
Year: 1967
Permit: O.L. 2
Operator: Canadian Superior Oil
Contractor: Namco Geophysical Co
Length: 106.7 km
Source: Airgun
Fold: 1200%
Line ID: Line 22
Reference: Northern Territory Geological Survey Reference Number PR 67/014

Survey: Sahul Rise Seismic Survey
Year: 1967
Permit: O.P. 151 (1 & 2) & P.E. 221H
Operator: ARCO Australia & Australian Aquitaine
Contractor: Compagnie Generale De Geophysique
Length: 6988 km
Source: Dynamite
Fold: 600 & 1200%
Line ID: Prefix SR
Reference: Northern Territory Geological Survey Reference Number PR 67/006

Survey: Lesueur Seismic Survey
Year: 1967
Permit: O.P. 151 & P.E. 221H
Operator: Australian Aquitaine & ARCO Australia
Contractor: Compagnie Generale De Geophysique
Length: 888 km
Source: Sparker
Fold: unspecified
Line ID: Prefix LS
Reference: Northern Territory Geological Survey Reference Number PR 67/005

Survey: Londonderry Rise Seismic Survey
Year: 1968
Permit: O.P. 151 (Part 1C & 2A & B), P.E. 221H
Operator: ARCO Australia & Australian Aquitaine
Contractor: Compagnie Generale De Geophysique
Length: 8270.7 (includes some in WA areas areas)
Source: Flexotir
Fold: 600 & 1200%
Line ID: Prefix LR
Reference: Northern Territory Geological Survey Reference Number PR 68/001

Survey: Flat Top Bank No II Sparker Survey
Year: 1969
Permit: NT/P17
Operator: Australian Aquitaine
Contractor: Compagnie Generale De Geophysique
Length: 140 km
Source: Sparker
Fold: 2400%
Line ID: Line 1-8
Reference: Northern Territory Geological Survey Reference Number PR 69/023

Survey: Parry Shoal Marine Seismic Survey
Year: 1969
Permit: O.L. 2
Operator: Longreach Oil Limited
Contractor: United Geophysical Corp.
Length: 610 miles
Source: Airgun
Fold: 1200%
Line ID: Line 2-14a
Reference: Northern Territory Geological Survey Reference Number PR 71/019

Survey: Lengendre-Marie Marine Seismic Survey
Year: 1969
Permit: NT/P5, NT/P6, NT/P11, NT/P12, NT/P15 & WA areas
Operator: B.O.C. of Australia
Contractor: Western Geophysical
Length: 4348.5 miles; 2 miles (NT/P 5), 403 miles (NT/P 6)
103 miles (NT/P 11), 74 miles (NT/P 12), 161 miles (NT/P15)
Source: Aquapulse
Fold: 2400%
Line ID: Prefix 69
Reference: Northern Territory Geological Survey Reference Number PR 69/013

Survey: Van Diemen Rise Seismic Survey
Year: 1969
Permit: NT/P2, NT/P3, NT/P4 & WA areas
Operator: ARCO Australia
Contractor: Compagnie Generale De Géophysique
Length: 1416.0 km
Source: Dynamite
Fold: 600%
Line ID: Prefix VR
Reference: Northern Territory Geological Survey Reference Number PR 69/003

Survey: Holothuria Seismic Survey
Year: 1970
Permit: NT/P2, NT/P3 & WA areas
Operator: ARCO Australia
Contractor: Western Geophysical Company
Length: 1720 km (1068.2 miles)
Source: Aquapulse
Fold: 2400%
Line ID: Prefix HS
Reference: Northern Territory Geological Survey Reference Number PR 70/011

Survey: Tryal-Evans Northwest Australia Marine Seismic Survey
Year: 1970
Permit: NT/P6, NT/P11 & NT/P12 & WA areas
Operator: B.O.C of Australia
Contractor: Western Geophysical Company
Length: 4604.3 miles 455.5 miles (NT/P6), 202.1 miles (Nt/P11), 464.7 (NT/P12)
Source: Aquapulse
Fold: 2400%
Line ID: Prefix 70
Reference: Northern Territory Geological Survey Reference Number PR 71/016

Survey: West Parry Shoal Marine Seismic Survey
Year: 1970
Permit: NT/P 16
Operator: Longreach Oil
Contractor: Western Geophysical
Length: 160 km
Source: Aquapulse
Fold: 1200%
Line ID: A-G
Reference: Northern Territory Geological Survey Reference Number PR 70/008

Survey: Gale Bank Seismic Survey
Year: 1971
Permit: NT/P 2, NT/P3 & WA areas
Operator: ARCO Australia
Contractor: Western Geophysical
Length: 1345 km
Source: Aquapulse
Fold: 2400%
Line ID: Prefix GB
Reference: Northern Territory Geological Survey Reference Number PR 71/018

Survey: Cape Scott Seismic Survey
Year: 1971
Permit: NT/P17, NT/P3, NT/P1, & WA areas
Operator: Australian Aquitaine
Contractor: Compagnie Generale De Géophysique
Length: 75 km
Source: Aquapulse
Fold: 2400%
Line ID: Prefix CS
Reference: Northern Territory Geological Survey Reference Number PR 71/011

Survey: Baldwin Bank Seismic Survey
Year: 1972
Permit: NT/P2, NT/P3, NT/P4 & WA areas
Operator: ARCO Australia
Contractor: Western Geophysical
Length: 3060 km
Source: Aquapulse
Fold: 2400%
Line ID: Prefix BB
Reference: Northern Territory Geological Survey Reference Number PR 72/009

Survey: Calder-Evans Marine Seismic Survey
Year: 1972
Permit: NT/P2, NT/P6
Operator: B.O.C. of Australia Limited
Contractor: Western Geophysical Company
Length: 394.458 miles
Source: Maxipulse
Fold: 2400%
Line ID: Prefix 72
Reference: Northern Territory Geological Survey Reference Number PR73/004

Survey: Cartier Seismic Survey
Year: 1973
Permit: NT/P3, NT/P4 & WA areas
Operator: Arco Australia
Contractor: Geophysical Services International
Length: 2043.8 km
Source: Airgun
Fold: 2400%
Line ID: Prefix C
Reference: Northern Territory Geological Survey Reference Number PR 74/016

Survey: Knob Peak Seismic Survey
Year: 1973
Permit: NT/P1 & WA areas
Operator: ARCO Australia
Contractor: Geophysical Services International
Length: 243.8 km
Source: Airgun
Fold: 2400%
Line ID: Prefix KP
Reference: Northern Territory Geological Survey Reference Number PR 73/006

Survey: Peron Island Seismic Survey
Year: 1973
Permit: NT/P17
Operator: Australian Aquitaine
Contractor: Western Geophysical Company
Length: 1645 km
Source: Aquapulse
Fold: 2400%
Line ID: Prefix PI
Reference: Northern Territory Geological Survey Reference Number PR 72/010

Survey: Cape Talbot Seismic Survey
Year: 1974
Permit: NT/P2, NT/P3, NT/P4 & WA areas
Operator: ARCO Australia
Contractor: Geophysical Services International
Length: 1777.4 km
Source: Airgun
Fold: 4800%
Line ID: Prefix CT
Reference: Northern Territory Geological Survey Reference Number PR 74/025

Survey: Tree Point Seismic Survey
Year: 1974
Permit: NT/P1 & WA areas
Operator: ARCO Australia
Contractor: Geophysical Services International
Length: 486 km
Source: Airgun
Fold: 2400%
Line ID: Prefix TP
Reference: Northern Territory Geological Survey Reference Number PR 74/026

Survey: Kendrew-Cootamundra Marine Seismic Survey
Year: 1975
Permit: NT/P5, NT/P6, NT/P11, NT/P12 & NT/P13
Operator: B.O.C. of Australia
Contractor:
Length:
Source:
Fold:
Line ID: Prefix 74
Reference: Northern Territory Geological Survey Reference Number PR 75/006

Survey: Tessa-Troubadour Marine Seismic Survey
Year: 1976
Permit: NT/P8, NT/P11, NT/P12 & WA areas
Operator: B.O.C. of Australia
Contractor: Geophysical Service International
Length: 108 km (NT/P8), 77 km (NT/P11), 148 km (NT/12)
Source: Aquapulse
Fold: 2400%
Line ID: Prefix 76
Reference: Northern Territory Geological Survey Reference Number PR 76/006

Survey: Van Cloon Seismic Survey
Year: 1976
Permit: NT/P2 & NT/P4
Operator: ARCO Australia
Contractor: Geophysical Services International
Length: 1304.2 km
Source: Airgun
Fold: 2400%
Line ID: Prefix VC
Reference: Northern Territory Geological Survey Reference Number PR 76/007

Survey: York Sound Seismic Survey
Year: 1977
Permit: NT/P2, NT/P4
Operator: ARCO Australia & Australian Aquitaine
Contractor: Geophysical Services International
Length: 1152.5 km
Source: Airgun
Fold: 2400%
Line ID: Prefix YS
Reference: Northern Territory Geological Survey Reference Number PR77/008

Survey: Bellona Seismic Survey
Year: 1979
Permit: NT/P4
Operator: Australian Aquitaine
Contractor: Geophysical Services International
Length: 666 km
Source: Airgun
Fold: 4800%
Line ID: Prefix B
Reference: Northern Territory Geological Survey Reference Numbers PR 79/009

Survey: Melville Marine Seismic Survey
Year: 1980
Permit: NT/P27
Operator: Magnet Petroleum
Contractor: Geophysical Services International
Length: 429.525 km
Source: Airgun
Fold:
Line ID: Prefix R80
Reference: Northern Territory Geological Survey Reference Number PR81/028

Survey: Howland Seismic Survey
Year: 1981
Permit: NT/P28
Operator: Australian Aquitaine
Contractor: Western Geophysical Company
Length:
Source: Airgun
Fold: 4800%
Line ID: Prefix HD
Reference: Northern Territory Geological Survey Reference Number PR82/002

Survey: NT/P33 Seismic Survey
Year: 1981
Permit: NT/P33
Operator: Tricentrol
Contractor: Geophysical Services International
Length: 1663.78 km
Source: Airgun
Fold: 4800%
Line ID: Prefix T81
Reference: Northern Territory Geological Survey Reference Number PR82/031

Survey: Jacaranda S/S
Year: 1983
Permit: NT/P33
Operator: Tricentrol
Contractor:
Length:
Source:
Fold:
Line ID:
Reference:

Survey: 1984 Darwinia Survey
Year: 1984
Permit: NT/P33
Operator: Tricentrol
Contractor: Geophysical Services International
Length: 805 km
Source: Airgun
Fold: 4800% & 6000%
Line ID: Prefix T84
Reference: Northern Territory Geological Survey Reference Number PR85/028

Survey: Barnett Seismic Survey
Year: 1985
Permit: NT/P 28
Operator: Australian Aquitaine
Contractor: Geophysical Services International
Length: 275 km
Source: Airgun
Fold: 4800%
Line ID: Prefix BN
Reference: Northern Territory Geological Survey Reference Number PR 85/49

Survey: Marine Seismic Survey
Year: 1985
Permit: NT/P 40
Operator: Western Mining Corporation
Contractor:
Length: 1410 km
Source:
Fold:
Line ID: Prefix 85MA
Reference: Northern Territory Geological Survey Reference Number PR87/050

Survey: Gloria Marine Seismic Survey
Year: 1986
Permit: NT/P40
Operator: Western Mining Corporation
Contractor: Geophysical Services Inc.
Length: 509 km
Source: Airgun
Fold: 6000%
Line ID: Prefix 86GL
Reference: Northern Territory Geological Survey Reference Number PR 87/060

A.1.2 ONSHORE SURVEYS

Survey: Port Keats
Year: 1961
Permit: OP.2
Operator:
Contractor:
Length:
Source:
Fold:
Line ID:
Reference:

Survey: Spirit Hill Seismic Survey
Year: 1962
Permit: O.P. 3
Operator: Oil Development
Contractor: General Geophysical Company
Length: 69.2 km
Source: Dynamite
Fold: Single
Line ID: EA, EC, NB, ND, NE, NF
Reference: Northern Territory Geological Survey Reference Number PR 62/014

Survey: Keep River Seismic Survey
Year: 1962
Permit: O.P. 2
Operator: Associated Australian Oilfields
Contractor: Geophysical Services International
Length: 43.25 miles (Reflection), 48.55 miles (Refraction)
Source: Dynamite
Fold: Single
Line ID: Line 22
Reference: Northern Territory Geological Survey Reference Number PR 62/015

Survey: Pearce Point Survey
Year: 1963
Permit: O.P. 2
Operator: Australian Aquitaine
Contractor: Compagnie Generale De Geophysique
Length: 117.6 km (reflection) & 58.8 km (refraction)
Source: Dynamite
Fold: Single
Line ID: Prefix PRP
Reference: Northern Territory Geological Survey Reference Number PR 63/019

Survey: The Ninbing-Burt Seismograph
Year: 1964
Permit: O.P. 3
Operator: Alliance Oil Development Australia
Contractor: United Geophysical
Length: 240 km reflection, 100 km refraction
Source: Dynamite
Fold: Single
Line ID: Prefix E, Preference N
Reference: Northern Territory Geological Survey Reference Number PR 63/013

Survey: Legune Seismic & Gravity Survey
Year: 1964
Permit: O.P. 2 & O.P. 3
Operator: Australian Aquitaine
Contractor: Petty Geophysical Engineering
Length: 18 miles (refraction), 38.28 miles (reflection)
Source: Dynamite
Fold: Single
Line ID: Prefix L
Reference: Northern Territory Geological Survey Reference Number PR 64/015

Survey: Kulshill Seismic & Gravity Survey
Year: 1964
Permit: O.P. 2
Operator: Australian Aquitaine
Contractor: Compagnie Générale De Géophysique
Length: 156 km
Source: Nitramon
Fold: Single
Line ID: Prefix K
Reference: Northern Territory Geological Survey Reference Number PR 64/014

Survey: Skull Creek
Year: 1965
Permit: O.P. 2
Operator:
Contractor:
Length: 60 km
Source:
Fold:
Line ID:
Reference:

Survey: Moyle River Seismic & Gravity Survey
Year: 1966
Permit: O.P. 2
Operator: Australian Aquitaine
Contractor: Compagnie Générale De Géophysique
Length: 1180 km
Source: Dynamite
Fold: 100 & 600%
Line ID: Prefix NM, Prefix SM
Reference: Northern Territory Geological Survey Reference Number PR 66/006

Survey: Oakes Creek Seismic & Gravity Survey
Year:: 1967
Permit: O.P. 2
Operator: Australian Aquitaine
Contractor: Compagnie Générale De Géophysique
Length: 112 km
Source: Dynamite
Fold: 600%
Line ID: Prefix OC
Reference: Northern Territory Geological Survey Reference Number PR 67/019

Survey: Hyland Seismic Survey
Year: 1968
Permit: O.P. 2 and O.P. 83
Operator: Australian Aquitaine
Contractor: Western Geophysical
Length: Unspecified
Source: Dynamite
Fold: 600%
Line ID: Prefix H
Reference: Northern Territory Geological Survey Reference Number PR 68/003

Survey: Keep River Reflection Project
Year: 1968
Permit: O.L. 1
Operator: Westralian Oil
Contractor: Geophysical Services International
Length: 37.08 miles
Source: Dynamite
Fold: 600%
Line ID: 1-6
Reference: Northern Territory Geological Survey Reference Number PR 68/005

Survey: Lone Hill Seismic and Gravity Survey
Year: 1969
Permit: O.P. 162
Operator: Australian Aquitaine
Contractor: Compagnie Generale De Geophysicque
Length: 80 km (approx) refraction, 60 km (approx) reflection
Source: Dynamite
Fold: 300% (Kulshill Area)
Line ID: Prefix TP (Tree Point Area), Prefix PH (Providence Hill)
Reference: Northern Territory Geological Survey Reference Number PR 69/012

Survey: Burt Range Project
Year: 1970
Permit: O.P. 162
Operator: Lennard Oil
Contractor: Geophysical Services International
Length: 6.2 km (1200%), 229.6 km (600%)
Source: Dynamite
Fold: 600 & 1200%
Line ID: Prefix BR
Reference: Northern Territory Geological Survey Reference Number PR 71/008

Survey: Border Creek Seismic Survey
Year: 1972
Permit: O.P. 162
Operator: Australian Aquitaine
Contractor:
Length:
Source:
Fold:
Line ID:
Reference: Northern Territory Geological Survey Reference Number PR 72/002

Survey: Quins Seismic Survey
Year: 1973
Permit: O.P. 162
Operator: Australian Aquitaine
Contractor: Digicon Australia Limited
Length: 116.6 km
Source: Dynamite - Anzite Blue
Fold: 600%
Line ID: Prefix Q
Reference: Northern Territory Geological Survey Reference Number PR 74/004

Survey: BNT-80 Seismic Survey
Year: 1980
Permit: O.P. 186
Operator: Elf Aquitaine (Aust. & NZ)
Contractor: Austral United Geophysical
Length: 141.2 km
Source: Vibroseis
Fold: 1200%
Line ID: BNT 80
Reference: Northern Territory Geological Survey Reference Number PR 82/001

Survey: BWA 81 Seismic Survey
Year: 1981
Permit: O.P. 186
Operator: Alliance Petroleum
Contractor:
Length: 129 km
Source: Vibroseis
Fold: 2400%
Line ID:
Reference:

Survey: Spirit Hill Seismic Survey
Year: 1984
Permit: O.P. 186
Operator: Alliance Petroleum
Contractor: Geo Systems
Length: 185 km
Source: Vibroseis
Fold: 5700%
Line ID: Prefix SH84
Reference: Northern Territory Geological Survey Reference Number PR 85/082

Survey:	Queens Channel
Year:	1986
Permit:	E.P. 3
Operator:	Barbara Investments
Contractor:	
Length:	
Source:	
Fold:	
Line ID:	Prefex QC
Reference:	Northern Territory Geological Survey Reference Number PR 86/013

Survey:	1987 Weaber Land Seismic Survey
Year:	1987
Permit:	O.P. 186
Operator:	Santos
Contractor:	GES Seismic Surveys
Length:	140.58 km
Source:	Vibroseis
Fold:	6000%
Line ID:	Prefix 87
Reference:	Northern Territory Geological Survey Reference Number PR 88/085

APPENDIX 2

MAGNETIC SURVEYS

Survey:	Aeromagnetic Survey Permit - 2
Year:	1959
Permit:	O.P. 2
Operator:	Mines Administration
Contractor:	Bureau of Mineral Resources
Length:	
Altitude:	
Grid:	
Reference:	Northern Territory Geological Survey Reference Number PR 59/2

Survey:	Anson Bay Aeromagnetic Survey
Year:	1963
Permit:	O.P. 83
Operator:	Mines Administration
Contractor:	Adastra Hunting Geophysics
Length:	1641 miles
Altitude:	2000 ft
Grid:	22 east-west flight lines at 10 mile intervals
Reference:	Northern Territory Geological Survey Reference Number PR 63/045

Survey:	Timor Sea Aeromagnetic Survey
Year:	1965
Permit:	O.P. 100
Operator:	ARCO Australia & Australian Aquitaine
Contractor:	C.G.G.
Length:	20 094 miles (35 550 kms)
Altitude:	2000 ft (610 m)
Grid:	Square grid of bands oriented N30°W. The interval between the lines is 2 miles and bands 24 miles
Reference:	Northern Territory Geological Survey Reference Number PR 65/007

APPENDIX 3

GRAVITY SURVEYS

Survey: Regional Gravity Survey Bonaparte Gulf Basin
Year: 1957
Permit:
Operator: Mines Administration
Contractor: Bureau of Mineral Resources
Reference: Northern Territory Geological Survey Reference Number PR 58/001

Survey: Cockatoo Gravity Survey
Year: 1980
Permit: O.P. 186
Operator: Australian Aquitaine
Contractor: Wongela Geophysical
Reference: Northern Territory Geological Survey Reference Number PR 1980/029

Survey: Bonaparte Gulf Onshore Gravity Survey BNT-80 Grid
Year: 1980
Permit: O.P. 186
Operator: Australian Aquitaine
Contractor: Solo Geophysics & Co.
Reference: Northern Territory Geological Survey Reference Number PR81/011

NOTE: Also see under seismic appendix for listings of combined seismic and gravity surveys.

APPENDIX 4

BORE HOLE & WELL INFORMATION

Well Name:	Barnett 1	**Operator:**	Aquitaine
Latitude:	14° 31' 50" S	**Contractor:**	Global Marine
Longitude:	129° 03' 09" E	**Rig:**	
Kelly Bushing:	32.0 m (105 ft)	**Water Depth:**	36 m (105 ft)
Total Depth:	2480 m (8134 ft)	**Spud Date:**	9 Jan 1985
Struct Prov:	Petrel Sub-basin	**Completion Date:**	20 feb 1985
Strat Target:		**Defined by:**	
Play Type:		**Results:**	
Status:	P & A	**Reference:**	NTGS PR 85/080

Well Name:	Barnett 2	**Operator:**	Aquitaine
Latitude:	14° 31' 50" S	**Contractor:**	Maersk Voyager
Longitude:	129° 03' 08" E	**Rig:**	
Kelly Bushing:		**Water Depth:**	36 m (108 ft)
Total Depth:	2815 m (9233 ft)	**Spud Date:**	30 Aug 1989
Struct Prov:	Petrel Sub-basin	**Completion Date:**	5 Nov 1989
Strat Target:		**Defined by:**	
Play Type:		**Results:**	
Status:	Suspended oil well	**Reference:**	NTGS PR 85/080

Well Name:	Bougainville 1	**Operator:**	Aquitaine
Latitude:	13° 46' 00" S	**Contractor:**	Zapata ODE
Longitude:	129° 02' 00" E	**Rig:**	Navigator
Kelly Bushing:	12.8 m (42 ft)	**Water Depth:**	36 m (118 ft)
Total Depth:	2676 m (8777 ft)	**Spud Date:**	8 Feb 1972
Struct Prov:	Petrel Sub-basin	**Completion Date:**	19 Mar 1972
Strat Target:	Mesozoic & Permain	**Defined by:**	Seismic
Results:	Trace of methane	**Play Type:**	Salt diapir in Permian
Status:	P & A	**Reference:**	NTGS PR 72/003

Stratigraphy

Formation	**Top (below KB)** metres	feet
Seabed (Tertiary undifferentiated)	48.8	160.0
Bathurst Island Group	250.0	820.0
Valanginian unconformity		
Flamingo Group	314.6	1030.0
Callovian unconformity		
Malita Formation	457.0	1499.0
Cape Londonderry Formation	600.4	1469.0
Mount Goodwin Formation	892.0	2926.0
Hyland Bay Formation		
Tern Member	1342.0	4402.0

Dombey Member	1415.0	4641.0
Cape Hay Member	1430.0	4690.0
Pearce Member	1785.0	5855.0
Fossil Head Formation	1823.0	5979.0
Keyling Formation	2372.0	7780.0
Total Depth		2676.0
8777.0		

Comments:

Bougainville 1 was drilled near the crest of a domal structure with closure at top Dombey Member of the Hyland Bay Formation reported to cover some 49 km^2 (19 miles^2) and having vertical closure of 228 m (748 ft). The Flamingo Group exhibited porosities in excess of 30% from within unconsolidated and well sorted sands.

The Triassic Cape Londonderry Formation sands varied from thin argillaceous units to porous uncon solidated sequences.

The sands present within the Hyland Bay Formation were reportedly clean and porous, with sonic calculated porosities in excess of 25%.

Traces of C 1 were observed by the mud loggers over the Mount Goodwin, Fossil Head and Keyling Formations, as well as traces of fluorescence and cut were observed towards the base of the Fossil Head Formation and the top of the Keyling Formation.

A dramatic contrast in formation water salinities was noted in the well completion report, over the Hyland Bay, Fossil Head and Keyling Formations, inferring selective flushing only, resulting from lateral stratigraphic barriers existing within the Hyland Bay and Keyling Formation reservoirs.

Oil generative source sediments were observed at 2561 - 2570 m (8400 - 8430 ft), a shale zone within the Keyling Formation.

Well Name:	Curlew 1	**Operator:**	ARCO
Latitude:	11° 46' 14" S	**Contractor:**	
Longitude:	128° 15' 50" E	**Rig:**	
Kelly Bushing:	25.0 m (82 ft)	**Water Depth:**	77.7 m (255 ft)
Total Depth:	2,035 m (6677 ft)	**Spud Date:**	6 Nov 1974
Struct Prov:	Petrel Sub-basin	**Completion Date:**	25 Jan 1975
Strat Type:	Jurassic	**Defined by:**	Seismic
Play Type:	Domal salt piercement	**Results:**	Trace gas Plover Fm
Status:	P & A	**Reference:**	NTGS PR 74/029

Stratigraphy

Formation	**Top (below KB)** metres	feet
Seabed (Recent to Miocene)	102.7	337.0
Bathurst Island Group Puffin Formation	339.0	1112.0
Wangarlu Formation (and Turonian marker)	816.0	2677.0

Aptian/Valanginian unconformity		
Flamingo Group Sandpiper Sandstone	1725.0	5660.0
Frigate Shale	1813.0	5948.0
Callovian unconformity		
Plover Formation	1992.0	6536.0
Total Depth	2035.0	6677.0

Comments:

Five F.I.T.'s and three D.S.T.'s were run over the Jurassic Flamingo Group and Plover Formation after shows of gas were observed while drilling, all recovered filtrate and salt water with no indications of hydrocarbons.

Well Name:	Darwinia 1A	**Operator:**	Tricentrol
Latitude:	11° 26' 31.63" S	**Contractor:**	Global Marine
Longitude:	127° 56' 05.72" E	**Rig:**	GMP III
Kelly Bushing:	30.6 m (100 ft)	**Water Depth:**	85.0 m (279 ft)
Total Depth:	2426 m (7960 ft)	**Spud Date:**	27 Jul 1985
Struct Prov:	Malita Graben	**Completion Date:**	19 Aug 1985
Strat Target:	Upper Cretaceous	**Defined by:**	Seismic
Play Type:	Faulted anticline	**Results:**	Dry
Status:	P & A	**Reference:**	NTGS PR 85/075

Stratigraphy

Formation	**Top (below KB)**	
	metres	**feet**
Seabed (Tertiary undifferentiated)	115.6	379.0
Pliocene	157.0	515.0
Miocene	552.0	1811.0
Unconformity		
Eocene	1263.0	4144.0
Palaeocene	1516.0	4974.0
Bathurst Island Group Puffin Formation	1670.0	5479.0
Wangarlu Formation	1822.0	5978.0
Turonian marker	2370.0	7776.0
Total Depth	2426.0	7960.0

Comments:

Darwinia 1 was spudded on 21 June 1985 and respudded as Darwinia 1A on the 27 July 1985. The four objective Upper Cretaceous sands were encountered with good porosity (averaging 25%) but were found to be water-wet.

Well Name:	Evans Shoal 1	**Operator:**	BHP
Latitude:	10_04'53.9"S	**Contractor:**	Maretech Energy
Longitude:	129_31'55.2"E	**Rig:**	Searcher
Kelly Bushing:		**Water Depth:**	110m
Total Depth:	3712m	**Spud Date:**	27 July 1988
Struct Prov:	Malita Graben	**Completion Date:**	25 Aug 1988
Strat Target:	Petrel Formation	**Defined by:**	Seismic
Play Type:	Faulted Anticline	**Results:**	Gas Show
Status:	P & A	**Reference:**	NTGS PR 88/050

Well Name:	Flamingo 1	**Operator:**	Arco
Latitude:	11° 01' 34" S	**Contractor:**	Sedco
Longitude:	126° 28' 55" E	**Rig:**	Sedco 135 G
Kelly Bushing:	34.5 m (113 ft)	**Water Depth:**	96.0 m (135 ft)
Total Depth:	3700 m (12 139 ft)	**Spud Date:**	4 Aug 1971
Struct Prov:	Sahul Syncline	**Completion Date:**	8 Dec 1971
Strat Target:	Jurassic	**Defined by:**	Seismic
Play Type:	Faulted anticline on edge of Sahul Platform	**Results:**	Trace oil stain Sandpiper Sst
Status:	P & A	**Reference:**	

Stratigraphy

Formation	**Top (below KB)** metres	feet
Seabed (Recent to pliocene)	130.5	428.0
Miocene	227.0	910.0
Oligocene	838.0	2750.0
Eocene to Palaeocene	3630.0	
Palaeocene	1540.0	5053.0
Bathurst Island Group Wangarlu Formation	2007.0	6584.0
Turonian marker	2480.0	8137.0
Aptian unconformity		
Darwin Formation	2930.0	9613.0
Valanginian unconformity		
Flamingo Group Sandpiper Sandstone	3266.0	10 716.0
Callovian unconformity		
Plover Formation	3393.0	12 139.0
Total Depth	3700.0	12 139.0

Comments:

An F.I.T. was undertaken over a section of the Jurassic Sandpiper Sandstone after encouraging hydrocarbon indications from a core. The test recovered only 0.13 cu. m (4.5 cu. ft) of gas which indicated the zone to be tight.

A very minor show was reported from the Jurassic Plover Formation while drilling.

Well Name:	Flat Top 1	**Operator:**	Aquitaine
Latitude:	12° 22' 35.3" S	**Contractor:**	Zapata (Australia)
Longitude:	129° 15' 55.9" E	**Rig:**	Investigator - ZO
Kelly Bushing:	12.2 m (40 ft)	**Water Depth:**	41.1 m (135 ft)
Total Depth:	2173 m (7127 ft)	**Spud Date:**	4 Jan 1970
Struct Prov:	Petrel Sub-basin	**Completion Date:**	12 feb 1970
Strat Target:	Mesozioc & Permian sediments	**Defined By:**	Seismic
		Results:	Trace gas from upper Fossil Head Fm
Play Type:	Stratigraphic pinchput		
		Status:	P & A
		Reference:	NTGS PR 70/005

Stratigraphy

Formation	**Top (below KB)** metres	feet
Seabed (Tertiary undifferentiated)	53.3	175.0
Bathurst Island Group	189.0	620.0
Valanginian unconformity		
Flamingo Group Sandpiper Sandstone	743.0	2437.0
Callovian unconformity		
Cape Londonderry Formation	978.0	3208.0
Mt Goodwin Formation	1182.0	2877.0
Hyland Bay Formation Tern Member	1292.0	4238.0
Dombey Member	1304.0	4277.0
Cape Hay Member	1329.0	4359.0
Pearce Member	1417.0	4648.0
Fossil Head Formation	1452.0	4763.0
Keyling Formation	1579.0	5179.0
Basement	2166.0	7104.0
Total Depth	2173.0	7127.0

Comments:

Good quality sandstone resevoir were encountered over the Permain to Cretaceous sections with porosities ranging from 15 to 30% and permeabilities fair to good.

An F.I.T. run at 1473 m (4831 ft) over the upper Fossil Head Formation yielded a trace of C2 along with a recovery of formaation water (37 000 PPM salinity).

Well Name:	Heron 1	**Operator:**	Arco
Latitude:	10° 26' 27" S	**Contractor:**	Zapata ODE
Longitude:	128° 57' 05" E	**Rig:**	Navigator
Kelly Bushing:	11.9 m (39 ft)	**Water Depth:**	38.4 m (126 ft)
Total Depth:	4208 m (13 808 ft)	**Spud Date:**	13 Sep 1971
Struct Prov:	Malita Graben	**Completion Date:**	5 Feb 1972
Strat Target:	Mesozoic	**Defined By:**	Seismic
Play Type:	Rift related half graben	**Results:**	Gas shows in Early Cretaceous and Jurassic
Status:	P & A	**Reference:**	NTGS PR 72/007

Stratigraphy

Formation	Top (below KB) metres	feet
Seabed (Recent to Late Miocene)	50.3	165.0
Middle to Early Miocene	253.0	830.0
Eocene to Palaeocene	533.0	1750.0
Palaeocene	870.0	2854.0
Bathurst Island Group Puffin Formation	1028.0	3374.0
Wangarlu Formation	1185.0	3888.0
Turonian Marker	2050.0	6726.0
Aptian unconformity		
Darwin Formation	3155.0	10 350.0
Valanginian unconformity		
Flamingo Group Frigate Shale	3604.0	11 825.0
Callovian unconformity		
Plover Formation	4170.0	13 682.0
Total Depth	4,208.0	13,808.0

Comments:

Heron 1 was located on a seismically delineated large faulted anticline corresponding to a deeply buried high in a rift related half graben. Several gas shows were observed while drilling the Cretaceous and Jurassic sections of the well.

The more notable gas shows were as follows:

2824 - 2926 m (9265 - 9600 ft)
3109 - 3155 m (10 200 - 10 350 ft)
3688 - 3703 m (12 100 - 12 150 ft)
3703 - 3828 m (12 150 - 12 560 ft)
4191 - 4208 m (13 750 - 13 808 ft)

However, none of the above zones was tested.

Well Name:	Jacaranda 1	**Operator:**	Tricentrol
Latitude:	11° 28' 15.417" S	**Contractor:**	Global Marine
Longitude:	128° 09' 50.306" E	**Rig:**	GMP III
Rotary Table:	26.2 m (86 ft)	**Water Depth:**	78.4 m (257 ft)
Total Depth:	3783 m (12 412 ft)	**Spud Date:**	25 Jun 1984
Struct Prov:	Malita Graben	**Completion Date:**	21 Aug 1984
Strat Target:	Jurassic	**Defined by:**	Seismic
Play Type:	Faulted anticline	**Results:**	Dry
Status:	P & A	**Reference:**	NTGS PR 85/009

Stratigraphy

Formation	Top (below KB) metres	feet
Seabed (Recent)	104.6	343.0
Pliocene	136.0	446.0
Miocene	220.0	722.0
Unconformity	530.0	1739.0
Palaeocene	710.0	2330.0
Bathurst Island Group Puffin Formation	817.0	2681.0
Wangarlu Formation	1130.0	3708.0
Turonian marker	1675.0	5496.0
Aptian/Valanginian unconformity		
Flamingo Group Sandpiper Standstone	2860.0	9384.0
Frigate Shale	2997.0	9833.0
Callovian unconformity		
Plover Formation	3525.0	11 566.0
Total Depth	3783.0	12 412.0

Comments:

Although it was thought dry gas was possibly present from 3,525 m (11,566 ft) to TD, cores from the objective sands had very low permeabilities. However excellent porosity and permeability were characteristic of Upper Cretaceous sands but the structure was not closed at this level.

Well Name:	Kinmore 1	**Operator:**	Aquitaine
Latitude:	14° 02' 01" S	**Contractor:**	Glomar
Longitude:	129° 15' 25" E	**Rig:**	Glomar Tasman
Kelly Bushing:	9.5 m (31 ft)	**Water Depth:**	28.5 m (94 ft)
Total Depth:	3250 m (10,660 ft)	**Spud Date:**	17 Jul 1974
Struct Prov:	Petrel Sub-basin	**Comp Date:**	3 Sep 1974
Strat Target:	Permian sediments	**Defined by:**	Seismic
Play Type:	Salt piercement	**Results:**	Dry structure
Status:	P & A	**Reference:**	NTGS PR 74/021

Stratigraphy

Formation	Top (below KB) metres	feet
Seabed (Tertiary undifferentiated)	38.0	125.0
Mount Goodwin Formation	202.0	663.0
Hyland Bay Formation Tern Member	505.0	1656.0
Dombey Member	562.0	1843.0
Cape Hay Member	586.0	1932.0
Pearce Member	847.0	2778.0
Fossil Head Formation	867.0	2844.0
Keyling Formation	1321.0	4333.0

Treachery Shale	2294.0	7524.0
Kuriyippi Formation	2505.0	8216.0
Diapir Sheath	2931.0	9614.0
Diapir Core (Salt) Devonian	3046.0	9991.0
Total Depth	3250.0	10 660.0

Comments:

Kinmore 1 was drilled on the southeastern flank of a seismically defined salt piercement structure. Two intervals containing mudstone and coal within the Early Permian Keyling Formation are considered to be viable source rock sequences for oil generation within the Petrel Sub-basin, should lateral thickening occur in these intervals.

Well Name:	Kulshill 1	**Operator:**	Aquitaine
Latitude:	14° 21' 47" S	**Contractor:**	Forasol
Longitude:	129° 32' 33" E	**Rig:**	
Kelly Bushing:	70.4 m (231 ft)	**Spud Date:**	20 Jun 1965
Total Depth:	4394 m (14 412 ft)	**Completion Date:**	11 Jun 1966
Struct Prov:	Petrel Sub-basin	**Defined by:**	Seismic
Strat Target:	Permian to Carboniferous	**Results:**	Oil shows in sediments Kulshill Group
Play Type:	Salt induced anticline	**Status:**	P & A
		Reference:	NTGS PR 66/022

Stratigraphy

Formation	**Top (below KB)** metres	feet
Fossil Head Formation	Surface	Surface
Keyling Formation	253.0	830.0
Treachery Shale	1095.0	3592.0
Kuriyippi Formation	1226.0	4021.0
Point Spring Sandstone	1740.0	5707.0
Tanmurra Formation	2650.0	8692.0
Milligans Formation	2831.0	9286.0
Bonaparte Formation	3750.0	12 300.0
Total Depth	4394.0	14 412.0

Comments:

Kulshill 1 was drilled on a deep seated salt feature.

Oil staining was observed while drilling the Kulshill Group. Six D.S.T.'s were run over the Kulshill Group to evaluate these shows, but unfortunately only small pipe recoveries of fresh water and or drilling mud were obtained.

Well Name:	Lynedoch 1	**Operator:**	Shell
Latitude:	9° 51' 43" S	**Contractor:**	Sedco
Longitude:	130° 18' 45" E	**Rig:**	Sedco 445 Drillship
Kelly Bushing:	11.3 m (37 ft)	**Water Depth:**	235.7 m (773 ft)
Total Depth:	3967 m (13 015 ft)	**Spud Date:**	14 Feb 1973
Struct Prov:	Calder Graben	**Completion Date:**	8 Jun 1973
Strat Target:	Early Cretaceous & Jurassic	**Defined by:**	Seismic
		Results:	Minor gas shows
Play Type:	Anticline	**Status:**	P & A
		Reference:	NTGS PR 73/009

Stratigraphy

Formation	**Top (below KB)** metres	feet
Seabed (Recent to Miocene)	247.0	810.0
Eocene to Palaeocene	1218.0	3995.0
Bathurst Island Group Puffin Formation	1551.0	5090.0
Wangarlu Formation	2115.0	6939.0
Turonian marker	3499.0	11 480.0
Aptian unconformity		
Darwin Formation	3709.0	12 168.0
Valanginian unconformity		
Flamingo Group Sandpiper Sandstone	3916.0	12 850.0
Frigate Shale	3947.0	12 950.0
Total Depth	3967.0	13 015.0

Comments:

Lynedoch 1 was drilled to test a broad anticlinal feature covering 150 km^2 (390 miles^2) with closure mapped at the Aptian unconformity seismic horizon. Gas shows were observed in limestones while drilling through the basal Albian section.

A drilling break and a small gas show in the mud were observed over the basal section of the Jurassic Sandpiper Sandstone. Thin-section analysis showed this zone to contain abundant fractured sand grains. These two zones were not evaluated any further.

Well Name:	Moyle 1	**Operator:**	Aquitaine
Latitude:	14° 19' 12" S	**Contractor:**	Forasol
Longitude:	129° 46' 27" E	**Rig:**	Emsco
Kelly Bushing:	61.2 m (201 ft)	**Spud Date:**	27 Jul 1966
Total Depth:	539.0 m (1768 ft)	**Completion Date:**	15 Aug 1966
Struct Prov:	Moyle Platform	**Defined by:**	Seismic
Strat Target:	Early Permian to Late Carboniferous sediments	**Results:**	Dry
		Status:	P & A
Play Type:	Upstanding basin margin block.	**Reference:**	NTGS PR 66/009

Stratigraphy

Formation	Top (below KB) metres	feet
Tertiary undifferentiated	Surface	Surface
Keyling Formation	105.0	344.0
Treachery Shale	390.0	1279.0
Basement	517.0	1696.0
Total Depth	539.0	1768.0

Comments:

Moyle 1 was located on the upthrown side of the Moyle Fault, a regional basin margin fault that appears to exhibit throws of greater than 4,000 m (13,120 ft) on the basement reflector.

The well was drilled to examine the sedimentary succession in the eastern part of the basin and to determine the nature of the sediments with basement.

There were no oil or gas shows encountered.

Well Name:	Newby 1	**Operator:**	Aquitaine
Latitude:	11° 50' 07" S	**Contractor:**	Zapata (Australia)
Longitude:	129° 06' 07" E	**Rig:**	Ideco Hydrair
Kelly Bushing:	12.2 m (40 ft)	**Water Depth:**	74.7 m (245 ft)
Total Depth:	1148 m (3765 ft)	**Spud Date:**	6 Dec 1969
Struct Prov:	Petrel Sub-basin	**Completion Date:**	31 Dec 1969
Strat Target:	Mesozoic sediments	**Defined by:**	Seismic
Play Type:	Stratigraphic pinchout	**Results:**	Dry
		Status:	P & A
		Reference:	NTGS PR 69/015

Stratigraphy

Formation	Top (below KB) metres	feet
Seabed (Tertiary undifferentiated)	86.9	285.0
Bathurst Island Group	259.0	850.0
Valanginian unconformity		
Flamingo Group Sandpiper Sandstone	960.0	3149.0
Callovian unconformity		
Basement	1115.0	3657.0
Total Depth	1148.0	3765.0

Comments:

No shows of hydrocarbons were reported from this well.

Well Name:	Petrel 2	**Operator:**	ARCO
Latitude:	12° 51' 14" S	**Contractor:**	Sedco
Longitude:	128° 30' 50" E	**Rig:**	Sedco 135 G
Kelly Bushing:	34.4 m (113 ft)	**Water Depth:**	97 m (318 ft)
Total Depth:	4725 m (15 498 ft)	**Spud Date:**	18 Dec 1970
Struct Prov:	Petrel Sub-basin	**Completion Date:**	23 Jul 1971
Strat Target:	Permain sediments	**Defined by:**	Seismic
Play Type:	Anticline	**Results:**	Cape Hay Member gas well
Status:	Suspended gas well	**Reference:**	NTGS PR 71/013

Stratigraphy

Formation	**Top (below KB)** metres	feet
Seabed (Tertiary undifferentiated)	131.4	431.0
Bathurst Island Group	411.0	1348.0
Valanginian unconformity		
Flamingo Group Sandpiper Sandstone	1295.0	4248.0
Frigate Shale	1492.0	4894.0
Callovian unconformity		
Plover Formation	1770.0	5806.0
Malita Formation	2159.0	7082.0
Cape Londonderry Formation	2464.0	8082.0
Mount Goodwin Formation	2878.0	9440.0
Hyland Bay Formation Tern Member	3460.0	11 349.0
Dombey Member	3526.0	11 565.0
Cape Hay Member	3561.0	11 680.0
Pearce Member	3952.0	12 963.0
Fossil Head Formation	4028.0	13 212.0
Total Depth	4725.0	15 498.0

Comments:

Petrel 2 was drilled as a follow up to the initial gas discovery well Petrel 1. Upper Permian sands of the Cape Hay Member between 3653 to 3671 m (11 982 - 12 040 ft) tested dry gas at rate of 186 000 - 411 000 m^3/D (6.6 - 14.5 MMCF/D) on a 1.27 cm (1/2") choke (DST 6). The Petrel Field is currently shut in awaiting development.

Well Name:	Shearwater 1	**Operator:**	Arco
Latitude:	10° 30' 49" S	**Contractor:**	Atwood Oceanics
Longitude:	128° 18' 37" E	**Rig:**	Margie
Kelly Bushing:	25.0 m (82 ft)	**Water Depth:**	69.8 m (229 ft)
Total Depth:	3177 m (10 425 ft)	**Spud Date:**	19 Sep 1974
Struct Prov:	Sahul Platform	**Completion Date:**	4 Nov 1974
Strat Target:	Jurassic	**Defined by:**	Seismic
Play Type:	Faulted anticline	**Results:**	Dead oil staining within Plover Fm
Status:	P & A	**Reference:**	NTGS PR 74/027

Stratigraphy

Formation	**Top (below KB)** metres	feet
Seabed (Recent to Miocene)	94.8	311.0
Unconformity	525.0	1722.0
Oligocene		
Eocene to Palaeocene	640.0	2100.0
Palaeocene	1308.0	4292.0
Bathurst Island Group Wangarlu Formation	1566.0	5138.0
Turonian marker	2057.0	6750.0
Aptian/Callovian unconformity		
Plover Formation	3054.0	10 021.0
Total Depth	3177.0	10 425.0

Comments:

Shearwater 1 was drilled to evaluate an elongate northeast-southwest trending faulted anticline located on the southern margin of the Sahul Platform. Minor dead oil staining was encountered in the Jurassic Plover Formation however, no tests were conducted.

Well Name:	Sunrise 1	**Operator:**	Bocal
Latitude:	9°35' 24.35" S	**Contractor:**	
Longitude:	128° 09' 13.64" E	**Rig:**	Ocean Digger
Kelly Bushing:	30.0 m (98 ft)	**Water Depth:**	159.0 m (522 ft)
Total Depth:	2341 m (7681 ft)	**Spud Date:**	31 Dec 1974
Struct Prov:	Sahul Ridge	**Completion Date:**	2 Feb 1975
Strat Target:	Jurassic	**Defined by:**	Seismic
Play Type:	Faulted anticline from Plover Fm	**Results:**	Gas and condensate
Status:	Suspended gas well	**Reference:**	NTHS PR 75/003

Stratigraphy

Formation		Top (below KB) metres	feet
Seabed (Recent to Pleistocene)		189.0	620.0
Miocene to Pliocene		492.0	1614.0
Unconformity			
Oligocene	(Upper)	852.0	2795.0
	(Lower)	1092.0	3583.0
Eocene		1116.0	3662.0
Palaeocene		1396.0	4580.0
Bathurst Island Group Wangarlu Formation			4830.0
Turonian marker			5289.0
Aptian unconformity			
Darwin Formation (?)		2092.0	6864.0
Valanginian/Callovian unconformity			
Plover Formation		2096.0	6877.0
Total Depth		2341.0	7681.0

Comments:

Sunrise 1 was drilled on a seismically delineated northwest-southeast trending elongate faulted anticline.

Fluorescence and an increase in gas readings was observed at the top of the Jurassic Plover Formation. Two zones of interest were identified and evaluated with F.I.T. numbers 2 and 4, both yielding recoveries of gas and condensate.

F.I.T.	Interval	Recovery
2	2303 m (7228 ft)	2.563 m^3 (90.5 ft^3) gas, 545 cc condensate and 365 cc mud/condensate emulsion
4	2144 m (7034 ft)	4.15 m^3 (146.6 ft^3) gas, 800 cc condensate and 800 cc mud

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Well Name:	Troubadour 1	**Operator:**	Bocal
Latitude:	9° 44' 03.82" S	**Contractor:**	
Longitude:	128° 07' 26.51" E	**Rig:**	
Kelly Bushing:	12.5 m (41 ft)	**Water Depth:**	96.5 m (317 ft)
Total Depth:	3459 m (11 349 ft)	**Spud Date:**	3 Jun 1974
Struct Prov:	Sahul Platform	**Completion Date:**	16 Sep 1974
Strat Target:	Jurassic	**Defined by:**	Seismic
Play Type:	Faulted anticline	**Results:**	Gas and condensate from Plover Fm
Status:	Suspended gas well	**Reference:**	NTGS PR 74/014

Stratigraphy

Formation	Top (below KB) metres	feet
Seabed (Recent to Miocene)	109.0	358.0
Unconformity		
Oligocene	868.0	2848.0
Eocene	1007.0	3304.0
Palaeocene	1241.0	4072.0
Bathurst Island Group Wangarlu Formation	1402.0	4600.0
Turonian marker	1546.0	5072.0
Aptian unconformity		
Plover Formation	2159.0	7084.0
Malita Formation	2502.0	8209.0
Cape Londonderry Formation	2764.0	9069.0
Mount Goodwin Formation	3003.0	9853.0
Unconformity		
Permian	3294.0	10 808.0
Basement - weathered granite indeterminate age	3315.0	10 877.0
Total Depth	3459.0	11 349.0

Comments:

Troubadour 1 was the first well to be drilled on the crest of the Sahul Platform. The well was located to test Jurassic objectives in a faulted anticline. Two D.S.T.'s were conducted over the Jurassic Plover Formation, both recovering gas and condensate.

D.S.T. 2	2228 - 2244 m (7310 - 7363 ft) rec. gas to surface at 279,000 m^3/D (9.85 MMCFPD) and 35.66 m^3/D condensate (224.3 BCPD) with a trace of water
D.S.T. 3	2206 - 2211 m (7238 - 7254 ft) rec. gas to surface at 41 500 m^3/D (1.447 MMCFPD) and 2.08 m^3/D condensate (13.1 BCPD) and 0.49 m^3/D water (3.1 BWPD)

Well Name:	Weaber 1	**Operator:**	Aquitaine
Latitude:	15°21' 10.4" S	**Contractor:**	Atco-APM
Longitude:	129° 07' 48.9" E	**Rig:**	A1 Nat.610
Kelly Bushing:	6.0 m	**Water Depth:**	N/A
Total Depth:	1950 m	**Spud Date:**	14 Sept 1982
Struct Prov:	Keep Inlet Sub-basin	**Completion Date:**	18 Oct 1982
Strat Target:	Ningbing Limestone eq	**Defined by:**	Seismic
Play Type:	Famennian Carbonate bank	**Results:**	Gas show plus traces of fluorescence
Status:	P & A	**Reference:**	NTGS PR 83/044

Comments:

Weaber 1 was re-entered in 1985 and four DSTs were run.

D.S.T. 1	1281 - 1313 m (4203 - 4308 ft) rec. gas to surface at 2.0 MMCFPD)
D.S.T. 4	1273 - 1421 m (4177 - 4662 ft) rec. gas to surface at 4.5 MMCFPD) No fluid recovery was reported

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Well Name:	Weaber 2	**Operator:**	Santos Ltd
Latitude:	15° 20' 55.5" S	**Contractor:**	Atco APM
Longitude:	129° 06' 30.3" E	**Rig:**	A2(Midcontinental U-36-A)
Kelly Bushing:	17.7 m	**Water Depth:**	N/A
Total Depth:	445 m	**Spud Date:**	3 Aug 1988
Struct Prov:	Keep Inlet Sub-basin	**Completion Date:**	17 Aug 1988
Strat Target:	Early Carboniferous	**Defined by:**	Seismic
Play Type:	Anticline	**Results:**	Dry
Status:	P & A	**Reference:**	NTGS PR 88/053

Well Name:	Weaber 2A	**Operator:**	Santos Ltd
Latitude:	15° 20' 51.5" S	**Contractor:**	Atco-APM
Longitude:	129° 06' 29.6" E	**Rig:**	A2 (Midcontinental U-36-A)
Kelly Bushing:	17.7 m	**Water Depth:**	N/A
Total Depth:	1657 m	**Spud Date:**	20 Aug 1988
Struct Prov:	Keep Inlet Sub-basin	**Completion Date:**	10 Sept 1988
Strat Target:	Early Carboniferous	**Results:**	Gas show in Milligans
Defind by:	Seismic		Fm. Enga Sandstone
Play Type:	Anticline		
Status:	P & A	**Reference:**	NTGS PR 88/053

APPENDIX 5

HYDROCARBON SHOWS & GEOCHEMISTRY INVENTORY

A5.1 DESCRIPTIVE GEOCHEMISTRY PARAMETERS

The following parameters are used in this study:

TOC Range (%) *	Rating	Quality (HI)*	Rating
0.0 - 0.5	Poor	100	Poor
0.5 - 1.0	Fair	100-200	Fair
1.0 - 2.0	Good	200-300	Good
2 - 4.0	Very Good	300-400	Very Good
> 4	Excellent	400 +	Excellent

SCI *	% Romax*	Maturity Rating
0 - 3.4	0.0 - 0.65	Immature
3.5 - 5.4	0.65 - 1.0	Oil Generation
5.5 - 7.0	1.0 - 1.35	Peak Oil Generation
> 7	> 1.35	Gas generative and oil destructive

* TOC - Total Organic Carbon
* SCI - Spore Colour Index
* % Ro - Vitrinite Reflectance
* HI - Hydrogen Index.

A 5.2 HYDROCARBON SHOWS & GEOCHEMISTRY WELL BY WELL INVENTORY

Depth (mKB)	Formation	Show Description
Well: Barnett #1		
825-846	Keyling Early Permian	Oil, dull gold fluorescence with an instant bright yellow white cut in sandstone. The core at this interval contained oil staining and bitumen.
1307-1311	Keyling Early Permian	Oil, bright yellow gold fluorescence with an instant bright yellow to white cut in sandstone.
1402-1415	Treachery Shale Early Permian	Oil; light yellow - yellow white fluorescence with a weak light yellow cut in a siltstone.
1503-1513	Kuriyippi Late Carboniferous	Oil; light yellow fluorescence with a trace of very pale yellow cut in a sandstone.
1519-1538	Kuriyippi Late Carboniferous	Oil; white fluorescence with dull white cut in sandstone/siltstone.
1544.7-1555	Kuriyippi Late Carboniferous	Oil; bright yellow fluorescence with light pale yellow cut in sandstone. Core at this interval was stained with brown oil.
1567-1569	Kuriyippi Late Carboniferous	Oil, light yellow to dull gold fluorescence with light yellow cut in sandstone.
1625-1630	Kuriyippi Late Carboniferous	Oil, dull pale yellow fluorescence pale yellow cut in sandstone.
1723-1750	Kuriyippi Late Carboniferous	Oil, dull yellow white fluorescence with yellow while cut in sandstone.
1854	Kuriyippi Late Carboniferous	Oil, bright yellow fluorescence with a light yellow cut in sandstone.
1880-2016	Kuriyippi Late Carboniferous	Oil, dull orange fluorescence with pale white cut in sandstone interbeds. Gas; up to 2% total gas with C_1 - C_4
2029.5-2036	Kuriyippi Late Carboniferous	Oil; dull orange to light yellow fluorescence with faint white cut in sandstone. 300 cc oil recovered in RFT and trace oil recovered in D.S.T. Gas; 1.53% total gas with C_1 - C_4.

2170-2180	Point Spring Sandstone Early Carboniferous	Oil; pale yellow fluorescence with very weak cut in sandstone/siltstone.
2196-2245	Point Spring Sandstone Early Carboniferous	Gas; several gas peaks over interval, with up to 2.2% total gas comprising C_1 - C_4.

Reference: AAP., 1985 Well Completion Report Barnett #1 NT/P28
Northern Territory Geological Survey Reference Number PR 85/080

Well: Bougainville #1

2358-2500	Keyling Early Permian	Gas; up to 12% C_1 recorded
2372-2373	Keyling Early Permian	Oil; fair bright yellow scattered fluorescence with cut in porous sandstone.

Reference: AAP., 1972 Well Completion Report Bougainville #1 NT/P17
Northern Territory Geological Survey Reference Number PR72/003.

Well: Curlew #1

591	Vee Late Cretaceous	Gas; minor (methane only) show in sand-shale sequence.

Reference: Arco., 1974 Well Completion Report Curlew #1 NT/P3
Northern Territory Geological Survey Reference Number PR 74/029.

Well: Darwinia 1/1A

Darwinia 1/1A did not encounter any significant hydrocarbons while drilling, nor were potential hydrocarbon zones detected on logs.

Reference: Tricentrol, August 1985 Who's Drilling.
Northern Territory Geological Survey Reference Number PR 85/075

Well: Evans Shoal #1

Reference: BHP (1988). Well Completion Report.
Northern Territory Geological Survey Reference Number PR 88/050

3440-3453	Albian Limestone	Recorded gas up to 6%, dominantly C_1 with minor C_2, trace of C_3 and C_4 at 3440m.
3453-3543	Flamingo Group	Gas recorded 1-3%, dominantly C_1 with minor C_2 at 3470 m and 3500 - 3510 m.
3453-T.D.	Plover Formation	Background gas mainly 1-5%, connection gas 16%, mainly C_1 with minor C_2 at 3569 m, 3597 m, 3668 - 3680 m and 3689 m. Gas confirmed on logs and RFT's recovered dry gas from 3554 and 3678 m. Gas confirmed to be very dry and thermally mature.
3558-3561	Plover Formation	Trace dull gold fluorescence, no solvent cut, pale yellow slow streaming crush-cut.
3567-3573	Plover Formation	Trace dull orange-brown fluorescence, no solvent cut, very slow white crush-cut.
3618-3627	Plover Formation	Trace orange-brown fluorescence with very slow white cut, instant white crush cut and residual ring.
3627-3636	Plover Formation	Trace orange-brown fluorescence, milky white no cut.
3669-3672	Plover Formation	Trace light blue to blue-white fluorescence.

Well: Flat Top #1

Flat Top #1 did not encounter any signficiant hydrocarbons while drilling, nor were potential hydrocarbon zones detected on logs.

Reference: AAP., 1970 Well Completion Report Flat Top #1 NT/P17
Northern Territory Geological Survey Reference Number PR 70/005.

Well: Heron #1

1232-1235	Turnstone Late Cretaceous	Gas show; methane and propane.
1558-1580	Turnstone Late Cretaceous	Gas show; methane and propane.
1614-1621	Vee Late Cretaceous	Gas show; methane and propane.
1635-1638	Vee Late Cretaceous	Gas show; methane and propane.
1733-1739	Vee Late Cretaceous	Gas show; methane and propane.
2028-2039	Vee Late Cretaceous	Gas show; methane and propane.
2485-2808	Wangarlu Late Cretaceous	Gas show; methane and propane.
2824-2924	Wangarlu Late Cretaceous	Gas show; C_1 - C_5.
3109-3155	Brown Gannet Late Cretaceous	Gas show; C_1 - C_5.
3688-3703	Frigate Shale Early Cretaceous	Gas show; C_1 - C_5.
3703.3-3828	Frigate Shale Early Cretaceous	Gas show; C_1 - C_5.
4191-4209	Frigate Shale Early Cretaceous	Gas show; C_1 - C_5.

Reference: Arco., 1972 Well Completion Report Heron #1 NT/P4
Northern Territory Geological Survey Reference Number PR 72/007.

Well: Jacaranda #1

1207	Turnstone Late Cretaceous	Gas show of 4% in a sandy streak. Associated with a small kick on the resistivity log.
1225-1230	Turnstone Late Cretaceous	A gas show of 9% was recorded in siltstones with no associated fluorescence.

1477-1526	Moonkinu Sandstone Late Cretaceous	A gas show of 4% total gas (C_1 27900 ppm, $C_2$420 ppm, C_3 82 ppm) recorded in fine grained sands.
2850	Wangarlu Early Cretaceous	A trace of C_5 recorded along with nC_4 with a total gas reading of 0.5%.
2867-2872	Wangarlu Early Cretaceous	Gas show of 3% in total (C_1 - C_5).
3130	Sandpiper Sandstone Early Cretaceous	Maximum total dry gas show of 6% with no fluorescence.
3550-3610	Plover Middle Jurassic	1% bright gold fluorescence with weak white cut. This show may have been caused by kerogen or inspissated bitumen.

Reference: Tricentrol, 1985 Well Completion Report Jacaranda #1 NT/P33, Northern Territory Geological Survey Reference Number PR 85/009.

Well: Kulshill #1

1173-1447	Upper Kuriyippi Late Carboniferous	Free oil liberated from argillaceous sandstone cuttings. Strong greenish yellow fluorescence along with good cut. D.S.T's 1 and 2 gave no oil flow.
1682-1700	Upper Kuriyippi Late Carboniferous	Shows as above (1173 - 1447 m) in sediments
1848-1878	Point Spring Sandstone Early Carboniferous	Gas shows comprising 1.5% methane and 0.05% ethane, D.S.T. 5 (1854 - 1878) recovered 22 ft^3 of mud
1885-1924	Point Spring Sandstone Early Carboniferous	Associated with methane gas. Free oil and heavy hydrocarbons (resin, bitumen) visible
2030-2152	Point Spring Sandstone Early Carboniferous	Gas shows of methane 10-15%, ethane 1-2% and propane 0.6% D.S.T's 3 and 4 over this internal recovered gas mixed with formation water and mud
2945-3060	Upper Milligans Early Carboniferous	Gas shows consisting of over 21% methane, 2% ethane and 0.6% propane DST over this interval recovered 72 ft^3 of gas cut mud.

Reference: AAP., 1966 Well Completion Report Kulshill #1 OP2
Northern Territory Geological Survey Reference Number PR 66/022.

Well: Kinmore #1

2830-2930	Lower Kuriyippi Late Carboniferous	Gas shows. Max 20 000 ppm C_1, 2000 ppm C_2, 300 ppm C_3, 70 ppm C_4 recorded opposite coally streaks

Reference: AAP., 1974 Well Completion Report Kinmore #1 NT/P17
Northern Territory Geological Survey Reference Number PR 66/009.

Well: Lynedoch #1

3675-3716	Lower Cretaceous	Thin hydrocarbon bearing zone, probably gas. The interval is predominantly water bearing with local occurrences of hydrocarbons observed below 3699 m on logs. A kick was observed while drilling at this depth and iC 4 and nC5 were detected. Minor gas shows in mud point to very low hydrocarbon saturation in the matrix with higher saturation in fractured intervals.

Reference: Shell., 1973 Well completion report Lynedoch #1 NT/P19, Arafura Sea Northern Territory Australia (unpublished), Northern Territory Geological Survey Reference Number PR 73/009A.

Well: Newby #1

Newby #1 did not encounter any significant hydrocarbons while drilling, nor were any potential hydrocarbon zones detected on logs.

Reference: AAP., 1969 Well Completion Report Newby #1 NT/P17
Northern Geological Survey Reference Number PR 69/015

Well: Petrel #2

2637-3657	Hyland Bay Late Permian	Gas; C_1 - C_5.
3683-3686	Hyland Bay Late Permian	Gas; C_1 - C_5.
3787-3790	Hyland Bay Late Permian	Gas; C_1 - C_5.
4137-4143	Fossil Head Early Permian	Gas; C_1 - C_5.
4389-4400	Fossil Head Early Permian	Gas; C_1 - C_5.
4680-4683	Fossil Head Early Permian	Gas; C_1 - C_5.

Reference: ARCO., 1971. Well Completion Report Petrel #2 NT/P3
Northern Territory Geological Survey Reference Number PR71/013.

Well: Shearwater #1

3106-3114	Plover Jurassic	Scattered traces of dead oil staining. Logs suggest very low porosity and high water saturation and this suggests the possibility of only occasional thin stingers of sandstone over this interval. Sidewall cores taken over this interval show no evidence of hydrocarbons.

Reference: ARCO., 1974 Well Completion Report Shearwater #1 NT/P4
Northern Territory Geological Survey Reference Number PR 74/027.

Well: Sunrise #1

2125	Plover Jurassic	Gas peak of 110 units (800 ppm methane) in a sand associated with trace-30% yellowish gold fluorescence in sidewall core.
2140	Plover Jurassic	Gas peak of 34 units (2000 ppm methane) in a claystone with trace - 30% yellowish gold fluorescence.

2151	Plover Jurassic	Gas peak of 61 units.
2280	Malita Early Jurassic	Trace very dull yellowish gold fluorescence in sandstone ditch cuttings.
2306	Malita Early Jurassic	Trace - 30% yellowish gold fluorescence in sandstone sidewall core.
2318	Malita Early Jurassic	Trace - 30% yellowish gold fluorescence in claystone sidewall core.

Reference: Bocal., 1975 Well Completion Report Sunrise #1 NT/P12
Northern Territory Geological Survey Reference Number PR 75/003.

Well: Troubadour #1

2152	Darwin Early Cretaceous	Gas; 2532 units recorded comprising 111 136 ppm methane and 4300 ppm ethane.
2159.5-2205	Plover Late Jurassic	Gas; readings ranged from 20-54 units with up to 9465 ppm methane and 180 ppm ethane. Oil; dull yellowish white sample fluorescence with bluish white cut. Gas jumped again below 2185 m and peaked at 335 units with 27840 ppm methane, 58 ppm ethane and 5 ppm propane.
2205-2290	Plover Late Jurassic	Gas; hot wire readings ranged from 4-46 units combrising up to 10000 ppm methane and low amounts of ethane, propane and butane. Oil; dull yellow and bluish-white fluorescence with a dull bluish-white cut in low porosity sandstones. D.S.T. 3 over this interval demonstrated the presence of mud, water and immovable gas.
2290-3294	Plover-Mt Goodwin Early Jurassic- Triassic	Oil; dull yellow fluorescence with a trace of bluish white and yellow cut. Gas; rare gas breaks of a maximum 3 units.

Reference: Bocal., 1974 Well Completion Report Troubadour #1 NT/P12
Northern Territory Geological Survey Reference Number PR 74/014.

Well: Weaber #1

615-655	Milligans Middle Carboniferous	Sand zone with a maximum gas show of 0.35% (0.29% C_1). No fluorescence was associated with this show.
1395-1415	Lower Carboniferous	Total gas show of 3.12 % with C_1 = 1.9% and $C_2 + C_3$ = 0.2%. This occurred in a sand zone.
1463 m	Burt Range Lower Carboniferous	Maximum total gas of 4.2% recorded. This consisted of 3.1% C_1 and 0.2% C_2 and originated from a 1.5 m thin sand.

Reference: AAP., 1983 Well Completion Report Weaber #1 OP-186
Northern Territory Geological Survey Reference Number PR 83/044

Well: Weaber #2/2A

1025-1028	Lower Milligans Early Carboniferous	A gas show of 963 units (91/7/2) was recorded in a tight sand with no associated fluorescence. D.S.T. 2 (1020-1037) recorded 59 m of gas cut mud and showed a gas flow to surface of 0.134 MMCFD.
1031-1032.5	Lower Milligans Early Carboniferous	A gas anomaly of 75 units (91/7/1) was recorded in tight sand.
1062-1063	Lower Milligans Early Carboniferous	Gas peak of 27 units (92/5/3) in a tight to poor porosity sand with no fluorescence.
1232.5-1233.5	Lower Milligans Early Carboniferous	Gas peak of 30 units (93/6/1) in a tight sand with no fluorescence.
1234	Lower Milligans Early Carboniferous	Gas peak of 22 units (92/7/1) in a tight sand with no fluorescence.
1373-1428	Lower Milligans Early Carboniferous	Gas peak of 32 units (93/6/1) in poor porosity sands with no fluorescence.
1468-1489	Lower Milligans Early Carboniferous	Gas peak of 24 units in a tight sand with no fluorescence.

Reference: AAP., 1988 Well Completion Report Weaber #2/2A OP-186
Northern Territory Geological Survey Reference Number PR 88/053.