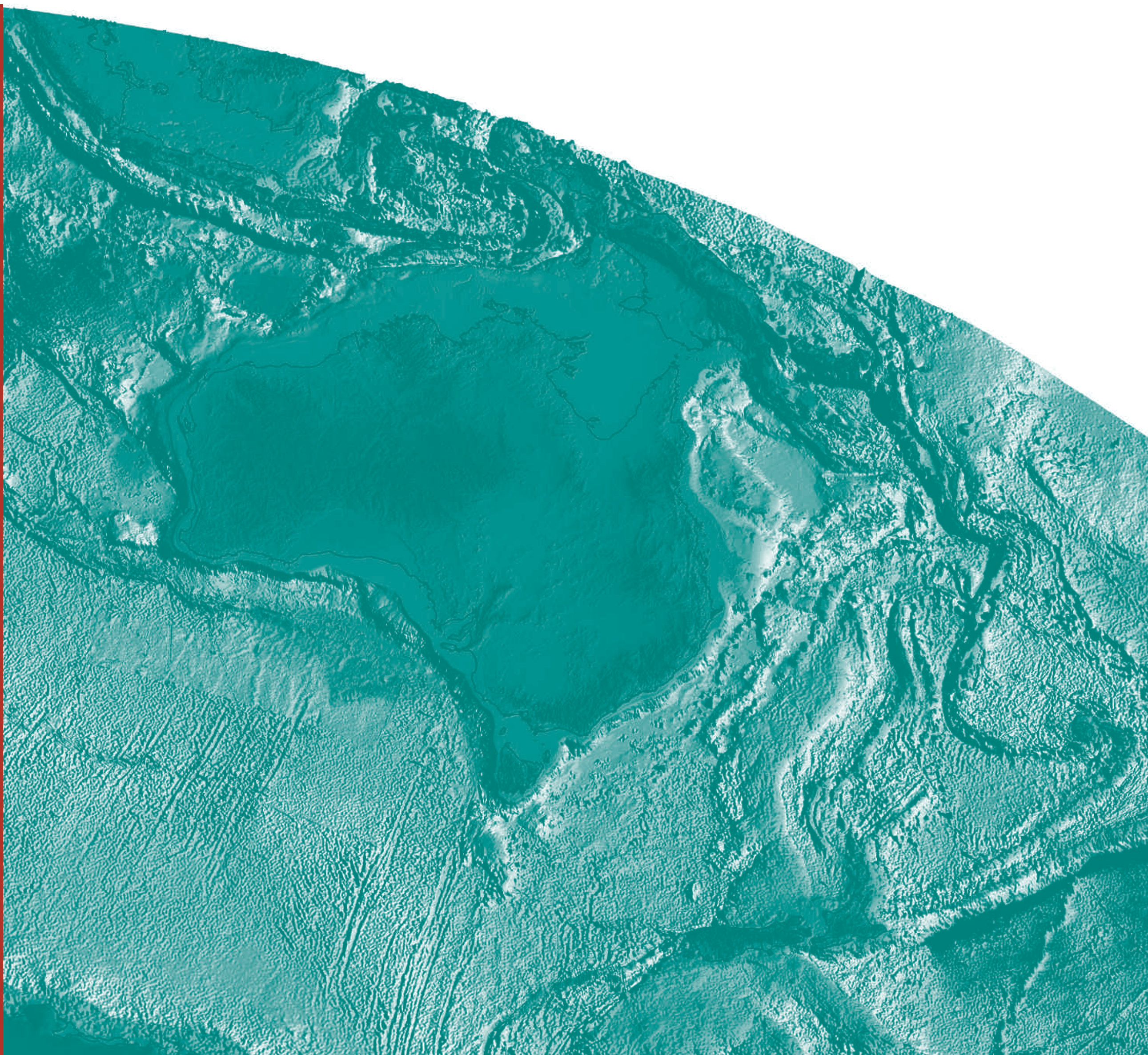
GEOSCIENCE AUSTRALIA

Australian Government
Geoscience Australia

An audit of wells in the Arafura Basin

Earl, K. L.

Record
2006/02



SPATIAL INFORMATION FOR THE NATION

An audit of wells in the Arafura Basin

GEOSCIENCE AUSTRALIA
RECORD 2006/02

by

Earl, K.L.

Australian Government
Geoscience Australia

Department of Industry, Tourism & Resources
Minister for Industry, Tourism & Resources: The Hon. Ian Macfarlane, MP
Parliamentary Secretary: The Hon. Bob Baldwin, MP
Secretary: Mark Paterson

Geoscience Australia
Chief Executive Officer: Dr Neil Williams

ISSN 1448-2177
ISBN 1 920 87166 7

GeoCat # 63694

Bibliographic reference: Earl, K.L., 2006. An audit of wells in the Arafura Basin. Geoscience Australia Record 2006/02.

Contents

Executive Summary

This report is a post-drill assessment of wells drilled in the Neoproterozoic to Palaeozoic Arafura Basin and the overlying Mesozoic to Cenozoic Money Shoal Basin. The Arafura Basin extends over an area of approximately 200,000 km^2 from the onshore Northern Territory to offshore Northern Australian and beyond the Australian-Indonesian border. The region is under-explored with only 9 wells drilled in Australian waters, all of which are located in the central Goulburn Graben, a complexly structured feature. They are: Arafura-1, Chameleon-1, Cobra-1A, Kulka-1, Goulburn-1, Money Shoal-1, Tasman-1, Torres-1 and Tuatara-1. These wells have been analysed using well completion reports, information from Geoscience Australia databases and published reports. A summary of the assessment is presented in Table 1.

Money Shoal-1 (1971, Shell Development) was the first well drilled in the Arafura Basin. It was important for establishing the stratigraphy of the region and targeted Cretaceous sands within an anticline. Despite the good quality reservoir, the only hydrocarbon indications in the well occurred in the Jurassic section. The failure of the primary target has been attributed to possible fault/seal breach or a lack of charge into the structure.

Arafura-1 (1983, Petrofina Exploration Australia) is historically important as a stratigraphic control, penetrating a thick Palaeozoic section in a fault block, and for intersecting the first oil shows in the region. Two hydrocarbon-bearing intervals were intersected in Devonian siltstone and Ordovician-Cambrian dolomite. The oil has been typed to a Cambrian source rock. In a generally tight section, fluid movement was facilitated by faults and fractures which also resulted in a breached structure. Fluid loss and poor reservoir quality are the primary reasons for well failure.

Tasman-1 (1983, ESSO) targeted the youngest structured sediments beneath the Mid-Jurassic unconformity in a raised fault block. The well was unsuccessful with the most significant hydrocarbon occurrence being oil indications in Permo-Carboniferous sediments. The well has been assessed to lack significant Palaeozoic reservoir and seal intervals.

Torres-1 (1983, ESSO) tested the giant Torres anticline, targeting Cambrian dolomite and Devonian clastics. The secondary aim of the well was to obtain stratigraphic information. No significant hydrocarbons were encountered with trace gas only. The failure of this well was disappointing due to the large size of the structure and has been attributed to a lack of charge and poor-quality reservoir intervals. A history of burial and subsequent uplift and erosion may have resulted in porosity destruction in the large Torres anticline.

Kulka-1 (1984, Diamond Shamrock Oil Co.) targeted the Palaeozoic within a faulted anticline. Numerous oil indications were encountered which could be associated with minor in-situ generation or migration up-section. The target failed due to a lack of significant, high-quality seal and reservoir facies.

The Goulburn-1 (1986, Petrofina Exploration) prospect was identified based on results from Arafura-1, targeting Devonian siltstones in a fault block. Three hydrocarbon bearing intervals were intersected, with numerous dead oil and bitumen occurrences in Devonian sandstone, Ordovician limestone and Ordovician-Cambrian dolomite. The lack of live oil and gas shows has been attributed to a lack of fault seal for the well objectives and subsequent flushing of the formations.

Tuatara-1 (1990, BHP Petroleum) tested Jurassic sands in a broad faulted anticline. No significant hydrocarbons were encountered. However oil and gas indications were recorded in the Jurassic and oil indications in the Cretaceous intervals. The well failed primarily due to a lack of seal but also had relatively low-quality Mesozoic reservoirs.

Chameleon-1 (1991, BHP Petroleum) tested two structures: a primary target anticline (Mesozoic section) and a secondary horst block (Palaeozoic section). No significant hydrocarbons were encountered, however numerous oil indications were noted throughout the well section. The hydrocarbon indications are probably sourced from the Palaeozoic with the well failing due to a lack of significant charge after structuring.

Cobra-1A (1993, BHP Petroleum) is the most recent well in the Arafura Basin. The well targeted Late Jurassic sandstones in a faulted, erosional dome that formed from a remnant topographic high between two Late Jurassic (Tithonian) channels. No significant hydrocarbons were encountered with oil indications only. The primary objective failed due to the lack of seal over the crest of the closure.

Based on the above assessment results, exploration risks in the Goulburn Graben of the Arafura Basin have been attributed to hydrocarbon charge and timing, reservoir quality and fluid movement, and breach of structure.

Despite these risks, the region as a whole does contain the required elements for viable petroleum systems. There is clear evidence for a Cambrian source rock in the basin. It is possible that late expulsion occurred in some localities, particularly north of the Goulburn Graben. Other Palaeozoic intervals also have source potential and have possibly contributed to hydrocarbon indications encountered in the wells. The Mesozoic is generally immature for hydrocarbon generation, with minor potential in the western Goulburn Graben region.

Palaeozoic reservoirs in the Goulburn Graben are generally of poor quality, relying on secondary porosity. However there is the potential for lateral improvement of these reservoirs, with thick channel sands likely in the Kulshill Group equivalent and the Arafura Group. Secondary porosity is common in Goulburn Group carbonates and is likely to be abundant in structures that encourage fracturing or focus fluid movement (such as folds and faulting). The Mesozoic reservoirs are high quality and laterally extensive, with a sand-dominated composition.

Seals are provided by Palaeozoic intraformational mudstones. The interbedded nature of the succession is a risk in regards to fault breach. The Mesozoic contains a thick regional seal, the Bathurst Island Group, which is a proven seal over the super giant Sunrise Troubadour gas field further to the west in the Bonaparte Basin.

Despite the lack of drilling success to date, the Arafura Basin region has significant hydrocarbon potential. Exploration has been limited to the highly structured Goulburn Graben, while the northern, less structured (and possibly more prospective) part of the basin is untested. The negative timing of structuring and charge is likely to be more favourable at this locality.

Table 1: Well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY

	WELLS	SHOWS	TARGETS	STRUCTURE	RISK ELEMENTS: STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	COMMENTS
Goulburn Graben	Arafura 1	Oil and gas shows	Devonian, Ordovician	Fault block	Low	Medium	Low	High	Low	Seals fault breached/fault leakage
	Chameleon 1	Oil indications	Cretaceous	Anticline	Low	Low	Medium	Low	High	No charge, immature source
	Cobra 1a	Oil indications	Lower Jurassic	Stratigraphic	Low	Low	Low	High	Medium	Thief zone above reservoir removing closure
	Goulburn 1	Oil shows	Devonian	Fault block	Low	Medium	Low	High	Low	Fault leakage, lack of seal
	Kulka 1	Oil indications	Permo-Carb	Fault roll-over	Low	High	Low	High	Medium	No suitable reservoir or seal
	Money Shoal 1	Dry	Lower Cretaceous	Anticline	Low	Low	Medium	Medium	Medium	Possible fault/seal leakage or lack of charge
	Tasman 1	Oil indications	Palaeozoic	Fault block	Low	Medium	Low	High	Medium	Lack of good reservoir/seal pairs
	Torres 1	Dry	Devonian, Cambrian	Anticline	Low	High	Medium	Low	High	Possible lack of charge
	Tuatara 1	Oil and gas indications	Lower Jurassic	Fault block	Low	Medium	Low	High	Medium	No seal

LEGEND

- **Low Risk** (green)
- **Medium Risk** (orange)
- **High Risk** (red)

1. Introduction

The Arafura Basin is located on the northern margin of Australia in the Arafura Sea and extends from the onshore Northern Territory to beyond the Australian-Indonesian border (Figure 1.1).

Despite shallow water depths, with a maximum depth of 230 m, the region is under-explored. A total of nine wells have been drilled, all within one structural element, the Goulburn Graben (Figure 1.2). To date, no commercial discoveries have been made, however, the potential of the northern and southern regions of the basin have not been tested. The aim of this report is to summarise and analyse the wells drilled, to better understand reasons for well failure and thus to provide new insights into the region's prospectivity.

1.1 REGIONAL SETTING*

The northern margin of Australia is structurally complex and contains three overlapping basins: the McArthur Basin (Proterozoic), the Arafura Basin (Neoproterozoic-Palaeozoic) and the Money Shoal Basin (Mesozoic-Cenozoic) (Figure 1.3).

The McArthur Basin is widely exposed onshore, covering an area of approximately 180 000 km^2, from the Queensland-Northern Territory border, along the west coast of the Gulf of Carpentaria, to the north coast of Arnhem Land (Rawlings, 1999). The exposed and intersected sediments contain a mixed carbonate-siliciclastic succession with minor volcanics and little deformation (Rawlings, 1999). The basin extent is poorly known, with some basin fill intersected offshore. It is inferred to lie unconformably beneath the Arafura Basin.

The Arafura Basin extends north from the onshore McArthur Basin and in Australia covers an area of approximately 200,000 km^2 (Figure 1.1). The basin contains up to 15 km of late Neoproterozoic to Early Permian sediments, overlain by up to 4 km of Middle Jurassic to Cenozoic sediments of the Money Shoal Basin. The basin formed in the Neoproterozoic in response to NW-SE extension which resulted in the formation of NE-SW trending half grabens (Struckmeyer et al., in prep.). Structurally, the Arafura Basin consists of a southern and northern part, divided by the Goulburn Graben.

The Goulburn Graben is a northwest trending asymmetric feature, over 400 km long and up to 125 km wide. The structure probably formed in the Late Carboniferous to Early Permian in response to oblique extension associated with the break-up of Gondwana, with subsequent contraction in the Triassic. The combination of the thick sedimentary succession and large inversion structures has lead to this area being the focus of hydrocarbon exploration in the region.

Flanking the graben to the north and south are two areas that underwent minor or no Carboniferous to Early Permian extension and Triassic contractional deformation. Because of this apparent lack of structure, these areas have been previously termed the northern and southern platforms (e.g. Bradshaw et al., 1990), however, seismic data show that the Neoproterozoic half grabens extend beyond the Goulburn Graben on both sides.

In the northern area, the sedimentary section is up to 15 km thick whereas the southern area contains up to 3 km. However, seismic coverage is poor in the southern region and areas with thicker sediments may be present. In the northern area, it is possible that any early formed traps and associated hydrocarbon accumulations have remained intact, thus up-grading the prospectivity compared with the Goulburn Graben. The southern inshore region probably has little hydrocarbon potential with inferred thin Palaeozoic sediments over a Pre-Cambrian basement (Miyazaki & McNeil, 1998).

* This section contains contributions by H.I.M. Struckmeyer (Geoscience Australia)

Sediments of the Mesozoic-Cenozoic Money Shoal Basin onlap the Arafura Basin section from the west, forming a time-transgressive sediment wedge ranging in age from Middle Jurassic in the west, to Late Cretaceous in the east. The Tertiary section is thin in the east.

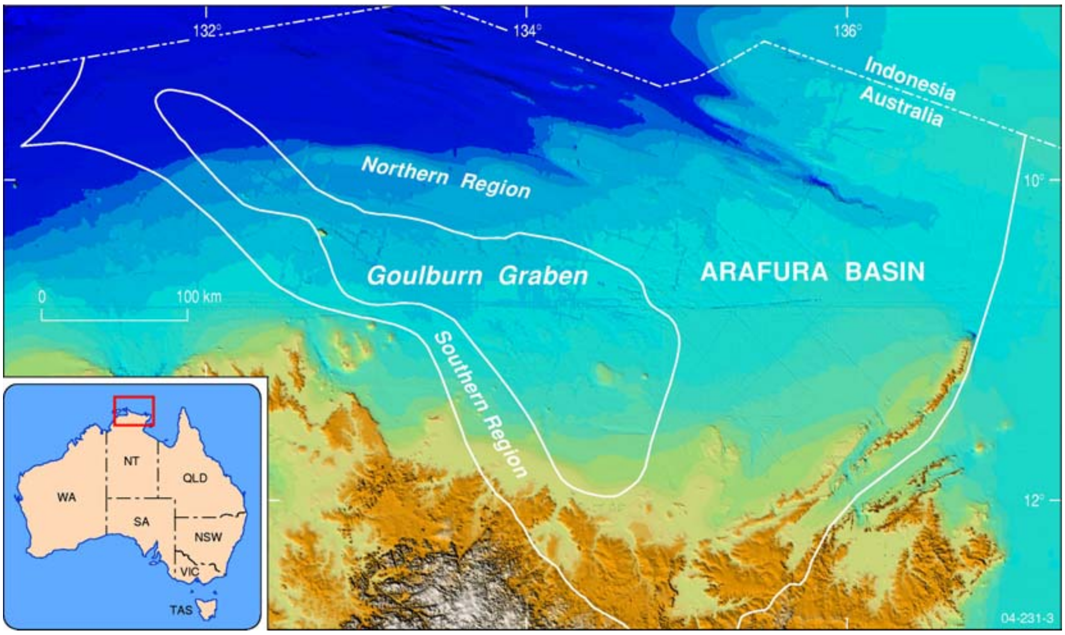


Figure 1.1: The Australian extent of the Arafura Basin.

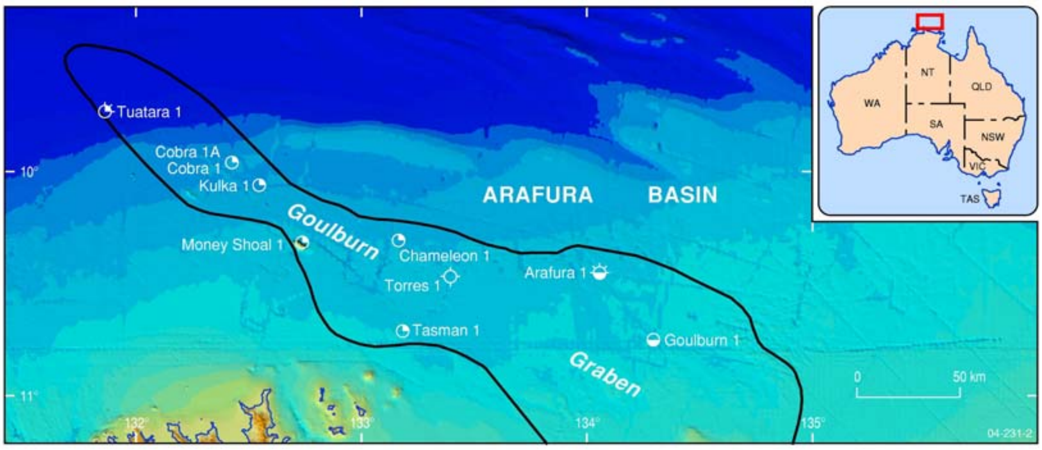


Figure 1.2: Petroleum exploration wells drilled in the Arafura Basin.

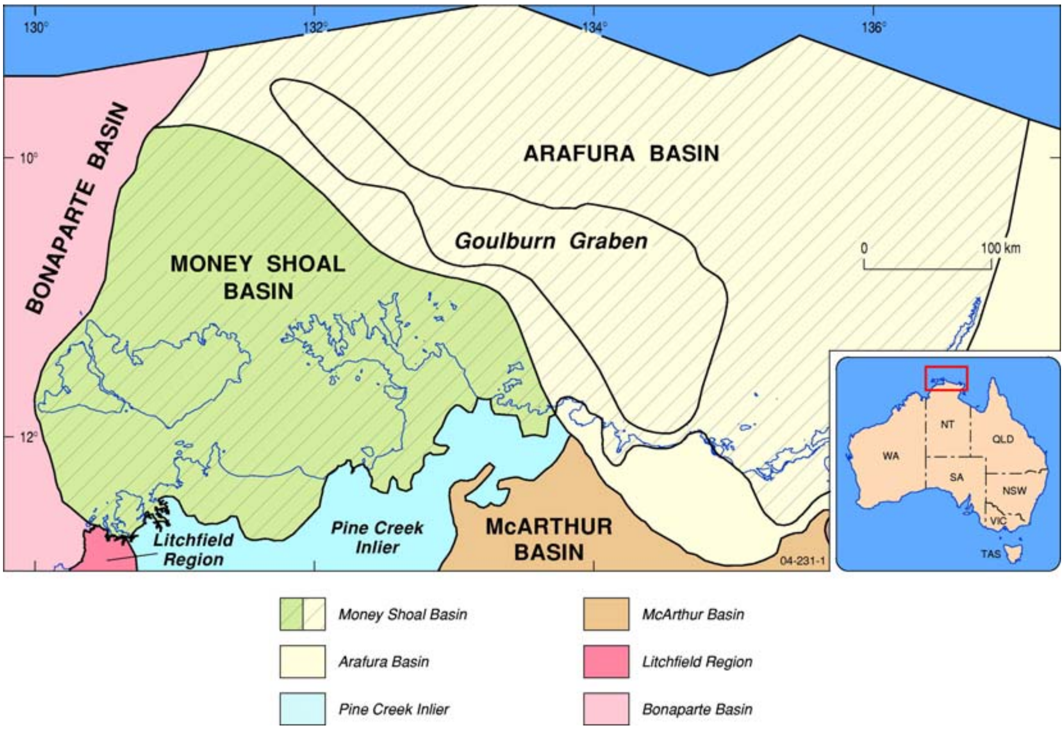


Figure 1.3: Basins in the Arafura Sea region.

1.2 TECTONOSTRATIGRAPHY*

Deposition in the Arafura Basin commenced in the Neoproterozoic (Figure 1.4) during a period of upper crustal extension. The oldest succession in the basin is the Neoproterozoic Wessel Group, which outcrops onshore (Plumb & Roberts, 1992; Rawlings et al., 1997), and is present throughout the offshore extent of the basin (Figures 1.5 to 1.7). Onshore, the group consists mainly of shallow marine sandstone and mudstone, with lesser conglomerate and carbonate rocks (Plumb & Roberts, 1992; Rawlings et al., 1997). The age of the Wessel Group is poorly constrained, but limited radiometric data and stratigraphic constraints suggest that it is Neoproterozoic (Rawlings et al., 1997). The group reaches a maximum thickness of approximately 10 km in the central part of the basin.

The Wessel Group is overlain disconformably by the early Middle Cambrian–Early Ordovician Goulburn Group (Figure 1.4) (Bradshaw et al., 1990; Nicoll et al., 1996). The Goulburn Group has a sag- to sheet-like geometry and reaches a maximum thickness of about 2500 m in the central Northern Region. The Goulburn Group represents prolonged deposition on a shallow marine shelf. The basal unit is the early Middle Cambrian Jigaimara Formation (Nicoll et al., 1996), a shallow marine limestone, shale and dolomite succession. It is overlain by the largely dolomitic ?Middle Cambrian–earliest Ordovician Naningbura Formation (Nicoll et al., 1996). The Early Ordovician marine shelf mixed carbonate and clastic rocks of the Milingimbi and Mooroongga formations form the uppermost units of the Goulburn Group.

The Late Devonian Arafura Group (Petroconsultants, 1989; Bradshaw et al., 1990; McLennan et al., 1990) overlies the Goulburn Group (Figure 1.4). Although the groups are generally structurally conformable, some localised uplift and erosion is evident. The Arafura Group has a sheet-like geometry and reaches a maximum thickness of approximately 1500 m. The Arafura Group consists of shallow marine to non-marine interbedded mudstone, siltstone, sandstone and minor carbonates. The basal unit is the Frasnian Djabura Formation, a dominantly shallow marine succession of interbedded clastics and minor limestone. It is overlain unconformably by the interbedded clastics of the ?Frasnian–Famennian Yabooma Formation (Bradshaw et al., 1990), which is also interpreted to represent dominantly shallow marine deposition. The overlying Famennian Darbilla Formation is a mudstone and siltstone dominated succession interpreted to have been deposited in a largely non-marine environment (Petroconsultants, 1989; Bradshaw et al., 1990).

The Arafura Group is overlain unconformably by a Late Carboniferous–Early Permian succession that is approximately equivalent in age to the Kulshill Group of the Bonaparte Basin (Figure 1.4). The hiatus of about 45 m.y. between the Arafura Group and the Permo-Carboniferous succession correlates with the Alice Springs Orogeny (Haines et al., 2001), however there is no evidence of any significant contractional deformation of the Arafura Basin at that time. Well intersections of the Kulshill Group (Figure 1.5) consist of non-marine to marginal marine interbedded sandstone, siltstone and claystone, with minor coal, and dolomitic rocks. On the Northern Region, the Kulshill Group is up to 1500 m thick and is structurally conformable with the underlying rocks. The group is thicker in the Goulburn Graben (up to 5000 m), where the lower part of the section comprises an extensional growth wedge. The upper part of the succession represents post-rift deposition.

* This section contributed by J.M. Totterdell (Geoscience Australia)

During the Triassic, the Goulburn Graben underwent contractional, probably transpressional, deformation, characterised by inversion on pre-existing faults, folding, uplift and the formation of thrust faults. The Northern Region underwent only minor deformation, notably inversion on some Neoproterozoic extensional faults, widespread folding of the eastern part of the Platform, and uplift of the eastern and western margins of the basin. Subsequent erosion resulted in the development of a peneplain across the basin and adjacent basement areas (Figures 1.6 and 1.7). This event is considered to be equivalent to the Middle–Late Triassic Fitzroy Movement (Forman and Wales, 1981), which affected the Canning Basin and adjacent regions, including the Bonaparte Basin.

The Money Shoal Basin overlies the Neoproterozoic to Palaeozoic Arafura Basin and comprises Jurassic to Cretaceous siliciclastic sediments and Cenozoic carbonates (Figure 1.4) that thin rapidly towards the east (Figures 1.5 to 1.7). Deposition commenced in the Early to Middle Jurassic in fluvial channels aligned along the axis of the western Goulburn Graben. Coarse, mature sandstones of the Plover Formation (Troughton Group equivalent) are unconformably overlain by mostly fine-grained, quartzose, partly glauconitic sandstones and interbedded mudstones and minor coals of the Flamingo Group. Deposition was more widespread and occurred in fluvio-deltaic environments grading into near-shore marine environments by the Early Cretaceous. The Albian to Late Cretaceous Bathurst Island Group comprises marine and deltaic mudstones and marls with interbedded sandstones deposited across a progradational shallow marine shelf. These are unconformably overlain by mostly late Neogene, shallow marine carbonates of the Woodbine Group.

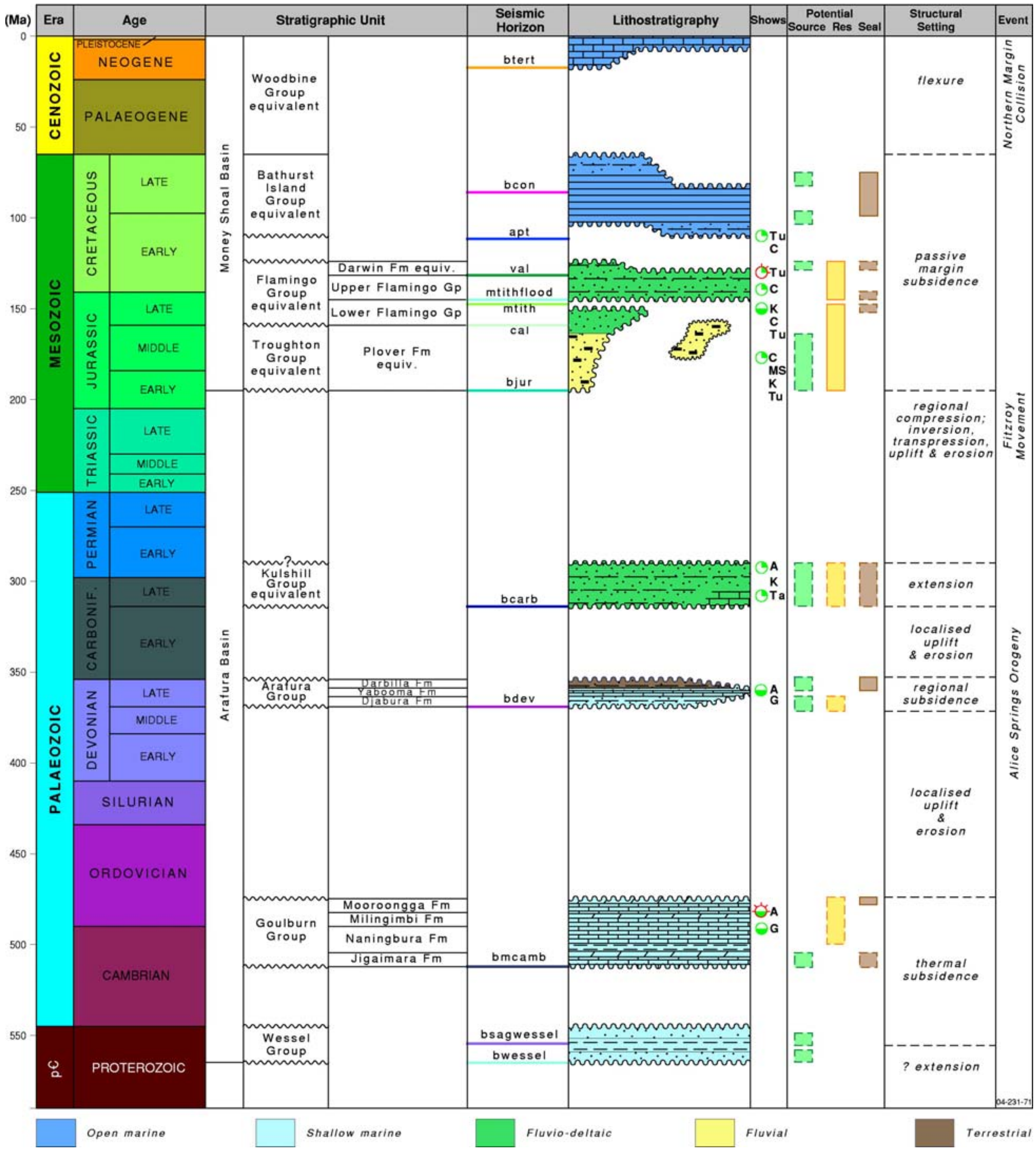


Figure 1.4: Stratigraphic column of the Arafura Basin region.

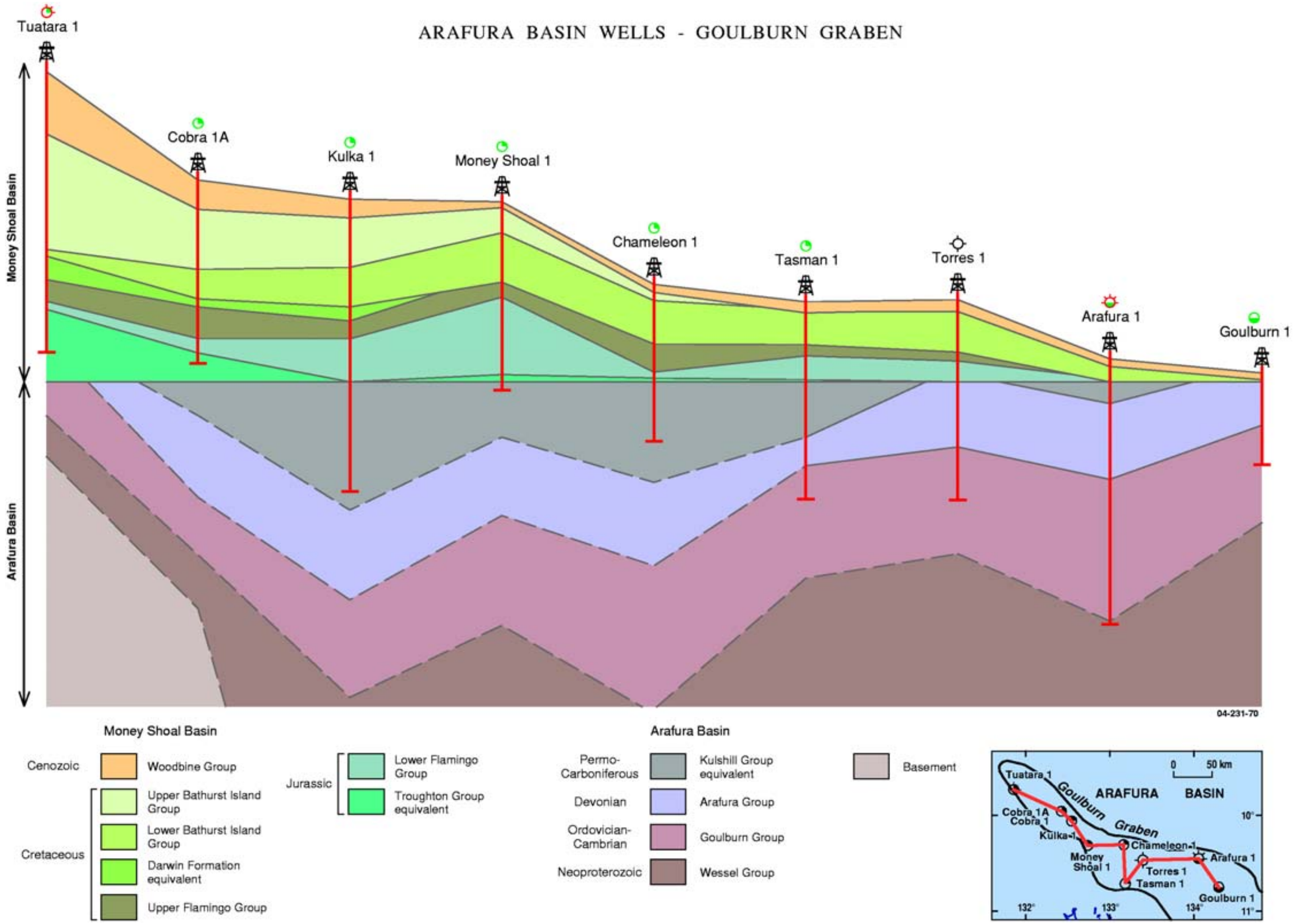


Figure 1.5: Well correlation for the Goulburn Graben flattened on the base Jurassic unconformity.

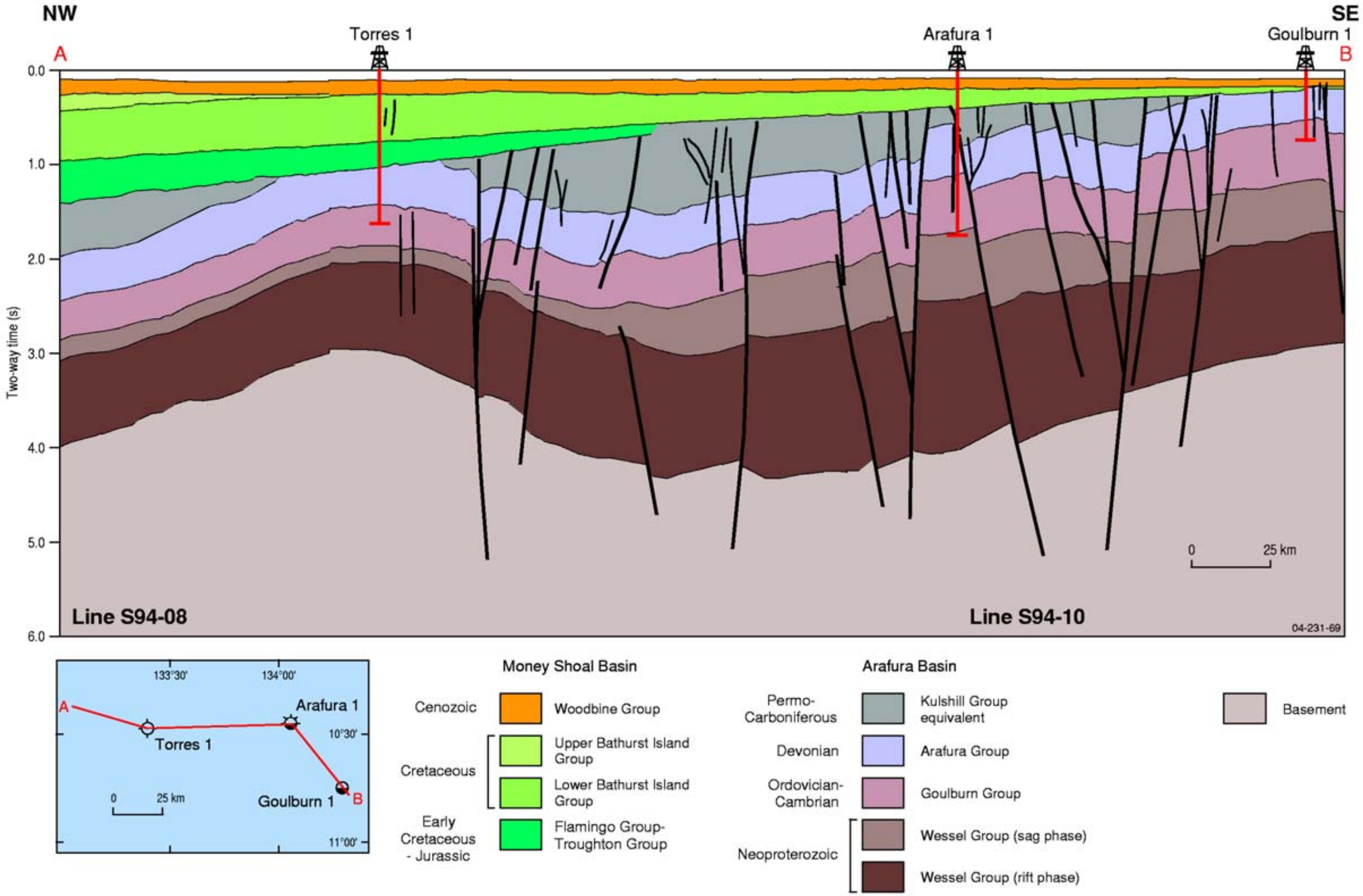


Figure 1.6: Regional cross-section through the Goulburn Graben – from Torres 1 to Goulburn 1.

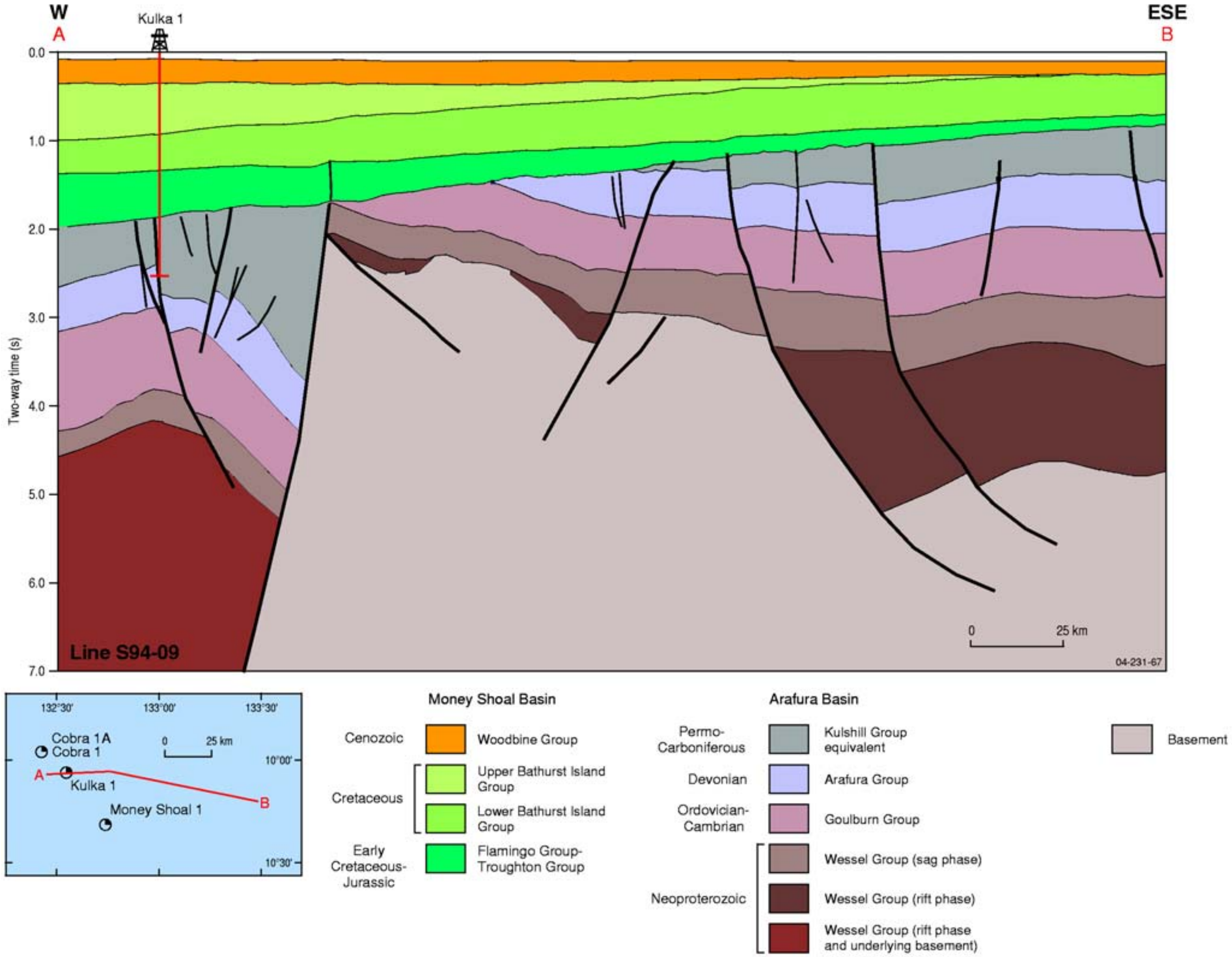


Figure 1.7: Regional cross-section from the Goulburn Graben (Kulka-1) to the northern platform.

1.3 PETROLEUM SYSTEM ELEMENTS

1.3.1 Source Rocks

Arafura Basin Source Rocks

Palaeozoic sediments have demonstrated source potential on the North-West Shelf of Australia with a number of significant hydrocarbon accumulations linked to them, for example in the Petrel Sub-basin of the Bonaparte Basin (Kennard et al., 2002). In the Arafura Basin potential source rock intervals include the Wessel Group (Neoproterozoic), the Goulburn Group (Ordovician-Cambrian), the Arafura Group (Devonian) and the Kulshill Group equivalent (Permo-Carboniferous) (Figure 1.8).

The Goulburn Group source rocks are potentially the most effective in the region, with geochemical evidence of expelled hydrocarbons from a marine Cambrian source migrating through Arafura Basin reservoirs (C. Boreham, Geoscience Australia pers. comm., July 2005; Moore et al., 1996). Abundant bitumen in samples near the base of the Arafura-1 well (Sherwood et al., 2005) have a similar geochemical signature and are indicative of a prolific Cambrian source nearby. Based on seismic data, bitumen and oil occurrences (e.g. Arafura-1 and Goulburn 1 oil) the unit could potentially be laterally extensive.

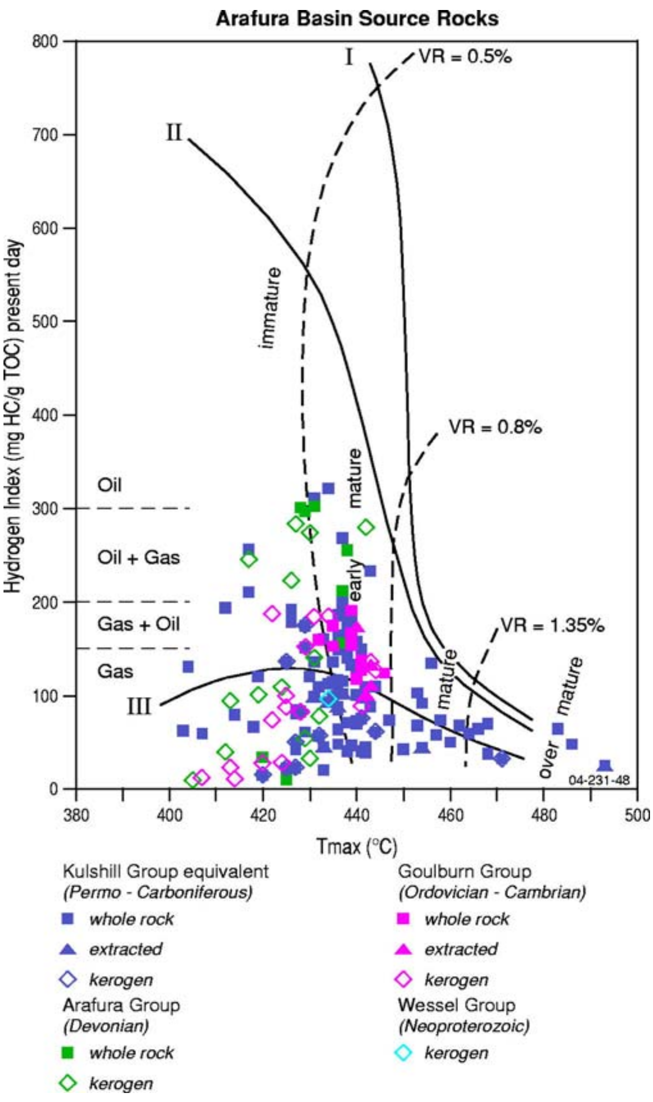


Figure 1.8: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in the Arafura Basin. The VR maturity lines are to be used only as guidelines for units older than the Devonian.

Other potential source rock intervals in the basin have not been geochemically linked to hydrocarbon occurrences. Proterozoic source rocks are a possibility in the region with the Wessel Group intersected at Arafura-1. The unit is comprised of shallow marine interbedded sandstones and mudstones with low-grade metamorphics. Reliable TOC data is not available for the unit.

The Arafura Group and Kulshill Group equivalent (Figure 1.4) were deposited in fluvio-deltaic environments and contain Type II/III kerogens in interbedded sandstones and mudstones (Figure 1.8). The units contain organic-rich intervals with TOC values up to 4% and 9.5% respectively. Where intersected the Arafura Group sediments are mature (Sherwood et al., 2005). However, based on seismic data, the unit is up to 7 km deep and in these places is likely to be overmature for hydrocarbon generation. The Kulshill Group equivalent is immature to overmature for hydrocarbon generation, attributed to the large range of depths of burial (from 500-6000 m in the Goulburn Graben).

There is evidence that before the Permo-Triassic erosion and structuring event, the Arafura Basin source rocks were buried deeper than present day, with consequent hydrocarbon generation and expulsion. This is indicated by offset VR trends between the Palaeozoic and Mesozoic, and depressed HI values.

Money Shoal Basin Source Rocks

Mesozoic sediments equivalent to those in the Money Shoal Basin have demonstrated source potential on the North-West Shelf (Barrett et al., 2004; Kennard et al., 1999; Preston and Edwards, 2000). The Troughton Group equivalent (Plover Formation) is an important source rock in the Malita/Calder Graben, adjacent to the Money Shoal Basin, where it provides the source for the Evans Shoal, Sunrise, Troubadour and Loxton Shoals gas/condensate fields. The Flamingo Group may have also had input into these fields. In the Money Shoal Basin, the Jurassic Troughton Group equivalent is composed of blocky sands with minor mudstone interbeds and coals. TOC values of up to 60% are related to the coaly nature of the sediments, rather than organic-rich mudstones. Sediments were deposited in fluvio-deltaic conditions and are early mature to mature for hydrocarbon generation (Figure 1.9).

Other potential source rocks in the Money Shoal Basin include the Flamingo Group equivalent (Jurassic to Early Cretaceous) and the Bathurst Island Group (Cretaceous), including the Darwin Formation equivalent (Figures 1.4 and 1.9). The Flamingo Group is composed of fluvio-deltaic blocky sands with some mudstone interbeds and minor coal in the Lower Flamingo Group. Both the Upper and Lower Flamingo Group are organic rich with Type II/III kerogens (Figure 1.9) and up to 27.5% and 8.27% TOC respectively. The Bathurst Island Group is a shallow marine mudstone dominated unit with Type II/III kerogens (Figure 1.9) and TOC values up to 3%. These shallower sediments are immature for hydrocarbon generation over most of the Goulburn Graben and probably marginally mature at best elsewhere.

Overall the Money Shoal Basin sediments contain potential source rocks associated with coaly sediments rather than organic-rich marine mudstones. These sediments form a sedimentary wedge, thickening to the west. There is an associated increase in maturity for hydrocarbon generation, with mature Troughton Group equivalent sediments in the western-most well, Tuatara-1. At other locations, particularly to the east, hydrocarbon indications in the Mesozoic are probably related to generation from older, more organic-rich mature units.

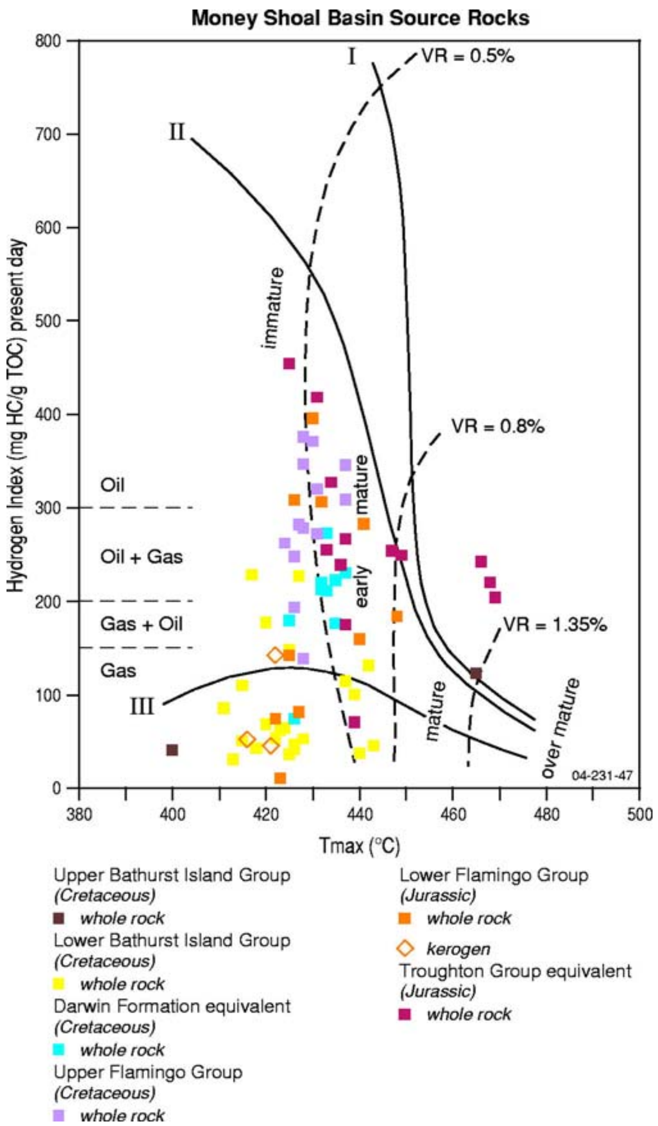


Figure 1.9: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in the Money Shoal Basin.

1.3.2 Reservoir Rocks

Arafura Basin Reservoirs

Where known Arafura Basin sediments vary greatly in composition and reservoir quality. Reservoirs within the basin include fluvio-deltaic interbedded sandstones and mudstones (Devonian Arafura Group and Permo-Carboniferous Kulshill Group equivalent) and shallow marine limestones and dolomites (Ordovician-Cambrian Goulburn Group).

The Goulburn Group dolomite is an important reservoir in the region, hosting an oil and gas show in Arafura-1 and numerous oil indications in Goulburn-1. The unit has little primary porosity and permeability, instead relying on the development of secondary porosity through features such as vugs and fractures. These features are common, evident by repeated mud losses, increases in drilling rates, variable calliper logs and drilling breaks. The unit has a maximum porosity of 7.7% but averages about 2% in intervals lacking significant secondary porosity (Figure 1.10). Permeability values are also generally low. Movement of fluid into and through the unit is facilitated by the secondary features, as indicated by the numerous oil occurrences within them. A risk associated with this unit is cementation reducing secondary porosity.

Siltstones and sandstones of the Arafura Group form another important reservoir in the basin, hosting oil shows at both Arafura-1 and Goulburn-1. The unit has a maximum porosity and permeability of 19% and 7.83 mD at Goulburn-1 but averages 9.6% porosity with a large standard deviation (Figure 1.10). Much of the original porosity has been destroyed by diagenetic effects, including silica and carbonate cementation.

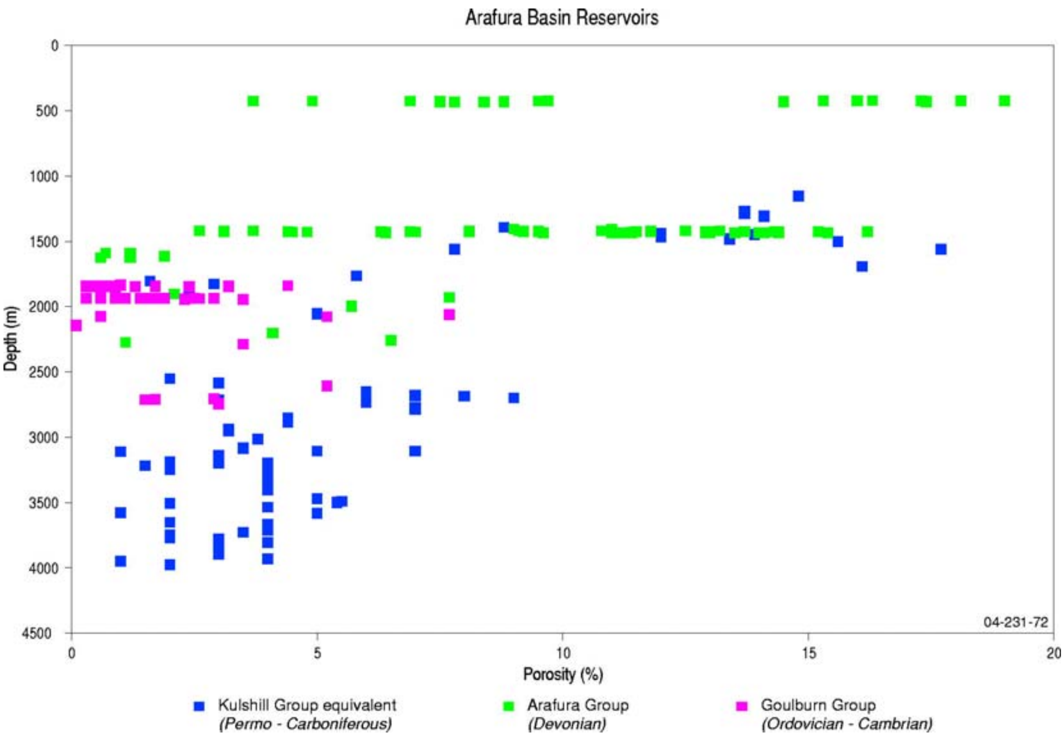


Figure 1.10: Porosity vs. depth for reservoirs in the Arafura Basin.

The Kushill Group equivalent generally has poor reservoir quality, with few large sandstone-rich intervals and low porosities, averaging 5.5% with a maximum of 17.7% at Tasman-1 (Figure 1.10). Carbonate cements are sporadic throughout the sequence but there is evidence of multiple fracture sets (such as at Chameleon-1), which could enhance the overall permeability and porosity.

Overall, the known Palaeozoic reservoir quality is poor (Figure 1.10). This dataset is not representative of the whole basin, being restricted to the Goulburn Graben area. Many of the wells in this region have undergone a complex history of deep burial, uplift, erosion, and, in some cases, hydrothermal alteration. The highest quality Palaeozoic reservoirs will most likely be located in structures and localities that encourage secondary porosity formation (e.g. folds/faults and karstic weathering). Faults also assist fluid movement and may be one of the primary mechanisms for Palaeozoic hydrocarbon migration, with laterally varying reservoirs hindering migration processes. Hydrothermal alteration is a concern with regards to reservoir quality and is common in the south-western region of the Goulburn Graben (at Money Shoal-1 and Kulka-1). The lack of intense structuring, with associated fluid flows, in the northern platform region may indicate better primary porosity preservation.

Money Shoal Basin Reservoirs

Mesozoic reservoirs are important in the adjoining Bonaparte Basin, hosting a number of commercial hydrocarbon accumulations (Cadman & Temple, 2005). The Money Shoal Basin contains high quality Mesozoic reservoirs, including the Troughton Group equivalent (Jurassic), the Flamingo Group (Jurassic to Early Cretaceous) and the Darwin Formation equivalent (Bathurst Island Group, Cretaceous).

The Troughton Group equivalent is composed of sandstone, with minor mudstone interbeds. Porosity averages 8.5% (doe to a low quality interval at Tuatara-1) with a maximum of 27% at Tasman-1 (Figure 1.11). The Flamingo Group equivalent consists of blocky sands with minor mudstone interbeds and becomes more mudstone-rich in the western region (Tuatara-1). The unit averages 18.5% porosity, with a maximum of 32% at Tasman-1 (Figure 1.11). There is some dolomite cementation in the section but the unit also contains fractures, helping to facilitate fluid movement. The Darwin Formation equivalent varies in composition, dominated by mudstones at Tuatara-1 to a sandstone dominated unit at Kulka-1. The unit has excellent porosity with an average of 25% in the sandy units (Figure 1.11).

The Money Shoal Basin sediments are distributed in a sedimentary wedge, forming planar, blanket-like deposits, thickening towards the western region of the Goulburn Graben (Figures 1.5 to 1.7). This thickening, with the associated increased diagenetic effects, results in reduced reservoir quality. For example at the Tuatara-1 location (the western-most well in the Goulburn Graben), reservoir quality in the Troughton Group equivalent has an average porosity of 8%, with the shallower Mesozoic reservoirs having porosities of 10% or more.

Due to their distribution, Money Shoal Basin reservoirs are well positioned to receive any late hydrocarbon charge from the underlying Palaeozoic source rocks with numerous Mesozoic hosted hydrocarbon indications at Tuatara-1, Cobra-1A and Chameleon-1. However, there is currently no geochemical evidence linking Mesozoic hosted hydrocarbons to in-situ generation or Palaeozoic-sourced fluid migration.

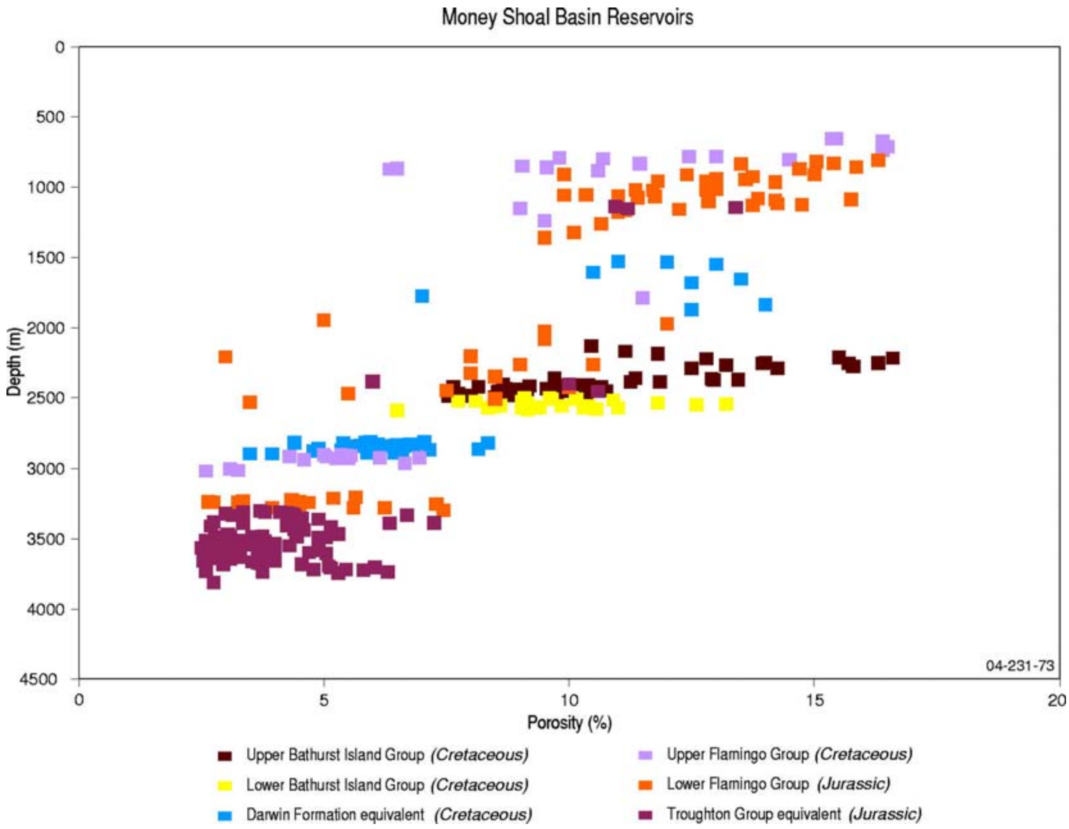


Figure 1.11: Depth vs. porosity for reservoirs of the Money Shoal Basin.

1.3.3 Seal

The Arafura and Money Shoal Basins contain a number of potential seals. In the neighbouring Malita Graben of the Bonaparte Basin, the Bathurst Island Group forms a regional seal, trapping accumulations such as Sunrise/Troubadour (Barrett et al., 2004). This regional seal is also present in the Arafura Basin region, with a predominant mudstone lithology. The unit is laterally and vertically extensive, generally overlying high quality Mesozoic reservoirs. Along the southeastern graben edges the unit directly overlies Palaeozoic sediments (Figures 1.5 and 1.6). Fault breach is unlikely due to the thickness of the unit.

Other seals in the region tend to be less vertically and laterally homogenous. The underlying Mesozoic section tends to be sand dominated with minor mudstone interbeds. These, and transgressive beds and channel fill sediments, could provide local intraformational seals. The generally poor reservoir quality of the Palaeozoic in the Goulburn Graben means that fluid movement is restricted within the section, with lateral decreases in reservoir quality possibly providing sealing and trapping structures. The Palaeozoic section also contains numerous mudstone intervals which could provide intraformational seals.

1.3.4 Traps

The structural setting of the Goulburn Graben is conducive to a variety of structural, stratigraphic and combination traps. The structural styles between the Money Shoal and Arafura Basin vary significantly, with some wells testing different trap styles in both sections (for example Chameleon-1 and Money Shoal-1).

The structure of the Arafura Basin (Palaeozoic) section is dominated by features formed during the Triassic (Fitzroy Movement equivalent). This includes fault blocks, fault roll-overs, anticlines and sub-unconformity traps. Trap formation in the Money Shoal Basin relies on faulting/fault re-activation and associated structuring, such as roll-overs and drape, erosional highs and subtle anticlines. Potential stratigraphic traps in both basins include pinch-outs, onlap, channel fills and slope- and basin-floor fans. Many of these potential traps are associated with contraction in the Late Mesozoic and Cenozoic, particularly in the Late Cenozoic, related to the collision of the northern margin of the Australian plate with Asia.

One of the main features of the Money Shoal Basin section is a Tithonian channel system that runs along the major bounding faults of the Goulburn Graben, from east to west. The northern channel has been assessed by BHP Petroleum (1993) to be at least 225 km long and on average 10 km wide. The southern bounding fault and associated channel is less extensive. Although the channel system has been unsuccessfully tested at several locations (such as Chameleon-1, Cobra-1A and Kulka-1) the feature still provides numerous untested stratigraphic/structural traps within the channel fill and associated erosion features. Late Cretaceous slope and basin floor fans remain untested.

1.3.5 Timing

Previous exploration and studies (e.g. Moore et al., 1996; McLennan et al., 1990) have indicated that the timing of hydrocarbon generation and expulsion, in relation to trap formation and reservoir deposition, is one of the key risk factors in the Goulburn Graben. New hydrocarbon expulsion and generation modelling by Stuckmeyer et al. (2005b) suggests that timing may be less of a risk in some areas of the basin, with expulsion not entirely limited to the Palaeozoic. There have also been Late Cretaceous, Tertiary and Cenozoic expulsion events from Palaeozoic sources, when reservoirs and traps were in place. It is unlikely that all structures have been breached, however a detailed analysis of charge in relation to structuring is beyond the scope of this report.

1.4 EXPLORATION HISTORY

Petroleum exploration activities in the Arafura region began in the 1920's with several boreholes drilled on Elcho Island in response to reported bitumen strandings. In the 1960's and early 1970's, stratigraphic drilling occurred on the Bathurst and Melville Islands (McLennan et al., 1990). During this time Shell Development (Australia) were awarded permits NT/P19, NT/P20 and NT/P21 (Figure 1.12), covering the western region of the Arafura Sea. Shell drilled the first well in the Arafura Basin, Money Shoal-1 (NT/P20), in 1971. This well was drilled primarily to test the Mesozoic Money Shoal Basin sequence. Aquitaine was also operating in the area, holding permit NT/P18, which covered the central southern region of the Arafura Sea. The two operators carried out extensive mapping based on seismic and defined the Goulburn Graben region.

The next phase of exploration was in the early 1980's with several companies operating in the region including Diamond Shamrock (NT/P34), ESSO (NT/P35), Petrofina (NT/P36) and Sion Resources (Figure 1.13). A number of wells were drilled at this time, all of which tested the Palaeozoic Arafura Basin sequence. Petrofina drilled two wells in permit NT/P36; Arafura-1 (1983) and Goulburn-1 (1985). Arafura-1 provides the most important Palaeozoic stratigraphic control in the graben. The company also mapped a number of large-scale fault-related closures that remain untested. ESSO drilled two wells in permit NT/P35, Tasman-1 (1983) and Torres-1 (1983), targeting a fault block and a prominent Palaeozoic anticline. The company also mapped out a number of Palaeozoic and Mesozoic leads. Diamond Shamrock drilled one well in permit NT/P34, Kulka-1 (1984), which provides important stratigraphic control for the Late Palaeozoic and Mesozoic sections.

A third phase of petroleum exploration and drilling was conducted by BHP Petroleum over permits NT/P41 and NT/P42 in the late 1980's to early 1990's (Figure 1.14). The exploration program included a large 17, 000 km seismic survey, acquired between 1988 and 1991, and an aeromagnetic survey. The company drilled three wells, Tuatara-1 (1990), Chameleon-1 (1991) and Cobra-1A (1993), in permit NT/P42. During the early 1990's Geoscience Australia (then the Bureau of Mineral Resources) also acquired a total of 5342 km of seismic across the Arafura Basin.

To date, no commercial discoveries have been made in the Arafura Basin but there are numerous hydrocarbon indications in the Goulburn Graben. Arafura-1 and Goulburn-1 had the most promising drilling results with oil shows and a gas show in Arafura-1. Chameleon-1, Cobra-1A, Kulka-1, Money Shoal-1, Tasman-1 and Tuatara-1 all contain oil indications in Mesozoic and Palaeozoic reservoirs.

Additional evidence for active petroleum systems in the region includes bitumen occurrences, which were the initial driver for exploration on the mainland Australian coastline and the Elcho, Melville, Goulburn and Howard Islands. Work by Summons et al. (1993) has linked one type of bitumen to Tertiary oils from South East Asia (similar to those found along the Western and Southern Australian coast) but two other marine derived bitumen have an unknown source.

Numerous potential oil slicks were identified on the sea surface over the western most Goulburn Graben during an airborne laser fluorescence survey conducted by BP in 1989 (Martin and Cawley, 1991). Several potential oil slicks have also recently been interpreted over the northern platform from synthetic aperture radar data (Infoterra, 2001).

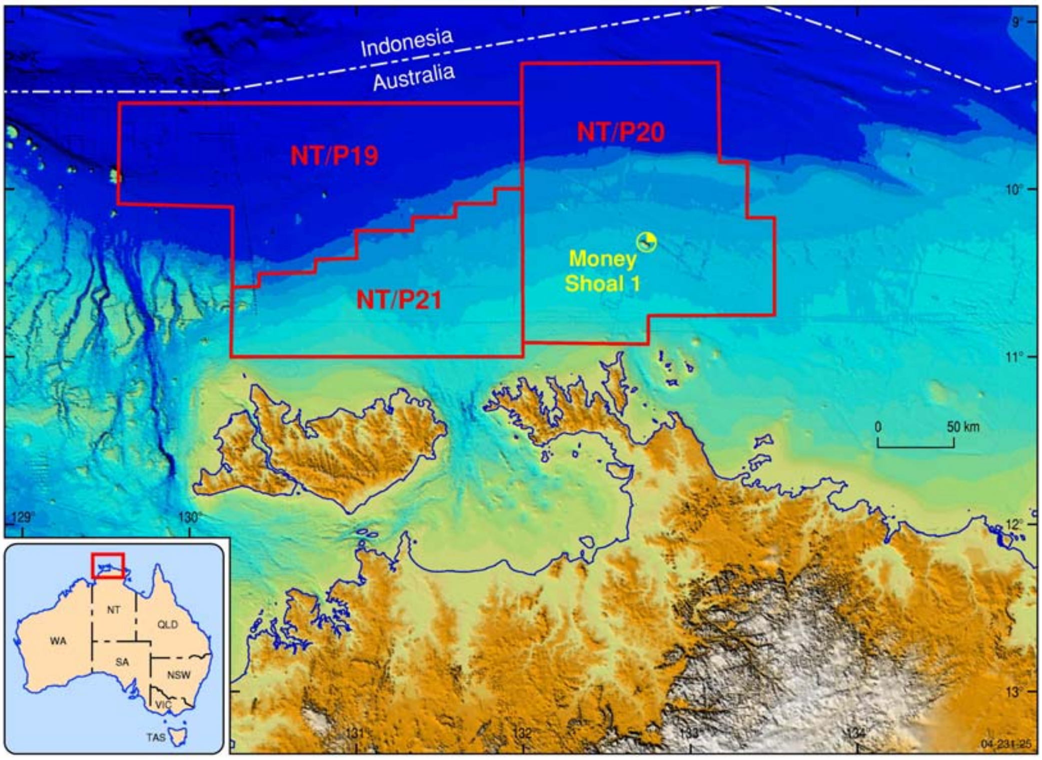


Figure 1.12: Permits and wells associated with the 1st phase of exploration in the Arafura Basin region (1960's-early 1970's).

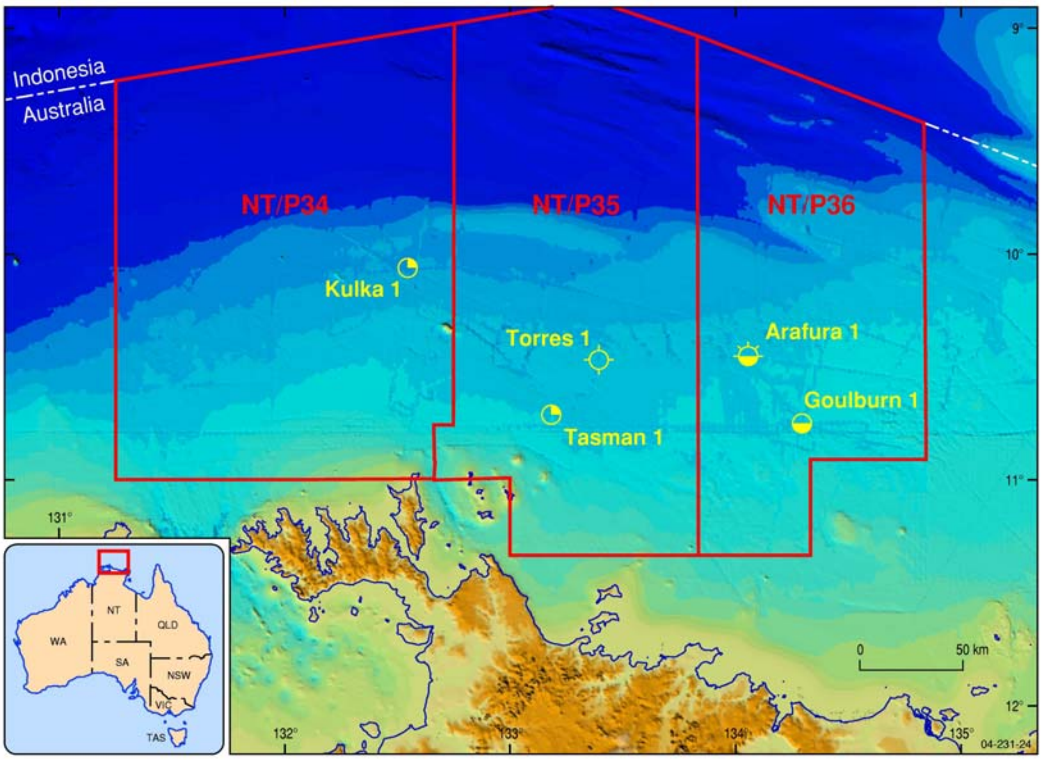


Figure 1.13: Permits and wells associated with the 2nd phase of exploration in the Arafura Basin region (early 1980's).

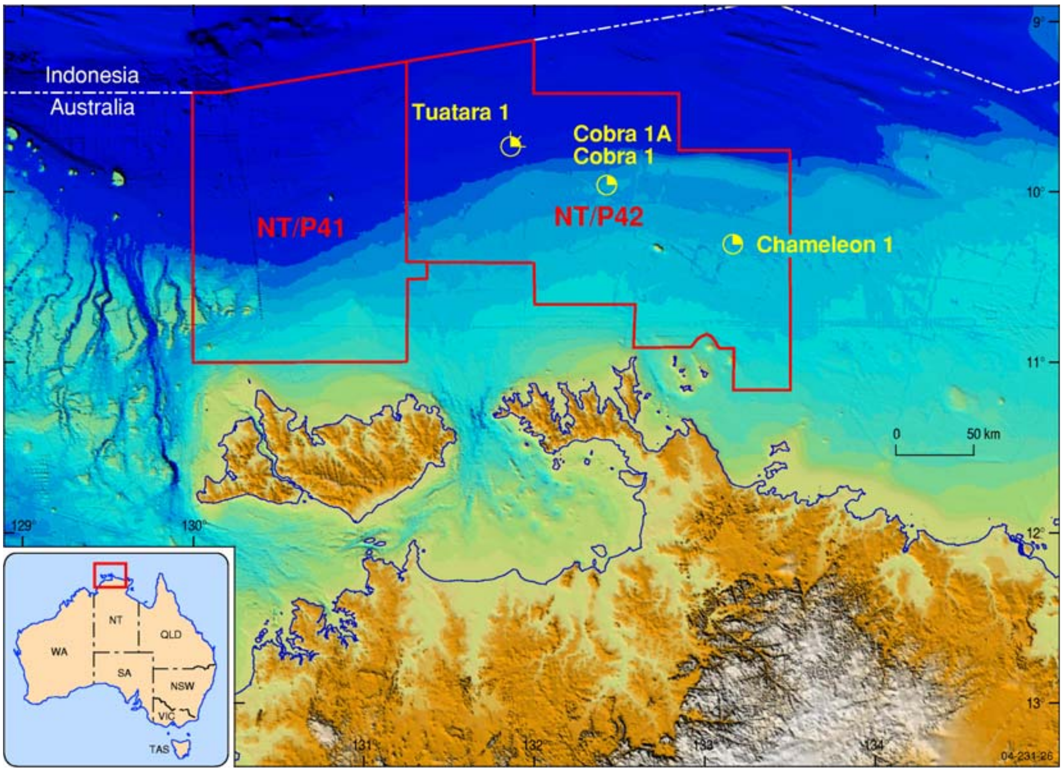


Figure 1.14: Permits and wells associated with the 3rd phase of exploration in the Arafura Basin region (late 1980's-early 1990's).

2. Well Risking Methodology

The purpose of this study was to evaluate the wells drilled in the Arafura Basin. This has been accomplished through a qualitative process to assess risks for the presence and/or quality of elements essential to a successful petroleum accumulation, i.e. structure, source, reservoir, seal and charge (as outlined below).

Each factor was assigned a ranking for the well using three categories: low, medium and high (Table 2.1). These categories refer to the level of risk for a well that an essential petroleum system element could be insufficient for a successful accumulation. For example: if a well was drilled off structure due to poor seismic quality, the closure risk for the well is “high”.

Structure

Refers to whether a well was drilled on structure or within structural closure. Each well and the associated structure were assessed based on post-drill analysis by the operator, supported by evaluation of seismic data. All closure figures in this report do not include faults. Faults can be viewed in the 2D cross-section for each well.

Source

Refers to whether a potential source rock has sufficient hydrocarbon generation and expulsion potential and is mature enough for generation/expulsion. Rocks with TOC values greater than 1 % are considered to have good or better potential. Source rocks were defined as early mature for oil generation with Tmax and VR values greater than 435˚C and 0.5% respectively. Samples with Tmax values between 440˚C and 470˚C and VR values between 0.7% and 1.2% were considered mature for oil generation. If a well contains hydrocarbon indications, a source rock in the vicinity probably generated hydrocarbons and is considered a low exploration risk with regards to source rocks. Potential source rocks below TD were not assessed.

Reservoir

Refers to whether an interval has sufficient porosity and permeability to operate as a reservoir for hydrocarbons. Porosity and permeability less than 10% and 50 mD respectively are considered poor to insufficient for reservoir potential.

Seal

Refers to whether a seal has sufficient potential (top and fault seal) and has maintained integrity. Seal properties were assessed by examining the composition of the potential seal, including its lateral consistency and thickness, and by using mud logs. With regards to fault seal, each structure was examined for fault breach risk, whether through fault re-activation or juxtaposition of lithologies across the fault.

Charge

Refers to whether hydrocarbons have migrated into the structure. A dry well or a well with minor hydrocarbon indications is assessed as having a charge risk. Oil shows or dead oil indicate possible charge into the structure, with potential trap breaching.

Table 2.1: Classification of risk elements

(green)	Low	Element is present and has adequate to good quality
(orange)	Medium	Element has poor or uncertain quality/presence
(red)	High	Element is insufficient/absent

A summary of the well results for the Arafura Basin is presented in Table 1. Detailed assessments for each well are given in the "Well Information" section of the report.

3. Data sources

BASIC INFORMATION

The primary data sources for this study were well completion reports submitted by permit operators and basic data from Geoscience Australia's databases. Copies of well completion reports are available from the Geoscience Australia Data Repository. Data downloads are also available from Geoscience Australia. This information can be accessed via www.ga.gov.au.

STRATIGRAPHY

A stratigraphy chart for the Arafura Basin is shown in Figure 1.4. This chart and the stratigraphy used in this report are based on recent work by Geoscience Australia (Struckmeyer et. al., in prep). Biostratigraphic information is available for download from Geoscience Australia's National Petroleum Wells Database. Original nomenclature for well stratigraphy is available in the appropriate well completion reports.

SOURCE ROCK DATA

The source rock data used in this report are mostly RockEval data provided in well completion reports and destructive analysis reports, as well as new sampling associated with this study. All data are available from Geoscience Australia's ORGCHEM geochemical database. These data can be accessed via the National Petroleum Wells Database.

For this report TOC values <0.4%, S2 values <0.2 mg/g and PI values <0.3 were not considered in the interpretation. Data within these ranges have been classified as unreliable and excluded from interpretation. This is based on the assessment that any analysis with TOC <0.4 % will not be accurate. An S2 value of <0.2 mg/g and a PI value >0.3 indicates that the SI peak will affect the Tmax value for that given sample.

Data from whole rock, extracted rock and kerogen analyses are included in this report. Whole rock data for this region has been found to have many high SI values affecting Tmax values. This could be related to oil migration and has been rectified by also using extracted and kerogen data. 'Extracted data' refer to material that has undergone solvent extraction of whole rock to remove S1 to gain an accurate Tmax value. 'Kerogen data' refers to mineral matter removed from extracted rock with strong acid to obtain more reliable HI and Tmax data. The TOC values for these two datasets should not be analysed as organic matter has been concentrated as part of the analysis process.

RESERVOIR DATA

Basic reservoir data, such as porosity and permeability, have been sourced from Geoscience Australia's RESFACS, an Oracle-based reservoir/facies database. This dataset can be accessed via the National Petroleum Wells Database.

WELL LOGS

Logs contained in each well composite were derived from digital datasets licensed by Wiltshire Geological Services.

SEISMIC

All seismic images provided in this study are from open file Geoscience Australia data unless otherwise indicated. Further information about surveys in the region can be obtained from the Geoscience Australia Data Repository.

4. Well Information

4.1 ARAFURA-1

Arafura-1 was the second well drilled in the Arafura Basin and is located near the northeastern margin of the Goulburn Graben (Table 4.1, Figure 4.1). The well was drilled by Petrofina Exploration Australia in permit NT/P36 and is historically important because it was the first well to target Palaeozoic sediments and it established the area as having oil potential. The objective of the well was to obtain stratigraphic information and evaluate the reservoir potential of Palaeozoic sediments in a fault block. The well intersected the target sediments with two hydrocarbon-bearing intervals, Devonian siltstone and Ordovician dolomite. Numerous oil indications were also found throughout the well section.

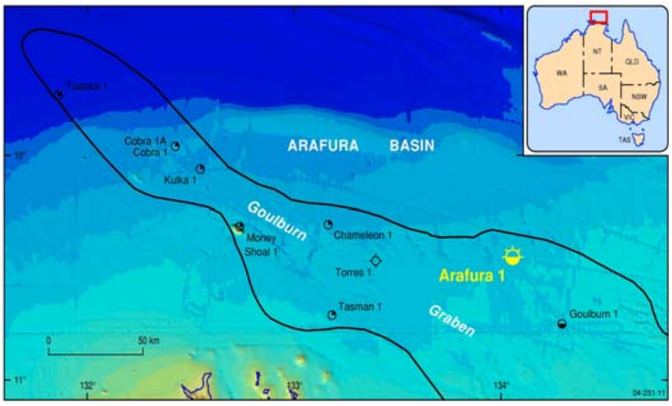


Figure 4.1 Arafura-1 well location.

Table 4.1: Arafura-1 well summary.

UNO	W8830001
Latitude	10° 27' 7.67" S
Longitude	134° 3' 22.40" E
Operator	Petrofina Exploration Australia
Year	1983
Permit:	NT/P36
Water Depth (m)	64.4
TD (mKB)	3635
TD Age	Neoproterozoic
KB (m)	32.1
Status	P & A
Hydrocarbon Shows	Oil and gas show
Play/Trap Type	Fault block
Primary Objectives	Palaeozoic section
Secondary Objectives	

STRATIGRAPHY

Arafura-1 penetrated a thin (320 m) succession of Late Cretaceous mudstones and Late Cenozoic carbonates of the Money Shoal Basin (Figure 4.2). The underlying Arafura Basin section contains Early Permian (Kushill Group equivalent, 311 m thick) interbedded sandstones and mudstones and Devonian (Arafura Group, 1009 m thick) siltstones.

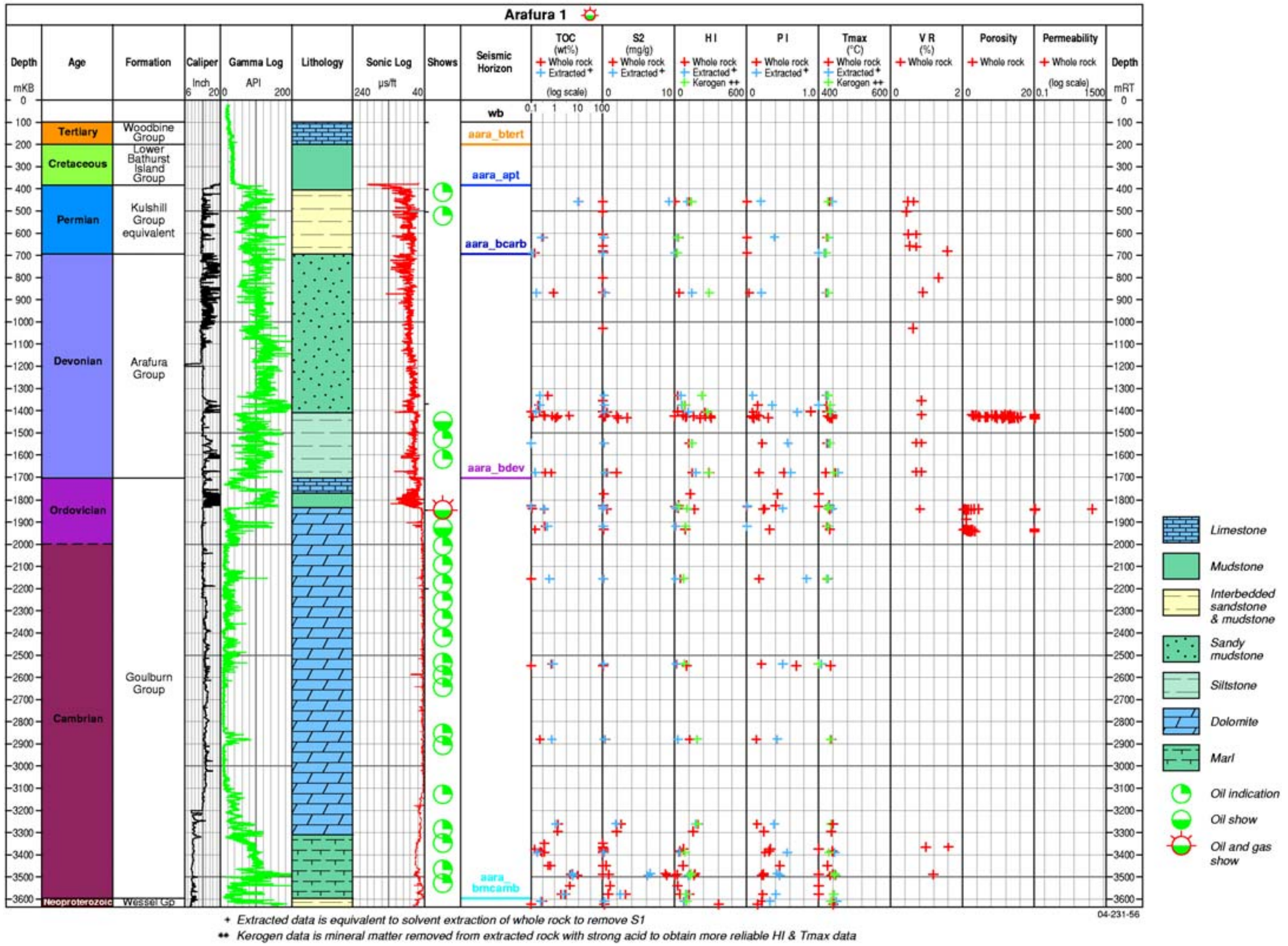


Figure 4.2: Arafura-1 well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

These are underlain by thick dolomites and carbonates of the Ordovician to Cambrian Goulburn Group. Arafura-1 is the only well in the Arafura Basin which intersected the ?Neoproterozoic Wessel Group (Figure 4.2). At this location it consists of highly indurated, white to yellow and pink, red and purple interbedded sandstone and mudstone (Petrofina Exploration SA, 1983)

STRUCTURE

The Arafura-1 structure was mapped on the basis of a 1981 to 1982 seismic campaign. Six structural prospects were identified (alpha to zeta), with the beta prospect recommended on the basis of the delineation of the structure, its areal extent and vertical closure (Figure 4.3) (Petrofina Exploration S.A., 1983).

The structure is an ENE-WSW trending fault block below the Tertiary to Cretaceous cover at or near the crest of a major anticline in the Goulburn Graben (Figures 4.4 and 4.5). Up-dip southern closure is provided by a set of ENE-WSW faults. A tentative evaluation of the structure by Petrofina indicated a maximum horizontal development of about 80 km^2 and a maximum vertical closure of 700 m.

SOURCE

The Early Permian (Kulshill Group equivalent) at the Arafura-1 location has good source potential, composed of interbedded mudstones with minor coal and sufficient organic richness for hydrocarbon generation with up to 9.44% TOC. The section is immature to early mature (Figure 4.6) and trace bitumen occurrences are probably related to coaly intervals or Cambrian sourced hydrocarbon migration.

The Devonian section (Arafura Group) contains thick mudstone intervals with up to 3% TOC. The interval is early mature to immature.

Although a Cambrian source facies was not intersected or sampled at Arafura-1, the numerous hydrocarbon occurrences indicate that the Cambrian is likely to contain excellent source rocks, probably towards the base of the section, where a dominantly dolomite unit becomes more claystone-rich. The intersected interval contains up to 9% TOC, however most of this is likely to be bitumen as described in organic petrological studies (Keiraville Konsultants, 1984; Sherwood et al., 2005). The bitumen has a Cambrian signature and indicates a prolific source rock nearby.

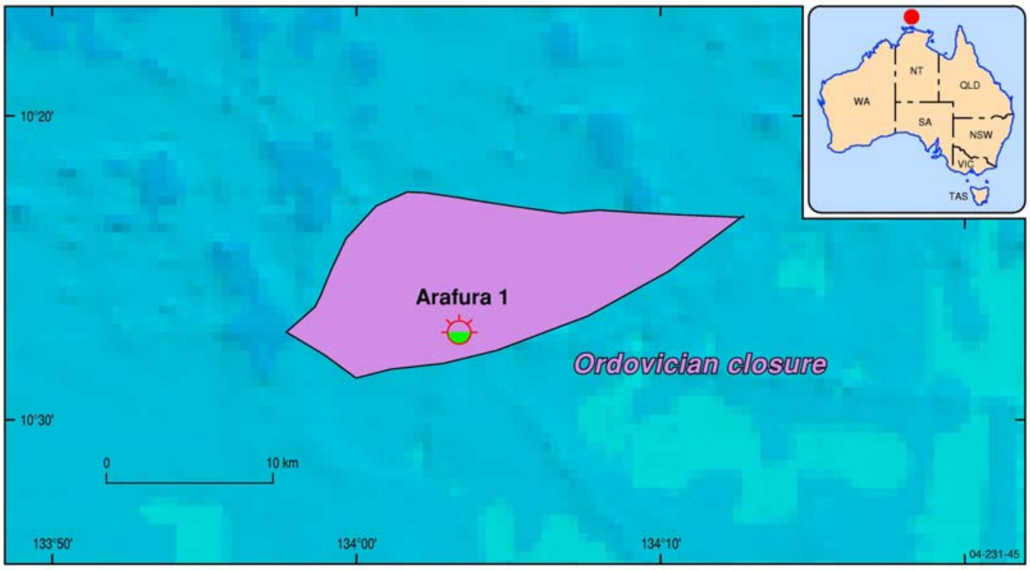


Figure 4.3: Closure of the Arafura-1 prospect (Petrofina Exploration S.A., 1983).

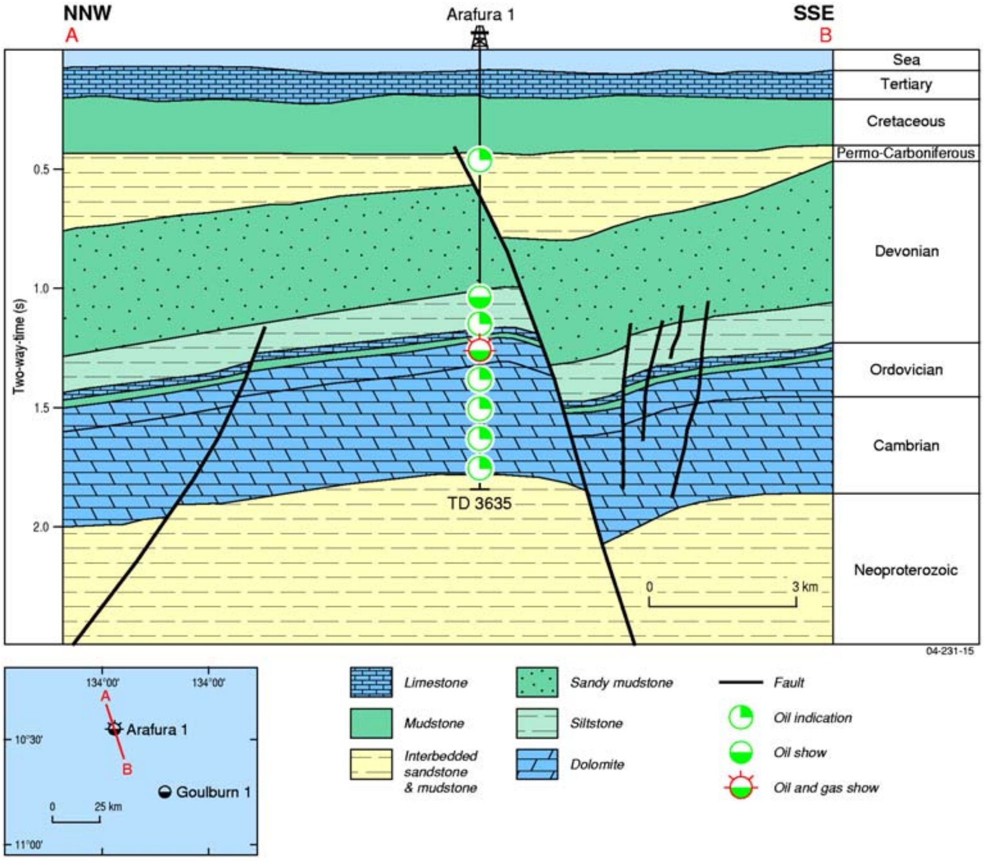


Figure 4.4: Simplified geological cross-section for Arafura-1.

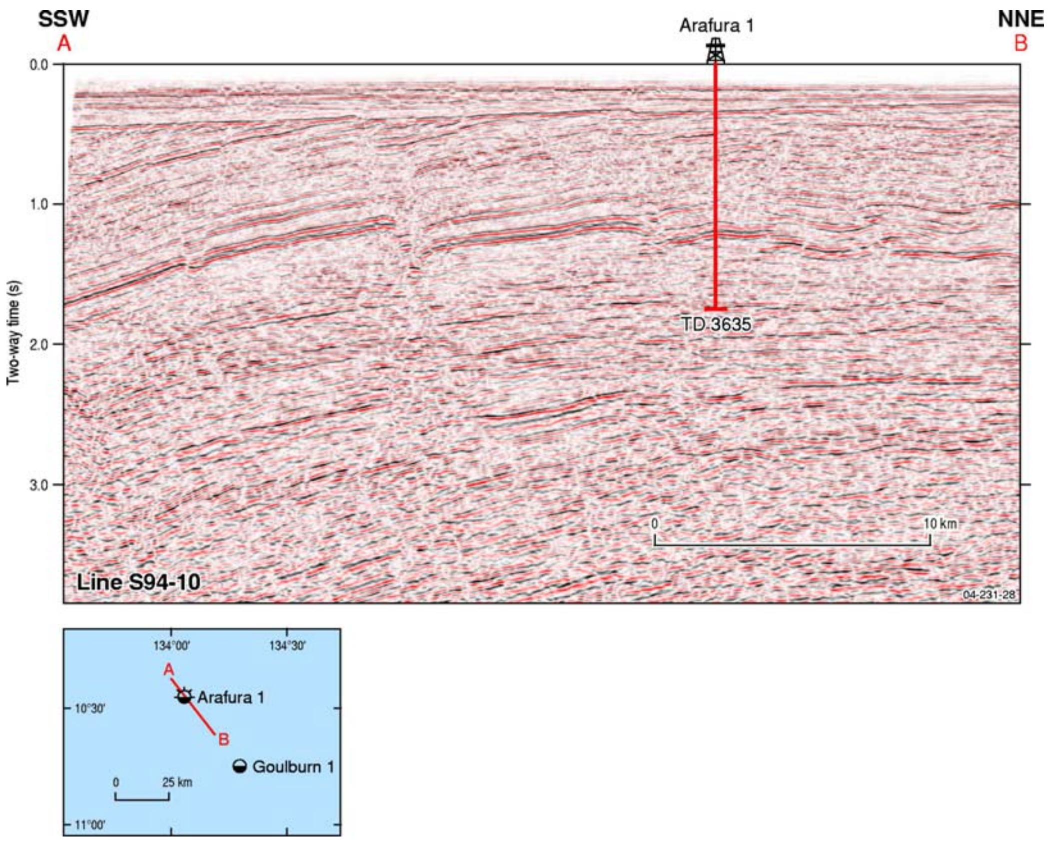


Figure 4.5: Seismic cross-section for Arafura-1.

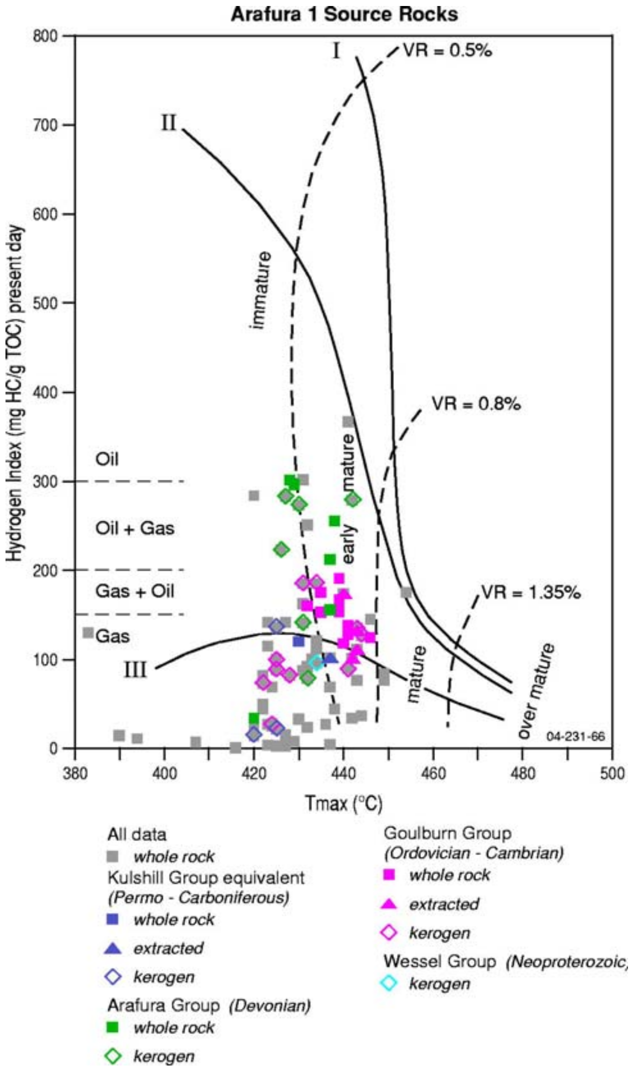


Figure 4.6: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Arafura-1. Note: data has been edited for reliability where coloured data points are deemed to be reliable and unreliable data are shown in grey ("all data"). The VR maturity lines are to be used only as guidelines for units older than the Devonian.

RESERVOIR

The two main reservoirs in the well are Devonian siltstone (Arafura Group) and Ordovician-Cambrian dolomite (Goulburn Group). Porosity and permeability data were obtained for the top sections of these intervals (Figures 4.2, 4.7 and 4.8).

The Arafura Group siltstone has poor porosity and permeability with an average of 10.6% and 1 mD respectively. Porosity and permeability reach a maximum at 16.2% and 9.8 mD. Cores 1 & 2 were cut between 1419 m and 1437 m, displaying irregular and light oil impregnation with rare and very slow bleeding from the matrix (Figure 4.7). Some bleeding was observed from fractures within the cores. The sediments have rare fractures, burrows and vuggy porosity with many vugs filled by calcite. Much of the original porosity has been destroyed by pressure solution and secondary crystallisation of quartz and dolomite. Lateral porosity/permeability improvement is possible with decreasing formation tightness or an increase in secondary porosity through fracturing, burrows and dissolution (Petrofina Exploration S.A., 1983).

The Goulburn Group dolomite has very low porosity, averaging 1.7% with a maximum of 4.4%. Permeability is also generally low, averaging 0.8 mD. These values indicate that the primary porosity prospectivity at the well location is low but the unit has good potential for the development of secondary porosity. Cores 4 (1842-1846 m) and 5 (1934-1943 m) were cut within this section and show that the dolomite is locally fractured with sub-vertical/diagonal fractures (Figure 4.8) and vugs up to 1 cm in size (Petrofina Exploration S.A., 1983).

Oil shows occur within the vugs, and larger vugs are covered with dolomite crystals and bitumen/tar. Permeability values higher than 1 mD are related to secondary porosity in the core plugs, for example the maximum permeability value of 1200 mD was attributed to sampling within a vug (Petrofina Exploration S.A., 1983). The dominantly low permeability values are probably due to selective sampling. This is reinforced by the presence of oils in areas of perceived low permeability. Repeated mud losses throughout the dolomite section indicate that the entire unit is heavily fractured.

SEAL

The hydrocarbon-bearing zones are capped by mudstone intervals. The Devonian sealing interval is a silty claystone with rare interbeds of dolomitic sandstone. The Ordovician seal is a silty mudstone interbedded with limestone streaks. The Devonian seal is much more homogenous in composition, and thus a better seal, compared to the Ordovician, but both seals are probably effective. The gas indication at 1370 m probably formed in-situ.

Leakage through the fault that intersects the well at 694.5 m, as well as fractures, are the most likely facilitators of hydrocarbon movement. Geochemical evidence suggests that the fault has also breached the structure, with a Cambrian signature within the oil film covered grains of Early Permian age.

HYDROCARBON SHOWS

The Goulburn Group dolomite has poor to moderate oil shows, mostly restricted to fractures and vugs (Figure 4.8). Oil in mud was recorded during drilling and coring of the upper section of this unit. A DST produced water with some gas. Solvent extraction of fluid samples yielded detectable hydrocarbons with significant aromatic components. The enrichment of these fluids in aromatic components suggests that the water had been in prolonged contact with oil (Petrofina Exploration S.A., 1983). Scattered bitumen occurrences were observed from the top of the dolomite unit down to TD.

Geochemical analyses from previous work (Moore et al., 1996) and analyses associated with this report (C. Boreham, Geoscience Australia pers. comm., July 2005) indicate that the Arafura and Goulburn Group hydrocarbon occurrences have been sourced from the Cambrian (Goulburn Group). There is evidence of oil biodegradation with mature aromatic crude derived from algal/bacterial organic matter. This implies that both reservoirs have been exposed to biologically-active meteoric waters at temperatures below 80 ^{o}C. The presence of biodegraded and non-biodegraded oils implies two episodes of migration into the structure (Petrofina Exploration S.A., 1983).

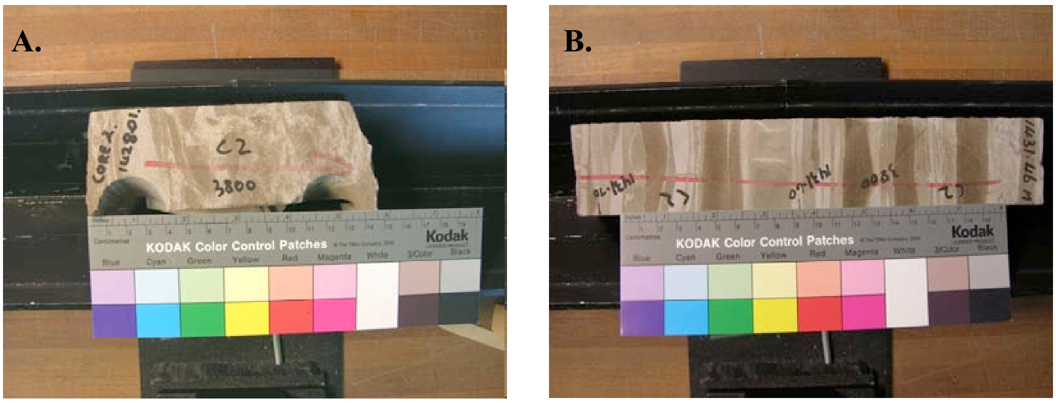


Figure 4.7: Core 2 - Devonian siltstone A) Mottled oil staining B) Banded oil staining.

No significant oil shows were noted during drilling above the Arafura Group oil show but there are traces of bitumen at 400-406 m and 505 m (Kulshill Group equivalent). Organic petrographic analysis by CSIRO (Sherwood et al., 2005) has also identified rare oil droplets in the Kulshill Group equivalent (450-460 m, 620-622 m, 690-694 m) and in the Arafura Group (870 m and 1332-1334 m). The first trace gas was in a sandstone bed at 1370 m (Arafura Group) with 85 ppm methane.

Geochemical analyses indicate that the Devonian section above the Devonian seal has not undergone migration of Cambrian-sourced oil. This suggests that the Cambrian-sourced oil has migrated through the section up to the Devonian seal and any oil droplets above this, as found by CSIRO petrography (Sherwood et al., 2005), have been locally sourced. Oil indications within the basal Kulshill Group equivalent have a Cambrian oil signature, as determined by oil film analysis (C. Boreham, Geoscience Australia pers. comm., July 2005), but the upper section, which contains bitumen, has a more indigenous signature. The presence of Cambrian-sourced oil above the Devonian seal indicates fault leakage facilitating migration into the formation. However, the oil did not migrate through the whole Permian section, with locally sourced bitumen occurring towards the top.

Figure 4.8: Core 5 - Oil staining in sub-vertical fractures within the Ordovician dolomite.

POST-DRILL ASSESSMENT

Arafura-1 is an important well in the region as it provided the first information about potential Palaeozoic source rocks, reservoirs and the presence of hydrocarbons. The well encountered two main reservoir sections, Devonian siltstone and Ordovician-Cambrian dolomite. Both reservoirs hosted oil, providing the first conclusive evidence of oil potential for the region. Reservoir porosity and permeability is low but there is evidence of secondary porosity with many vugs, fractures and burrows containing oil. Lateral improvement of the reservoir is also a possibility. The presence of both biodegraded and non-biodegraded oil in the reservoirs indicates at least two different hydrocarbon charges. The oil has been correlated to Cambrian source rocks thought to occur near the base of the Goulburn Group. They are likely to be rich in Type I/II kerogen and to have excellent source potential.

The reservoirs are sealed by mudstone intervals which appear to be effective, so fluid movement was probably facilitated by faults. This is supported by a Cambrian oil signature in oil film coated grains at the base of the Kulshill Group equivalent, where the main fault intersects the well section. This is clear evidence for fault leakage at this location. Whether the fault breached an accumulation, or tapped into migrating hydrocarbons is unknown. Ultimately, as a result of Triassic uplift and erosion, fault leakage resulted in fluid loss and is the primary reason for well failure. A summary of the well analysis is given in Table 4.2.

Table 4.2: Arafura-1 well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY

WELL	SHOWS	TARGETS P = Primary S = Secondary	STRUCTURE	RISK ELEMENTS: STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	COMMENTS
Arafura 1	Oil shows	P Devonian	Fault block	Low Risk	Medium Risk	Low Risk	High Risk	Low Risk	Seals fault breached/fault leakage
	Oil and gas shows	P Ordovician	Fault block	Low Risk	Medium Risk	Low Risk	High Risk	Low Risk	Seals fault breached/fault leakage

LEGEND

Low Risk	green
Medium Risk	orange
High Risk	red

4.2 CHAMELEON-1

Chameleon-1 was the eighth well drilled in the Arafura Basin and is located near the northern margin of the Goulburn Graben (Table 4.3, Figure 4.9). The well was the second well drilled by BHP Petroleum in permit NT/P42. Chameleon-1 intersected sediments ranging in age from the Tertiary to the Permian, testing Mesozoic sediments for generation and expulsion from underlying Permo-Carboniferous sediments. The well is assessed as having failed due to a lack of charge into the structure.

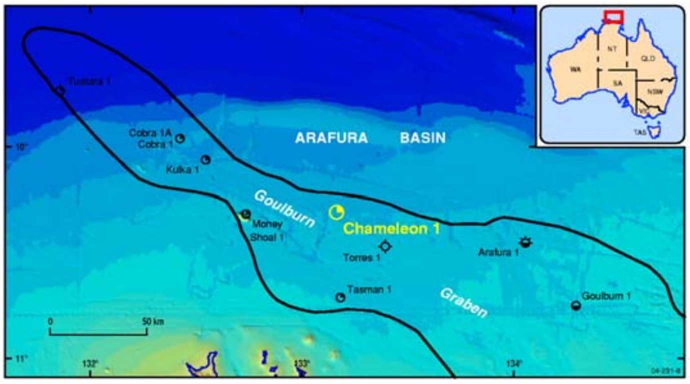


Figure 4.9: Chameleon-1 well location.

Table 4.3: Chameleon-1 well summary.

Uno	W8910012
Latitude	10° 18' 26.28" S
Longitude	133° 9' 50.85" E
Operator	BHP Petroleum
Year	1991
Permit:	NT/P42
Water Depth (m)	73
TD (mKB)	2179
TD Age	Permian
KB (m)	22
Status	P & A
Hydrocarbon Shows	Oil indications
Play/Trap Type	Anticline
Primary Objectives	Cretaceous (Upper Flamingo Group)
Secondary Objectives	Jurassic (Lower Flamingo Group), Permian (Kulshill Group equivalent)

STRATIGRAPHY

Chameleon-1 intersected sediments of Tertiary (Woodbine Group), Cretaceous (Upper and Lower Bathurst Island Group, Upper Flamingo Group), Jurassic (Lower Flamingo Group, Troughton Group equivalent) and Permian (Kulshill Group equivalent) age (Figure 4.10). The Money Shoal Basin sediments comprise Cenozoic shallow marine carbonates and Mesozoic clastics deposited in fluvio-deltaic to shallow marine environments. The Arafura Basin Kulshill Group equivalent consists of interbedded sandstone with mudstone and traces of coal deposited in fluvio-deltaic to shallow marine environments.

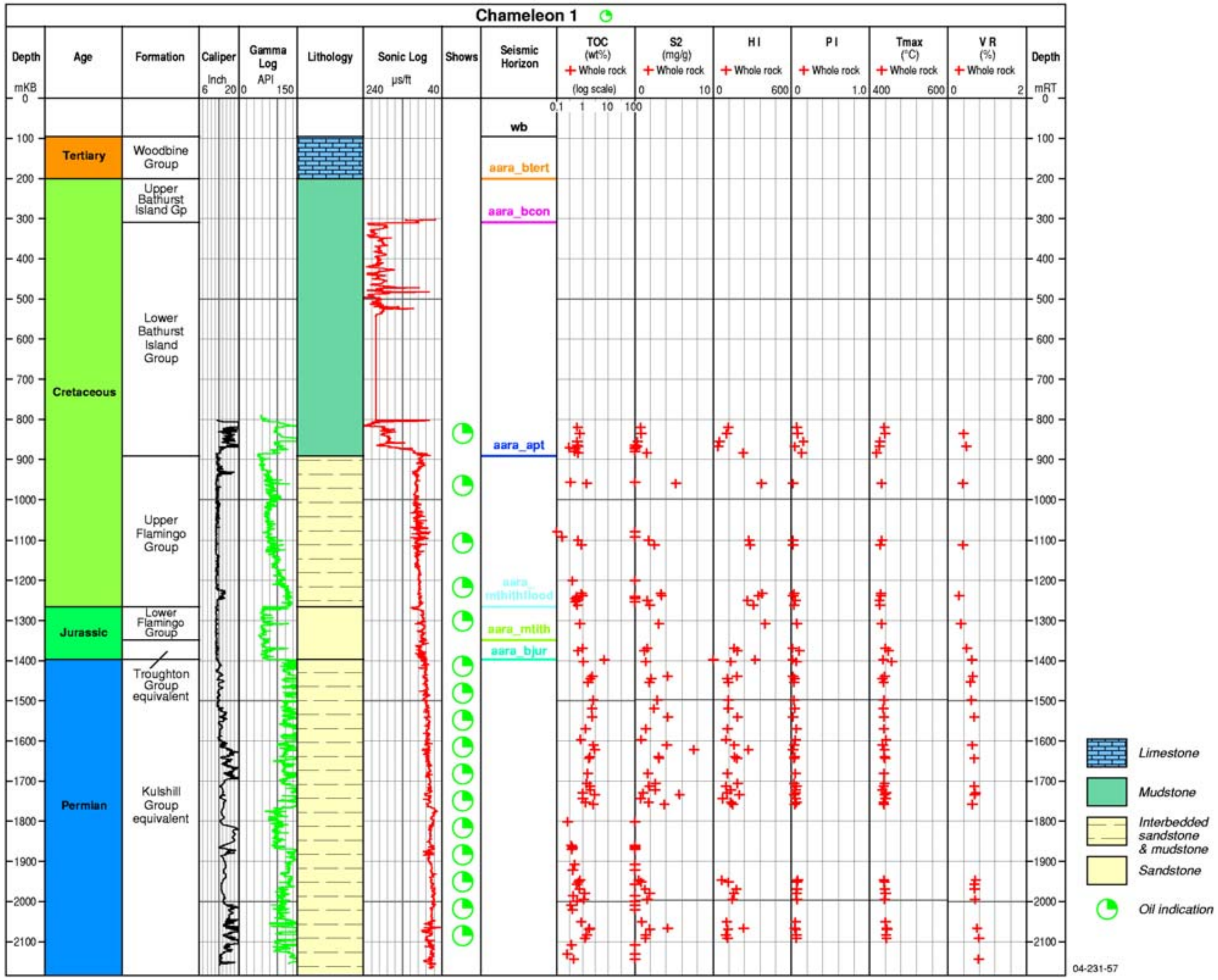


Figure 4.10: Chameleon-1 well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

STRUCTURE

Chameleon-1 is located near the northern margin of the Goulburn Graben and tested two different structures (Figures 4.12 and 4.13). The primary structure is an EW-trending anticline in the Cenozoic-Mesozoic section formed by Late Cenozoic to Recent reactivation of a pre-Jurassic normal fault. The structure is flanked to the north by an EW-trending reverse fault which merges with the SW-NE trending main graben–bounding fault along the eastern flank of the closure. The event that formed the structure also re-activated this fault (BHP Petroleum, 1992).

The primary target of the well was the Cretaceous sandstone (Upper Flamingo Group, Figure 4.11) immediately below the base Albian unconformity (aara_apt in Figure 4.10). The closure at the base Albian unconformity was assessed by BHP Petroleum to have an area of approximately 12 km^2 with vertical relief of approximately 20 m. Good vertical seal was expected from thick Cretaceous claystones. The primary risk identified at the time of drilling was the maturity of Palaeozoic source rocks. Secondary objectives in the structure included a stratigraphic trap within the Lower Flamingo Group reservoir (Figure 4.11). The Lower Flamingo Group was interpreted to have no structural closure due to a Tithonian-Berriasian channelling event along the edge of the Goulburn Graben (BHP Petroleum, 1992). The axis of the channel was intersected by Chameleon-1. Chameleon-1 is believed to have tested valid Cretaceous to Recent traps but trap formation probably post-dated the main hydrocarbon charge.

The second target structure was a SW-NE trending pre-Jurassic horst block with a small closure in the Permian section (Figure 4.11), containing approximately 50 m of vertical relief over a 5 km^2 area (BHP Petroleum, 1992).

SOURCE

There are numerous oil indications in the Mesozoic section, indicating possible source potential or migration into the section (Figure 4.14). The Bathurst Island Group, despite being dominated by mudstones, is not organic-rich; TOC values range from 0.3 to 0.65%. The section is immature for hydrocarbon generation and sparse oil indications are probably related to free hydrocarbons associated with more organic-rich intervals.

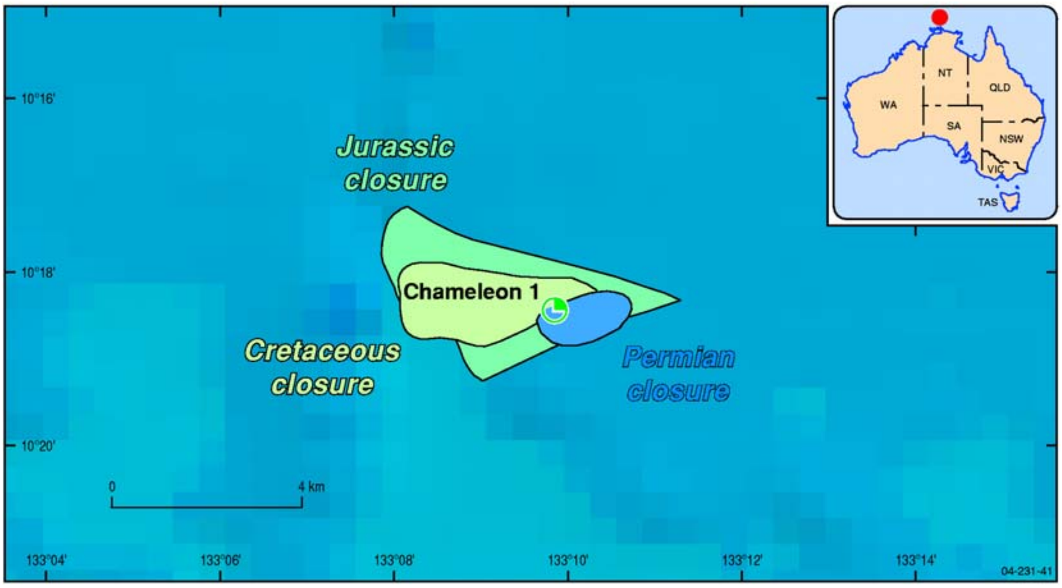


Figure 4.11: Closure of the Chameleon-1 prospect (BHP Petroleum, 1992). The Permian closure was originally assessed as being within the Carboniferous but, based on new interpretation, the age has been reassigned.

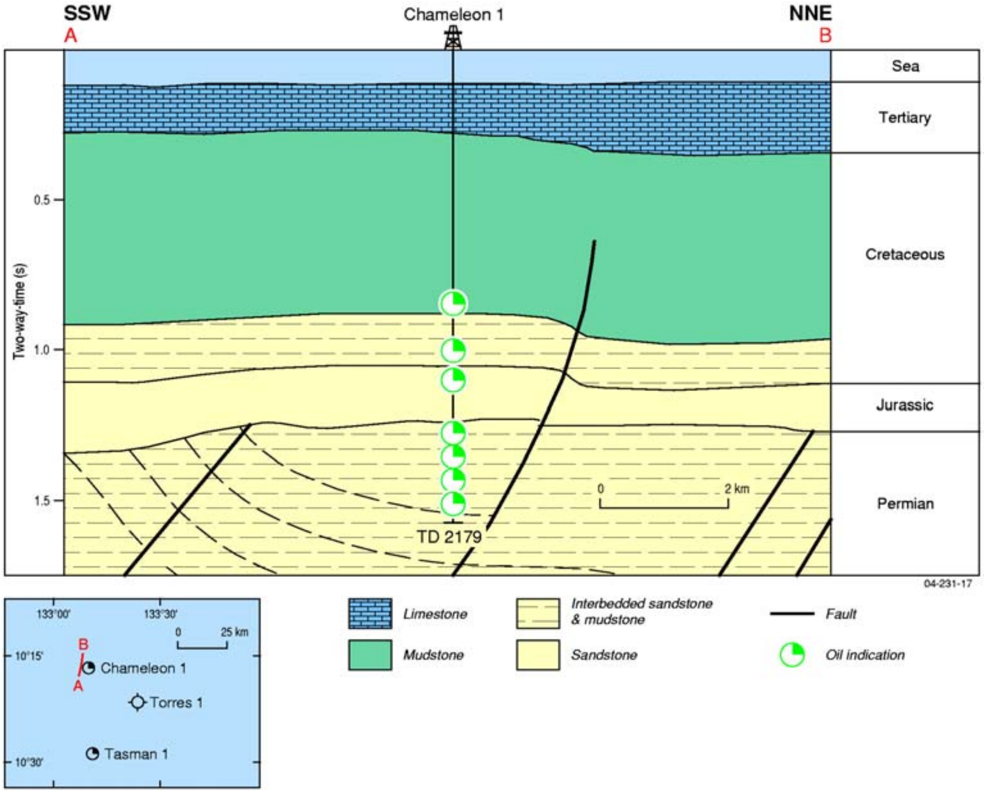


Figure 4.12: Simplified geological cross-section for Chameleon-1.

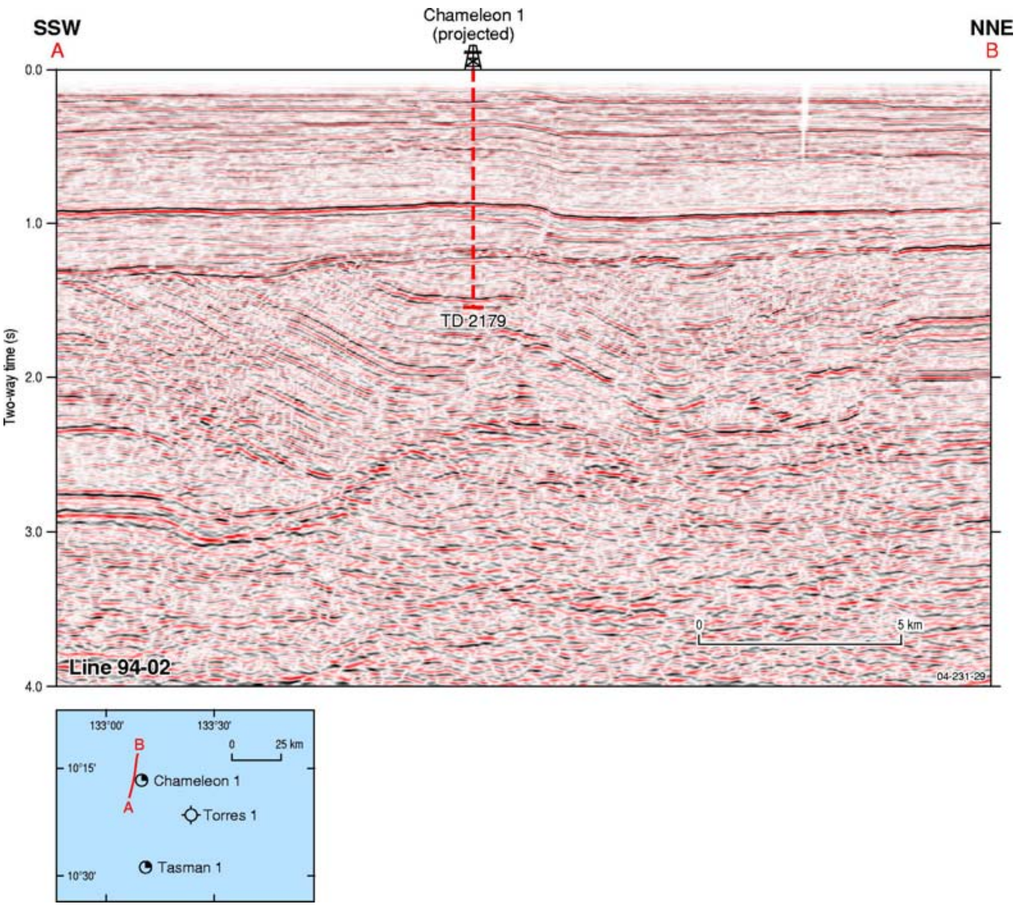


Figure 4.13: Seismic cross-section for Chameleon-1.

The Upper Flamingo Group (Cretaceous) is richer in sands and contains interbedded mudstones. The section has fair source potential, with a maximum of 1.4% TOC, and is immature for hydrocarbon generation. The Lower Flamingo Group and Troughton Group equivalent (Jurassic) are sand-rich and have poor source potential at this location.

Chameleon-1 was drilled partly as a test of Palaeozoic (Permian) source rocks. The Permian section (Kulshill Group equivalent) is about 800 m thick at this location although maturity data indicate that more than 2000 m of Early Permian sediments were eroded in the Triassic. The Kulshill Group equivalent contains a significant proportion of organic-rich mudstones and minor coals (0.3-6.6% TOC) and is early mature for oil generation. This is reflected in the numerous oil indications throughout the section. BHP Petroleum (1992) concluded that the Kulshill Group equivalent generated hydrocarbons in the Permo-Triassic which were lost during the Triassic uplift event. Recent geohistory modelling by Geoscience Australia (Struckmeyer et al., in prep) suggests that although minor in-situ generation from this section took place in the Permian, no hydrocarbons were expelled and the Mesozoic deposition following the Triassic uplift event was not sufficient to result in any further generation/expulsion. The Kulshill Group equivalent contains many oil indications. These are probably remnants of Permo-Triassic in-situ hydrocarbon generation.

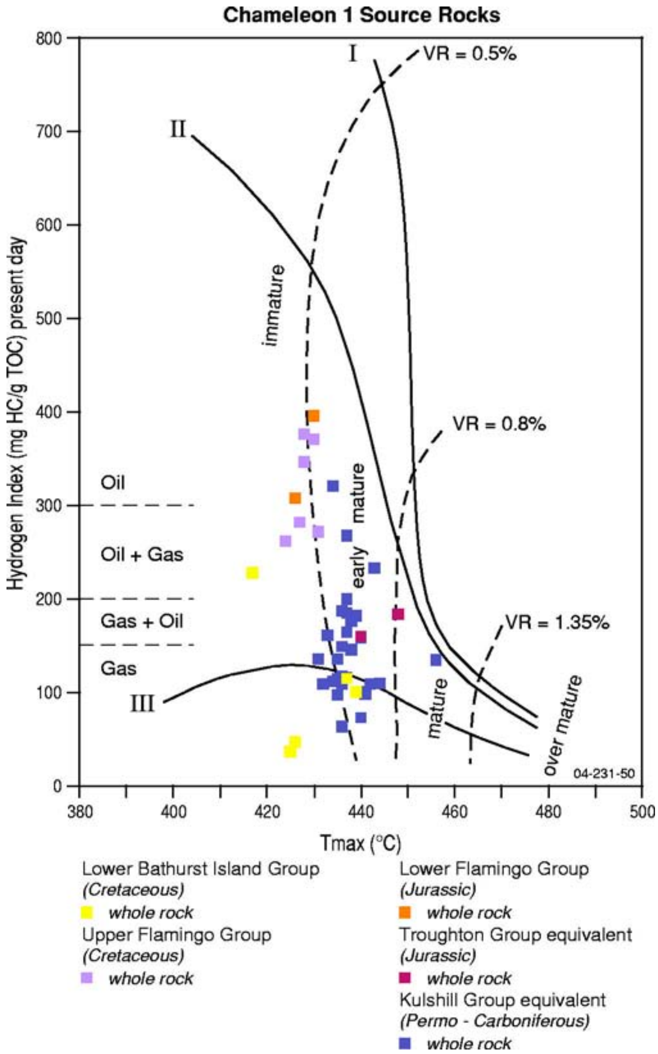


Figure 4.14: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Chameleon-1.

RESERVOIR

Chameleon-1 confirmed the existence of excellent Mesozoic reservoir units in the Jurassic to Cretaceous Flamingo Group and the Jurassic Troughton Group equivalent. The Cretaceous (Upper Flamingo Group) sands are composed of medium- to coarse-grained, well sorted sandstones with an average porosity of 21.2%. The Jurassic Lower Flamingo Group and Troughton Group equivalent also have good reservoir characteristics with medium- to coarse-grained sandstones with minor mudstone beds and coal fragments, averaging 20.5% porosity. There is some carbonate/siliceous cementation in the section. The units also contain fractures helping to facilitate fluid movement (BHP Petroleum, 1992).

Reservoir quality is significantly reduced in the Palaeozoic, with the section averaging approximately 6% porosity. The Permian section is composed of interbedded sandstones and siltstones with some thick sandstone beds and minor coals. Carbonate cements are sporadic throughout the Permian sequence. There is evidence of multiple fracture sets, some healed and some open, which could enhance the overall permeability and porosity of the interval.

SEAL

The primary reservoir target is sealed by overlying Cretaceous claystones (Lower Bathurst Island Group). The claystone is about 350 m thick and has a consistent composition of silty claystone with minor interbeds of fine- to very fine-grained sandstone, indicating an effective top seal. Fault leakage is unlikely due to the vertical extent of the Lower Bathurst Island Group claystone. The secondary target, in the Lower Flamingo Group sands, is overlain by sandy claystone channel fill sequences of the Upper Flamingo Group, which may have sealing potential.

There are two main claystone-rich sealing intervals in the Permian. These intervals have a heterogeneous composition with numerous sand layers. The sealing integrity of these units is doubtful, although the mud log indicates a decrease in gas within each unit, with reservoir units producing a clear increase in gas. Fault leakage is likely due to the interbedded nature of the section. However, many of the fractures, if not the faults, may now be filled with sparry calcite and dolomite (BHP Petroleum, 1992).

Oil indications are present throughout all of the sealing intervals. This could be due to a lack of effective seal, extensive migration or minor local sourcing of oil indications, at least for the marginally mature Palaeozoic section.

HYDROCARBON SHOWS

No significant hydrocarbons were found in the well. Numerous oil indications occur throughout the well section, not only in reservoir sands. No repeat formation tests or drill stem tests were carried out.

POST-DRILL ANALYSIS

Chameleon-1 tested the hydrocarbon prospectivity of a large anticline in the Mesozoic section, with a secondary horst block target in the Palaeozoic section. The presence of high quality Mesozoic reservoirs effectively sealed by Cretaceous (Bathurst Island Group) claystones was confirmed. The secondary target contained a much lower quality seal and reservoir. The well also intersected a Tithonian-Berriasian channel located along the graben edge. No significant hydrocarbons were encountered, attributed to a lack of charge to the reservoir sands.

The Permian source rocks have good source potential but are not mature enough at this location to have expelled hydrocarbons, although minor in-situ generation probably took place in the Late Carboniferous to Early Permian.

During the Triassic Fitzroy Movement equivalent event, approximately 2 km of sediment was uplifted and eroded from the section (BHP Petroleum, 1992); subsequent deposition was not sufficient to move the Permian into the generation window. However mature Permian sediments are likely to be present to the west, where the Mesozoic sediment wedge thickens. A summary of the well analysis is shown in Table 4.4.

Table 4.4: Chameleon-1 well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY									
WELL	**SHOWS**	**TARGETS** **P = Primary** **S = Secondary**	**STRUCTURE**	**RISK ELEMENTS**					
				STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	**COMMENTS**
Chameleon 1	Oil indications	P Lower Cretaceous	Anticline	Low	Low	Medium	Low	High	No charge, immature source
	Oil indications	S Jurassic	Stratigraphic	Low	Low	Medium	Medium	High	No charge, immature source
	Oil indications	S Permian	Fault block	Low	Medium	Medium	Medium	High	No charge, immature source

LEGEND

Low Risk	Low (green)
Medium Risk	Medium (orange)
High Risk	High (red)

4.3 COBRA-1, 1A

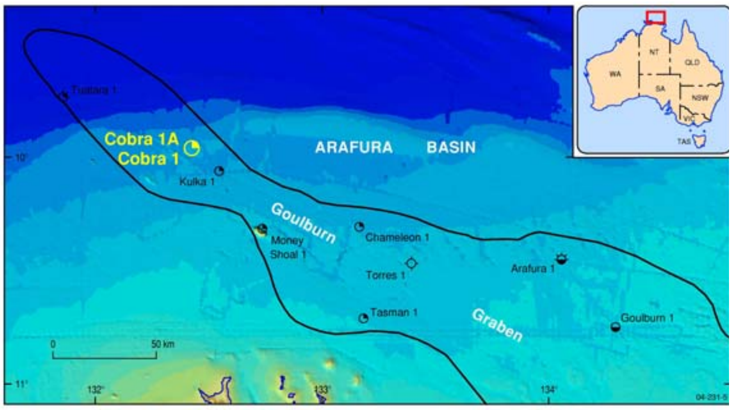


Figure 4.15: Cobra-1A well location.

Cobra-1, 1A is located near the northwestern margin of the Goulburn Graben and is the most recent well drilled in the Arafura Basin (Table 4.5, Figure 4.15). It was drilled by BHP Petroleum in permit NT/P42. The well targeted Late Jurassic sands in a faulted erosional dome. Oil indications were found throughout the Jurassic and Cretaceous sections. The primary objective failed due to a thief zone resulting in a lack of seal over the crest of the closure.

Table 4.5: Cobra-1A well summary.

Uno	W8930003
Latitude	9° 57' 36.66" S
Longitude	132° 25' 29.35" E
Operator	BHP Petroleum Pty. Ltd.
Year	1993
Permit:	NT/P42
Water Depth (m)	78
TD (mRT)	2542
TD Age	Jurassic
RT (m)	22
Status	P & A
Hydrocarbon Shows	Oil indications
Play Type/Trap	Stratigraphic
Primary Objectives	Jurassic (Lower Flamingo Group)
Secondary Objectives	Cretaceous (Upper Flamingo Group) and the Jurassic (Troughton Group equivalent)

STRATIGRAPHY

Cobra-1A intersected Money Shoal Basin sediments of Tertiary (Woodbine Group), Cretaceous (Bathurst Island Group, Darwin Formation equivalent and Upper Flamingo Group) and Jurassic (Lower Flamingo Group and Troughton Group equivalent) age (Figure 4.16). The Bathurst Island Group and Darwin Formation equivalent are dominated by mudstones deposited in mostly marine environments and reach a combined thickness of 1192 m. The Bathurst Island Group also contains minor interbeds of sandstone and traces of coal. The Flamingo Group consists of blocky sandstones with interbedded mudstones deposited in a variety of deltaic environments.

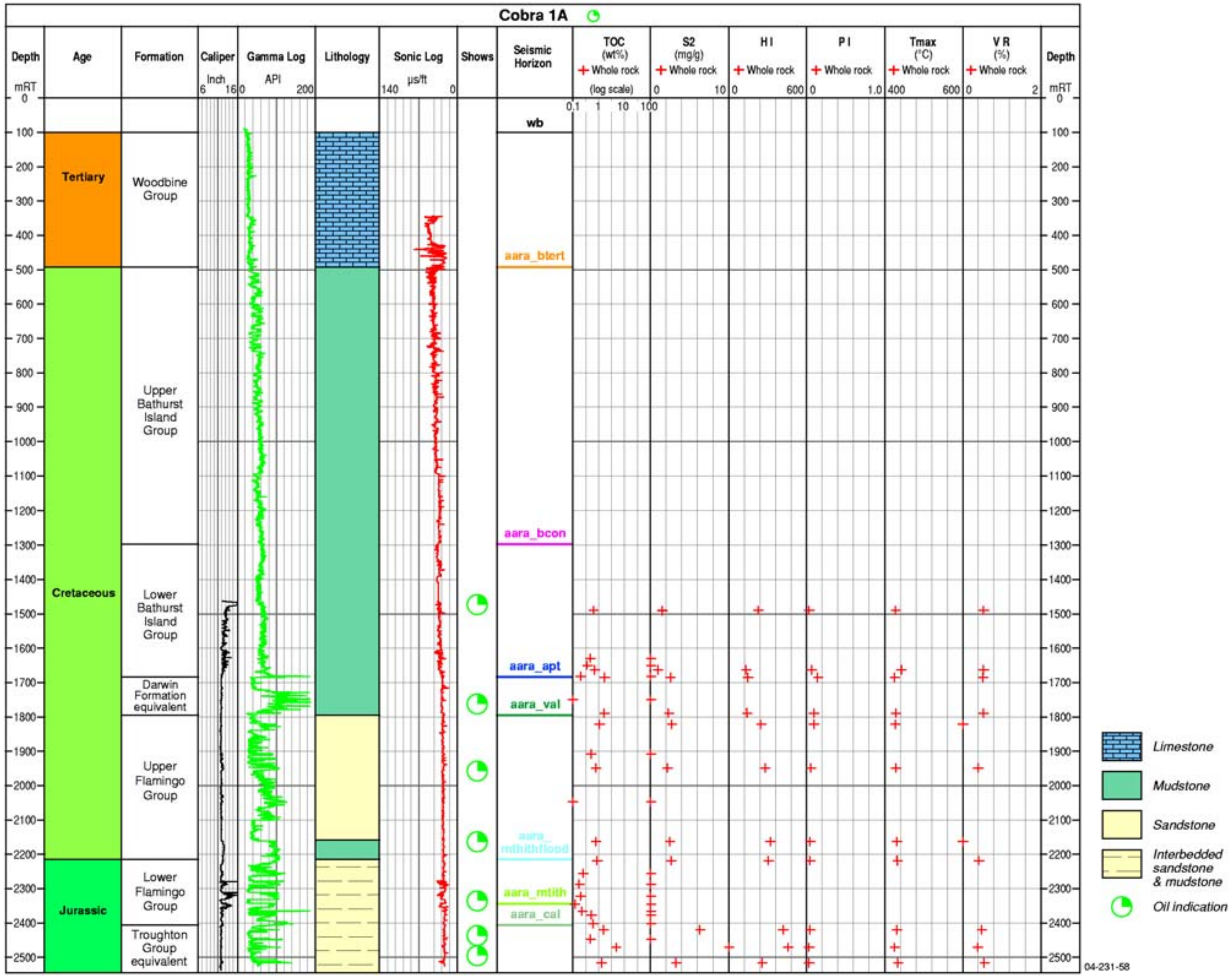


Figure 4.16: Cobra-1A well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

The Troughton Group equivalent is dominated by fluvial sandstone with minor mudstone interbedding and coal stringers.

STRUCTURE

The Cobra-1A structure is a broad domal closure formed by a large, buried, WNW-ENE trending remnant topographic high between two channels and bounded by faults (Figure 4.18 and 4.19). The primary target was Late Jurassic (Lower Flamingo Group) sandstone. The closure configuration is only present at the Tithonian surface and is sealed by overlying Cretaceous mudstones. Also included in the trap configuration were the underlying sandstones of the Jurassic Troughton Group equivalent. The erosional high had an estimated fault dependant closure of 23 km^2 and a height of 128 m (BHP Petroleum, 1993).

The top sandstones of the Early Cretaceous (Upper Flamingo Group) were considered a minor secondary target, as a small closure was mapped at the base Albian unconformity (Figure 4.17) (BHP Petroleum, 1993).

SOURCE

Cobra-1A intersected several intervals with some source potential in terms of TOC content (>1%) but the entire section is immature for hydrocarbon generation (Figure 4.20). Seismic data suggests that Permo-Carboniferous sediments underlie the penetrated section. It is likely that these have sourced the oil indications, suggesting a late generation and expulsion event.

RESERVOIR

Reservoir quality for all of the well targets is excellent. The primary reservoir target, the Jurassic Lower Flamingo Group, has an average porosity of approximately 21%. Jurassic Troughton Group equivalent sandstones have an average porosity of approximately 20.5%. Sandstones within the Cretaceous Darwin Formation have an average porosity of 25%. The thick blocky sands of the Upper Flamingo Group have an average porosity of 24%. All reservoirs have high water saturation.

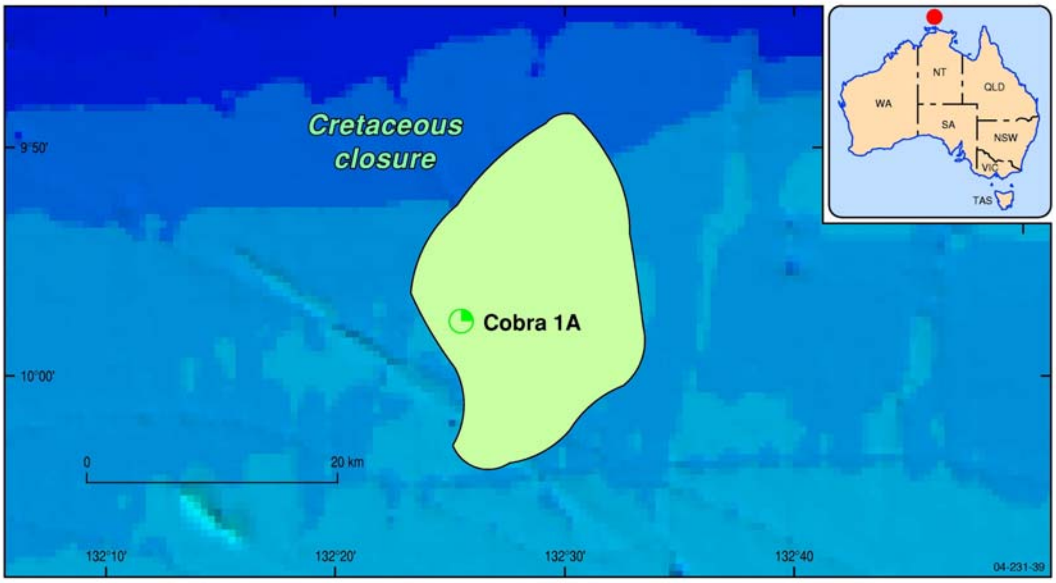


Figure 4.17: Closure of the Cobra-1A prospect (BHP Petroleum, 1993).

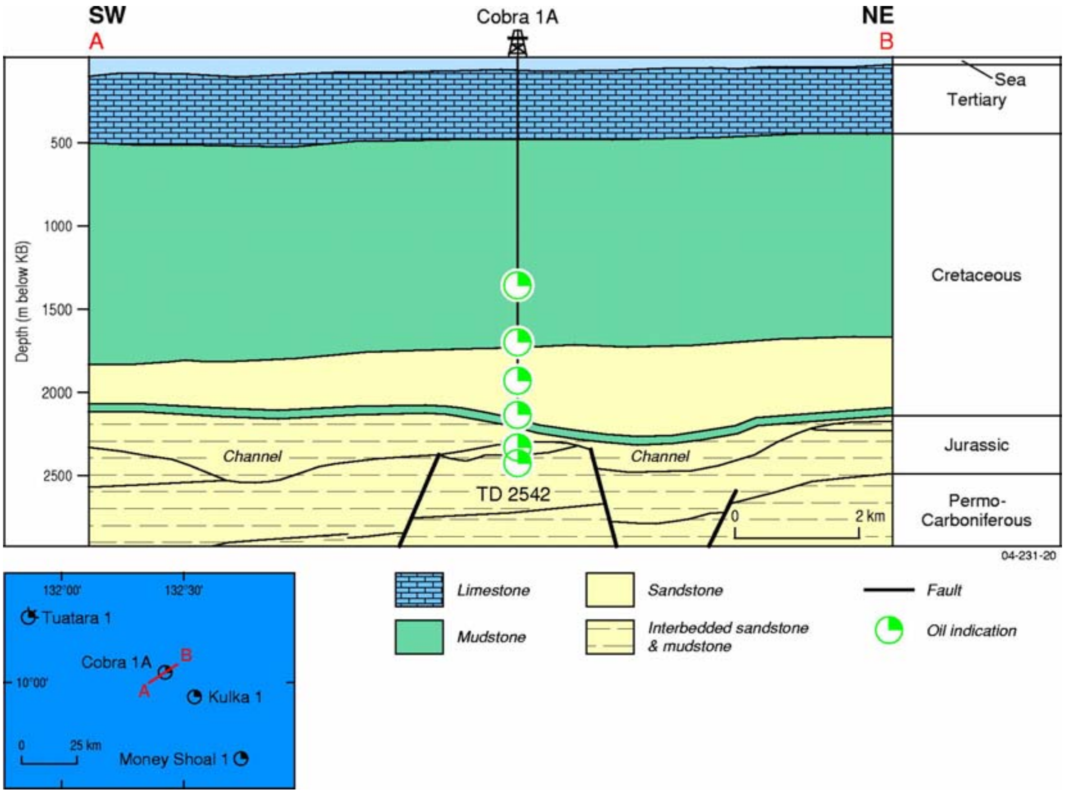


Figure 4.18: Simplified geological cross-section for Cobra-1A (modified from BHP Petroleum, 1993)

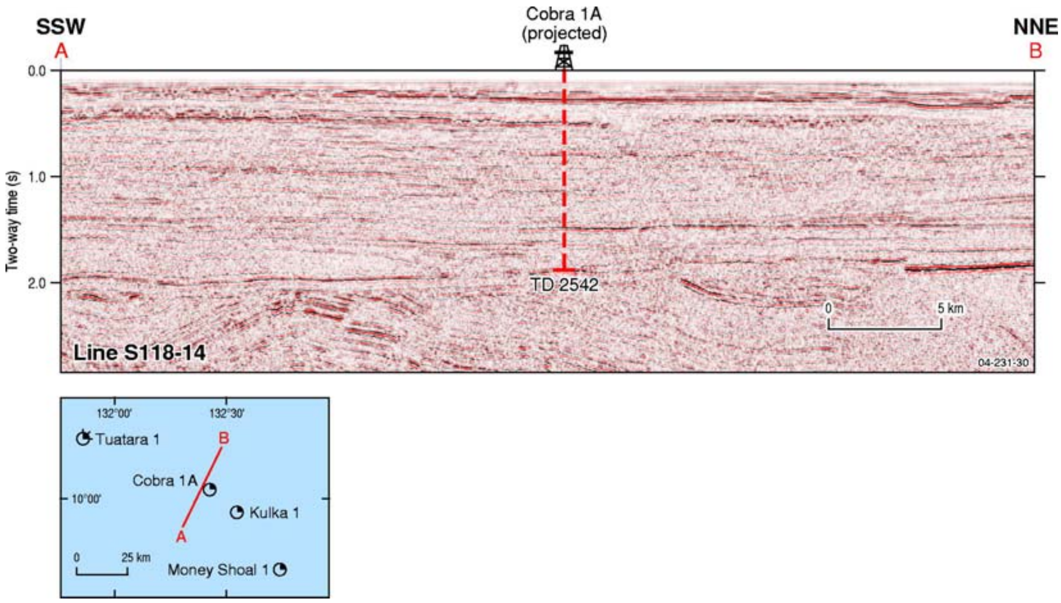


Figure 4.19: Seismic cross-section for Cobra-1A.

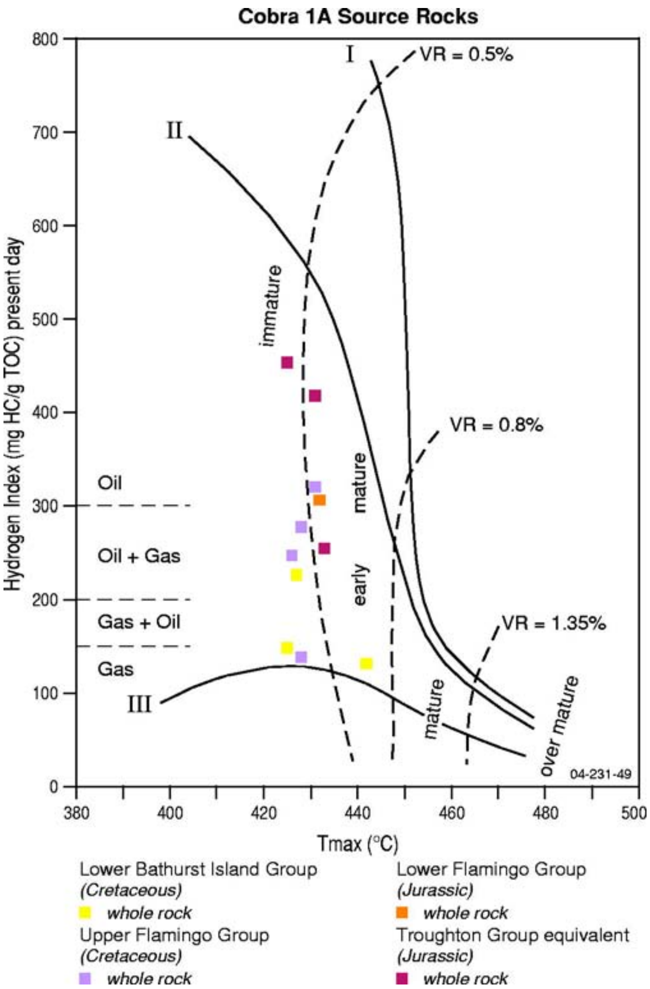


Figure 4.20: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Cobra-1A.

SEAL

Pre-drill, the primary reservoir target was interpreted to be sealed by Early Cretaceous claystones (BHP Petroleum, 1993). Post-drill, the inferred sealing unit has been placed at the top of the Jurassic Lower Flamingo Group. In fact, the section between 2215-2264.5m (Figure 4.16) is composed of interbedded sandstone and claystone which could have acted as a thief zone for hydrocarbons, removing the trapping ability of the structure. This zone is overlain by an Early Cretaceous claystone section with good sealing properties.

The secondary targets are overlain by Cretaceous claystone (Bathurst Island Group) and Jurassic claystone (Troughton Group equivalent) respectively. The Cretaceous seal is a thick interbedded, but dominantly clay-rich, sequence of claystone and sandstone. The thickness and consistent composition indicates good seal potential. The Jurassic claystone was initially proposed as a seal for the Jurassic Troughton Group equivalent reservoir but is thin and composed of coarse clastics.

HYDROCARBON SHOWS

No significant hydrocarbons were found in the well but oil indications are present throughout the Cretaceous and Jurassic sections. Due to the immaturity of the Mesozoic sediments, the hydrocarbon indications are probably sourced from underlying Permo-Carboniferous sediments. No repeat formation tests or drill stem tests were carried out.

POST-DRILL ANALYSIS

Cobra-1A intersected Money Shoal Basin sediments, targeting Jurassic sands within a faulted, eroded high. Drilling confirmed the high quality of the target reservoirs. No significant hydrocarbons were encountered but oil indications are present throughout the Cretaceous and Jurassic sections. Thermal immaturity of the Mesozoic section suggests that the hydrocarbon indications are likely sourced by underlying Palaeozoic sediments. Cobra-1A relied on channel fill to act as a seal over the primary target. The interbedded nature of the channel fill was unexpected and it was interpreted to be a thief zone. This is seen as the primary reason for well failure. A summary of the well analysis is shown in Table 4.6.

Table 4.6: Cobra-1A well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY									
WELL	SHOWS	TARGETS P = Primary S = Secondary	STRUCTURE	RISK ELEMENTS					
				STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	COMMENTS
Cobra 1a	Oil indications	P Upper Jurassic	Stratigraphic	Low Risk	Low Risk	Low Risk	High Risk	Medium Risk	Thief zone above reservoir removing closure
	Oil indications	S Cretaceous	Stratigraphic	Low Risk	Low Risk	Low Risk	Low Risk	Medium Risk	Charge problem?
	Oil indications	S Lower Jurassic	Stratigraphic	Low Risk	Low Risk	Low Risk	High Risk	Medium Risk	No seal

LEGEND: Low Risk (green); Medium Risk (orange); High Risk (red)

4.4 GOULBURN-1

Goulburn-1 is located in the southeastern part of the Goulburn Graben (Figure 4.21). The well was drilled by Petrofina Exploration in permit NT/P36, based largely on results of the nearby Arafura-1 well (Table 4.7). The primary target was Devonian siltstone within a fault block. Three hydrocarbon-bearing intervals; Devonian sandstone, Ordovician limestone and Ordovician-Cambrian dolomite, were intersected with numerous dead oil and bitumen occurrences. The lack of live oil and gas shows has been attributed to a lack of fault seal for the well objectives and subsequent flushing of the formations.

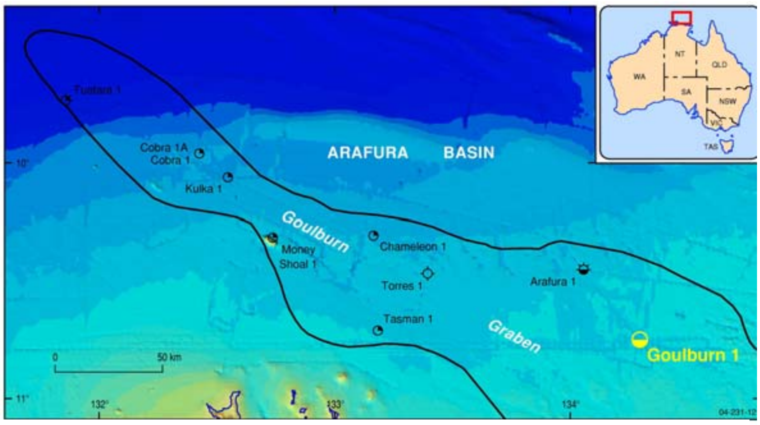


Figure 4.21: Goulburn-1 well location.

Table 4.7: Goulburn-1 well summary.

Uno	W8860007
Latitude	10° 44' 52.47" S
Longitude	134° 17' 44.23" E
Operator	Petrofina Exploration
Year	1986
Permit:	NT/P36
Water Depth (m)	65.5
TD (mKB)	1300
TD Age	Cambrian
KB (m)	11.3
Status	P & A
Hydrocarbon Shows	Oil shows
Play Type/Trap	Fault block
Primary Objectives	Devonian siltstone (Arafura Group)
Secondary Objectives	Ordovician dolomite (Goulburn Group)

STRATIGRAPHY

Goulburn-1 is located up-dip from Arafura-1 and intersects similar sediments of Tertiary (Woodbine Group), Cretaceous (Lower Bathurst Island Group), Devonian (Arafura Group) and Ordovician-Cambrian (Goulburn Group) age.

The Money Shoal Basin sediments are thin (only 120 m thick) at this location and consist of Tertiary carbonates underlain by Lower Bathurst Island Group claystones deposited in a shallow-marine shelf environment (Figure 4.22).

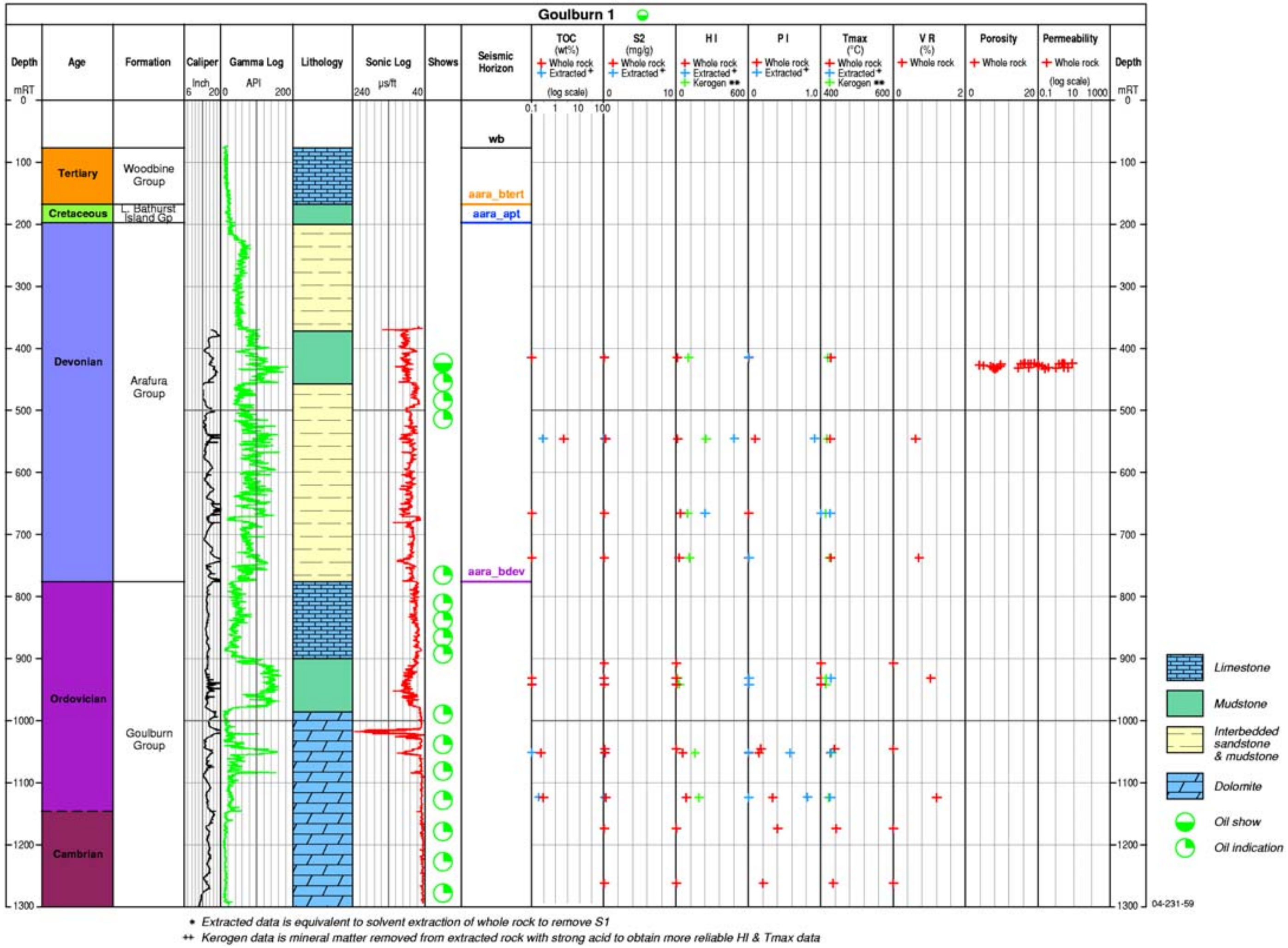


Figure 4.22: Goulburn-1 well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

The Arafura Basin sediments comprise a mixed succession of clastics and carbonates including 507 m of Devonian sandstones and siltstones with minor carbonates and more than 1500 m of Goulburn Group dolomite, minor mudstone and limestone.

STRUCTURE

The Goulburn-1 structure is a NW-SE trending, elongate, up-thrown fault block. It is flanked to the south by a NW-SE trending graben and is dependant on a southwest dipping fault for closure (Figures 4.24 and 4.25) (Petrofina Exploration Australia S.A., 1986).

The main objective of the well was to assess the Palaeozoic sediments within the structure, particularly the Devonian siltstone (Figure 4.23). In Arafura-1 this target interval was found to contain only oil shows due to poor reservoir quality and fault leakage. As the Goulburn structure was interpreted to have been located closer to the inferred palaeo-shoreline the operator believed that the reservoir quality would be better, with coarse sandstones and less fine-grained material (Petrofina Exploration Australia S.A., 1986). Ordovician carbonates were a secondary target in the well.

SOURCE

Goulburn 1 did not intersect any viable source rock units, however, sampling density was very low and TD is above potential organic-rich Cambrian source rocks of the Goulburn Group (Jigaimara Formation; Figure 4.26). Only one sample (in the Devonian Arafura Group) contains sufficient organic matter for the generation of hydrocarbons (at >1% TOC) but it is immature for generation. The oil show in Devonian clastics has been correlated to a Cambrian source (C. Boreham, Geoscience Australia pers. comm., July 2005) and it is highly likely that the Goulburn Group (Jigaimara Formation) is the source.

RESERVOIR

There are three main reservoir intervals in the Goulburn-1 well: Arafura Group sandstones/siltstones, Goulburn Group limestone and Goulburn Group dolomite.

The Arafura Group reservoir is composed of alternating beds of siltstone, sandstone, claystone and minor dolomite. Core 1 (424.13-433.54 m) was cut within the top part of this section and has poor reservoir characteristics. Porosity and permeability are poor with an average of 12% and 1.74 mD, respectively, with a maximum of 19% and 7.83 mD. There is no fracturing within the section.

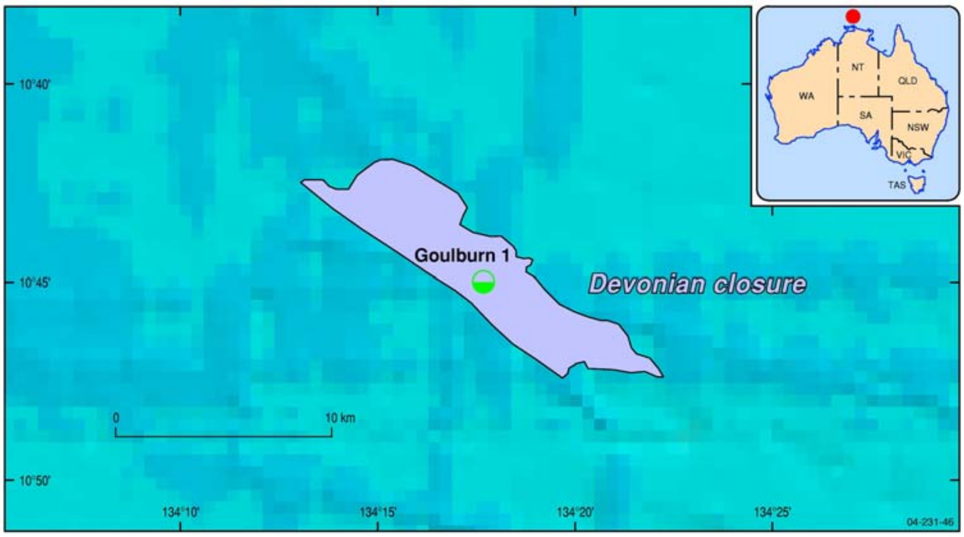


Figure 4.23: Closure of the Goulburn-1 prospect (Petrofina Exploration Australia S.A., 1986).

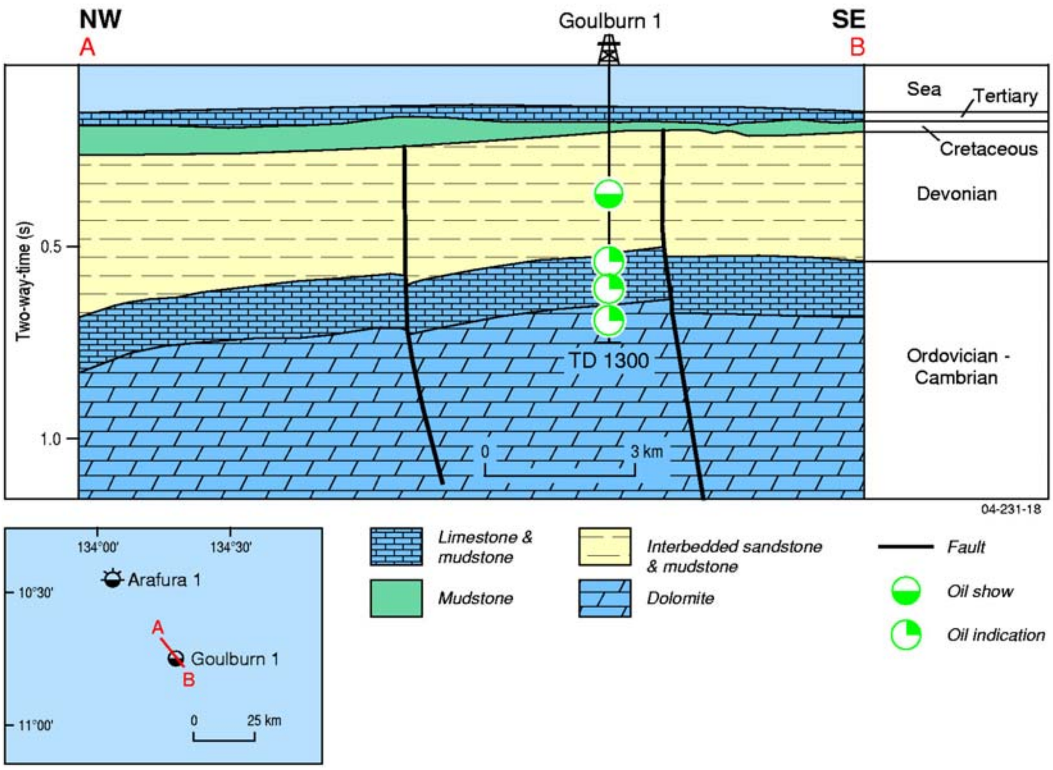


Figure 4.24: Simplified geological cross-section for Goulburn-1.

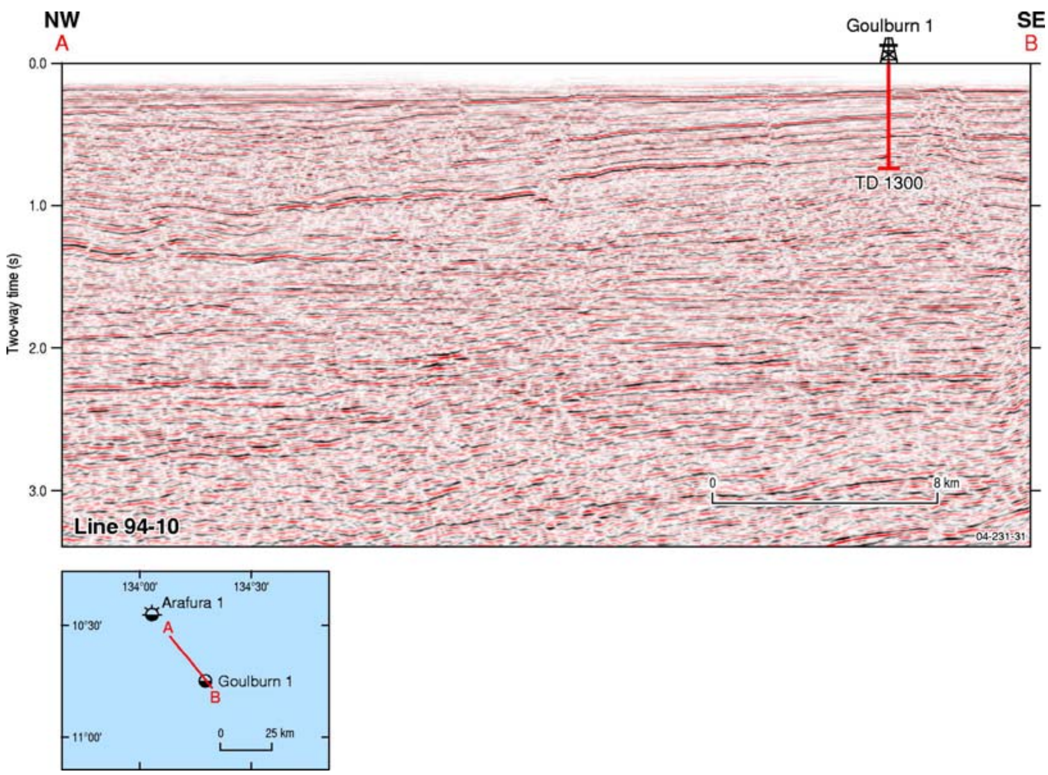


Figure 4.25: Seismic cross-section for Goulburn-1.

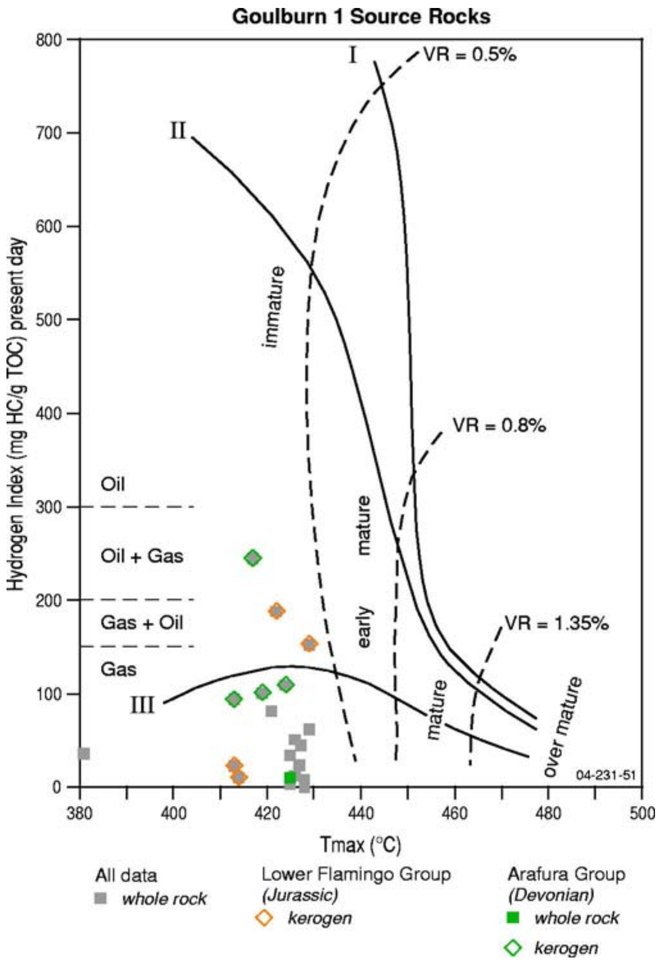


Figure 4.26: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Goulburn-1. Note: data has been edited for reliability where coloured data points are deemed to be reliable and unreliable data are shown in grey ("all data").

Compared to the Devonian Arafura Group reservoir in Arafura-1, the unit has coarser sandstones, indicating that it is located closer to the palaeo-shoreline (Petrofina Exploration Australia S.A., 1986). However, average porosity values are only slightly higher.

The Goulburn Group limestone reservoir is interbedded with fine-grained sandstone grading to siltstone and minor claystone. No cores were cut in the section and the average porosity was calculated to be 5% by the operator. There is no evidence of fracturing in the unit.

The Goulburn Group dolomite reservoir is interbedded with limestone, claystone and minor siltstone/sandstone. There is evidence that the section is fractured, with some mud losses and minor amounts of well-developed crystals of dolomite, quartz and calcite in cuttings indicating growth in open voids (Petrofina Exploration Australia S.A., 1986). There is also a possibility of karsts in the limestone interval at 1013.5-1020 m. No cores were cut and the average porosity was calculated to be 3%.

The Goulburn Group reservoir was inferred by Petrofina Exploration to remain constant between Arafura-1 and Goulburn-1. This is not so, with the Arafura-1 section having a lower porosity average but more secondary porosity though extensive fracturing.

SEAL

At Goulburn-1, the Cretaceous Bathurst Island Group seal directly overlies Palaeozoic sediments. Although this is a high-quality regional seal with a homogenous, mudstone-rich composition, it is very thin (at 29 m) at this location.

The Devonian (Arafura Group) and Ordovician (Goulburn Group) sections both contain potential sealing units overlying the main reservoir units. The Arafura Group seal is heterogeneous, composed of alternating beds of siltstone, sandstone and clay. The equivalent unit at Arafura-1 is more homogeneous with better seal qualities. The Goulburn Group seal is composed of claystone grading to siltstone and sandstone. The seal quality here has improved compared to Arafura-1, with a more homogenous composition.

The lack of live oil and gas shows indicates a lack of top or fault seal.

HYDROCARBON SHOWS

The well contains three main zones with weak to medium dead oil/bitumen and very weak gas traces:

1) Arafura Group sandstones, siltstones and claystones (Figure 4.27)
2) Goulburn Group limestone with minor interbeds of sandstone, siltstone and claystone
3) Goulburn Group dolomite

There were no live oil or gas shows reported during drilling. Combined with low formation salinities, this was interpreted by the operator to reflect a lack of seal and flushing of the reservoir. The hydrocarbon remnants in the Arafura Group reservoir have been typed by C. Boreham (Geoscience Australia pers. comm., July 2005) to a Cambrian source. No shows were encountered above 420 m except for trace gas at 421 m. No repeat formation tests or drill stem tests were carried out.

Figure 4.27: Oil-stained Devonian siltstone, Goulburn-1.

POST-DRILL ANALYSIS

Goulburn-1 tested a fault block near the margin of the Goulburn Graben, targeting Palaeozoic reservoirs based on the results of Arafura-1. An increase in Devonian reservoir quality, in comparison to Arafura-1, was expected at this location. The intersected sediment is coarser but there is a negligible difference between two units in porosity, with both being low-quality reservoirs. Three hydrocarbon-bearing intervals were intersected with numerous dead oil and bitumen occurrences: Arafura Group sandstone, Goulburn Group limestone and Goulburn Group dolomite. The lack of live oil and gas shows has been attributed to a lack of fault seal, with leakage during the Triassic structuring event. Subsequent deposition of the Bathurst Island Group provides a high-quality seal which has not been penetrated by faults. This indicates that any late expulsion would be trapped in the structure. A summary of the well analysis is given in Table 4.8.

Table 4.8: Goulburn-1 well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY									
WELL	**SHOWS**	**TARGETS** P = Primary S = Secondary	**STRUCTURE**	**RISK ELEMENTS**					
				STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	**COMMENTS**
Goulburn 1	Oil shows	P Devonian	Fault block	Low Risk	Medium Risk	Low Risk	High Risk	Low Risk	Fault leakage, lack of seal
	Oil indications	S Ordovician	Fault block	Low Risk	Medium Risk	Low Risk	High Risk	Low Risk	Fault leakage, lack of seal

LEGEND

- **Low Risk** (green)
- **Medium Risk** (orange)
- **High Risk** (red)

4.5 KULKA-1

Kulka-1 is located in the northwestern Goulburn Graben (Table 4.9 and Figures 4.28). The well was the first well drilled by Diamond Shamrock/Western Mining Corp. in permit NT/P34 The well penetrated a thick Mesozoic and Permo-Carboniferous section .

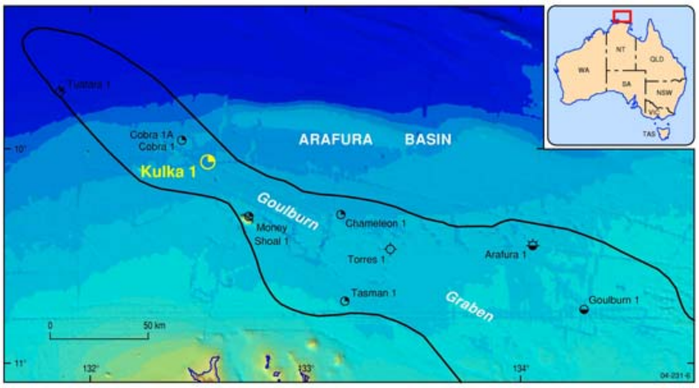


Figure 4.28: Kulka-1 well location.

The primary objective was to locate Palaeozoic targets in a faulted anticline. Numerous oil indications were encountered and are either the result of migration or in-situ generation from the Permo-Carboniferous. The targets failed due to a lack of seal, sufficient reservoir and possibly charge. The secondary targets, Mesozoic sediments, contain good-quality reservoirs and seals but lack structural closure.

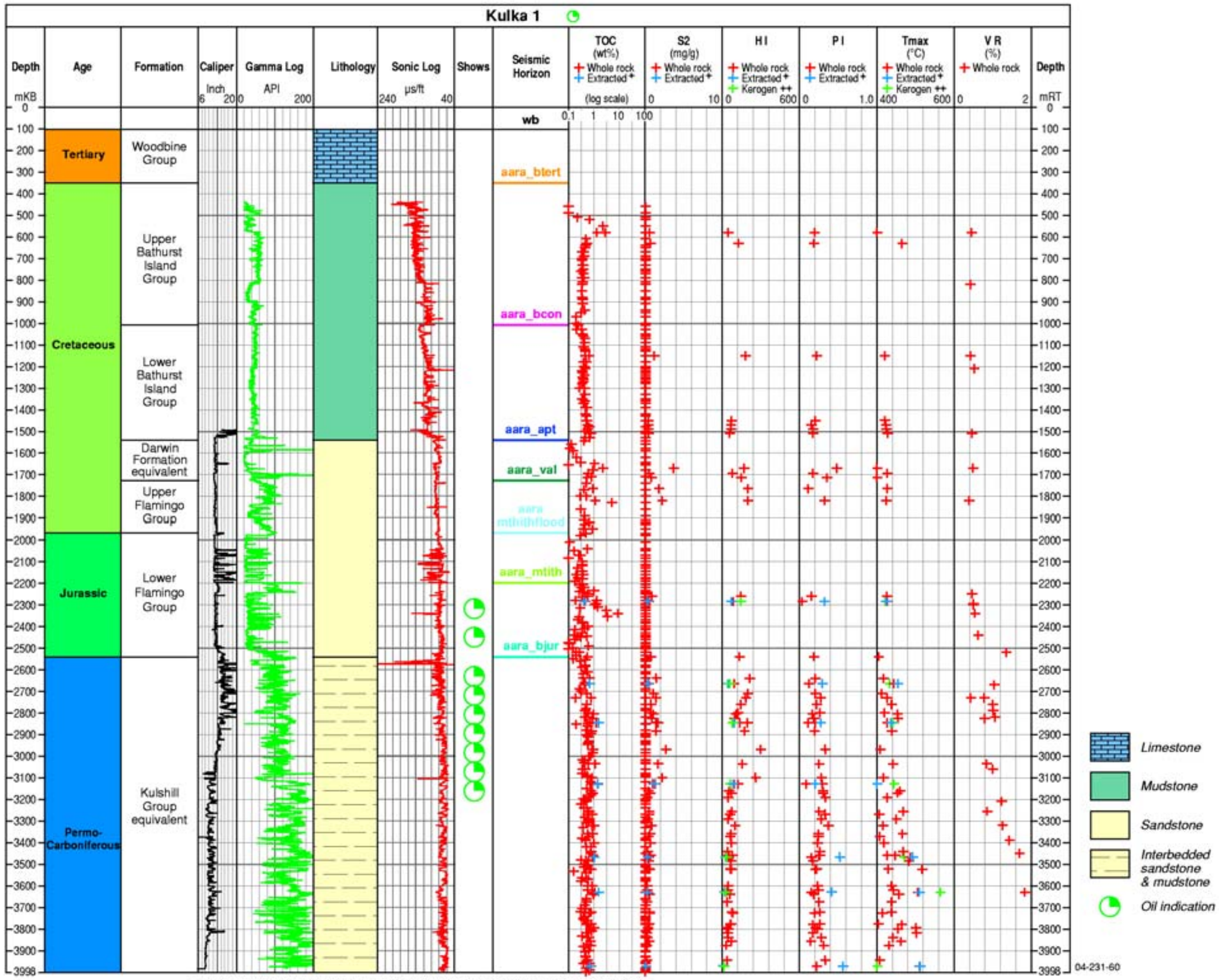
Table 4.9: Kulka-1 well summary.

Uno	W8840003
Latitude	10° 3' 40.92" S
Longitude	132° 32' 44.75" E
Operator	Diamond Shamrock Oil Co (Aust)
Year	1984
Permit:	NT/P34
Water Depth (m)	77
TD (mKB)	3998
TD Age	Carboniferous
KB (m)	26
Status	P & A
Hydrocarbon Shows	Oil indications
Play Type/Trap	Faulted anticline
Primary Objectives	Permo-Carboniferous (Kulshill Group equivalent) and Devonian (Arafura Group)
Secondary Objectives	Mesozoic

STRATIGRAPHY

Kulka-1 penetrated Tertiary (Woodbine Group), Cretaceous (Bathurst Island Group, Darwin Formation equivalent and Upper Flamingo Group), Jurassic (Lower Flamingo Group) and Permo-Carboniferous (Kulshill Group equivalent) sediments (Figure 4.29).

The Bathurst Island Group is dominantly composed of claystones with minor sandstone/mudstone interbedding and overlies sandstones of the Darwin Formation.



\+ Extracted data is equivalent to solvent extraction of whole rock to remove S1

++ Kerogen data is mineral matter removed from extracted rock with strong acid to obtain more reliable HI & Tmax data

Figure 4.29: Kulka-1 well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

The Upper Flamingo Group consists of sandstones with interbedded mudstones. The lower Flamingo Group comprises blocky sands with up to 1 m thick coal seams (Diamond Shamrock, 1985).

The Kulshill Group equivalent sediments are interbedded sandstones and mudstones with minor coal deposited in fluvio-deltaic to shallow marine environments. Pre-drill, it was suggested that the well would intersect Permo-Carboniferous clastics overlying Devonian carbonates but no Devonian section was penetrated. Igneous activity is evidenced by a dolerite of Permo-Carboniferous age, intersected between 2555-2578 m.

STRUCTURE

Kulka-1 tested a large faulted anticline in the north western part of the Goulburn Graben (Figure 4.31 and 4.32). The structure was mapped to have closure on a northwest trend in sediments of Palaeozoic age with the principal objectives being Carboniferous and Devonian clastics/carbonates (Figure 4.30) (Diamond Shamrock, 1985). No Devonian was intersected and the primary targets are all within Permo-Carboniferous sediments. Secondary objectives were possible accumulations in stratigraphic traps in the Mesozoic sequence but there is no closure at this level.

SOURCE

Kulka-1 intersected a number of organic-rich intervals including: the Darwin Formation equivalent (<0.5-2.2% TOC), Upper Flamingo Group (<0.5-4.9% TOC) and Lower Flamingo Group (<0.5-8.3% TOC). The Kulshill Group equivalent also contains rocks with fair to good source potential with a TOC range of <0.5 to >50% TOC. The Mesozoic intervals are all immature for hydrocarbon generation whereas the Kulshill Group equivalent is immature to overmature for oil generation (based on vitrinite reflectance data) (Figure 4.33).

There is a clear offset in vitrinite reflectance between the Mesozoic and Palaeozoic intervals indicating that the Palaeozoic section has undergone deeper burial in the past. This is also evident in the low HI values of the section, indicating past generation.

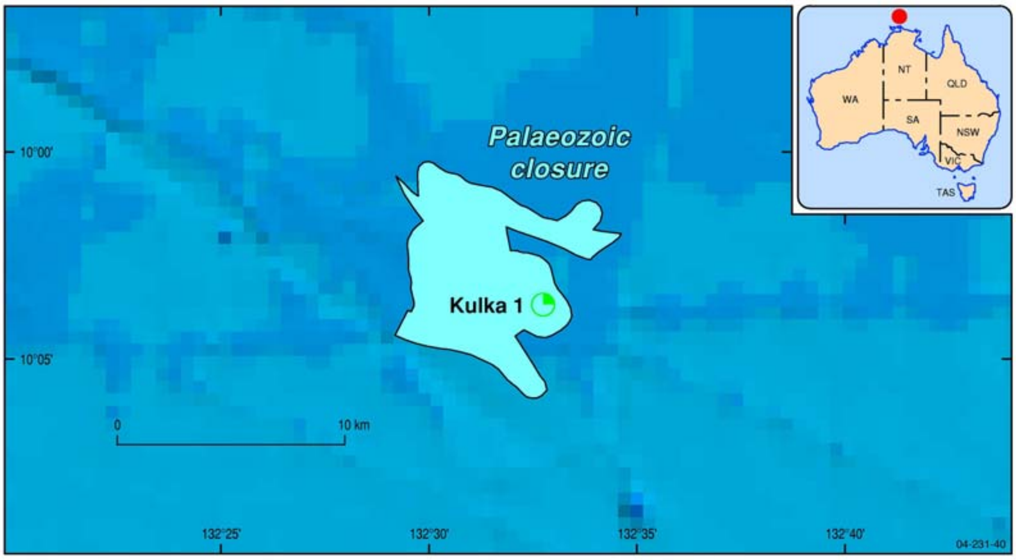


Figure 4.30: Kulka-1 prospect closure (Diamond Shamrock, 1985).

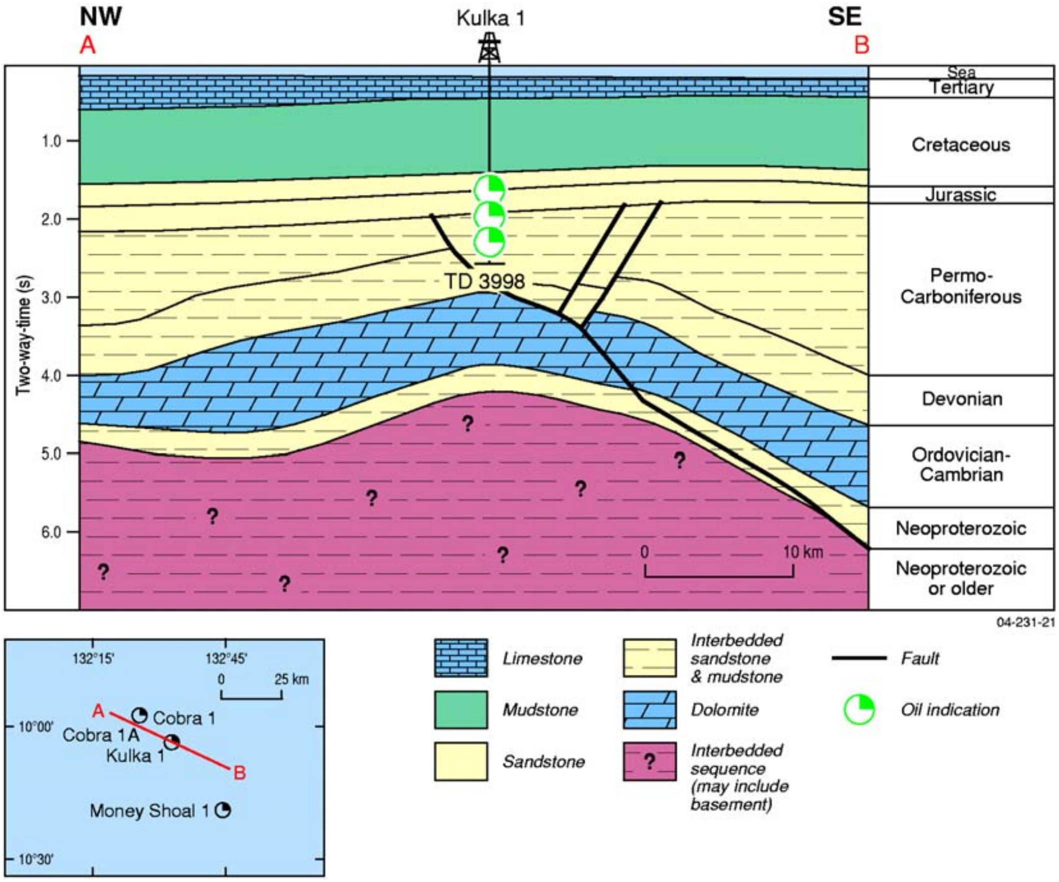


Figure 4.31: Simplified geological cross-section for Kulka-1.

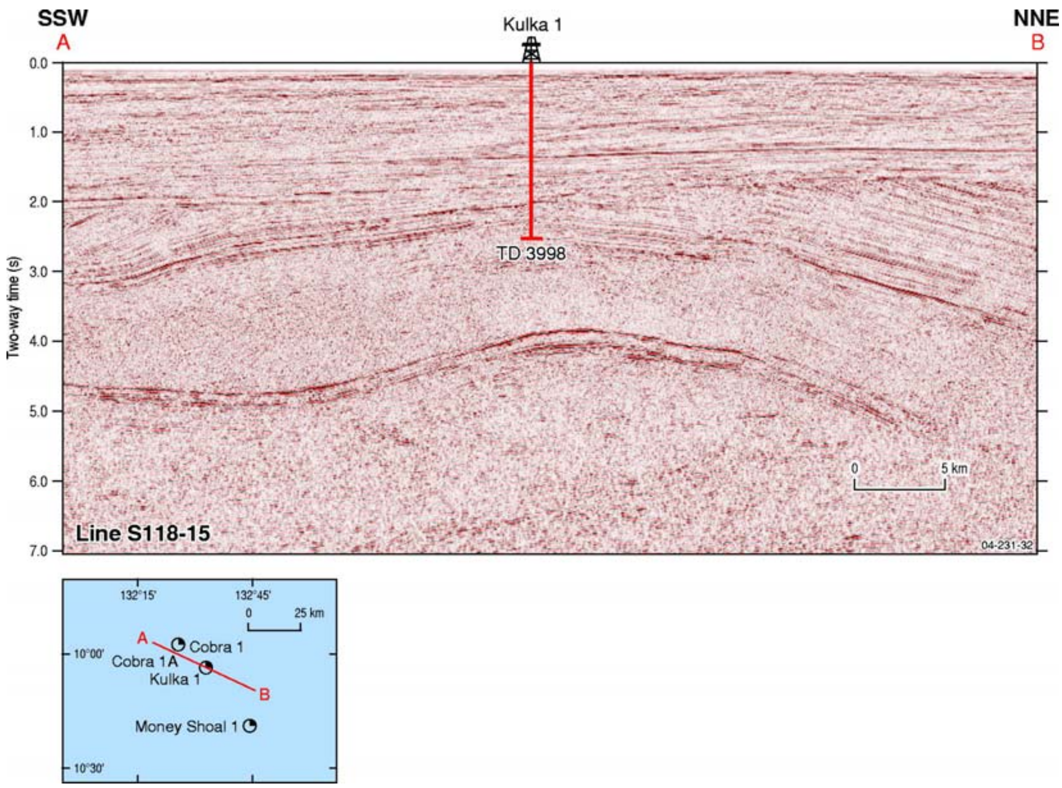


Figure 4.32: Seismic cross-section for Kulka-1.

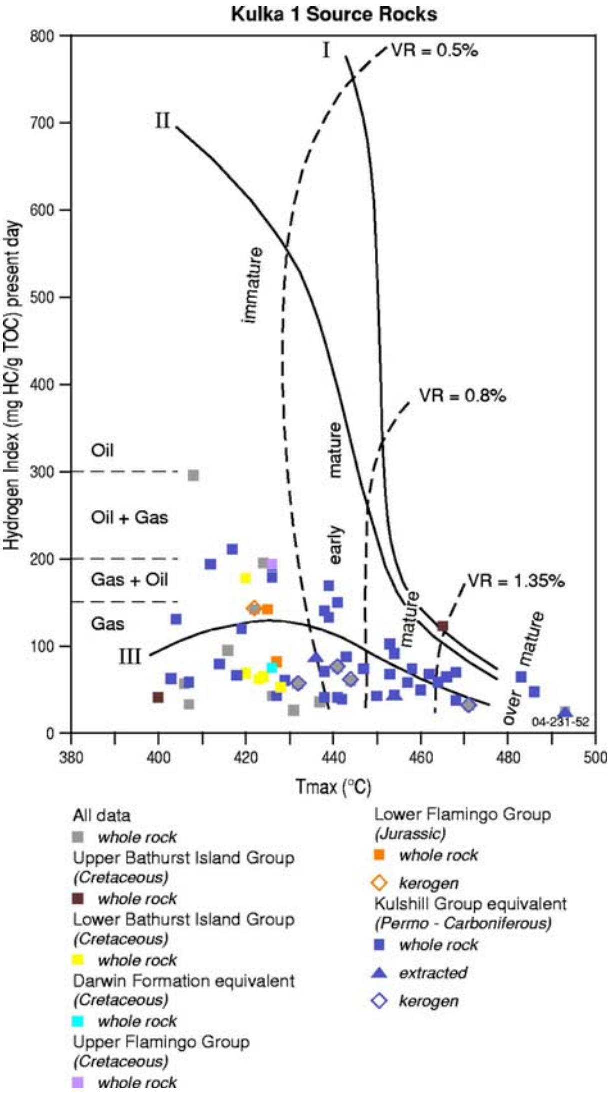


Figure 4.33: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Kulka-1. Note: data has been edited for reliability where coloured data points are deemed to be reliable and unreliable data are shown in grey ("all data").

RESERVOIR

The Mesozoic sediments have excellent reservoir characteristics with high porosities in the sand-rich sections. The Cretaceous Darwin Formation equivalent is composed of a thick coarse-grained sandstone unit with average porosities of approximately 25%. The Cretaceous Upper Flamingo Group is also sand-rich with some siltstone and claystone interbeds. Despite the fine-grained nature of the sands the unit has an excellent porosity of approximately 19%. The Jurassic Lower Flamingo Group is composed of blocky sands interbedded with claystones, siltstones and minor shales. Porosity averages 17.5%.

The Palaeozoic section marks a decrease in reservoir quality. The Permo-Carboniferous interval is composed of a heavily interbedded sequence of very fine-grained sandstones, siltstones and silty claystones. There is a lack of significant sandstone bodies throughout the section and porosity averages 4%. "Severe silica and carbonate cementation has reduced the porosity and permeability of the Palaeozoic sandstones to such an extent that fluid movement would be unlikely" (Diamond Shamrock, 1985, p.28). Labutis et al. (1992) suggested that washouts within the section beneath the dolerite sill could be related to sandstone sections with reasonable porosity. It is not possible to confirm this, but data in the well completion report indicate that the wash-outs were in shalier intervals, not sand-rich sections.

SEAL

Seal is a major risk for the Palaeozoic target. The Palaeozoic section lacks good sealing intervals, with a very heterogeneous succession. The overlying Mesozoic section is very sandy. The best sealing interval in the well is the Cretaceous (Lower Bathurst Island Group) section, which is predominantly claystone with interbedded quartz sandstones and siltstones. This interval is thick with a consistent composition but does not directly overlie the main well objectives.

HYDROCARBON SHOWS

No significant hydrocarbon occurrences were encountered. Numerous oil indications were found in the Jurassic (Lower Flamingo Group) and the Permo-Carboniferous (Kulshill Group equivalent) sections. Possible recent expulsion from the Kulshill Group equivalent on the flanks of the structure could be the source of the hydrocarbon indications (H. Struckmeyer, Geoscience Australia pers comm. – 14/6/2005). The hydrocarbons could also be generated in-situ, from coals in the Lower Flamingo Group and/or carbonaceous claystones in the Kulshill Group equivalent. No repeat formation tests or drill stem tests were carried out.

POST-DRILL ANALYSIS

Kulka-1 was drilled to test the potential of Palaeozoic reservoirs in a faulted anticline. However, the Permo-Carboniferous section is thicker than anticipated and the Devonian was not intersected. No significant hydrocarbons were encountered but numerous oil indications were observed in the Permo-Carboniferous (Kulshill Group equivalent) and, to a lesser extent, the Jurassic (Lower Flamingo Group). The Kulshill Group equivalent is a low quality reservoir, with no thick sand beds, and cementation destroying pre-existing porosity and permeability at this location. It is likely that all of the hydrocarbon indications in the well have been sourced from the Kulshill Group equivalent section, either locally or from the flanks of the anticline. Due to the lack of porosity and permeability, fluid movement within the Kulshill Group equivalent would be restricted and could be the reason for the lack of significant hydrocarbons. The well is assessed as having failed due to a lack of good reservoir and seal in the Palaeozoic. Well analysis is summarised in Table 4.10.

Table 4.10: Kulka-1 well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY									
WELL	**SHOWS**	**TARGETS** **P = Primary** **S = Secondary**	**STRUCTURE**	**RISK ELEMENTS**					
				STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	**COMMENTS**
Kulka 1	Oil indications	P Permo-Carb	Fault roll-over	Low	High	Low	High	Medium	No suitable reservoir or seal
	NA	P Devonian	NA	NA	NA	NA	NA	NA	No Devonian intersected
	Oil indications	S Mesozoic	Stratigraphic	High	Low	Low	Low	Medium	No structural closure

LEGEND

Low Risk	green
Medium Risk	orange
High Risk	red

4.6 MONEY SHOAL-1

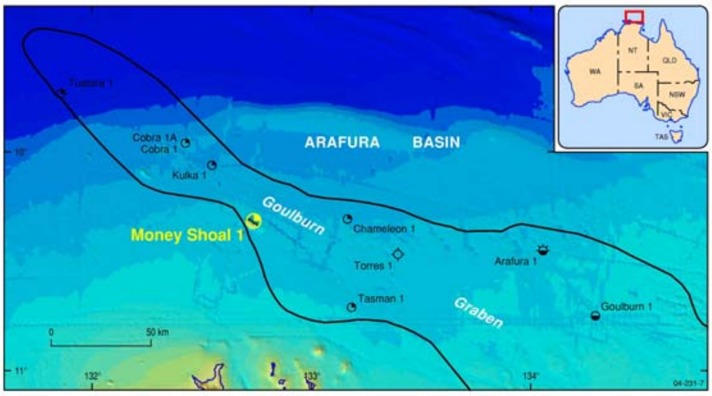


Figure 4.34: Money Shoal-1 well location.

Money Shoal-1 (1971) was the first well drilled in the Arafura Basin and was important for establishing the stratigraphy of the region (Table 4.11). The well (Figure 4.34) was drilled by Shell Development in permit NT/P20, straddling the western Goulburn Graben. The well intersected a dominantly Mesozoic section, targeting Cretaceous sands in a faulted anticline. Despite the good quality reservoir, the only hydrocarbon indications in the well occurred in the Jurassic section. This could be due to a lack of charge into the structure or leakage due to fault/seal breach.

Table 4.11: Money Shoal-1 well summary.

Uno	W8710003
Latitude	10° 18' 57.84" S
Longitude	132° 44' 12.70" E
Operator	Shell Development (Australia) Pty. Ltd.
Year	1971
Permit:	NTP/20
Water Depth (m)	69
TD (mKB)	2590
TD Age	Permian
KB (m)	10
Status	P & A
Hydrocarbon Shows	Oil indications
Play Type/Trap	Anticline
Primary Objectives	Lower Cretaceous Sandstone (Upper Flamingo Group)
Secondary Objectives	Upper Cretaceous Sandstone (Bathurst Island Group)

STRATIGRAPHY

Money Shoal-1 provided the first stratigraphic information for the Money Shoal and Arafura Basins. The well intersected sediments of Tertiary (Woodbine Group), Cretaceous (Bathurst Island Group and Upper Flamingo Group), Jurassic (Lower Flamingo Group and Troughton Group equivalent) and Permian (Kulshill Group equivalent) age (Figure 4.35).

The Money Shoal Basin sediments are approximately 2490 m thick and consist of clastic sediments deposited in mostly shallow marine shelf environments.

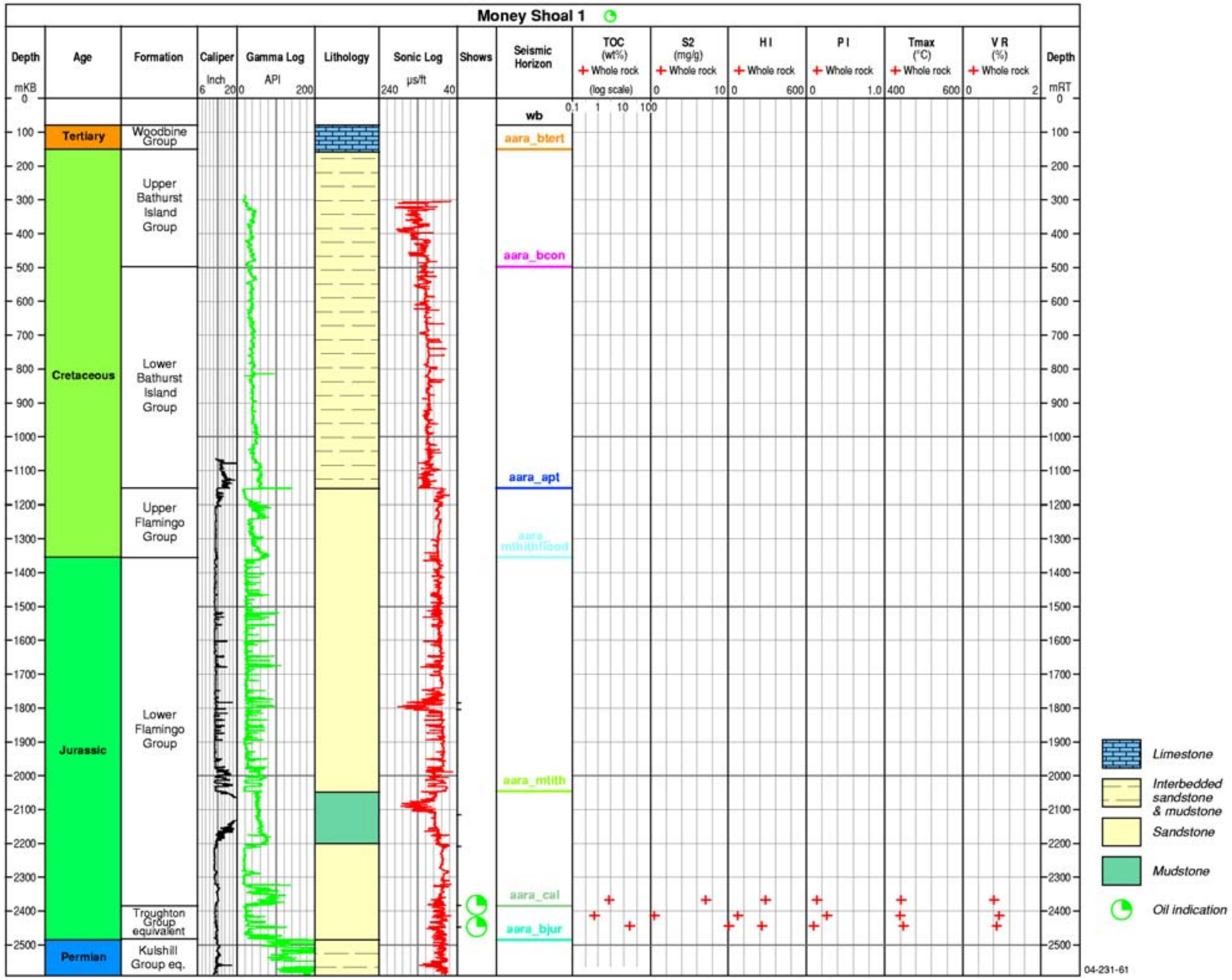


Figure 4.35: Money Shoal-1 well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

The Bathurst Island Group is composed of interbedded sandstones and mudstones with some coals. Down section the material becomes more claystone-rich. The fluvio-deltaic Upper Flamingo Group comprises two cycles of regressive sands (roughly 100 m thick each). The Jurassic Lower Flamingo Group is characterised by a thick section of stacked channel sands with mudstone interbeds. The Lower Flamingo Group is composed dominantly of a large sandstone unit with mudstone beds. The Troughton Group equivalent is composed of fluvial sandstones with minor coals and some mudstone interbeds.

The Arafura Basin sediments (Kulshill Group equivalent) intersected at the base of the well are less than 150 m thick and consist of interbedded mudstones and sandstones with weathered igneous material. The section has undergone hydrothermal alteration with quartz overgrowths.

STRUCTURE

Money Shoal-1 drilled a faulted Cenozoic-Mesozoic anticline above a faulted Palaeozoic anticline (Figures 4.37 and 4.38). The Palaeozoic structure has undergone extensive hydrothermal alteration. This created a zone of weakness that resulted in the development a valley system (approximately 30 km wide) in the Triassic. The valley was subsequently filled by Jurassic sedimentation. Compression during the Late Cretaceous to Cenozoic resulted in the formation of a domal structure. This movement has continued to the present day, with the anticlinal structure affecting the sea bed. Late formed (Cretaceous to Tertiary) normal faults cut the crest of the structure.

The primary targets for Money Shoal-1 were Cretaceous (Upper Flamingo Group) reservoir rocks capped by Cretaceous (Lower Bathurst Island Group) shales. The closure for this prospect is shown in Figure 4.36. A secondary target was the Bathurst Island Group. There was no structural closure at the near-base Jurassic.

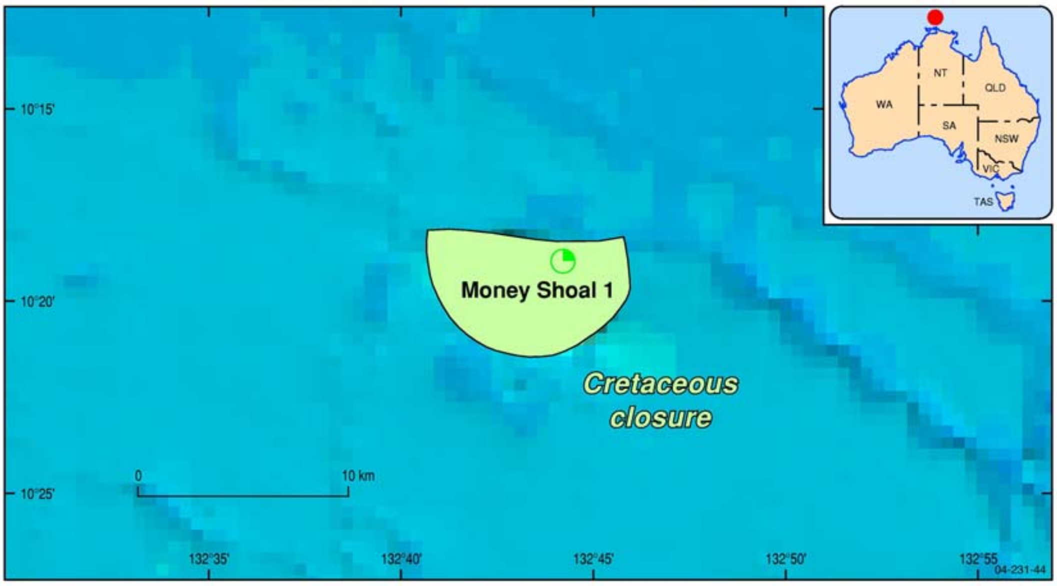


Figure 4.36: Money Shoal-1 prospect closure (Shell, 1971).

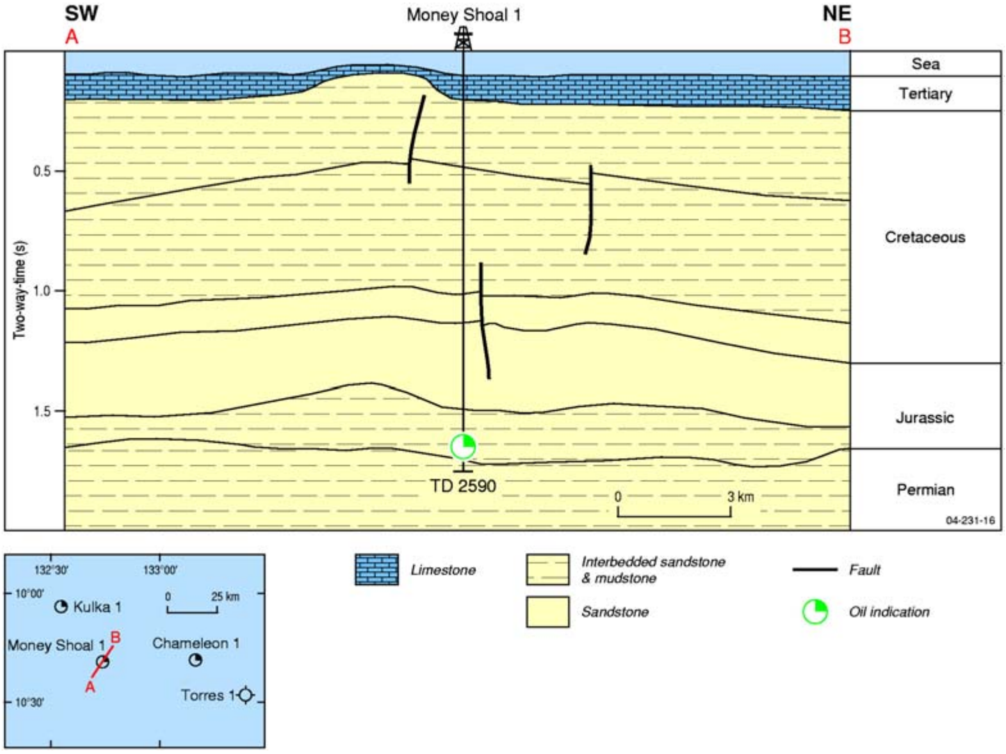


Figure 4.37: Simplified geological cross-section for Money Shoal-1.

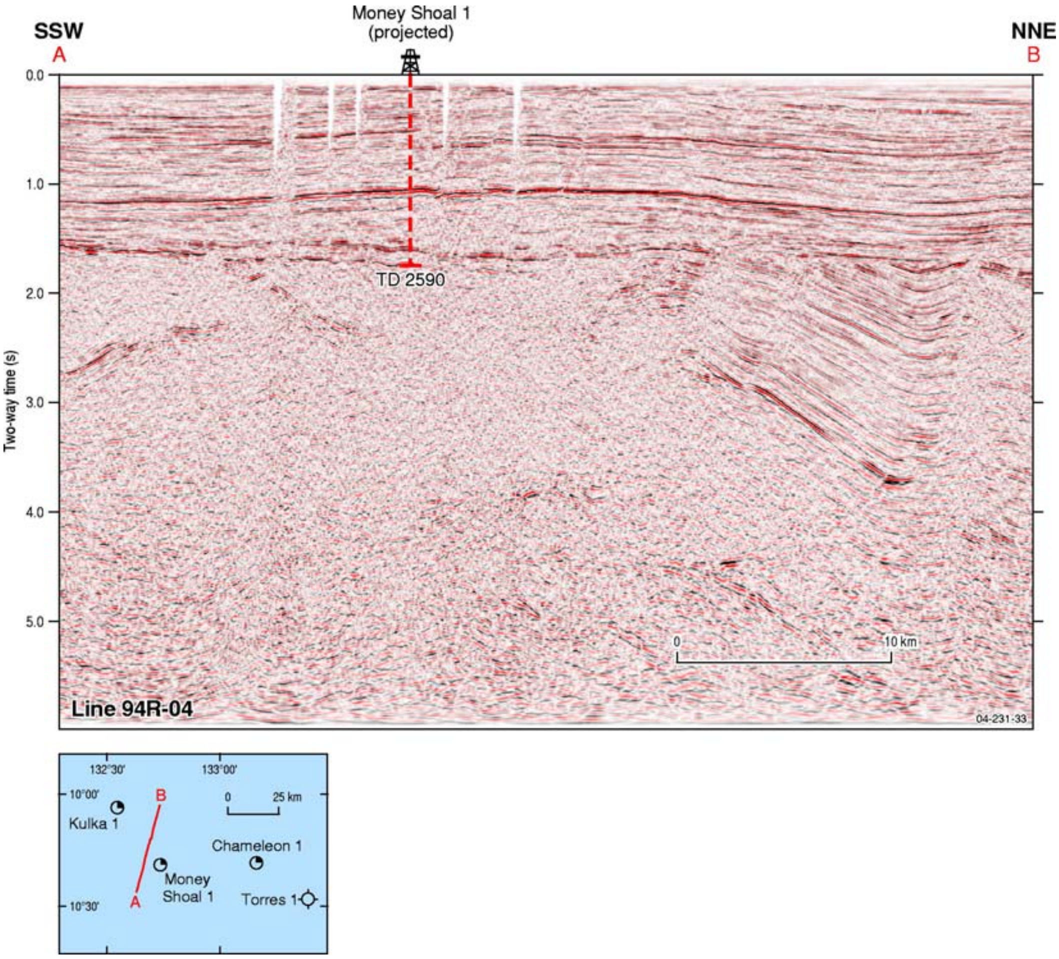


Figure 4.38: Seismic cross-section for Money Shoal-1.

RESERVOIR

Mesozoic sediments intersected at Money Shoal-1 contain thick sand-rich intervals and generally have excellent reservoir potential. The Cretaceous Bathurst Island Group is comparatively sandy with interbedded mudstones and increasing sand content up section. Sandstones of the Upper Flamingo Group have porosities averaging 18.5%. The Lower Flamingo Group contains blocky sandstones with an average porosity of 17.5%. Sandstones of the Troughton Group have an average porosity of 12% and contain the only hydrocarbon indications in the well.

The Palaeozoic section (Permian Kulshill Group equivalent) shows a marked decrease in reservoir quality with no thick sandstone intervals and quartz overgrowths related to hydrothermal alteration destroying porosity. The unit is fractured with carbonate cements infilling the fractures.

SEAL

The primary Cretaceous target (Upper Flamingo Group) is sealed by Cretaceous mudstones (Lower Bathurst Island Group). The interval is not vertically extensive, at less than 100 m, but has a homogenous composition. Above this, the unit becomes increasingly sandy. The Upper Flamingo Group also contains interbedded mudstones which could provide intraformational seals. The secondary Cretaceous target (Bathurst Island Group) lacks a sealing interval.

Two Jurassic Lower Flamingo Group seals were intersected at this location. The upper claystone has better sealing potential as it is approximately 150 m thick and homogenous. The lower claystone is a less effective seal as it has a more heterogeneous composition and is thinner (at approximately 50 m).

Fault breach through Late Cretaceous to Tertiary normal faulting on the crest of the anticline provides a risk in addition to a low-quality regional seal at this location.

SOURCE

Very few data related to source rock quality are available for Money Shoal-1 (Figure 4.39) although some data from the Jurassic Lower Flamingo Group and the Troughton Group equivalent suggest good to very good source potential with TOC values up to 2.5% and 61%, respectively. The high value for the Troughton Group equivalent reflects the coaly nature of the sand-dominated sediments. The intervals are early mature to mature for hydrocarbon generation (Figure 4.39).

The underlying Permian Kulshill Group equivalent could contain mature source rocks but no data is available at this location.

HYDROCARBON SHOWS

Money Shoal-1 did not encounter any significant hydrocarbons. Oil indications were found in the Jurassic section (Troughton Group equivalent) and were probably generated in-situ or from the underlying Permian (Kulshill Group equivalent). All other porous intervals were water saturated. No repeat formation tests or drill stem tests were carried out.

POST-DRILL ANALYSIS

Money Shoal-1 is historically important as it provided the first information about the region and its prospectivity. The well established the Money Shoal Basin stratigraphy as it intersected a dominantly Mesozoic succession. The Mesozoic sands provide excellent quality reservoirs at this location. The well was also the first to intersect Arafura Basin sediments, a thin interval of Permian Kulshill Group equivalent. At this location the section does not have reservoir potential due to hydrothermal alteration.

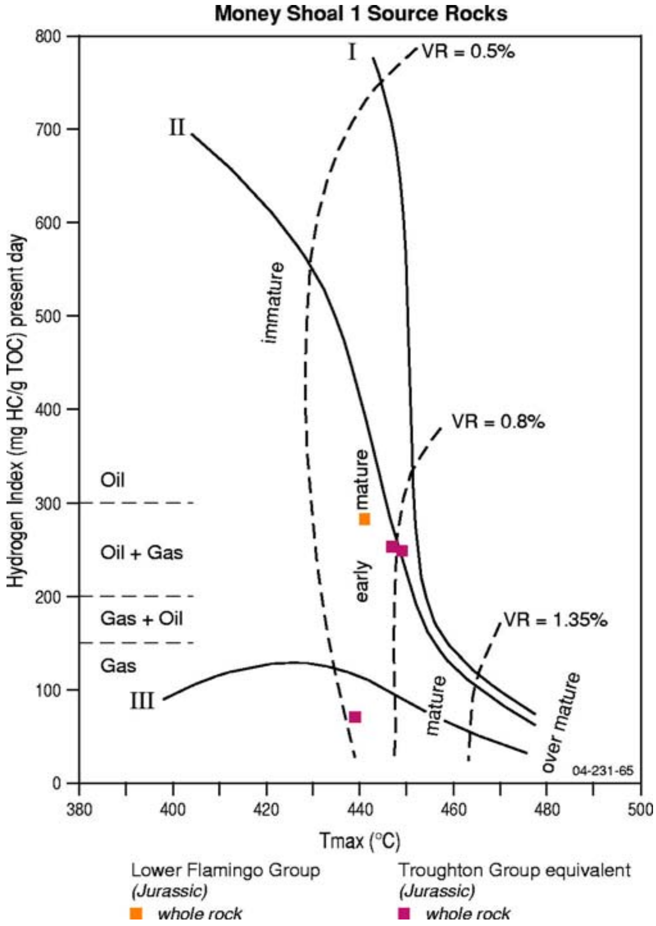


Figure 4.39: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Money Shoal-1.

The well did not encounter significant hydrocarbons, but has some minor oil indications in the lower Troughton Group equivalent. The section lacks organic-rich sediments but contains minor coals. Thus, sourcing could be in-situ with the oil indications representing the early stages of generation from minor carbonaceous layers. Alternatively the oil indications could be sourced from the underlying Kulshill Group equivalent.

The failure of the primary target could be due to fault or seal breach, with late formed faults cutting the crest of the structure and a sandy Bathurst Island Group seal. There is no evidence of hydrocarbon migration through the section so a lack of charge is also likely. A summary of the well analysis is given in Table 4.12.

Table 4.12: Money Shoal-1 well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY									
WELL	SHOWS	TARGETS P = Primary S = Secondary	STRUCTURE	RISK ELEMENTS: STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	COMMENTS
Money Shoal 1		P Lower Cretaceous	Anticline	Low Risk	Low Risk	Medium Risk	Medium Risk	Medium Risk	Possible fault/seal leakage or lack of charge
		S Upper Cretaceous	Anticline	Low Risk	Medium Risk	Medium Risk	High Risk	Medium Risk	No sealed sand units

LEGEND: Low Risk (green); Medium Risk (orange); High Risk (red)

4.7 TASMAN-1

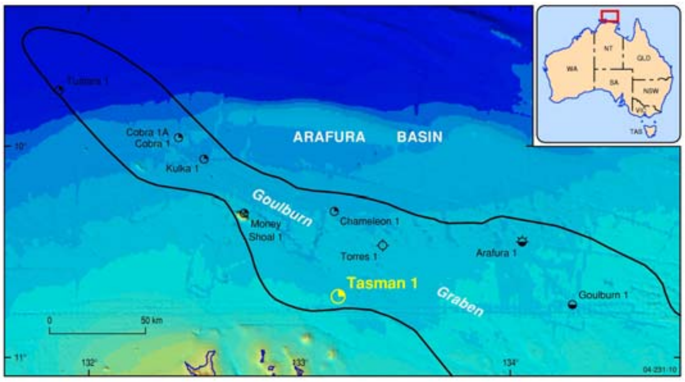


Figure 4.40: Tasman-1 well location.

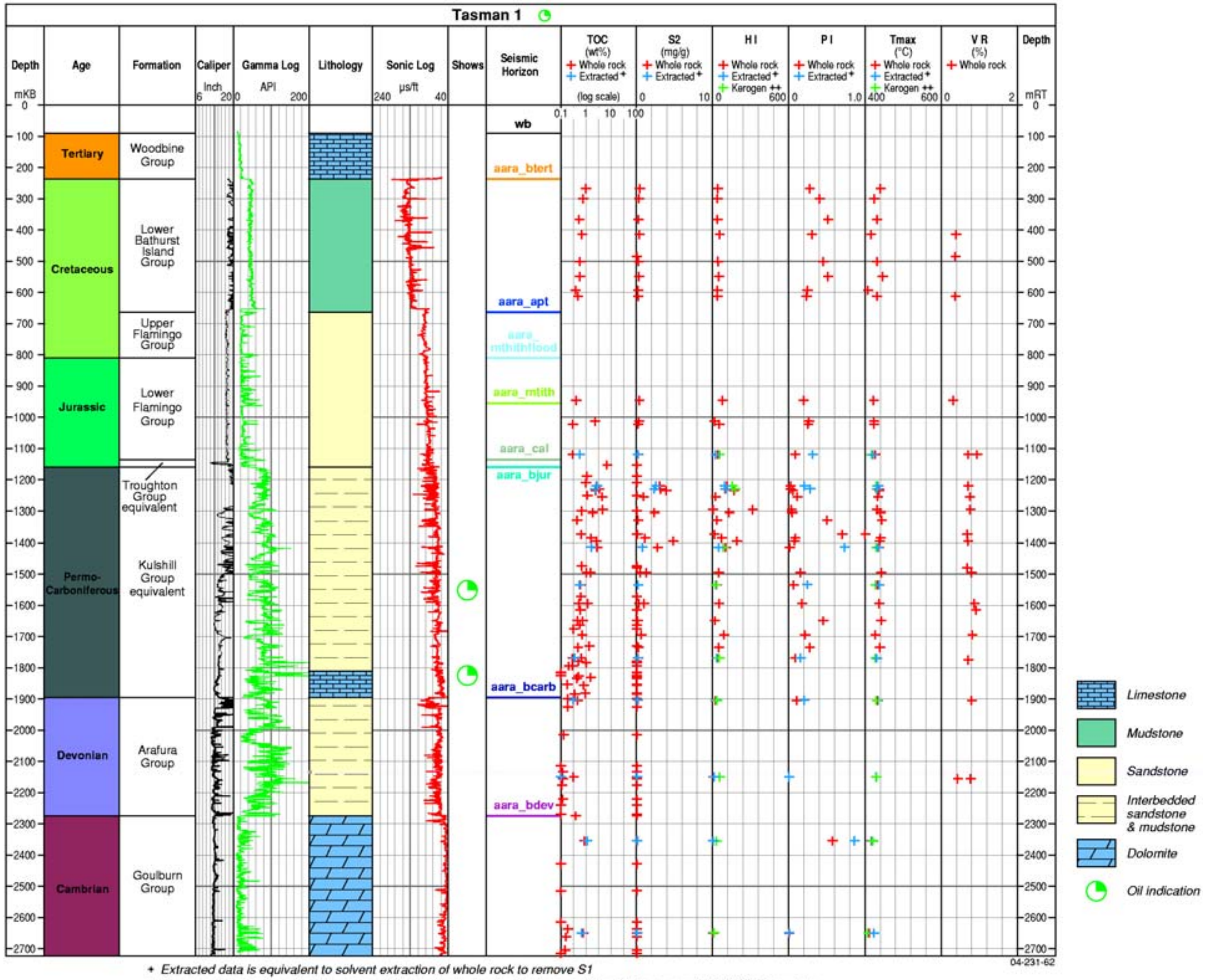
Tasman-1 is located near the southern margin of the Goulburn Graben (Table 4.13, Figure 4.40). The well was drilled by ESSO Australia Limited in permit NTP/35 and was their first well in the region. At the time of drilling Arafura-1 was also being drilled so there was no prior stratigraphic knowledge about the fill of the graben. The well targeted Palaeozoic sediments in a fault block. The target horizon lacked thick sandstone reservoir units and a good sealing interval but oil indications were found in interbedded sandstones, mudstones and limestones. Source rock data indicate that there has not been significant hydrocarbon generation and expulsion at this location but a Cambrian source may underlie the penetrated section. A combination of factors including lack of reservoir, seal and possible hydrocarbon charge, are the reasons for well failure.

Table 4.13: Tasman-1 well summary.

Uno	W8830002
Latitude	10° 42' 40.52" S
Longitude	133° 10' 57.15" E
Operator	ESSO Exploration and Production Australia Inc.
Year	1983
Permit:	NT/P35
Water Depth (m)	65.8
TD (mKB)	2720
TD Age	Cambrian
KB (m)	25
Status	P & A
Hydrocarbon Shows	Oil indications
Play Type/Trap	Fault block
Primary Objectives	Youngest sediments beneath Mid-Jurassic unconformity (Kulshill Group equivalent)
Secondary Objectives	Stratigraphic information

STRATIGRAPHY

Tasman-1 intersected sediments of Tertiary (Woodbine Group), Cretaceous (Lower Bathurst Island Group and Upper Flamingo Group), Jurassic (Lower Flamingo Group and Troughton Group equivalent), Permo-Carboniferous (Kulshill Group equivalent), Devonian (Arafura Group) and Cambrian (Goulburn Group) age (Figure 4.41).



\+ Extracted data is equivalent to solvent extraction of whole rock to remove S1

++ Kerogen data is mineral matter removed from extracted rock with strong acid to obtain more reliable HI & Tmax data

Figure 4.41: Tasman-1 well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

The Money Shoal Basin sediments are dominated by shallow-marine clastics. The Woodbine Group is composed of limestones and claystones. These are underlain by the Lower Bathurst Island Group claystones. The Flamingo Group comprises fluvial sandstones with minor mudstone interbeds and coal (in the lower section). The Troughton Group equivalent is also sand-rich with minor coal.

The Arafura Basin sediments are a mixed succession of clastics and carbonates. The Kulshill Group equivalent is composed of interbedded sandstones and mudstones, with minor coals and limestones towards the base of the section. They were deposited in fluvio-deltaic to shallow marine environments. The Arafura Group consists of interbedded sandstones and mudstones in shallow-marine to non-marine environments. The Goulburn Group is composed of shallow-marine dolomites.

STRUCTURE

The Tasman-1 prospect was originally interpreted as a salt-related domal feature along the southern edge of the graben fault. Post-drill analysis concluded that the well was a valid test of an isolated perched fault block against the main graben edge fault, associated with carbonates rather than salt (Figure 4.43 and 4.44). Structuring occurred in the Permo-Triassic and is restricted to the Palaeozoic section. The closure is fault dependant (Esso Australia Limited, 1983a).

The well was primarily designed to test the hydrocarbon potential of the youngest structured sediments (Kulshill Group equivalent) beneath the Mid-Jurassic unconformity (Figure 4.42). The secondary objective was to provide stratigraphic information.

SOURCE

The Jurassic sediments are the only Mesozoic sediments with sufficient organic richness for hydrocarbon generation (Figure 4.45). TOC values range from <0.5% to 6.7% and are related to coaly components, rather than organic-rich mudstones. HI values are low and indicate that the interval has poor source potential. The interval is immature at this location (Figure 4.45)

The 750 m thick Kulshill Group equivalent contains fair to good, mostly coaly potential source rocks with TOC values typically above 1% and up to 6.6%, particularly in the upper part of the section. High Production Index (PI) values, associated with organic-lean intervals with low pyrolysis yields, resulted in data being classified as unreliable and not used in this interpretation.

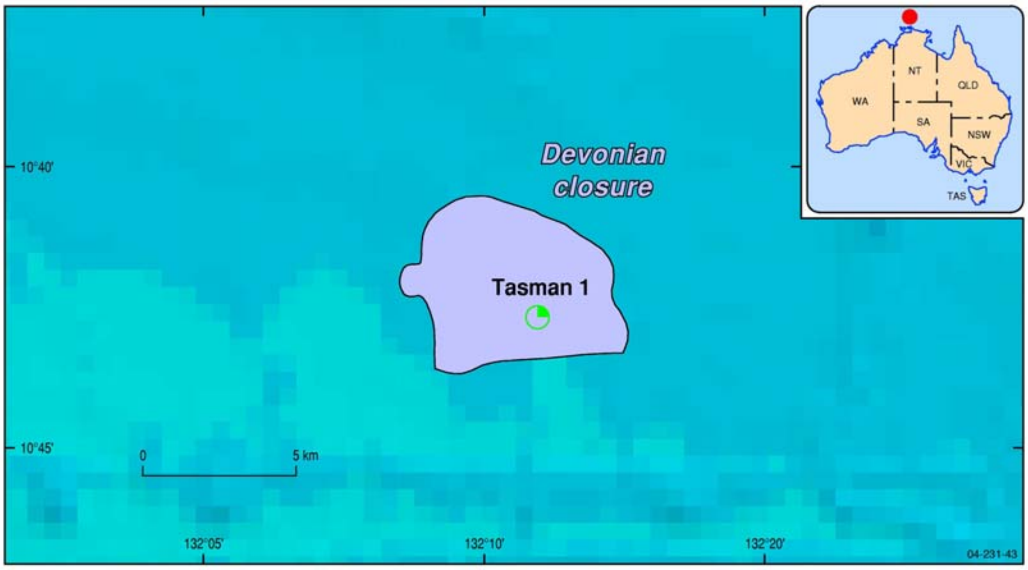


Figure 4.42: Tasman-1 prospect closure (Esso Australia Limited, 1983a).

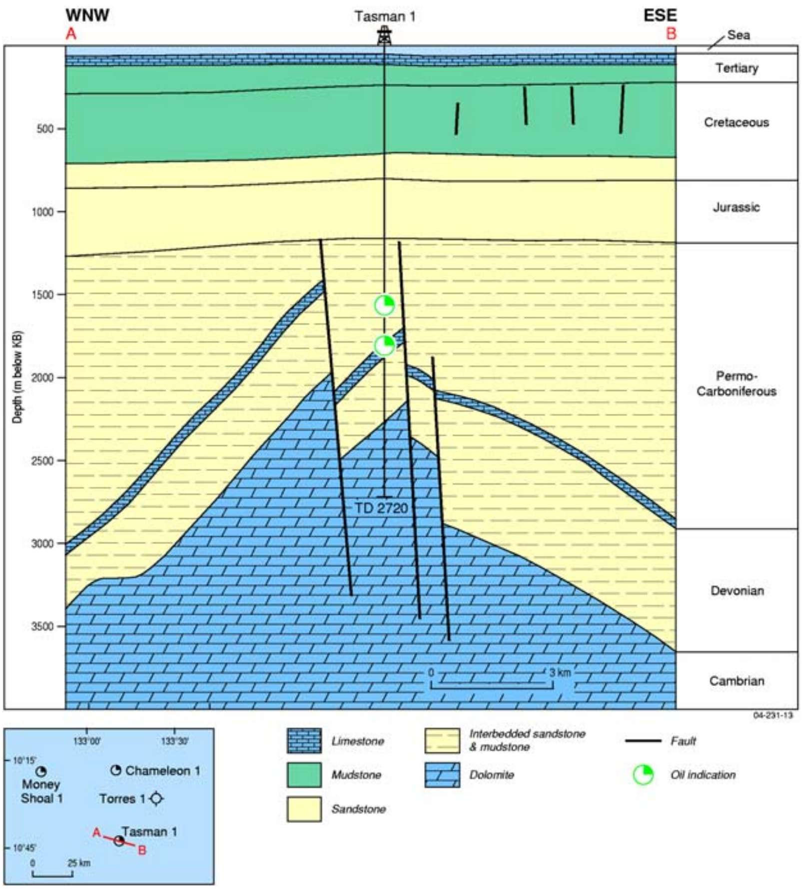


Figure 4.43: Simplified geological cross-section for Tasman-1.

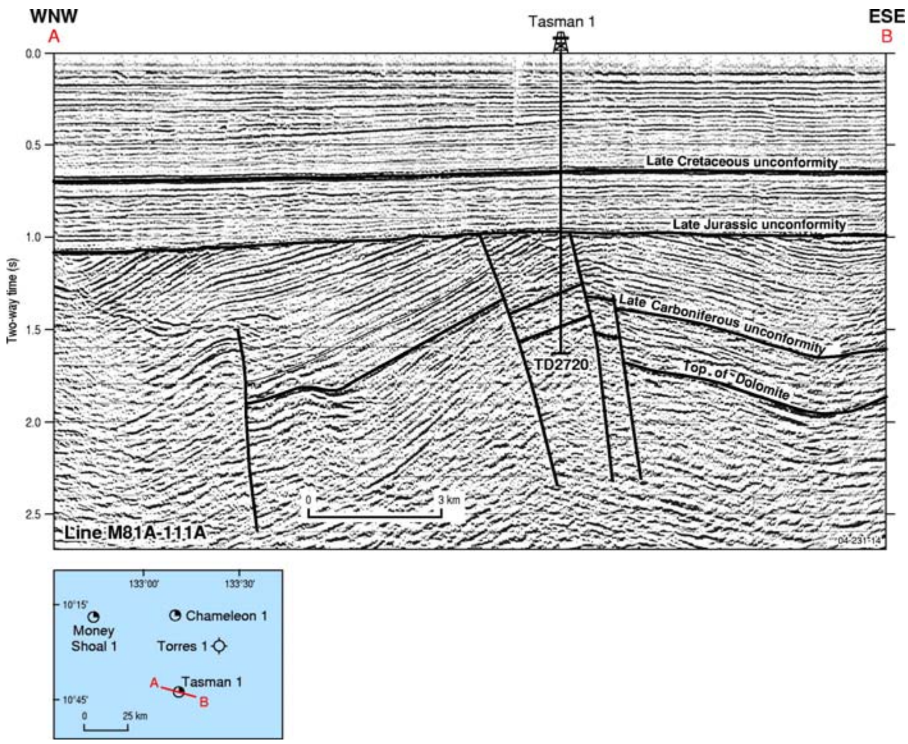


Figure 4.44: Seismic cross-section for Tasman-1 (modified from Esso Australia Limited, 1983a).

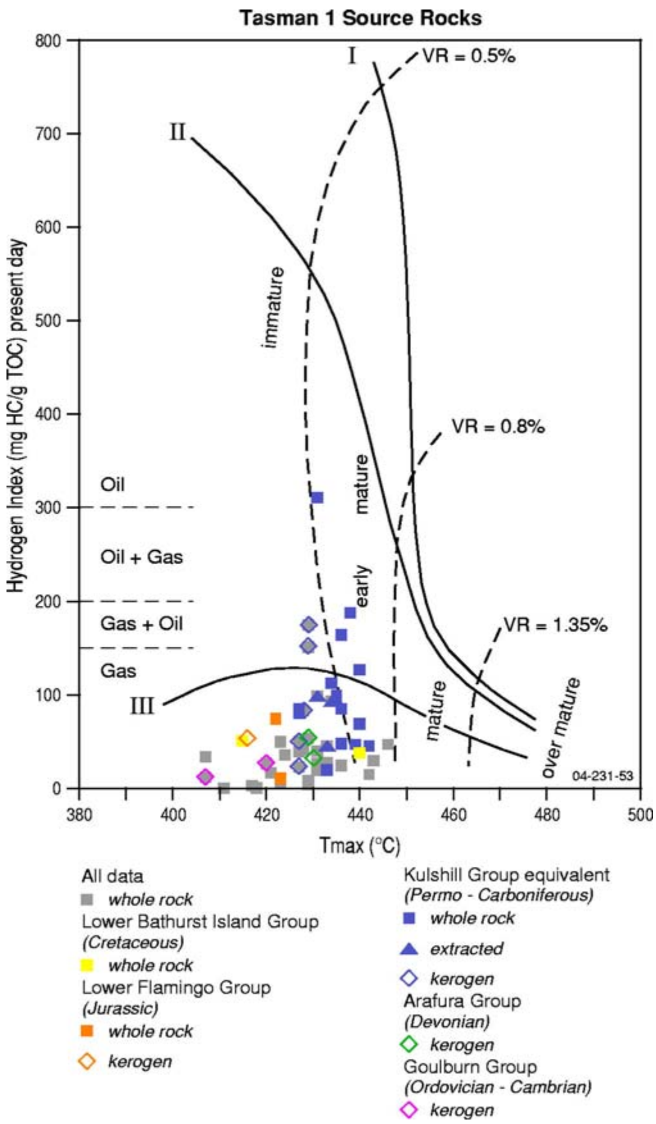


Figure 4.45: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Tasman-1. Note: data has been edited for reliability where coloured data points are deemed to be reliable and unreliable data are shown in grey ("all data"). The VR maturity lines are to be used only as guidelines for units older than the Devonian.

This unit is immature to early mature for hydrocarbon generation (Figure 4.45). Oil indications within the sediments are restricted to two intervals (Figure 4.41) and may be related more to migration than in-situ sourcing. Many of the organic-rich intervals lack any oil indications. Expulsion from an underlying Cambrian source is a possibility.

RESERVOIR

Tasman-1 contains a number of potential reservoir units. The Cretaceous (Upper Flamingo Group) and Jurassic (Lower Flamingo Group and Troughton Group equivalent) are composed of thick sandstone units with minor mudstone interbeds. These units have average porosities of 24-32%. Despite this, the Mesozoic section did not prove to be a viable test due to a lack of structural closure.

The underlying Palaeozoic displays a decrease in reservoir quality. The Permo-Carboniferous (Kulshill Group equivalent) section lacks thick sand intervals. All of the sediments are fine-grained and water-saturated, with porosity averaging 13%. Limestones have poor porosity (with an average of 4%) but are highly fractured, with fractures filled with calcite and oil.

The Devonian (Arafura Group) section is mostly fine-grained and retains little primary porosity, averaging 5%.

The dolomites of the Cambrian (Goulburn Group) interval are very fine-grained and have retained very little primary porosity after diagenesis with an average of 4.5%. The dolomites are fractured, however the fractures have been filled by secondary calcite.

SEAL

The Flamingo and Troughton Group reservoirs are sealed by Cretaceous mudstones (Lower Bathurst Island Group). This unit has a uniform composition of claystones with minor siltstones over a thickness of approximately 400 m, indicating good sealing potential. However the interval lacks structural closure.

Although the Palaeozoic section is mostly fine-grained, the interbedded nature of the sediments suggests a relatively poor seal capacity.

HYDROCARBON SHOWS

The well did not intersect significant hydrocarbons with oil indications within interbedded Permo-Carboniferous limestones and clastics. The oil is interpreted to have been generated in-situ associated with carbonaceous sediments. Three attempts at drill stem tests in the Permo-Carboniferous were mechanically unsuccessful and inconclusive.

POST-DRILL ANALYSIS

The Tasman-1 structure was originally interpreted to be a salt-related anticline feature. Post-drill analysis has concluded that the feature is a raised fault block with carbonates, rather than salt. Tasman-1 was drilled to test the youngest structured sediments beneath the base Jurassic unconformity. It was believed that the shallow nature of the Palaeozoic sediments would optimise the chances of a good-quality reservoir. Well results indicate that while the porosity of the target horizon (Kulshill Group equivalent) is acceptable at 13%, there is a lack of thick sand-rich intervals or good seals intervals. Oil indications were found within the section and are probably locally sourced from early mature sediments, although they could be related to migrated hydrocarbons sourced from older source rocks. There is no evidence of fluid movement through the high-quality reservoirs of the Mesozoic, which lack structural closure at this location. Source rock data indicate that there has not been significant hydrocarbon generation and expulsion from intersected potential source rocks at this locality. Well failure is attributed to a lack of reservoir/seal pairs in the Palaeozoic and a possible lack of significant charge into the structure. A well analysis summary is shown in Table 4.14.

Table 4.14: Tasman-1 well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY									
WELL	SHOWS	TARGETS P = Primary S = Secondary	STRUCTUR	RISK ELEMENTS					
				STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	COMMENTS
Tasman 1	Oil indications	P Palaeozoic	Fault block	Green	Orange	Green	Red	Orange	Lack of good reservoir/seal pairs
		LEGEND	Low Risk	Green					
			Medium Risk	Orange					
			High Risk	Red					

4.8 TORRES-1

Torres-1 is located in the central Goulburn Graben (Table 4.15, Figure 4.46). The well was drilled by ESSO Australia Limited, after Tasman-1, in permit NT/P35 to test a giant anticline along the axis of the graben. Targets included Devonian clastics and Cambrian dolomites. This well was one of the biggest disappointments in the Arafura Basin due to the large size of the structure and the lack of significant shows. The well failure has been attributed to a possible combination of lack of charge/access to migration pathways and poor-quality Palaeozoic reservoirs.

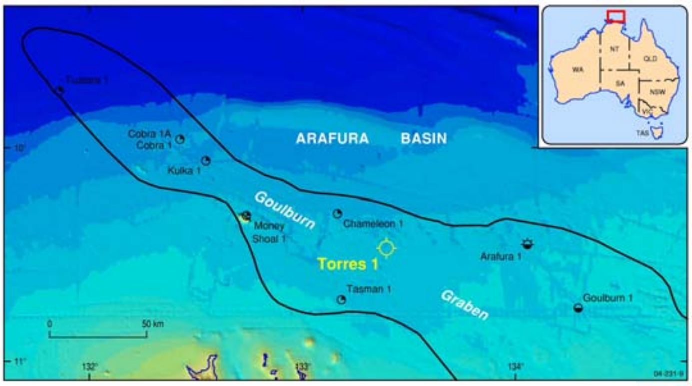


Figure 4.46: Torres-1 well location.

Table 4.15: Torres-1 well summary.

Uno	W8830003
Latitude	10° 28' 6.18" S
Longitude	133° 23' 37.81" E
Operator	ESSO Exploration and Production Australia Inc.
Year	1983
Permit:	NTP35
Water Depth (m)	67
TD (mKB)	2758
TD Age	Cambrian
KB (m)	24
Status	P & A
Hydrocarbon Shows	Traces of gas
Play Types/Trap	Anticline
Primary Objectives	Cambrian (Goulburn Group) and Devonian (Arafura Group)
Secondary Objectives	Stratigraphic information

STRATIGRAPHY

Torres-1 intersected sediments of Tertiary (Woodbine Group), Cretaceous (Lower Bathurst Island Group and Upper Flamingo Group), Jurassic (Lower Flamingo Group), Devonian (Arafura Group) and Ordovician-Cambrian (Goulburn Group) age (Figure 4.47).

The Bathurst Island Group consists mostly of claystones deposited in shelfal environments. These are underlain by deltaic Flamingo Group sandstones. The Flamingo Group probably contains traces of coal, described as “trace black mineral” in the well completion report, as found at other well locations.

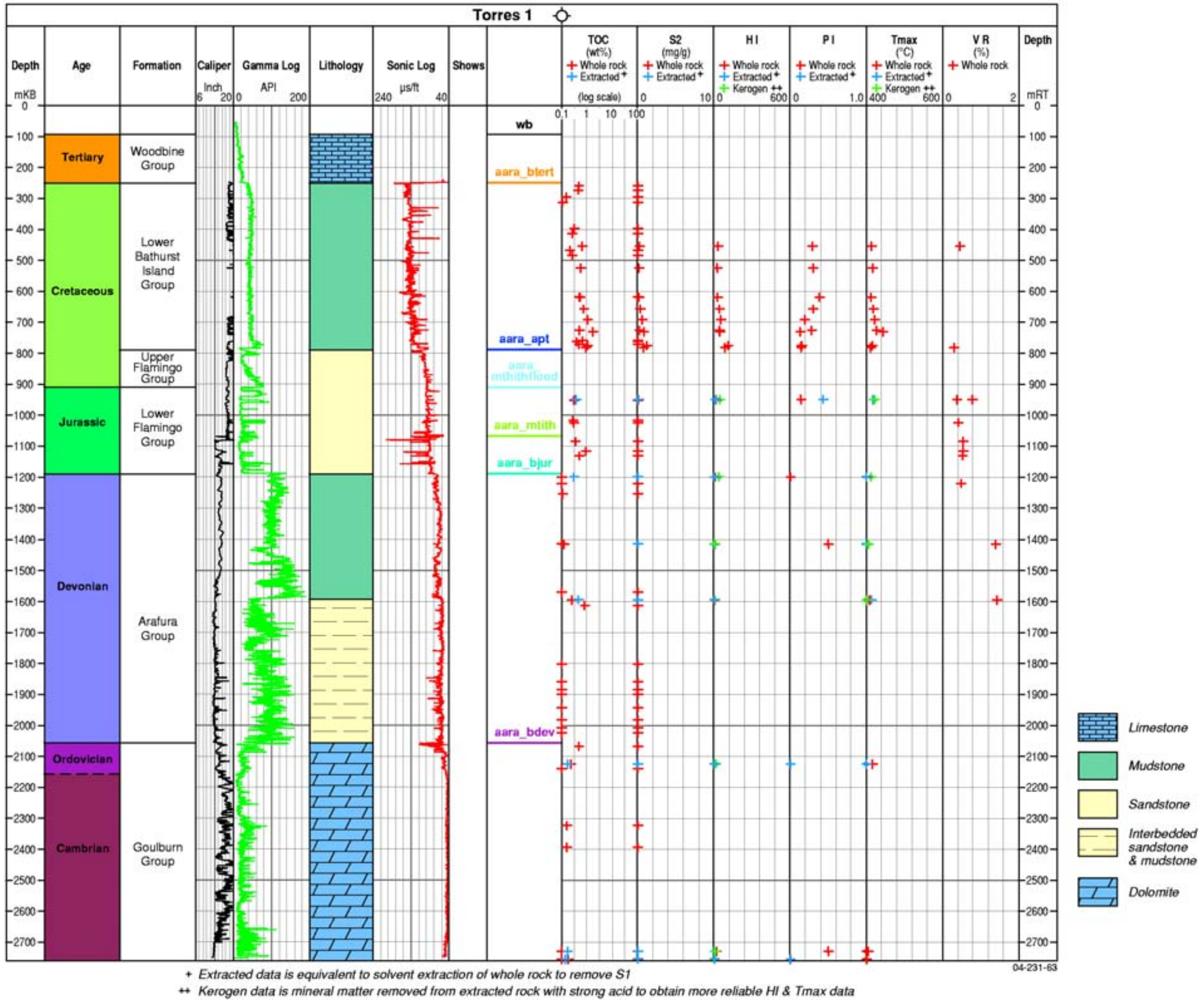


Figure 4.47: Torres-1 well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

The Arafura Group is composed dominantly of non-marine to marginal marine siltstones and sandstones. The Goulburn Group comprises dolomites deposited in a shallow marine environment.

STRUCTURE

The Torres prospect is a broad gentle, east-west trending anticline located along the axis of the Goulburn Graben (Figure 4.49 and 4.50). The areal closure of the structure is 500 km^2 at the Mid-Devonian level (Figure 4.48) (Miyazaki and McNeil, 1998) and fault-dependant, with small faults on the northern, eastern and southern flanks (Esso Australia Limited, 1983b). The anticline formed during Triassic compression which was followed by an erosional episode which stripped approximately 3000 m of sediments from the crest (Esso Australia Limited, 1983b). The subsequently deposited Mesozoic sediments are largely unstructured.

The primary targets of the well were to evaluate the interpreted carbonate section between 2430 to 3650 m (Cambrian dolomite); the clastic section between the Late Jurassic unconformity and the carbonate (1215-2430 m); and beneath the carbonate (3650 m). The second target, interpreted as Devonian age, only extended to 2056 m. The last target was not reached. The secondary objective was to obtain stratigraphic information. The present day structure is interpreted as viable, with no fault re-activation, so any late expelled hydrocarbons would be captured. There is no evidence of a late charge into the structure, with only traces of gas.

SOURCE

The intersected section generally has poor source potential with the exception of the Lower Bathurst Island Group claystones, which have fair potential with TOC values typically between 0.5 and 1.5%. The kerogen is mostly Type III and is immature for hydrocarbon generation (Figure 4.51).

RESERVOIR

The well intersected a number of reservoir rocks of varying quality, with the Mesozoic containing the highest quality reservoirs. The Upper Flamingo Group is composed of a well sorted regressive sand sequence, with an average porosity of approximately 21%. The Lower Flamingo Group is composed of blocky sandstones which contain some siliceous/calcareous cement, however, porosity is still excellent, averaging 20%.

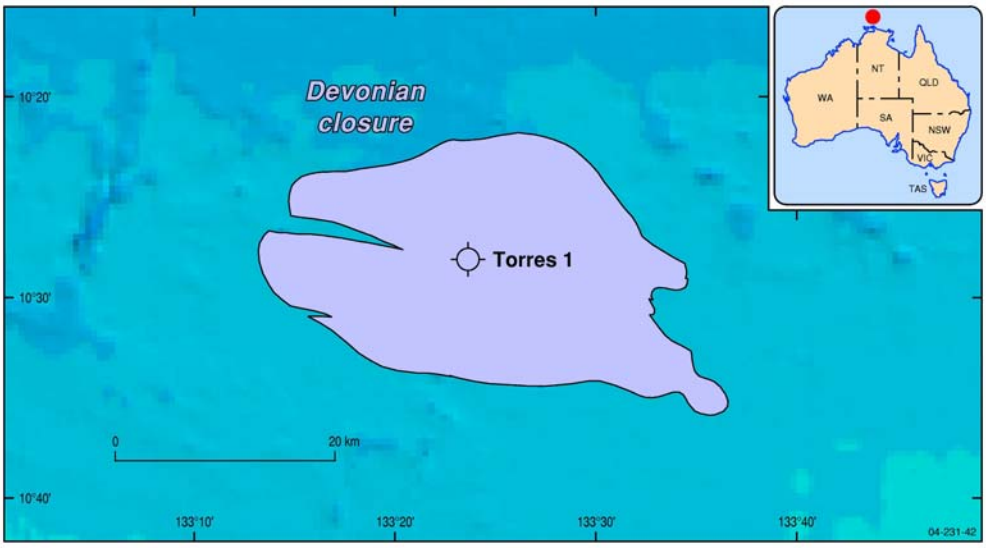


Figure 4.48: Torres-1 prospect closure (Esso Australia Limited, 1983b).

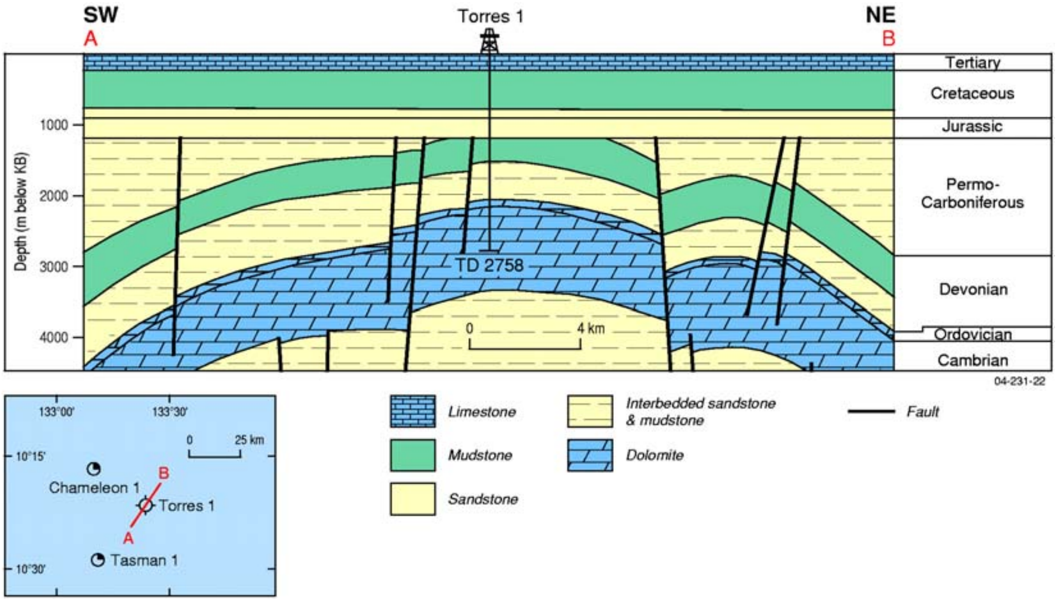


Figure 4.49: Simplified geological cross-section for Torres-1.

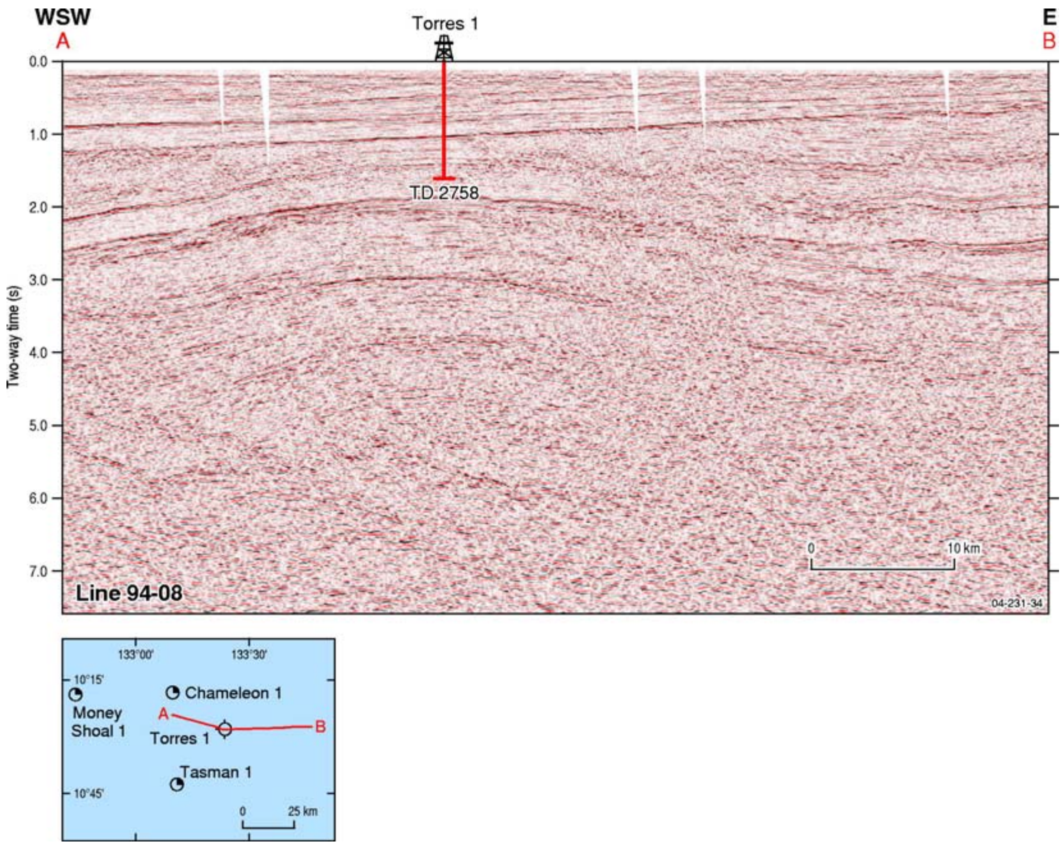


Figure 4.50: Seismic cross-section for Torres-1.

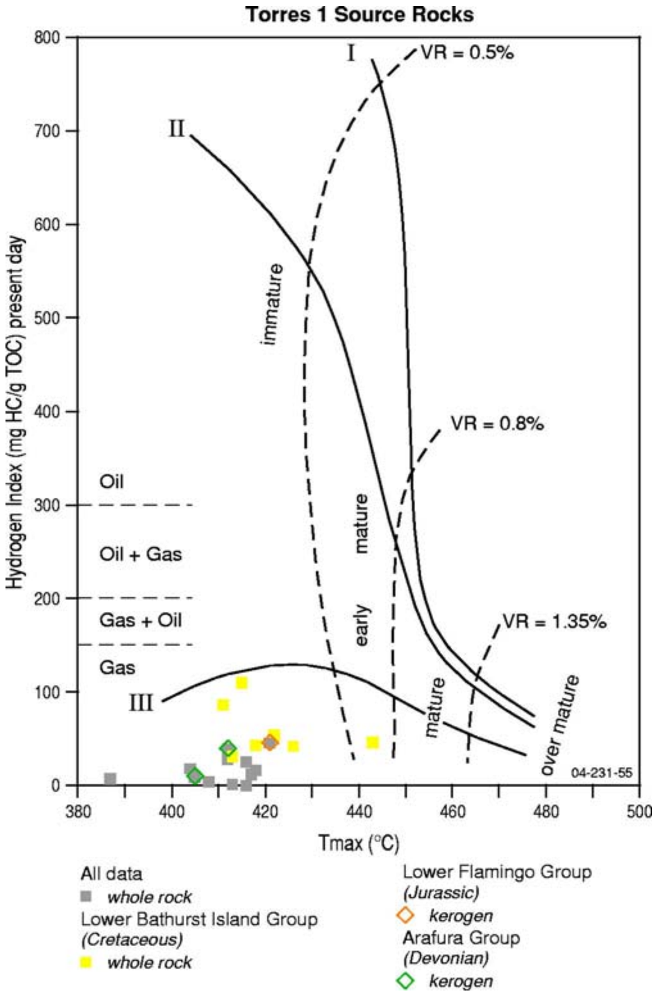


Figure 4.51: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Torres-1. Note: data has been edited for reliability where coloured data points are deemed to be reliable and unreliable data are shown in grey ("all data").

The Palaeozoic section generally has poor reservoir characteristics, with evidence of deeper burial prior to uplift and erosion (Figure 4.49). Porosity of the Arafura Group siltstones and sandstones averages 1% over the section. Despite the low porosity, gas traces occur through the section.

The Goulburn Group generally has poor porosities of <3% although thin layers have porosities of up to 7.7%. A zone of pervasive fracturing is indicated between 2150-2703 m by variable caliper logs, gas peaks and associated increases in drilling rates (with a maximum increase of 2 m per hour). A core (2754.8-2757.95 m) was drilled in the section beneath the fracture zone and has little primary or secondary porosity. Any secondary fracture porosity appears to have been filled by calcite.

All reservoir zones within the well section were found to be water-saturated.

SEAL

The Mesozoic reservoirs are sealed by thick, uniform Cretaceous claystones (Lower Bathurst Island Group).

Devonian reservoir rocks (Arafura Group) are sealed by mudstones in the upper part of the Arafura Group. The seal is over 300 m thick, and appears effective, with gas traces dropping off markedly across it

The Ordovician dolomites (Goulburn Group) do not have a distinctive seal, although gas traces drop off towards the top of the unit and may be related to limestones and interbedded mudstones with negligible porosity.

The crest of the structure contains numerous Permo-Triassic faults which could have breached any early formed traps (although there is no evidence of a remnant hydrocarbon accumulation).

HYDROCARBON SHOWS

Torres-1 did not contain significant hydrocarbons. The well encountered traces of gas in Cretaceous (Upper Flamingo Group) and Devonian (Arafura Group) clastics and in the Ordovician-Cambrian (Goulburn Group) dolomites. Organic petrographic analysis by CSIRO (Sherwood et al., 2005) has found rare oil droplets in the Lower Flamingo Group associated with coal. Rare oil droplets and bitumen were also found in the Devonian section, possibly associated with in-situ generation or hydrocarbon migration. No repeat formation tests or drill stem tests were carried out.

POST-DRILL ANALYSIS

Torres-1 was drilled to test the giant Torres anticline along the axis of the Goulburn Graben. The well targeted Devonian clastics, Cambrian dolomites and a section underlying the Cambrian dolomites. The latter was not intersected. A secondary objective was to obtain stratigraphic information because little was known about the Palaeozoic succession.

Torres-1 confirmed the presence of high-quality Mesozoic reservoirs (which were not within the structural closure) and poor-quality Palaeozoic reservoirs. The well was one of the biggest disappointments in the Arafura Basin due to the large size of the structure and the lack of significant shows within the reservoirs. Only minor gas traces were found in the Cretaceous Upper Flamingo Group, Devonian Arafura Group and Ordovician-Cambrian Goulburn Group. Well failure could be due to a breach of structure (via faults or erosion in the Permo-Triassic) but there is no evidence for a remnant hydrocarbon accumulation, such as dead oil and bitumen. The current-day structure is viable and would have captured any late expelled hydrocarbons. It is more likely that Torres-1 has not been charged by hydrocarbons. This could be due to a lack of fluid movement in the poor-quality Palaeozoic reservoirs and/or no access to migration pathways such as faults. There are no viable source rocks in the well section to locally source hydrocarbons. Gas traces are likely generated from a postulated underlying Cambrian source rock. The well analysis is summarised in Table 4.16.

Table 4.16: Torres-1 well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY									
WELL	SHOWS	TARGETS P = Primary S = Secondary	STRUCTUR	RISK ELEMENTS: STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	COMMENTS
Torres 1	Dry	P Devonian	Anticline	Low Risk	High Risk	Medium Risk	Low Risk	High Risk	Possible lack of charge
	Dry	P Cambrian	Anticline	Low Risk	Medium Risk	Medium Risk	Medium Risk	High Risk	Possible fracture zone, lack of charge

LEGEND: Low Risk (green); Medium Risk (orange); High Risk (red)

4.9 TUATARA-1

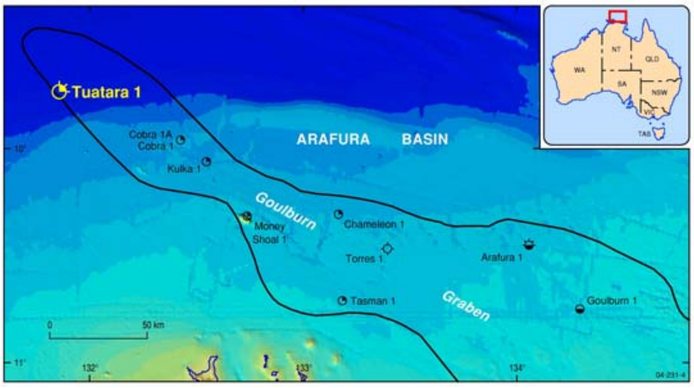


Figure 4.52: Tuatara-1 well location.

Tuatara-1 is located in the northwestern part of the Goulburn Graben near its southern boundary (Table 4.17, Figure 4.52). The well was drilled by BHP Petroleum in permit NT/P42 as the start of a drilling campaign in the early 90's. Tuatara-1 intersected only Money Shoal Basin sediments and tested Jurassic sands in a fault block within a broad faulted anticline. No significant hydrocarbons were encountered although oil indications are present throughout the well section and gas indications are present in Cretaceous sands. Well failure is attributed to a lack of seal over the primary target.

Table 4.17: Tuatara-1 well summary.

Uno	W8900009
Latitude	9° 43' 59.92" S
Longitude	131° 51' 41.10" E
Operator	BHP Petroleum
Year	1990
Permit:	NT/P42
Water Depth (m)	115
TD (mKB)	3874.2
TD Age	Jurassic
RT (m)	22
Status	P & A
Hydrocarbon Shows	Oil and gas indications
Play Type/Trap	Anticline/fault block
Primary Objectives	Jurassic (Troughton Group equivalent)
Secondary Objectives	Jurassic (Lower Flamingo Group) and Palaeozoic clastics/carbonates

STRATIGRAPHY

Tuatara-1 intersected sediments of Tertiary (Woodbine Group), Cretaceous (Upper Bathurst Island Group, Lower Bathurst Island Group, Darwin Formation equivalent and Upper Flamingo Group) and Jurassic (Lower Flamingo Group and Troughton Group equivalent) age (Figure 4.53).

The original well interpretation by the operator stated that the well reached TD in the Palaeozoic, which was a secondary objective. However, there is no biostratigraphic evidence for a Devonian age and seismic data suggests that the well bottomed in Jurassic rocks that overlie a probable Cambrian section. Pre-drill interpretation indicated that the Mesozoic would be clay-rich, compared to Kulka-1, because Tuatara-1 is more distal to sediment sources.

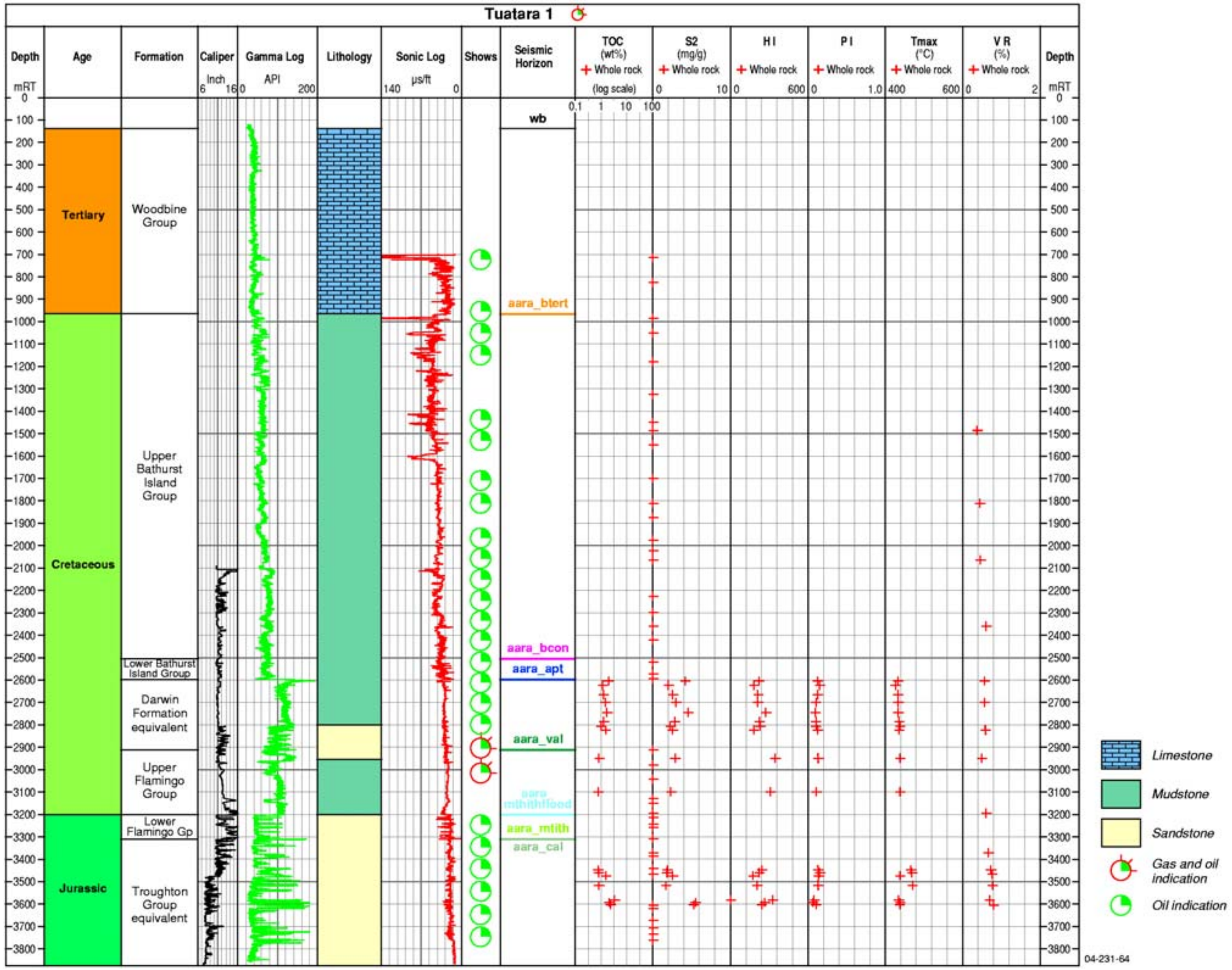


Figure 4.53: Tuatara-1 well composite summarising stratigraphy, predominant lithologies, hydrocarbon shows, organic geochemical data and maturity data.

This was confirmed with clays dominating the Cretaceous section. The Jurassic section consists mainly of sandstones with some minor coal, deposited a fluvio-deltaic environment.

STRUCTURE

The Tuatara-1 structure is located in the northwestern part of the Goulburn Graben and forms a broad NW-SE trending anticlinal feature dependant on crestal fault closure (Figures 4.55 and 4.56). The well was sited to test Jurassic Sandstones (Troughton Group equivalent) (Figure 4.54). At this level, closure (based on analysis by BHP Petroleum) consists of a NW-SE tilted fault block with an area of 18.9 km^2 and approximately 84 m vertical height. The SW-dipping bounding fault on the southern side of the structure forms part of the edge of the Goulburn Graben. Closure persists to the lower Cretaceous levels, encompassing the secondary Jurassic target (Lower Flamingo Group). Structuring in the Upper Jurassic section is mainly due to drape and compaction over the fault block and closure dies quickly up section (BHP Petroleum, 1991). The secondary Early Cretaceous target (Upper Flamingo Group/Darwin Formation equivalent) is not within structural closure.

The Tuatara structure formed in response to normal faulting during the Early-Middle Jurassic. The fault location is probably controlled by reactivation of pre-existing Palaeozoic faults at depth (BHP Petroleum, 1991).

SOURCE

Tuatara-1 did not intersect a significant source rock interval as indicated by geochemical data (Figure 4.57). The mudstone-dominated Bathurst Island Group lacks organic-rich material and is immature for hydrocarbon generation.

The Cretaceous (Darwin Formation equivalent) and Jurassic (Troughton Group equivalent) sections contains fair source rock intervals with TOC values above 1%. The Darwin Formation equivalent is immature to early mature for hydrocarbon formation. The organic richness of the Troughton Group equivalent is probably related to the coaly nature of the sediments, with a sand dominated section. The section is early mature for hydrocarbon generation. Potential Cambrian source rocks are likely present below TD.

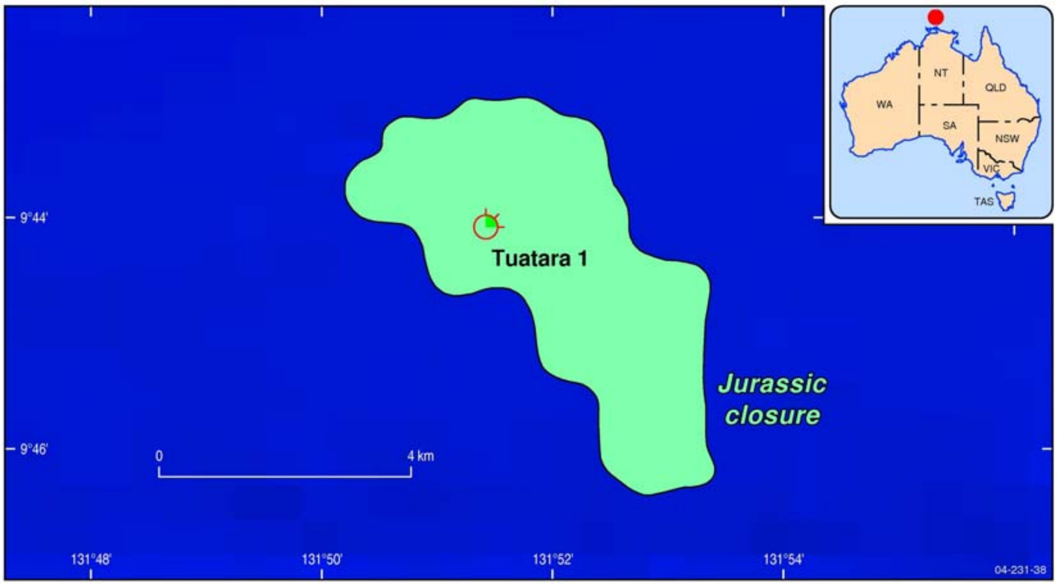


Figure 4.54: Tuatara-1 prospect closure (BHP Petroleum, 1991).

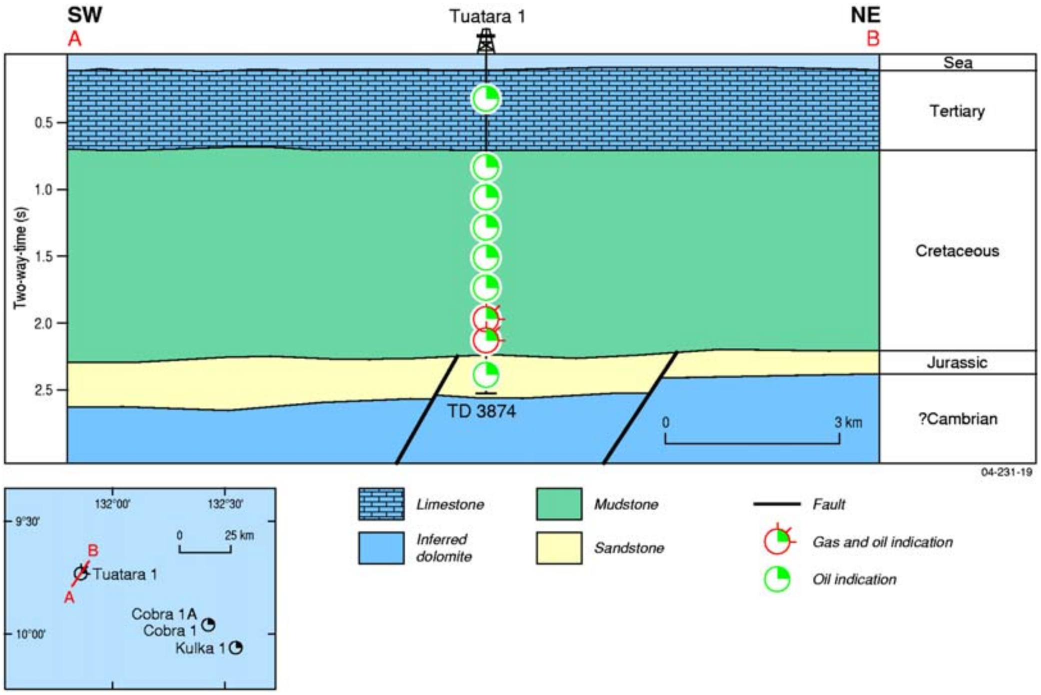


Figure 4.55: Simplified geological cross-section for Tuatara-1.

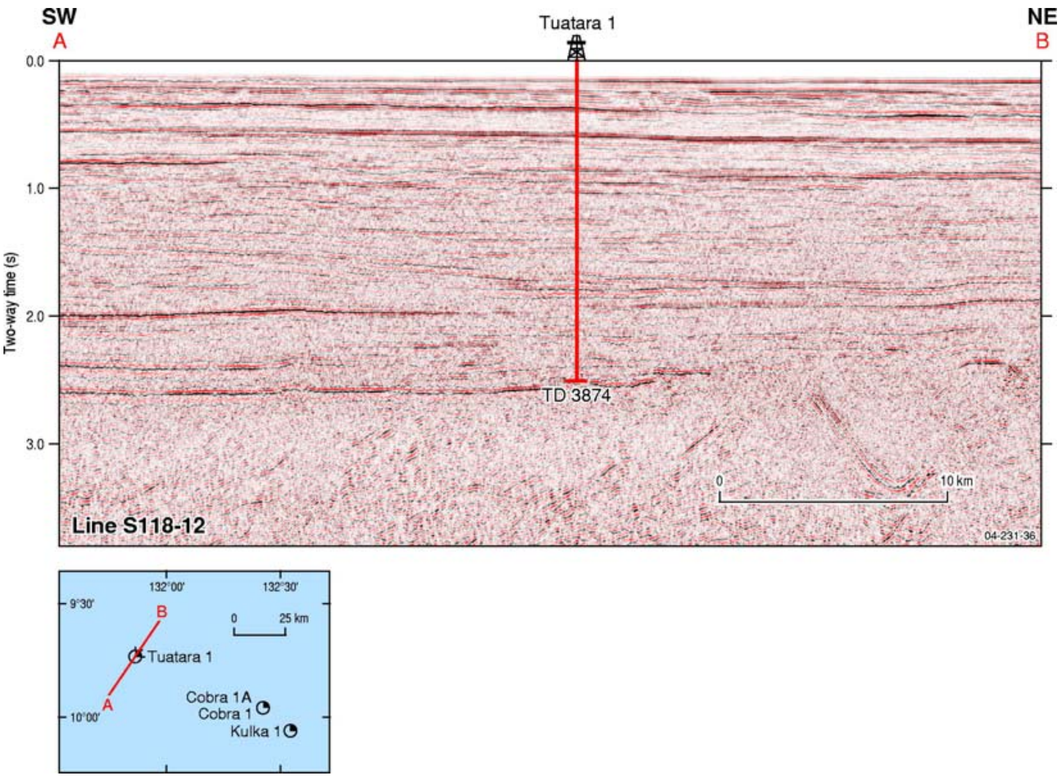


Figure 4.56: Seismic cross-section for Tuatara-1.

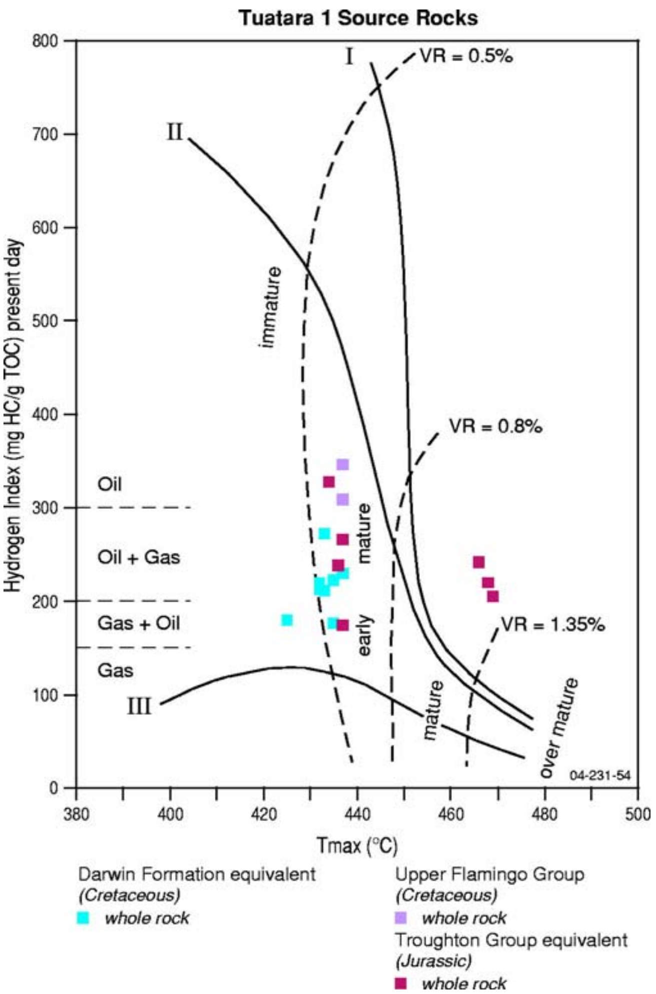


Figure 4.57: Hydrogen Index versus Tmax plot (from whole rock, extracted rock and kerogen) showing kerogen type (oil/gas potential) and maturity for rocks in Tuatara-1.

RESERVOIR

The Cretaceous (Darwin Formation Equivalent and Upper Flamingo Group) section contains very little sand at this location, and comprises a claystone-dominated succession averaging 11% and 10% porosity, respectively. There is a lack of permeability in the fine grained sediments. Fluid movement through the section would be difficult.

The Jurassic section is a sand-rich interval composed of blocky medium-grained sandstones interbedded with mudstones. However, at this location this section has low porosity with an average porosity of 9% for the Flamingo Group and 8% for the Troughton Group equivalent. Porosities of the target Jurassic horizon were lower than expected due to increased depth of burial (compared with pre-drill seismic interpretation) and an overall deterioration in sand quality.

All potential reservoirs were interpreted to be water saturated.

SEAL

Tuatara-1 was inferred to contain better quality seals compared to Kulka-1, because of the more distal location to the interpreted sediment source (BHP Petroleum, 1991). However, the primary Jurassic (Troughton Group equivalent) target is sealed by a thin claystone unit and has been judged to be insufficient due to its small vertical extent (<10 m).

The secondary Jurassic (Lower Flamingo Group) objective is overlain by interbedded claystone, siltstone and sandstone of the Upper Flamingo Group. The section is mudstone-rich with poor permeability but good porosity. Seal quality is uncertain.

The Early Cretaceous section (Darwin Formation Equivalent and Upper Flamingo Group) is sealed by the Bathurst Island Group (Cretaceous) regional seal. This section is thick and mudstone-rich, indicating good seal qualities, however, there is no structural closure at this level.

Faults of the main structure do not penetrate into the Cretaceous section. There should be no fault leakage above the regional Bathurst Island Group seal.

HYDROCARBON SHOWS

Tuatara-1 encountered no significant hydrocarbon shows. Oil indications were common in the Jurassic and the Cretaceous sections, with gas indications also present in the Cretaceous section. Many of the Jurassic (Troughton Group equivalent) hydrocarbon indications are associated with coals and interbedded mudstones and are likely to be locally sourced. However, this section is unlikely to have sourced the numerous indications throughout the whole section and the Cambrian section below TD is a possible source for these. No repeat formation tests or drill stem tests were carried out.

POST-DRILL ANALYSIS

Tuatara-1 intersected Money Shoal Basin sediments and targeted Jurassic (Troughton Group equivalent) sands in a fault block within a broad faulted anticline. Secondary targets were the Jurassic Lower Flamingo Group sands and Palaeozoic sediments. Re-assessment of seismic data indicates that the well did not penetrate Palaeozoic sediments but Cambrian dolomites are probably present below TD. The porosities of the target horizons were lower than expected because all seismic picks were 9-10% deeper than originally interpreted (BHP Petroleum, 1991). Hydrocarbon indications are common throughout the well section, from the Tertiary to the Jurassic, with no obvious concentration in reservoir intervals.

Tuatara was drilled near the western margin of the Goulburn Graben to minimise the seal and source risks found in Kulka-1. The more distal sedimentary environment, compared to Kulka-1, was confirmed by the well, with claystone-rich Early Cretaceous sediments. The seal integrity of these sediments is uncertain. The Jurassic section does not contain a significant seal interval overlying the primary target.

The well failed primarily due to a lack of seal and poor quality reservoirs. Well analysis is summarised in Table 4.18.

Table 4.18: Tuatara-1 well analysis summary.

ARAFURA BASIN WELL ANALYSIS SUMMARY									
WELL	SHOWS	TARGETS P = Primary S = Secondary	STRUCTURE	RISK ELEMENTS					
				STRUCTURE	RESERVOIR	SOURCE	SEAL	CHARGE	COMMENTS
Tuatara 1	Oil indications	P Lower Jurassic	Fault Block	Low	Medium	Low	High	Medium	No seal
	Oil indications	S Upper Jurassic	Fault Block	Low	Medium	Low	Medium	Medium	Uncertain seal
	NA	S Palaeozoic	Fault roll-over	NA	NA	NA	NA	NA	No Palaeozoic intersected

LEGEND: Low Risk (green); Medium Risk (orange); High Risk (red)

5. Conclusions

The Arafura Basin is an under-explored region with all drilling to date restricted to the Goulburn Graben. There is evidence for active source rocks with interpreted seeps (Infoterra, 2001), bitumens of unknown origin (Summons et al., 1993) and hydrocarbon indications within wells. The nine wells drilled have tested a variety of stratigraphic and structural plays, with the most significant hydrocarbons found being oil and gas shows in Arafura-1 and an oil show in Goulburn-1. There are also numerous hydrocarbon indications in Chameleon-1, Cobra-1A, Kulka-1, Money Shoal-1, Tasman-1 and Tuatara-1. Oil-source correlation from previous work (Moore et al., 1996) and analysis associated with this report (C. Boreham, Geoscience Australia pers. comm., July 2005) indicates that the Arafura-1 and Goulburn-1 oils have been sourced from the Cambrian proving conclusively that there is a viable source rock in the region. There have been at least two different charge events from these sediments, with both biodegraded and non-biodegraded oil in reservoirs at Arafura-1. There is evidence of significant vertical migration of these fluids, with Cambrian oil signatures throughout the Palaeozoic and Neoproterozoic sections (as seen at Arafura-1). A Cambrian oil signature has not yet been found in the overlying Money Shoal Basin sediments.

There is strong evidence for viable petroleum systems within the region with sufficient petroleum system elements such as source, reservoir and seal. A number of exploration risk factors have contributed to the current lack of drilling success, as outlined below:

1) Hydrocarbon Charge and timing

This is one of the key factors in the Goulburn Graben, with a historical perception that there is a timing issue between Palaeozoic expulsion, the Permo-Triassic structuring event and Mesozoic reservoir deposition (outlined in Moore et al., 1996 and McLennan et al., 1990). A Cambrian source rock has generated and expelled hydrocarbons, with geochemical evidence linking the hydrocarbons to a number of Palaeozoic reservoirs. However, many of the reservoirs are of poor quality, relying on secondary porosity. A Cambrian or Palaeozoic oil signature has not yet been found in the higher-quality Mesozoic reservoirs. This would suggest that the main expulsion event was in the Palaeozoic, before the reservoirs were deposited. This is not necessarily the case, with recent modelling by Geoscience Australia (Struckmeyer et al., in prep) suggesting that there may be late generation and expulsion from Palaeozoic sources in some localities. There are numerous hydrocarbon indications in Mesozoic reservoirs which may have been sourced from these sediments. Potential Mesozoic sources are marginally mature at best over most of the Goulburn Graben, with significant in-situ sourcing unlikely. Further analysis is needed to definitively link the hydrocarbons to their sources.

The main structuring event in the region occurred in the Triassic. This transpressional event may have post-dated early expulsion from Palaeozoic sources. Any late expulsion (Jurassic onwards) could be trapped by Triassic structures. There are also later formed structures such as reactivated older faults and Late Cretaceous to Tertiary contractional features.

2) Reservoir quality and fluid movement

Money Shoal Basin sediments form excellent reservoirs with high porosity and permeability over most of the Goulburn Graben. Fluid movement in these reservoirs would not be restricted, with the potential for long-range migration. The sediments are also well placed to receive hydrocarbon charge from the underlying Palaeozoic.

Arafura Basin reservoirs are an exploration risk in the Goulburn Graben that has been identified by previous work such as Bradshaw et al. (1990) and Miyazaki and McNeil (1998). The reservoir rocks are of generally poor-quality, relying on secondary porosity such as fractures and vugs. It is likely that the primary porosity features of Permo-Carboniferous and Devonian reservoirs were poor, with a lack of thick sandstones and fine-grained sediments. The Ordovician-Cambrian dolomites could have potentially had good primary porosity which was removed by subsequent diagenetic effects (such as possible fluid movement associated with the Triassic transpressional event).

The secondary porosity characteristics of the reservoirs are not laterally continuous and are probably associated with folds and faults, which encourage their formation. Fluid movement in the section would be restricted, unless there is access to conduits. This could be a critical factor in the region, with the failure of structures (such as Torres-1) attributed to a lack of charge most likely caused by a lack of access to fluid conduits. The lack of fluid movement in the Palaeozoic may also hinder hydrocarbon movement from Palaeozoic sources into Mesozoic reservoirs. A higher-quality Palaeozoic reservoir, which may be present in the northern region, may also result in a more prospective Mesozoic section.

3) Breach of Structure

Breach of structure is a risk in the region, facilitated by uplift and erosion in the Triassic. The Triassic event stripped up to 3.5 km of sediment from the Palaeozoic section, potentially breaching pre-existing accumulations.

Faults are an important factor in the region, providing access to deeply-generated hydrocarbons and creating most of the structures tested in the Arafura Basin. Nearly all of the structures rely on fault closure, generally as crestal faulting. Faults are also one of the main fluid conduits in Palaeozoic sediments, facilitating the migration of hydrocarbons through otherwise impermeable sediments. A lack of access to major faults (extending down to sources such as the Goulburn Group) could be a reason for well failure in the region.

The risk of fault breach is higher within Palaeozoic targets, in comparison to the Mesozoic, due to the highly interbedded nature of the Permo-Carboniferous and Devonian sediments. Mesozoic reservoir rocks are overlain by a thick regional seal, the Bathurst Island Group, which is unlikely to be breached by fault movement. Both Arafura-1 and Goulburn-1 contain clear evidence of fault leakage from Palaeozoic sediments, with dead oil and bitumens within the primary reservoirs.

6. Acknowledgements

The author would like to thank members of the Arafura Basin study group at Geoscience Australia: Heike Struckmeyer, Jennifer Totterdell, Georgina Ryan and Chris Boreham, for their contributions to this record. Many thanks to Geoscience Australia’s Geospatial and Visualisation Group for drafting of all figures, particularly: Chris Evenden, Lindy Gratton, Angie Jaensch and Silvio Mezzomo. The author acknowledges Jim Colwell, Heike Struckmeyer and Chris Boreham for their comprehensive review and editing of the report.

7. References

Barrett A.G., Hinde A.L. & Kennard J.M., 2004. Undiscovered resource assessment methodologies and application to the Bonaparte Basin. *In:* Ellis G.K., Baillie P.W. and Munson T.J. (Eds) *Timor Sea Petroleum Geoscience. Proceedings of the Timor Sea Symposium*, Darwin, Northern Territory, 19-20 June 2003. Northern Territory Geological Survey, Special Publication 1.

BHP Petroleum, 1991. Tuatara-1 well completion report (unpublished).

BHP Petroleum, 1992. Chameleon-1 well completion report (unpublished).

BHP Petroleum, 1993. Cobra-1A well completion report (unpublished).

Bradshaw, B., Nicoll, R.S., & Bradshaw, M., 1990. The Cambrian to Permo-Triassic Arafura Basin, Northern Australia. *The APEA Journal* 30, 107-127.

Cadman, S.J. & Temple, P.R., 2004, Bonaparte Basin, NT, WA, AC & JPDA, Australian Petroleum Accumulations Report 5, 2nd Edition, Geoscience Australia, Canberra.

Diamond Shamrock, 1985. Kulka-1 well completion report (unpublished).

Esso Australia Limited, 1983a. Tasman-1 well completion report (unpublished).

Esso Australia Limited, 1983b. Torres-1 well completion report (unpublished).

Forman, D.J. and Wales, D.W., 1981. Geological evolution of the Canning Basin, Western Australia. Bureau of Mineral Resources, Australia, *Bulletin* 210.

Haines, P.W., Hand, M. and Sandiford, M., 2001. Palaeozoic synorogenic sedimentation in central and northern Australia: a review of distribution and timing with implications for the evolution of intracontinental orogens. *Australian Journal of Earth Sciences*, 48(6), 911–928.

Infoterra, 2001. *Arafura Sea, Indonesia-Australia: A combined hydrocarbon occurrence and seep-seismic correlation study* (unpublished non-exclusive study).

Labutis, V., Moore, A. & Bradshaw, J., 1992. Arafura petroleum prospectivity evaluation report. *AGSO Record* 1992/84.

Kennard J.M., Deighton I., Edwards D.S, Boreham C.J. & Barrett A.G., 2002. Subsidence and thermal history modelling: New insights into hydrocarbon expulsion from multiple petroleum systems in the Petrel Sub-basin, Bonaparte Basin. *The Sedimentary Basins of Western Australia 3: Proceedings of the Petroleum Exploration Society of Australia Symposium*, Perth, WA, 2002, 409-437.

Kennard J.M., Deighton I., Edwards D.S., Colwell J.B., O'Brien G.W. & Boreham C.J., 1999. Thermal history modelling and transient heat pulses: New insights into the hydrocarbon expulsion and "hot flushes" in the Vulcan Sub-basin, Timor Sea. The *APPEA Journal,* 39(1), 177-207.

Kieraville Konsultants, 1984. Organic petrology of a suite of samples from Arafura No. 1. *Shell Destructive Analysis Report*.

Martin, B.A. & Cawley, S.J., 1991. Onshore and offshore petroleum seepage: contrasting a conventional study in Papua New Guinea and airborne laser fluorosensing over the Arafura Sea. *APEA Journal* 31(1), 333-353.

McKirdy, D.M. & Horvath, Z., 1976. Geochemistry and significance of coastal bitumen from southern and northern Australia. *APEA Journal* 16, 123-135.

McLennan, J.M., Rasidi, J.S., Holmes, R.L. & Smith, G.C., 1990. The geology and petroleum potential of the western Arafura Sea. *APEA Journal* 30, 91-106.

Moore A., Bradshaw J. & Edwards D., 1996. Geohistory modelling of hydrocarbon migration and trap formation in the Arafura Sea. *The Petroleum Exploration Society of Australia Journal* 24, 35-51.

Miyazaki, S. & McNeil, B., 1998. Arafura Sea. *Petroleum Prospectivity Bulletin and Database*1998/1. Bureau of Resource Sciences, Canberra.

Nicoll, R.S., Shergold, J.H., Laurie, J.R. & Bischoff, G.C.O., 1996. Cambrian and Ordovician biostratigraphy of the Arafura Basin, northern Australia. *Geological Society of Australia, Abstracts* 41, 318.

Petroconsultants, 1989. Northern Territory Geological Survey petroleum basin study - Arafura Basin. *Northern Territory Department of Mines and Energy Report*.

Petrofina Exploration Australia S.A., 1983. Arafura-1 well completion report (unpublished).

Petrofina Exploration Australia S.A., 1986. Goulburn-1 well completion report (unpublished).

Plumb K.A., 1979a. Structure and tectonic style of the Precambrian shields and platforms of northern Australia. *Tectonophysics* 58, 291-235.

Plumb, K.A. and Roberts, H.G., 1992. The geology of Arnhem Land, Northern Territory. *Bureau of Mineral Resources, Australia, Record* 1992/55.

Preston J.C & Edwards D.S., 2000. The petroleum geochemistry of oils and source rocks from the Northern Bonaparte Basin, offshore northern Australia. *APPEA Journal* 40(1), 257-282.

Rawlings D.J., 1999. Stratigraphic resolution of a multiphase intracratonic basin system: the McArthur Basin, northern Australia. *Australia Journal of Earth Sciences* 46, 703-723.

Rawlings, D.J., Haines, P.W., Madigan, T.L.A., Pietsch, B.A., Sweet, I.P., Plumb, K.A. and Krassay, A.A., 1997. Arnhem Bay-Gove, Northern Territory. 1:250 000 Geological Map Series. *Northern Territory Geological Survey, Explanatory Notes* SD53-3,4.

Shell, 1971. Money Shoal-1 well completion report (unpublished).

Sherwood, N., Russell, N. & Faiz, M., 2005. Thermal maturity evaluation using combined FAMM and conventional organic petrological analyses for samples from a suite of wells in the Arafura Basin, Australia. *CSIRO Report* (unpublished).

Struckmeyer, H.I.M. (compiler), 2006a—New datasets for the Arafura Basin. Geoscience Australia Record.

Struckmeyer, H.I.M. (compiler), 2006b—Petroleum Geology of the Arafura Basin. Geoscience Australia Record.

Struckmeyer, H.I.M., Totterdell, J.M. and Earl, K.L., in prep.— New insights into the geology and petroleum prospectivity of the northern Arafura Basin, offshore northern Australia.

Summons, R.E., Bradshaw, J.B., Brooks, D.M., Goody, A.K., Murray, A.P. & Foster, C.B., 1993. Hydrocarbon composition and origins of coastal bitumens from the Northern Territory, Australia. *PESA Journal*, 31-42.

Totterdell, J.M., 2006—Basin Evolution. In: Struckmeyer, H.I.M. (compiler) 2006, Petroleum Geology of the Arafura Basin. Geoscience Australia Record.