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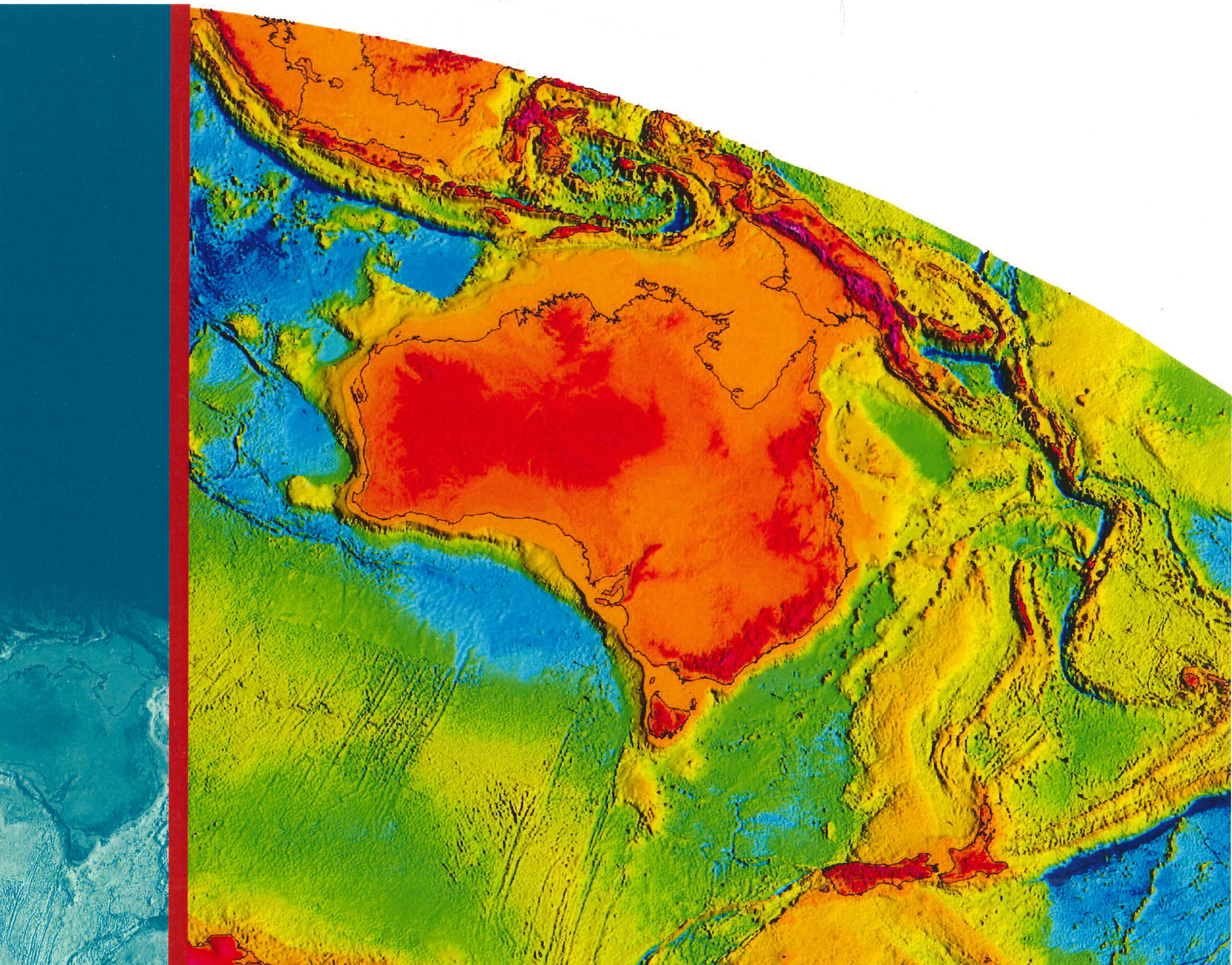

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GEOSCIENCE AUSTRALIA RECORD 2003/21

AN AUDIT OF SELECTED OFFSHORE PETROLEUM EXPLORATION WELLS IN THE OTWAY BASIN, SOUTHEASTERN AUSTRALIA

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EXECUTIVE SUMMARY

This Record is a summary of an analysis of 21 offshore Otway Basin wells (Fig. 1) based on data provided in open file Well Completion Reports (WCRs), Geoscience Australia's biostratigraphic and geochemical databases, and published literature. This report focuses on individual well results, and success and failure analysis.

Pre-1975, wells were drilled using poorer quality seismic data, and wire-line logging technology. Several of the older wells, such as Mussel-1 and Crayfish-A1, were drilled off-structure, while Voluta-1 did not reach the primary target, due to misinterpretation of the seismic data. When considering the offshore well spacing (average 30 km), the offshore Otway Basin is clearly sparsely explored.

The main findings of this study are summarised in Table 1 with results presented by geological province, from west to east. Several themes emerged as a result of this study.

- Failure of Crayfish Platform wells to encounter commercial hydrocarbon accumulations can generally be attributed to poor quality source potential of the Pretty Hill and older formations. Troas-1/ST1 intersected a non-commercial gas accumulation on the adjacent Chama Terrace, although sealing capacity of the Eumeralla Formation is reduced by the presence of sandy interbeds.

- Wells in the Morum Sub-basin wells failed through seal related issues for the primary and secondary targets. These seal failures include late fault breaching and poorer seal quality in the Late Cretaceous succession. In general, seaward of these wells, seals are expected to be present in distal prodelta settings. In the Belfast Mudstone, thinner, higher quality seals are variably developed. Onshore, at the Caroline gas field these seals trap commercial quantities of carbon dioxide (CO_2).

- In the Discovery Bay High area, reasons for failure are variable. The Belfast Mudstone is relatively thick and well developed. It appears to have prevented migrating hydrocarbons from reaching reservoirs within the overlying Paaratte and Curdies formations. Thin shales within the Paaratte and Curdies formations and overlying Tertiary section result in considerable risk of fault seal breaching in this area. Two of the three wells either failed to reach the primary Waarre Sandstone target or were drilled downdip from the trap crest.

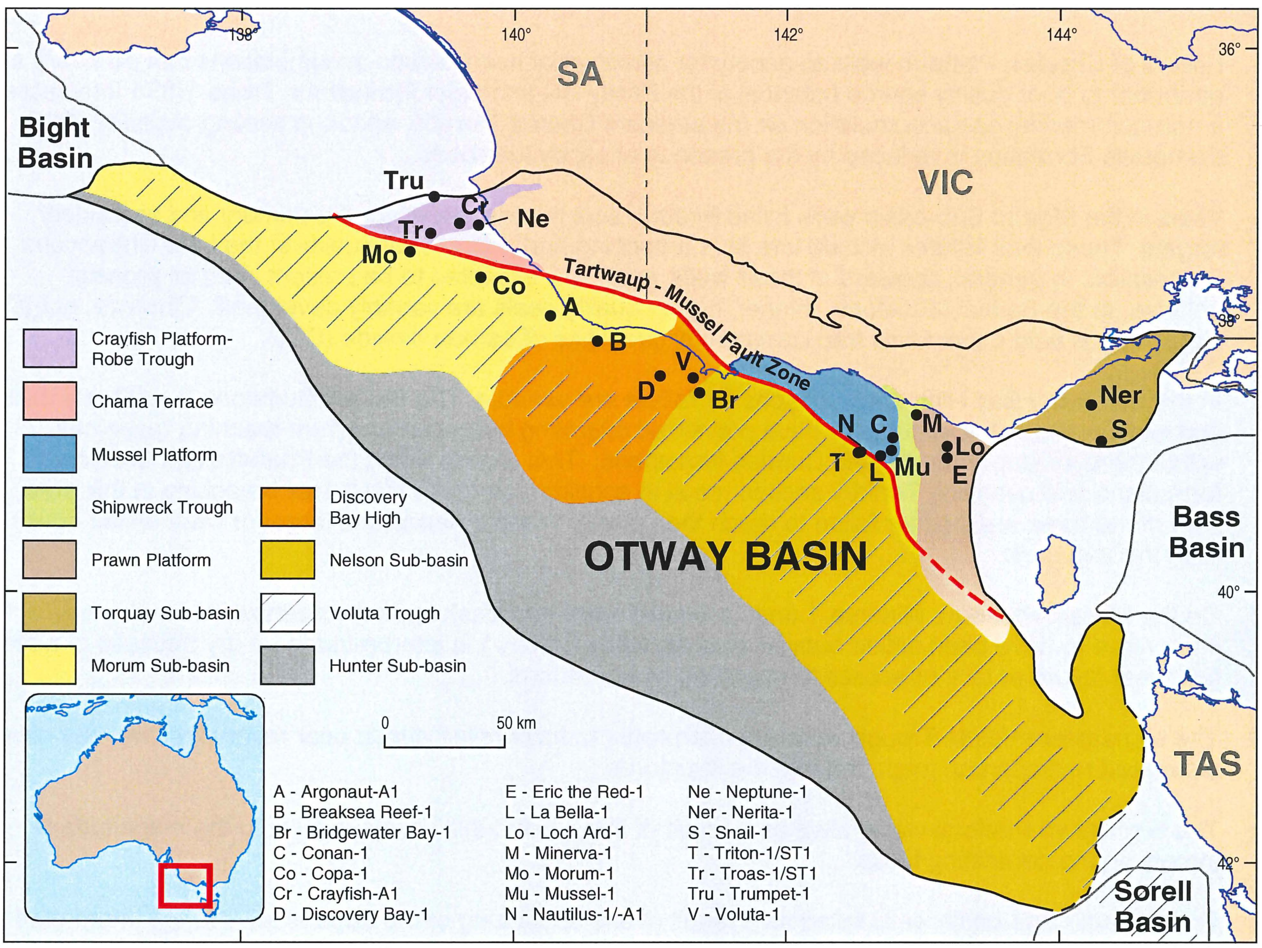
- On the Mussel Platform, Minerva-1 and La Bella-1 were successful gas discoveries. Mussel-1 is interpreted to have been drilled outside closure, while Conan-1 is interpreted to be dry because of either fault seal failure or lack of access to migrating hydrocarbons.

- The two eastern Voluta Trough wells are interpreted to have failed due to poor reservoirs that may have prevented hydrocarbon migration into the structures.

- The two Prawn Platform wells failed as a result of thin, poor quality seals relative to the magnitude of throws on the controlling faults.

- The Torquay Sub-basin wells failed as a result of late structuring of the traps relative to the interpreted time of peak generation and migration in the Tertiary. Well documented gas seeps in the sub-basin attest to at least some gas migration in this region.

This work identifies the Mussel Platform as having all the required petroleum system elements in place at the "crititcal moment" for hydrocarbon accumulations. In other areas, there is significant remaining potential if the key exploration risks can be addressed through the application of appropriate new technology, and detailed facies models and structural mapping within these areas.



Modified after Geary & Reid, 1998, Moore et al., 2000, Boult & Hibburt, 2002.

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Figure 1. Location map showing all wells included in this study superimposed on the major structural elements of the Otway Basin.

OTWAY BASIN WELL AUDIT REPORT - WELL ANALYSIS SUMMARY

GEOLOGICAL SETTING & WELLS	TARGET P-primary S-secondary		STRUCTURE STYLE	RISK ELEMENTS: STRUCTURE	SEAL-FAULT BREACH	SEAL-QUALITY	RESERVOIR	SOURCE	MATURITY	MIGRATION	TIMING	COMMENTS
CRAYFISH PLATFORM CHAMA TERRACE												
Trumpet-1	P	Pretty Hill Sandstone	Faulted anticline	G	G	Y	G	R	Y	Y	G	Poor intra-Pretty Hill Fm seal/Poor source & migration
Crayfish-A1	P	Pretty Hill Sandstone	Fault block/subcrop	R	Y	Y	G	R	Y	Y	G	Well drilled outside closure/inadequate source? Source volume in drainage area-sandy Pretty Hill Fm
	S	Cretaceous sands	Drape structure	Y	G	Y	G	R	Y	R	G	Migration through Eumeralla Fm seal to reservoirs
Neptune-1	P	Pretty Hill Formation	Tilted fault block	G	G	Y	G	R	Y	Y	G	Main concern is source/some question about seal quality
Troas-1/ST1	P	Pretty Hill Formation	Tilted fault block	G	Y	R	G	G	G	G	Y	Eumeralla Fm not adequate cross-fault seal
MORUM SUB-BASIN												
Morum-1	P	Waarre Sst	Faulted anticline	G	R	R	Y	G	G	G	Y	Poor quality thin seals & very late faulting
	S	Paaratte and Pretty Hill fms	Faulted anticline	G	R	R	G	G	G	G	Y	Thin poor quality seals and Pretty Hill Fm not reached
Copa-1	P	Waarre Sst	Lowside fault block	G	R	Y	Y	G	G	G	Y	No thick Belfast Mudstone above Waarre Sst-fault breached
	S	Curdies/Paaratte Fm and Timboon Sst	Faulted anticline	Y	R	Y	G	G	G	Y	Y	No thick seals-fault breaching-late faulting
Argonaut-A1	P	Waarre Sst	Tilted fault block	R	Y	Y	Y	G	G	G	Y	Down dip on structure, seal breach by faulting. Late faulting
	S	All Late Cret. & Tert.	Tilted fault block	Y	R	Y	G	G	G	Y	Y	Thin seals & no Tertiary seal
Breaksea Reef-1	P	Waarre Sst/intra-Belfast Fm	Tilted fault block	G	G	Y	Y	G	G	G	R	Late faulting leakage & seal quality?
	S	Curdies/Paaratte fms	Tilted fault block	Y	R	Y	G	G	G	R	Y	Thin seals fault breached Limited migration through thick Belfast Mudstone
DISCOVERY BAY HIGH												
Discovery Bay-1	P	Curdies/Paaratte Fm, Tert.seal	Faulted anticline	G	R	Y	G	G	G	R	G	Pember Mudstone poorly developed
	S	Intra-Belfast Fm sands	Faulted anticline	G	R	Y	Y	G	G	R	G	Thin seals fault breached Limited migration through thick Belfast Mudstone
Voluta-1	P	Waarre Sst	Faulted anticline	R	G	G	Y	G	G	G	G	Well failed to drill to deeper primary target
	S	Upper Sherbrook and Wangerrip groups	Faulted anticline	G	R	Y	G	G	G	R	G	Thin seals fault breached/Access to migratiing oil & gas Migration access through thick Belfast seal interval
Bridgewater Bay-1	P	Waarre Sst	Tilted fault block	R	G	G	Y	G	G	G	G	Well 35m downdip. Off structure? - Reservoir quality poor
	S	Curdies/Paaratte formations and intra-Belfast Mudstone	Tilted fault block	Y	R	Y	G	G	G	Y	G	Thin seals fault breached Limited migration through thick Belfast Mudstone
MUSSEL TERRACE												
Minerva-1	P	Waarre Sst (Shipwreck Sub-gp)	Faulted anticline	G	G	G	G	G	G	G	G	**Successful well test**
	S	Sherbrook/Wangerrip/Nirranda groups	Faulted anticline	G	G	Y	G	G	G	Y	G	Small Sherbrook Group gas column identified Fault seal and migration adequacy critical to play
Conan-1	P	Waarre Sst - Shipwreck Sub-group	Fault block	G	Y	Y	G	Y	Y	Y	G	No late source rock reactivation in local area? Complex large south bounding fault leakage?
Mussel-1	P	Waarre Sst - Shipwreck Sub-gp	Tilted fault block	R	G	G	G	G	G	G	G	Well downdip from trap leak point
	S	Tertiary sands	Channelled trap	G	G	Y	G	G	G	R	G	Limited migration through Belfast Mudstone
La Bella-1	P	Waarre Sst (Shipwreck Sub-gp)	Faulted anticline	G	G	G	G	G	G	G	G	**Successful well test**
EASTERN VOLUTA TROUGH												
Nautilus-A1	P	Tertiary sand wedge	erosional & pinchout	Y	Y	Y	Y	G	G	Y	G	Poor top seal/very poor reservoir/migration problem
Triton-1/ST1	P	Waarre Sst	Faulted anticline	Y	G	G	R	G	G	G	G	Poor reservoir with high cap seal entry pressures
PRAWN PLATFORM												
Eric the Red-1	P	Waarre Sst (Shipwreck Sub-gp)	Faulted anticline	G	R	Y	G	G	G	Y	Y	Late fault breach of thin seals Likely absence of late mature source
Loch Ard-1	P	Waarre Sst (Shipwreck Sub-gp)	Faulted anticine	G	R	Y	G	G	G	Y	Y	Late fault breach of thin seals
	S	Shipwreck A and Sherbrook B sands		G	R	Y	G	G	G	Y	Y	Late fault breach of thin seals Possible absence of late mature source
TORQUAY SUB-BASIN												
Snail-1	P	Eastern View Coal Measures	Faulted anticline	G	R	Y	G	G	Y	Y	R	Seal and timing of structure relative to migration
Nerita-1	P	Multiple-Tertiary to Cretaceous	Faulted anticline	G	Y	G	G	G	Y	Y	R	Seal and timing of structure relative to migration

LEGEND		
	G (green)	LOW RISK ELEMENT - ADEQUATE PROPERTIES
	Y (yellow)	POORER OR UNCERTAIN QUALITY/PRESENCE
	R (red)	HIGH RISK - INADEQUATE ELEMENT

Table 1. Summary of the well analyses contained in this Record.

1. Introduction

1.1 Regional Geology

A variety of structural models have been proposed for the early extensional history of both the Otway Basin (e.g., Megallaa, 1986; Williamson et al., 1988; O'Brien et al., 1994; Cockshell et al., 1995; McClay et al., 2001) and the southern Australian margin (e.g., Stagg et al., 1990; Veevers et al., 1990; 1991; Sayers et al., 2001). In general, the Otway Basin developed as a consequence of latest Jurassic to Early Cretaceous rifting between Australia and Antarctica. Crustal extension initially created a narrow, extensive rift system along the southern margin of Australia, referred to as the Southern Rift System (SRS) (Stagg et al., 1990; Willcox and Stagg, 1990). This initial rifting and subsequent subsidence and extension along the SRS resulted in the development of the Bight, Otway, Bass, Gippsland and Sorell Basins, and the west Tasmanian transtensional margin basins (Willcox and Stagg, 1990; Hill et al., 1996; Totterdell et al., 2000; Norvick and Smith, 2001). The initiation of seafloor spreading between Australia and Antarctica was originally dated as Early Cretaceous (95 Ma; Veevers et al., 1990; 1991). Recent studies based on interpretation of seismic transects across the continent–ocean boundary have dated the initiation of seafloor spreading between Australia and Antarctica as base Campanian, c. 83 Ma (Sayers et al., 2001). The age of first oceanic crust is progressively younger to the east with the Otway Basin and sub-basin axes oriented progressively more obliquely to the final spreading direction.

The Late Jurassic to Cainozoic Otway Basin is a northwest–southeast trending, onshore–offshore basin. Late Jurassic to Early Cretaceous rifting resulted in the east–west trending Inner Otway Basin, which comprises the onshore basin elements and most of the continental shelf (Moore et al., 2000). Late Cretaceous rifting, culminating in continental breakup in the Maastrichtian, produced northwest-southeast trending depocentres beneath the outer shelf and slope. The resultant transtensional regime formed northwest–southeast to north–south oriented depocentres basinward of the "Inner Otway Basin" known as the Morum and Nelson sub-basins (Moore et al., 2000). This region has also been termed, in part, the Voluta Trough (Geary and Reid, 1998). To the east, the Otway Basin is increasingly influenced by wrench tectonics associated with the west Tasmanian–Antarctica wrench margin variably developed from the mid Cretaceous through to the Eocene (Norvick and Smith, 2001). Contractional episodes in the mid Cretaceous and Tertiary caused partial inversion of the basin, and the development of angular unconformities and disconformities. Subsequently, passive margin sediments built out across the shelf during the Cainozoic. The Recent compressive stress regime has resulted in local inversion and reactivation of selected faults in the Otway Basin (Perincek and Cockshell, 1995; Norvick and Smith, 2001).

1.2 Petroleum Geology

Hydrocarbon generation and migration may be linked to several key tectonic events in the Otway Basin. During the Cenomanian, there was a period of significant and variable uplift and erosion across the basin. This is coincident with a fall in geothermal gradients from 50–70 °C/km to 30–40 °C/km. The shift to lower heat flows in the Late Cretaceous is very significant for hydrocarbon generation from the primary source, the Eumeralla Formation, within the Otway Supergroup. The regional uplift, erosion and cooling effectively turned off hydrocarbon generation at this time, particularly in the eastern part of the basin (Duddy, 1997).

A second phase of hydrocarbon generation from initially shallow Otway Supergroup source rocks is confined to areas where Late Cretaceous to Tertiary sediments exceed 500 m (Duddy, 1997). The optimal setting for an Otway Supergroup sourced play is interpreted to occur where Late Cretaceous sediments are thin and the Late Tertiary section is thickest (Duddy, 1997). A calibration of this model is achieved by looking at the thickness of the Tertiary in the area of the Minerva, La Bella, Geographe, Thylacine and Casino discoveries. Here, the Tertiary is between 900 and 1600 m thick, and increases dramatically seaward of the Mussel Platform.

Accurate thermal modelling is critical for risk management in this basin, and requires ongoing research to unravel the complex tectonic and thermal history of the Otway Basin. Comments made in this report highlight this topic as a general area of concern; however, a more detailed understanding is required for the development of prospects. In the well analyses, the Tertiary thickness is used only as a guide to the potential for late generation and migration.

1.3 Exploration History

Petroleum exploration interest in the Otway Basin predates that in the Gippsland Basin. Records of coastal bitumen strandings led to the drilling of an exploration well in Kingston, South Australia in 1892. The first wells in the Victorian part of the Otway Basin were drilled in the 1920s to 1940s in the Anglesea and Torquay areas (Sprigg, 1986). These wells were relatively shallow (<500 m) and did not reach the Late Cretaceous. In 1959, Port Campbell-1 drilled into the Late Cretaceous and intersected the first hydrocarbon column in the basin. Drilled by the Frome-Broken Hill consortium, it flowed at a rate of 4.2 MMcf/d from the Waarre Sandstone (Bernecker et al., in press)

In 1966, Esso and Shell farmed into the Otway Basin, and with Frome-Broken Hill drilled 22 offshore wells in Victoria and South Australia. Hoping to find success similar to the Gippsland Basin, their efforts were largely unrewarded with only minor gas shows in Pecten-1.

After a period of limited drilling and seismic acquisition, Beach Petroleum discovered gas in the Waarre Sandstone at North Paaratte-1, only 3 km northeast of Port Campbell-1. Encouraged by the gas find onshore, offshore permits were awarded to Esso, Phillips and Ultramar, but no new discoveries were made. In contrast, more small onshore gas discoveries were made by Beach Petroleum in 1981 at Grumby-1 and Wallaby Creek-1, also within the Late Cretaceous Waarre Sandstone.

In 1987, gas fields in the Port Campbell area went into production, supplying the regional centres of Portland and Warrnambool with gas. In 1992, offshore permits VIC/P30 and P31 were awarded to BHP Petroleum (BHPP) who drilled two discovery wells, La Bella-1 (217 bcf GIP) and Minerva-1 (558 bcf GIP) in 1993, and two dry wells. After drilling three additional wells that recorded a few gas shows, BHPP relinquished the permits in 1997, retaining the Minerva and La Bella fields.

Since 1999, there has been a resurgence in exploration activity in the Otway Basin, driven by changes in the gas market and technological advances. A major exploration program, by an Origin Energy led joint venture, resulted in the large gas discoveries at Geographe (500 bcf GIP) and Thylacine (600 bcf GIP) in Victorian and Tasmanian waters respectively (Woollands and Wong, 2001). A targeted exploration program led by Strike Oil, with Santos as a farm-in partner resulted in the Casino discovery offshore (Poynton, 2003). Onshore, a Santos joint venture exploration program discovered three new gas fields. Elsewhere in the basin, a high level of exploration activity persists with other groups currently at various stages of their exploration programs.

2. Generalised Stratigraphic scheme

The Otway Basin sedimentary fill comprises five unconformity-bounded successions (Fig. 2): the Otway Supergroup, and Sherbrook, Wangerrip, Nirranda and Heytesbury groups.

Otway Supergroup

The Casterton Formation and the oldest section of the overlying Otway Supergroup, the Crayfish Group, are synrift units comprising nonmarine to lacustrine reservoir source and seal intervals, which are prospective and productive in the onshore Otway Basin at Katnook. Onshore, the Casterton Formation is an organic rich, oil prone, algal shale, intersected in Robertson-1, in the Penola Trough. This interval is described as a 'torbanitic lamosite' with 10% by volume oil shale (Struckmeyer, 1988). Rock Eval analysis within the interval gives a TOC=7.05%, HI=515 mg HC/g TOC and OI=25 mg CO_2/g TOC, indicating an excellent Type I/II source rock (Trupp et al., 1994). These early rift sediments are preserved in discrete narrow half grabens onshore. Similar half grabens are interpreted from seismic data to exist offshore (e.g., on the Crayfish Platform, Moore et al., 2000; and in the Torquay Sub-basin, Trupp et al., 1994). On the Crayfish Platform, these units are preserved beneath a relatively thin Late Cretaceous and Tertiary section, making them potential targets in this western offshore part of the basin.

The overlying Eumeralla Formation was deposited in a rift to sag setting. Regionally, sediments were deposited in a vast fluvial system that transported predominantly dacitic clastic material into the Gippsland, Bass, Otway, Eromanga, Surat and Clarence–Moreton basins (Bryan et al., 1997), an interpretation supported by detailed petrographic work (Duddy, 1983). Volcaniclastic sediment supply was so great that the proportion of continentally derived sediment was as low as 25% in the southeastern basins. Input of continentally derived sediments is variable and appears to be more prominent in the west of the Otway Basin where the quartz-rich Heathfield Sandstone Member is preserved. In addition, the first appearance of marine influence indicators, dinoflagellates and algal acritarchs reported in the Troas-1/ST1 well completion report, suggests a shift to lower energy facies at this more distal end of the basin.

The lower Eumeralla Formation (*P. notensis*–lower *C. paradoxa*) has good oil and gas source potential. It contains up to 10% by volume dispersed organic matter (DOM), shaly coal and thin (1–2 m) coals. The DOM contains between 20 and 60% liptinite of variable composition. The shaly coals are usually liptinite and locally grade to canneloid shales. The coals are dominantly vitrinite, but may contain up to 23% liptinite, which would indicate more lacustrine conditions during deposition.

The upper Eumeralla Formation contains less organic matter, typically 3–4% by volume. Vitrinite-rich coals, which have only poor oil source potential, are dominant. HI is typically <100 mg HC/g TOC, indicating a kerogen Type III, humic source type (Struckmeyer, 1988).

Coal-rich units in the Eumeralla Formation can be recognised seismically as intervals of slightly higher amplitude reflections with moderate to low continuity. Seismic character indicates that the source rocks are not uniformly developed. The best seismic signature appears to coincide with sag axes of the Eumeralla Formation depocentres. The Eumeralla Formation source rocks and stratigraphic characteristics are described in detail by Struckmeyer (1988), Struckmeyer and Felton (1990), and Mehin and Link (1996).

Sherbrook Group

The Late Cretaceous synrift deposition of the Sherbrook Group was coeval with a major sea level rise resulting in the first major marine incursion into the Otway Basin. Large deltas prograded southwards across the marginal platforms into the Voluta Trough, where the Sherbrook Group is in excess of 5000 m thick. A three-fold stratigraphic subdivision is recognised in the Sherbrook Group: the basal Waarre Sandstone; the Flaxman Formation; and an overlying sequence comprising the Belfast Mudstone, Nullawarre Greensand, Paaratte Formation and Timboon Sandstone that represent facies equivalents within major prograding delta complexes.

The shallow marine, lower to upper-deltaic sediments of the Waarre Sandstone and Flaxman Formation represent the initial deposits of the Late Cretaceous transgression. These were deposited on an irregular and structured Eumeralla Formation surface with considerable variability in depositional facies depending on the local setting. Depositional styles in this interval range from high energy sandy fluvial systems to shallow marine, low clastic input embayments dominated by claystone deposition.

From the Coniacian to Santonian, sedimentation was dominated by open marine conditions leading to the deposition of the inner to outer shelf Belfast Mudstone (Laing et al., 1989). Ongoing local structuring had less influence on facies offshore, where significant growth occurs in the marine Belfast Mudstone across a series of active faults. This is most evident on the Mussel Platform and Bridgewater Bay–Discovery Bay High areas. In wells to the east on the Prawn Platform and to the west in the Morum Sub-basin, coarse clastic sediment supply was relatively high, resulting in generally more proximal deltaic and inner shelf deposition. At these eastern and western ends of the Otway Basin, growth on the active faults is likely to have resulted in an increase in local structural controls on reservoir and seal facies development. This introduces an increased reservoir and seal risk in these areas.

Deposition of the Sherbrook Group, although controlled by active rift-related tectonism, was also influenced by wrench-related processes increasingly to the east. Synchronous faulting and large scale folding in the Coniacian to Santonian associated with inversion of deeper half grabens created such features as the Shipwreck Trough. The Shipwreck Trough, as described by Miller et al. (2002), is a sinistral transtensional graben located over the lithospheric boundary between the Delamerian and Lachlan fold belts. Structural failure along this boundary may have influenced the development of the Tasman Fracture Zone. Recent studies on basement elements demonstrate the importance of these major structures in the development of petroleum systems across the whole basin (Bernecker and Moore, 2003).

It is interpreted that structuring related to movement along this boundary in the Late Cretaceous initially provided a focus for deposition of the Waarre Sandstone in the Shipwreck Trough. Subsequent structuring both isolated the trough from direct sediment input and enhanced accommodation, resulting in the accumulation of a thick, higher quality Belfast Mudstone seal in this area.

From the Santonian to Maastrichtian, regressive, shallow marine, lower to upper-deltaic and interdistributary sediments of the Nullawarre Greensand, Paaratte Formation and Timboon Sandstone prograded over the Belfast Mudstone. Structuring during this period was diminished and depositional patterns were primarily controlled by variation in sediment supply along the basin.

It is considered that the stratigraphy of the Sherbrook Group is yet to be resolved to a level adequate to lower the risk of hydrocarbon exploration. More detailed stratigraphic work has recently been published by a number of authors. These include Partridge (2001), describing a revised stratigraphy of the Sherbrook Group, and Boyd and Gallagher (2001), interpreting sedimentology and depositional environments. These and similar studies need to be integrated with modern higher quality seismic to interpret and 'de-risk' this important interval.

Wangerrip, Nirranda and Heytesbury groups

Renewed structuring and regional uplift occurred during Maastrichtian continental breakup along the Otway Basin section of the Australian–Antarctic margin, producing the Late Maastrichtian Unconformity (Lavin, 1997). Post-rift (Tertiary and Recent) sediments were deposited on the continental shelf in a divergent, passive margin setting as Antarctica separated and drifted farther away from Australia with concurrent opening of the Southern Ocean. Wrench-related processes, although diminished, continued until the Eocene.

Passive margin development in the Tertiary is first represented by the sandstones and mudstones of the Paleocene Wangerrip Group. These sediments, deposited in coastal plain, deltaic and inner shelf environments, unconformably overlie the Sherbrook Group. Siliciclastic progradation terminated abruptly in the Eocene with a major marine transgression and deposition of the calcareous Nirranda Group (Arditto, 1995). The basal mixed siliciclastics and carbonates of the Mepunga Formation represent proximal marine sediments that are conformably overlain by the open marine Narrawaturk Marl. Following an Oligocene sea level fall and development of a regional unconformity, the open marine, predominantly calcareous, Miocene Heytesbury Group was deposited throughout the Otway Basin (Gallagher and Holdgate, 2000).

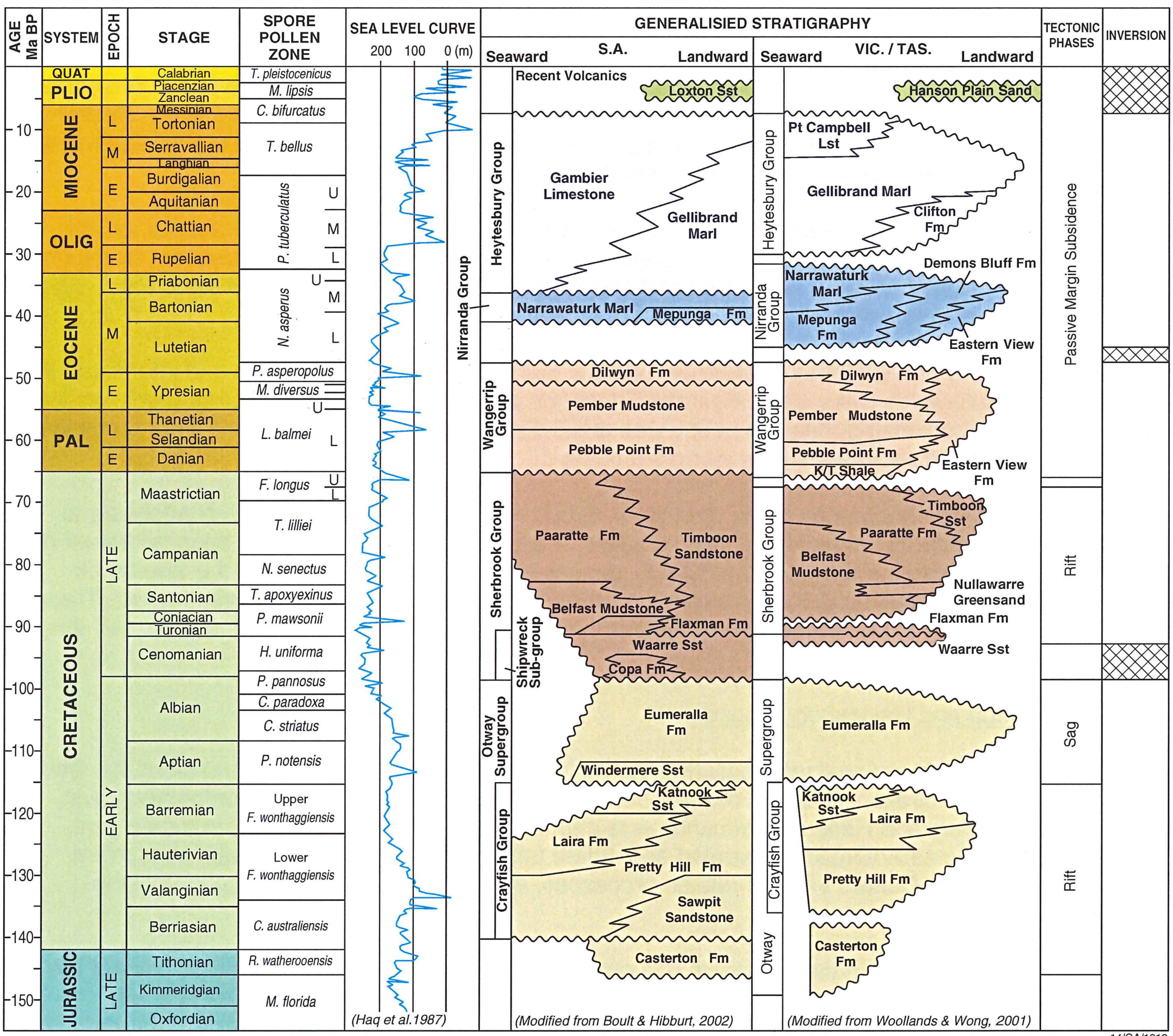

Figure 2. Stratigraphic chart of the Otway Basin using terminology from Boult and Hibburt (2002) and Woollands and Wong (2001). Note: terminology used within the well descriptions reflects that used at the time of drilling.

3. Well information

Basic Information

The primary sources of information for this report are the well completion reports (WCRs) submitted by the permit operator upon completion of the well. Copies of WCRs are available from the Petroleum Data Repository at Geoscience Australia at www.ga.gov.au. In each summary, the source of unpublished biostratigraphic reports is provided. Data contained in these reports can be obtained from Geoscience Australia's STRATDAT Oracle-based biostratigraphic database (www.ga.gov.au/oracle/apcrc).

Stratigraphy

A generalised stratigraphic chart for the Otway Basin is presented in Figure 2. The stratigraphic nomenclature used in each well reflects that which was current at the time of drilling, we have not attempted to update the terminology to represent changes that have occurred in Otway Basin nomenclature. Some variations in nomenclature are apparent, e.g., Belfast Mudstone is variably termed "Belfast Shale", "Belfast Formation" and "Belfast Shale Formation". Recent stratigraphic summaries can be found in Boult and Hibburt (2002), and Woollands and Wong (2001).

Potential Source Rocks and Maturity

ORGCHEM, Geoscience Australia's Oracle-based geochemical database (www.ga.gov.au/oracle/apcrc), is the source of the bulk Rock Eval pyrolysis and vitrinite reflectance (VR) data used in this study. Sample ages were estimated using age-depth curves generated from Geoscience Australia's STRATDAT Oracle-based biostratigraphic database, and later verified against current well log interpretations. The geochemistry and biostratigraphic data in Geoscience Australia's databases were compiled from WCRs submitted under the Petroleum Submerged Lands Act (PSLA) 1967, and destructive analysis reports submitted to Geoscience Australia by external agencies.

Porosity and Permeability

RESFACS, Geoscience Australia's Oracle-based reservoir facies database (www.ga.gov.au/oracle/apcrc), is the source of the porosity and permeability data used in this study. The data were compiled from WCRs submitted under the Petroleum (Submerged Lands) Act (PSLA) 1967, and destructive analysis reports submitted to Geoscience Australia by external agencies following analyses of sediment samples from the Core and Cuttings Repository.

Well Logs

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

Seismic Images

Figures of seismic data are based on Geoscience Australia and open-file surveys in the Otway Basin. Geoscience Australia lines are published with the permission of Fugro MCS.

3.1 Crayfish Platform-Chama Terrace

The Crayfish Platform and Chama Terrace, located landward of the Tartwarp–Mussel fault zone, are characterised by thick Early Cretaceous synrift and synrift to sag intervals, with thin overlying Late Cretaceous and Tertiary sections. These synrift intervals have proven to be economically prospective onshore for gas and oil (e.g., Katnook, Ladbroke Grove, Haselgrove, Haselgrove South and Redman fields in the Penola Trough). The Chama Terrace marks the edge of the Crayfish Platform where the Late Cretaceous section expands over a series of faults into the Morum Sub-basin. Resolution of the Early Cretaceous structures is possible, with only thin, fairly uniform and lightly structured overlying Late Cretaceous and Tertiary sections.

The Late Cretaceous Sherbrook Group section comprises non-marine to shallow marine shelfal facies. Adequate reservoir and seal pairs were developed in some settings where local structuring, sediment supply and eustatic conditions resulted in the development of seal facies in environments such as interdistributary settings. On the Crayfish Platform, Late Cretaceous–Tertiary loading was minimal reducing the potential for late generation and expulsion of hydrocarbons.

Trumpet-1

WELL SUMMARY

Operator	Esso Exploration and Production Australia Inc
Date Spudded	11 December 1973
TD Date	22 December 1973
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No significant shows encountered
UNO	W5730005
Permit	EPP2
Latitude	37° 05' 47.353" S
Longitude	139° 24' 42.379" E
Reference datum	Not provided in WCR
Projection	Not provided in WCR
KB (m) datum	9.75 m
Water Depth	49.4 m
TD (mKB)	2256 m
Age at TD	Early Cretaceous
Primary Objective	Intra-Pretty Hill Formation sandstone
Secondary objective	None stated
Play/Trap Type	Faulted anticline
Reason for failure	Lack of source and/or migration.

DATA SUMMARY

Palynology:

The original palynological analysis was undertaken by Stover, L.E., (1974). "*Palynological determinations for Trumpet-1, Otway Basin, Australia.*", and is contained in Appendix 4 of the WCR. Palynology is based on assemblages from 28 sidewall cores (SWCs) and 2 core samples.

A reinterpretation of the same samples was performed by Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report, 1996/5.

Additional analysis was also done by Macphail, M.K. (1998). "*Revised age determinations based on palynological data of L.E. Stover (1974)*", appended to the Trumpet-1 WCR. Macphail (1998) examined the report by Stover (1974) and found there was insufficient detail to review the age determinations.

Micropalaeontology:

The original micropalaeontological analysis was performed by Taylor, D.J. (1974). "*Trumpet-1 Foraminiferal Biostratigraphy*", and is included in Appendix 4 of the WCR. This report contains no species listing or range chart.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (mKB)	Comments (Core recovery %)
Core-1	1313.4	1321.3	7.9	100% recovery
SWC	851	2240.3	30 of 30	100% recovery
Cuttings	210	2256		3–9.1 m sample interval (drill rate dependant)

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Run	Tool string	Interval (mKB)	Comments
1	CAL	158.5–841.2	Run 1, 91.45–842.5 mKB
1 and 2	ISF–SONIC	166.4–2244.9	Run 2, 823.6–2244.8 mKB
1 and 2	FDC–CNL	1188.7–2244.2	
1 and 2	HDT	1188.7–2244.2	with directional survey
2	GR	823.6–2244.2	

Velocity Survey:

A checkshot velocity survey was run over the interval 989.7–2225 mKB. A total of 5 levels were surveyed with records reported to be very good. The report can be found in Appendix 5 of the Trumpet-1 WCR.

Well Tests:

No FITs, DSTs or Production tests were carried out.

PRIMARY OBJECTIVE

The primary objective of Trumpet-1 was to test a faulted anticlinal closure within the Early Cretaceous Pretty Hill Formation. Intraformational seals are required for an effective trap to exist.

SECONDARY OBJECTIVE

None stated.

STRUCTURE

Trumpet-1 was located over a southeast plunging, faulted anticline (Fig. 3) interpreted to be related to right lateral wrench movement on faults flanking the basement high to the north (Eyles, 1974). The trough to the south could provide a large drainage area for any hydrocarbons sourced from mudstones and shales within the Eumeralla and Pretty Hill formations that were intersected in the well (Fig. 4), or from deeper intervals. Structuring in the upper section in the vicinity of Trumpet-1 appears insignificant.

Seismic lines, cross sections and maps contained in enclosures 1 to 6 of the WCR show that the main period of growth of the structure was Early Cretaceous, prior to deposition of the Eumeralla Formation, with a significant angular unconformity at the boundary (Eyles, 1974). The intra-Pretty Hill Formation structure contour map in enclosure 3 of the WCR shows the well was located on a fault bounded four-way dip closed anticlinal dome. Postdrill interpretation of the structure remained largely unchanged (Eyles, 1974).

SOURCE ROCKS

The prognosed source rocks were the Early Cretaceous Eumeralla Formation mudstones, or shales within the Pretty Hill Formation (Fig. 4). Additional source potential may come from the Casterton Formation below the TD of Trumpet-1. Oil prone source rocks of the Casterton Formation developed in the early synrift grabens onshore may be present beneath the Crayfish Platform.

The Early Cretaceous Eumeralla Formation down to approximately 1300 mKB has TOC values typically <2% with an increase up to 4% in the coaly lower third of the interval. HIs indicate a gas prone source (Appendix 1). Maturity levels from Tmax and VR data show the interval to be immature for oil (VR <0.5%). It is unlikely that the Eumeralla Formation is an effective source in this area.

The Early Cretaceous Pretty Hill Formation below 1300 mKB has TOC values typically <1%, decreasing down section (Appendix 1). HIs indicate poor gas prone source. Maturity levels from Tmax and VR data show the interval to be just mature for oil at the well TD. The shales and sandstones here are interbedded with sands and silts with shale thicknesses rarely over 10 m. The net to gross is approximately 70% sandstone.

Trumpet-1 is located on the edge of a significant trough where, below the TD of the well (Fig. 3), Early Cretaceous to Late Jurassic Casterton Formation source rocks may be present. From basin wide timing and maturity studies, these source rocks would have reached maturity at some point near the mid Cretaceous

(Duddy, 1997). Tertiary loading here is less than 450 m. As such, it is considered unlikely that late reinitiation of any source rocks has occurred in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

The single core taken near the top of the Pretty Hill Formation at 1313.4 mKB (Fig. 4) has porosities in the range of 13 to 27%, with permeabilities up to 950 mD (Fig. 5). The sands are fine to medium grained, non-marine facies with thin interbeds of shale, siltstone and minor coal. No log porosities were calculated.

SEAL

Intraformational seals within the Pretty Hill Formation are required to be thick and extensive to provide both a seal across the area of the domal intra-Pretty Hill Formation structure, and adequate migration surfaces over the drainage area. Good, reasonably thick potential seals are present within the Pretty Hill Formation and would likely provide a seal for hydrocarbons in the domal closure. Even allowing for the presence of such extensive seals, it is difficult to understand a viable mechanism in this setting that would provide migration access from the proposed primary source, the overlying Eumeralla Formation. Any intra-Pretty Hill Formation trap is dependent on deeper source rocks for charging.

The basal part of the Eumeralla Formation is argillaceous and coaly and likely to be a good top seal. However, at this level the mapped closure is downthrown, juxtaposing the reservoir on either side of the fault. Seal potential here is very low.

SHOWS

No significant shows were recorded in this well.

RESULTS

The stratigraphic succession penetrated by Trumpet-1 was as predicted, although no predrill prognosis was made for the Tertiary interval. The well intersected good intraformational seals and sandstones within the Pretty Hill Formation, and was a valid structural test of the four-way dip closure. Therefore, any migrated and trapped hydrocarbons from deeper in the section would probably be intersected. However, the primary source is interpreted to be the overlying Eumeralla Formation, with difficult migration pathways into sealed reservoirs within the Pretty Hill Formation. Therefore, the primary cause of failure for Trumpet-1 appears to be lack of adequate source and migration. It is difficult to see how Eumeralla Formation sourced hydrocarbons can access any sealed intra-Pretty Hill Formation structure. Hydrocarbons would, therefore, need to migrate from deeper in the section.

REFERENCES

EYLES, D.R., 1974. Trumpet No.1, S.A., Well Completion Report. Esso Exploration and Production Australia Inc (unpublished).

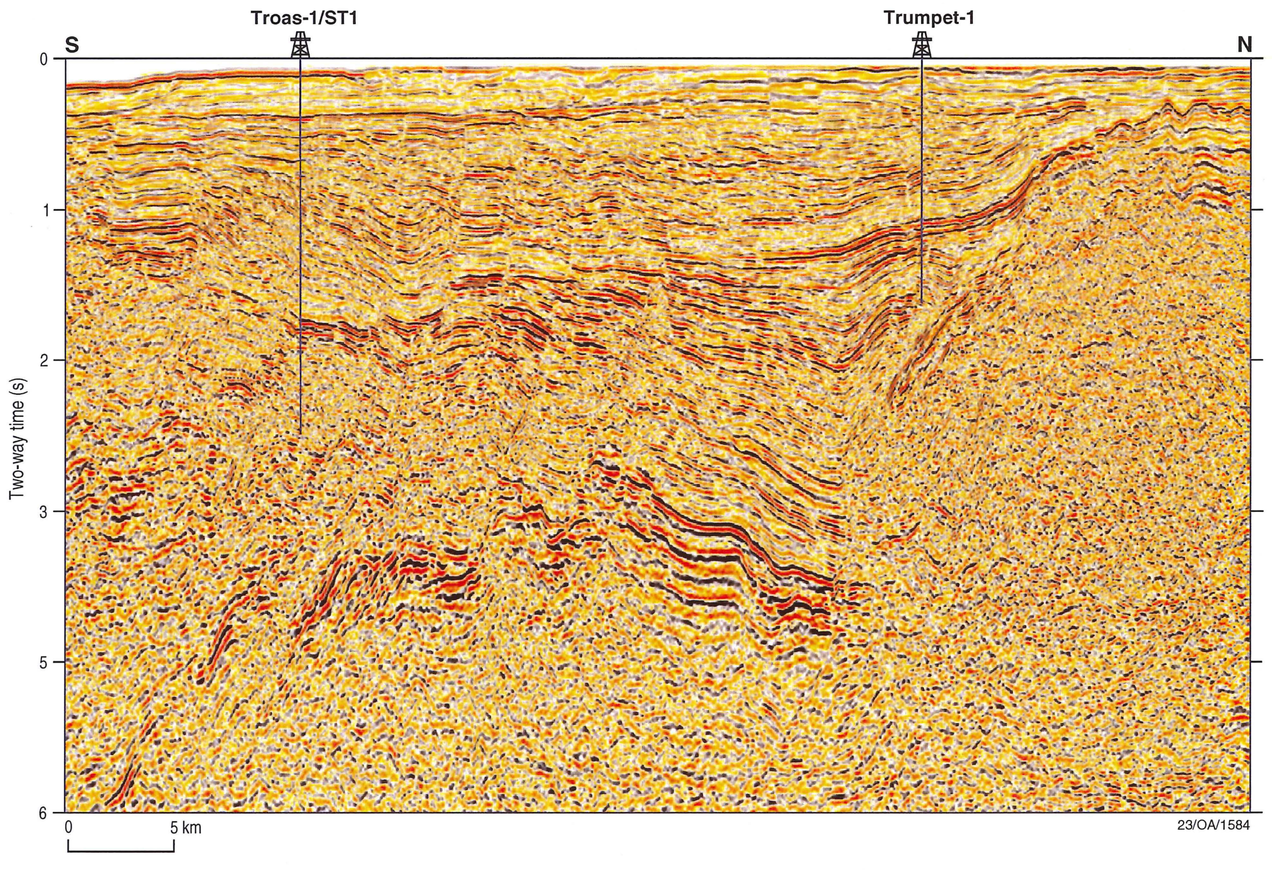

Figure 3. Seismic section showing location of Troas-1/ ST1 and Trumpet-1. Seismic reproduced with permission of Fugro MCS.

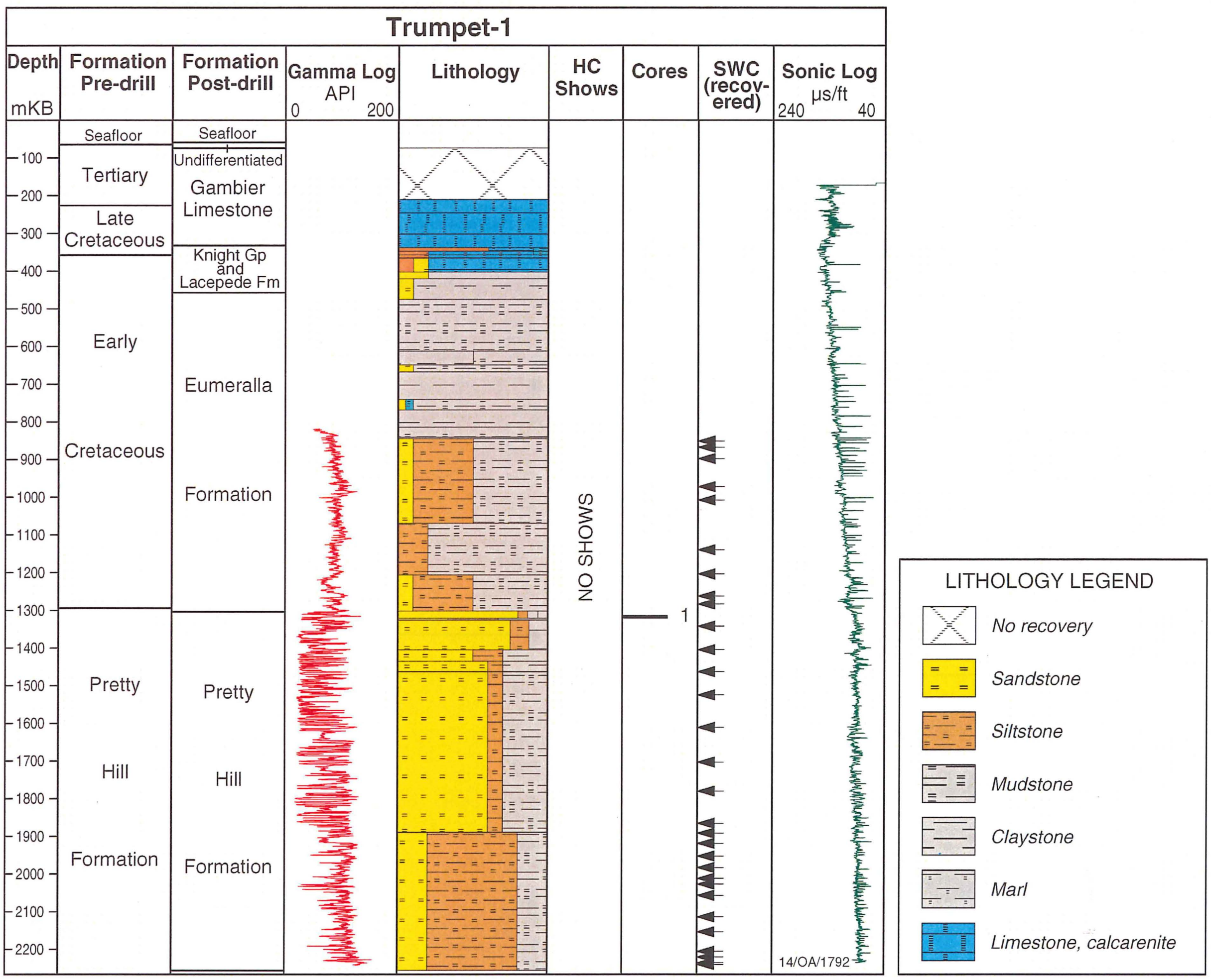

Figure 4. Trumpet-1 well composite.

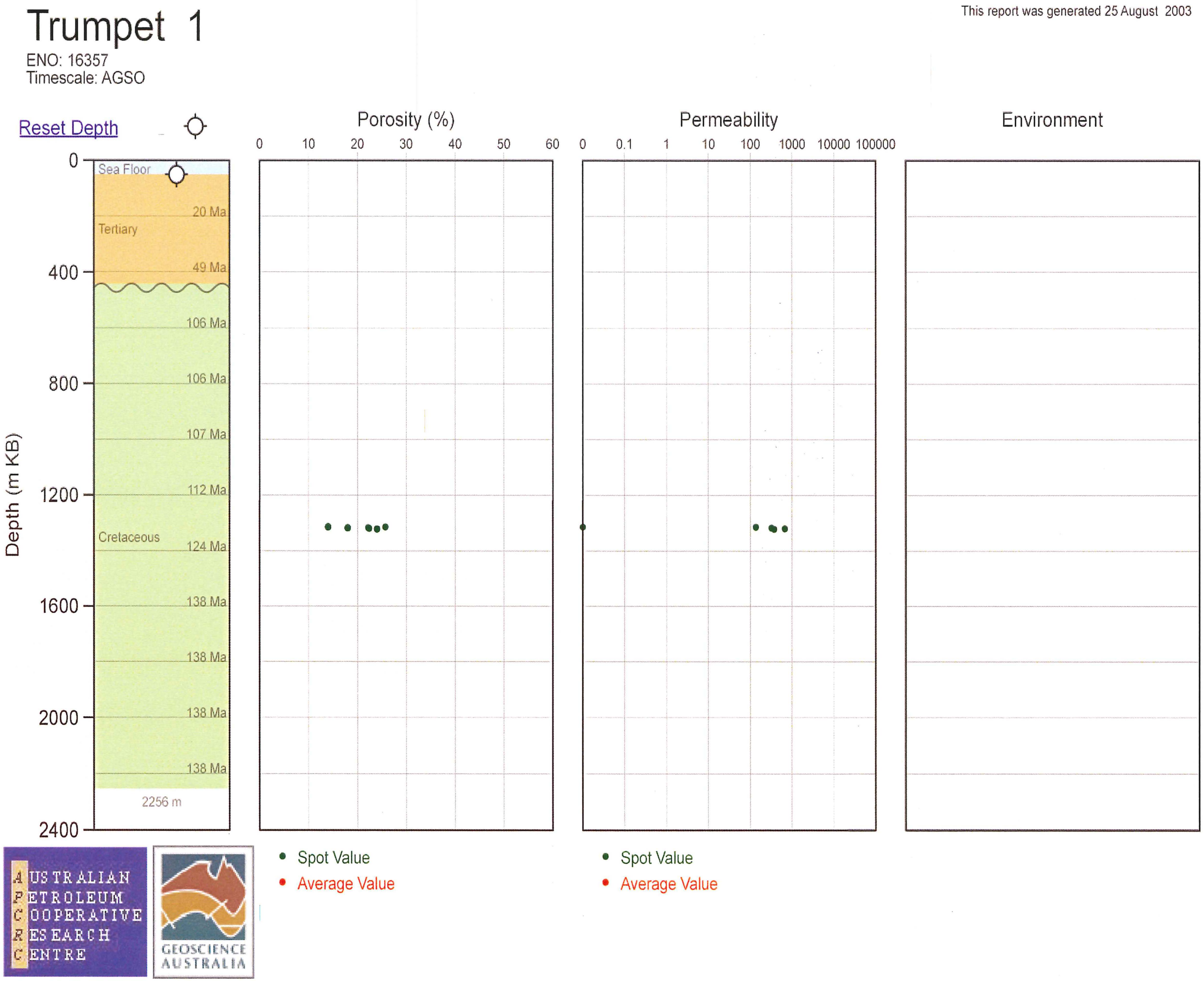

Figure 5. Porosity and permeability measurements recovered from Trumpet-1. Source: www.ga.gov.au/oracle/apcrc. Acce sse dAugust, 2003.

Crayfish-A1

WELL SUMMARY

Operator	Esso Standard Oil (Australia) Ltd.
Date Spudded	24 September 1967
TD Date	20 December 1967
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No significant shows encountered
UNO	W5670009
Permit	OEL26
Latitude	37° 17' 22" S
Longitude	139° 35' 50" E
Reference datum	Not provided in WCR
Projection	Not provided in WCR
RT (m) datum	28.3 m
Water Depth	77.7 m
TD (mRT)	3199 m
Age at TD	Early Cretaceous
Primary Objective	Jurassic sands
Secondary objective	Early and Late Cretaceous sands
Play/Trap Type	Faulted anticline block
Reason for failure	Drilled outside closure

DATA SUMMARY

Palynology:

The original palynological analysis was undertaken by Dettmann, M. E., (1968). "*Palynological report on Esso Crayfish A-1well 1110–10439 feet*". The report is included in Appendix 2 of the WCR.

Additional analyses were performed by:
Morgan, R., (1985). "*Palynology of Crayfish A-1*", prepared for Ultramar Australia.

Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report, 1996/5

Morgan, R., (1998). "*New Crayfish-1 palynology and revision of Sophia Jane*", included as an addendum to the WCR.

and, Macphail, M. K., (1998). "*Revised age determinations based on palynological data of Dettmann (1968)*", appended to the Crayfish-A1 WCR.

Micropalaeontology:

The original micropalaeontological analysis, Taylor, D. (1968), "*Foraminifera Biostratigraphy-Esso Crayfish A-1 well, Otway Basin, South Australia*", is included in Appendix 2 of the WCR.

Additional analysis was undertaken by Macphail, M. K., (1998). "*Revised age determinations based on micropalaeontological data of Taylor (1968)*", appended to the Crayfish-A1 WCR.

Cores and cuttings:

Sample Type	Top (mRT)	Base (mRT)	Recovered (m)	Comments (Core rec. %)
Core-1	333.2	340.2	0.15	2.2
Core-2	449.0	461.8	0.15	1.2
Core-3	540.4	549.6	9.14	100.0
Core-4	692.8	702.0	7.62	83.3
Core-5	845.2	852.2	1.83	26.1
Core-6	1004.9	1006.8	1.83	100.0
Core-7	1007.4	1013.8	0.00	0.0
Core-8	1172.6	1178.1	4.27	77.8
Core-9	1318.3	1323.1	0.24	5.0
Core-10	1323.1	1326.2	0.15	5.0
Core-11	1467.9	1475.5	3.75	49.2
Core-12	1522.2	1531.3	7.62	83.3
Core-13	1615.7	1624.6	8.84	100.0
Core-14	1624.6	1633.7	9.14	100.0
Core-15	1656.0	1663.3	7.32	100.0
Core-16	1691.9	1700.5	8.53	100.0
Core-17	1700.5	1709.6	8.84	96.7
Core-18	1856.5	1860.8	4.27	100.0
Core-19	2011.7	2016.3	2.74	60.0
Core-20	2168.0	2177.2	8.53	93.3
Core-21	2302.2	2305.2	3.05	100.0
Core-22	2465.5	2473.2	6.40	84.0
Core-23	2626.2	2635.3	8.84	96.7
Core-24	2769.4	2778.9	9.45	100.0
Core-25	2778.9	2788.0	6.40	70.0
Core-26	2908.1	2913.0	4.88	100.0
Core-27	3034.6	3037.6	2.13	70.0
Core-28	3186.4	3195.5	9.14	100.0
SWC	362.7	3187.0	60 of 69	86.9% recovery
Cuttings	240.0	3199.0		3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Run	Tool string	Interval (mRT)	Comments
1	IES–SGRC–FDC	226.2–756.8	Run 1, 226.2–757.7
1	MLL	493.2–762.0	
1	CDM	225.6–754.1	Dipmeter
1	CTR	1524.0–1667.6	Gamma Ray
2	IES–SGRC–FDC–CDM	716.3–1731.9	Run 2, 719.3–1734.9
2	MLL	1158.2–1219.2	
3	IES–SGRC–FDC	1717.2–2792.6	Run 3, 1717.2–2792.6
3	MLL	1585.0–1732.2	
3	CDM	1716.9–3198.3	
4	IES–SGRC	2728.0–3199.5	

Velocity Survey:

A checkshot velocity survey was run at 1768 mRT and again at 3199.5 mRT. A total of 10 levels were surveyed with records reported to be very good apart from some cyclic noise from the geophone. The report is included in the WCR as part of Appendix 6, starting on page 123.

Well Tests:

To obtain data on hydrocarbons, formation fluid and pressure characteristics, testing using the RFT was run at 1598.4, 1599.3 and 2782.5 mRT.

Test type	Depth (mRT)	Result	Comments
RFT-1	1598.4	No reliable pressure data obtained. 800 cc mud recovered.	Thick, F–VF grained sand w/ mud log gas show
RFT-2	1599.3	Packer failed 16,000 cc mud filtrate + 100 cc mud recovered	Thick, F–VF grained sand w/ mud log gas show
RFT-3	2782.5	Shaped charge misfired. No fluid recovery	Cores 25 & 26 showed pinpoint to even yellow fluorescence in tight sandstone
RFT-4	2782.5	RFT-3 rerun. Recovered 0.15 cu.ft gas, 17500 cc water and sand.	
DST-1	1597.5–1599.3	Casing perforated and well did not flow. Rec. formation water. Solution gas from water. C_1 -4200ppm, C_2 -80ppm (in air)	

PRIMARY OBJECTIVE

Crayfish-A1 was planned as a stratigraphic test, designed to evaluate the following;

- Regional stratigraphy and interpreted seismic structure in an undrilled portion of the South Australian Otway Basin.
- Lithology of the offshore section, previously conjectural. Predrill, a Jurassic section was prognosed.
- A partial evaluation of the hydrocarbon potential of the Otway Basin in South Australia.
- The presence or absence of hydrocarbons on the Crayfish prospect.

SECONDARY OBJECTIVE

The secondary objectives of Crayfish-A1 were Cretaceous sandstones above the top Jurassic unconformity.

STRUCTURE

Crayfish-A1 was located on the crest of a northeast–southwest trending faulted anticline mapped on a regional unconformity that intersects the well trace at ~1.5 s (Fig. 6). It was interpreted that the unconformity surface had ~107 m of closure, truncating northeast dipping "Jurassic" beds (James, 1967). A trap was postulated to exist beneath the anticlinal high created by the unconformity surface, with hydrocarbons reservoired in the underlying "Jurassic" beds (James, 1967). It was also suggested that the majority of structural movement occurred in the late Early Cretaceous, post-dating the unconformity surface. Therefore, the anticline could provide a trap for the basal Early Cretaceous sandstone possibly present above the unconformity surface (James, 1967).

Postdrill interpretation indicates that a downfaulted block on the crest of the anticline destroyed closure on the structure (James, 1967). The seismic example and postdrill map presented in the Neptune-1 WCR show the well was positioned on the downthrown side of a small fault cutting the broader structure (Eyles, 1975). Fault throw was interpreted from this map to be ~45 m, with the well located a similar distance downdip from the trap crest. Mapping at the top of the Pretty Hill Formation suggested that Crayfish-A1 penetrated the reservoir at, or below, the dip spill level of the structure present to the west toward Neptune-1. Also, because of the dip of the Pretty Hill Formation sub-crop beds, the well tested potential traps progressively farther downdip with increasing depth of the well.

The well results did not significantly change the interpretation of the structural form. However, palynological results indicated the unconformity surface developed within the Early Cretaceous. Therefore, the sub-cropping, rotated reflections below the unconformity are, in part, Early Cretaceous (James, 1967). The well intersected Early Cretaceous Pretty Hill Formation to at least 2743 mRT, with possible Jurassic rocks below 2771 mRT (Fig. 7).

SOURCE ROCKS

Two source intervals were examined (Appendix 1), the Early Cretaceous Otway Group and Pretty Hill Formation equivalent (Fig. 7).The Otway Group, down to approximately 1600 mRT, has TOC values typically <1%, with a slight increase in TOC through the coaly lower third of the interval. HIs indicate a gas prone source. It is interesting to note that no coaly facies appears to have been sampled (no coal TOCs). Maturity levels from Tmax and VR data show the interval to be immature for oil (VR <0.5%).

The Early Cretaceous Pretty Hill Formation equivalent below 1600 mRT, and the possible Jurassic interval (below 2771 mRT), have higher TOC values than the Otway Group (typically between 1 and 2%), with a slight increase in the lower third of the interval (some values up to 4.59%). HIs indicate a gas to wet gas prone source, with some oil prone interbedded intervals (HIs 300–500 mg HC/g TOC). Maturity levels from Tmax and VR data show the interval to be just mature for oil at the top, to just at the gas window at the base. The organic shales and sandstones here are interbedded with sands and silts, with shale thicknesses rarely over 10 m. The net to gross is approximately 70% sandstone.

The effect of Late Cretaceous to Tertiary loading was limited, with less than 500 m of sediment intersected at Crayfish-A1. Therefore, it is considered unlikely that this load is sufficient for late generation of hydrocarbons from the Early Cretaceous and older source rocks.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Potential reservoirs exist in the Tertiary succession and Late Cretaceous Sherbrook Group. Excellent porosities are preserved where sampled (Fig. 8).

The Early Cretaceous Otway Group has limited reservoir development (Fig. 8). Porosity values decrease rapidly downsection in this lithologically immature interval. This is driven by the high amounts of volcaniclastic material, which has undergone diagenetic alteration with increasing depth and temperature. Reservoir quality is better in the Pretty Hill Formation, with porosity values typically between 20 and 30%. Permeability values range between 1 and 1000 mD. Reservoir quality declines less with depth than for the overlying Otway Group. From an oil or gas productivity perspective, the upper portion of this interval has moderate to good quality reservoir characteristics (James, 1967).

SEAL

The primary seal proposed for this target was the interval immediately overlying the unconformity surface. Postdrill this interval was interpreted as the Otway Group, a highly interbedded claystone, siltstone, sandstone and coal interval (James, 1967). This interval has been demonstrated to act as a seal in the onshore Otway and offshore Gippsland basins. Across both basins, the volcaniclastic sediments within the Otway Group altered rapidly with burial producing low porosity and permeability rocks. Therefore, the Otway Group is likely to provide a top and cross fault seal for the underlying Pretty Hill Formation equivalent reservoir sequences. Many thin potential intraformational seals exist within the Pretty Hill Formation equivalent. However, no quantitative data are available on their quality.

SHOWS

Top (mRT)	Base (mRT)	Source	Show	Lithology	Comment
1597		Mud gas	G1	sandstone	Up to 1200 ppm C_1, and 100 ppm C_2. After log interpretation, thought to be solution gas
1646	1656	Mud gas	G1	sandstone	C_1 3200–4000 ppm After log interpretation, thought to be solution gas
2767	3199	Core and cuttings	L0	sandstone & siltstone	Scattered pinpoint and slight yellow cut. Attributed to asphalt like material associated with coals.

Geochemical analysis of bitumens in Crayfish-A1 by Geoscience Australia suggests that the contaminant, gilsonite, may be present (personal communication C. Boreham, 2003), so care should be taken with any inferences made.

RESULTS

Crayfish-A1 intersected a much thicker than expected Early Cretaceous section. This succession contains reservoir quality sands in the Pretty Hill Formation equivalent below the unconformity surface that are effectively sealed above and across faults by the Otway Group. However, at reservoir level the well is located ~45 m downdip from the fault controlled trap crest as indicated on the cross sections in the WCR (James, 1967) and in the map from the later Neptune-1 WCR (Eyles, 1975). Given this downdip location, there would need to be a substantial accumulation at the crest of the structure for hydrocarbons to be present at Crayfish-A1. Additionally, the well penetrates the top Pretty Hill Formation equivalent reservoir at, or below, the interpreted dip spill level of the structure. The spill point is located to the west toward Neptune-1.

The timing of generation and migration (if there are adequate volumes of source and hydrocarbons available), was probably around middle Cretaceous. There appears little chance of late migration through Tertiary loading. Therefore, traps need to be relatively undisturbed to preserve any older accumulations. Seismic data show that some minor Late Cretaceous and Tertiary structuring has occurred, introducing this as a risk element.

REFERENCES

EYLES, D.R., 1975. Neptune No.1, S.A., Well Completion Report. Esso Exploration and Production Australia Inc (unpublished).

JAMES, E.A., 1967. Crayfish No. A1, S.A., Well Completion Report. Esso Standard Oil (Australia) Ltd. (unpublished).

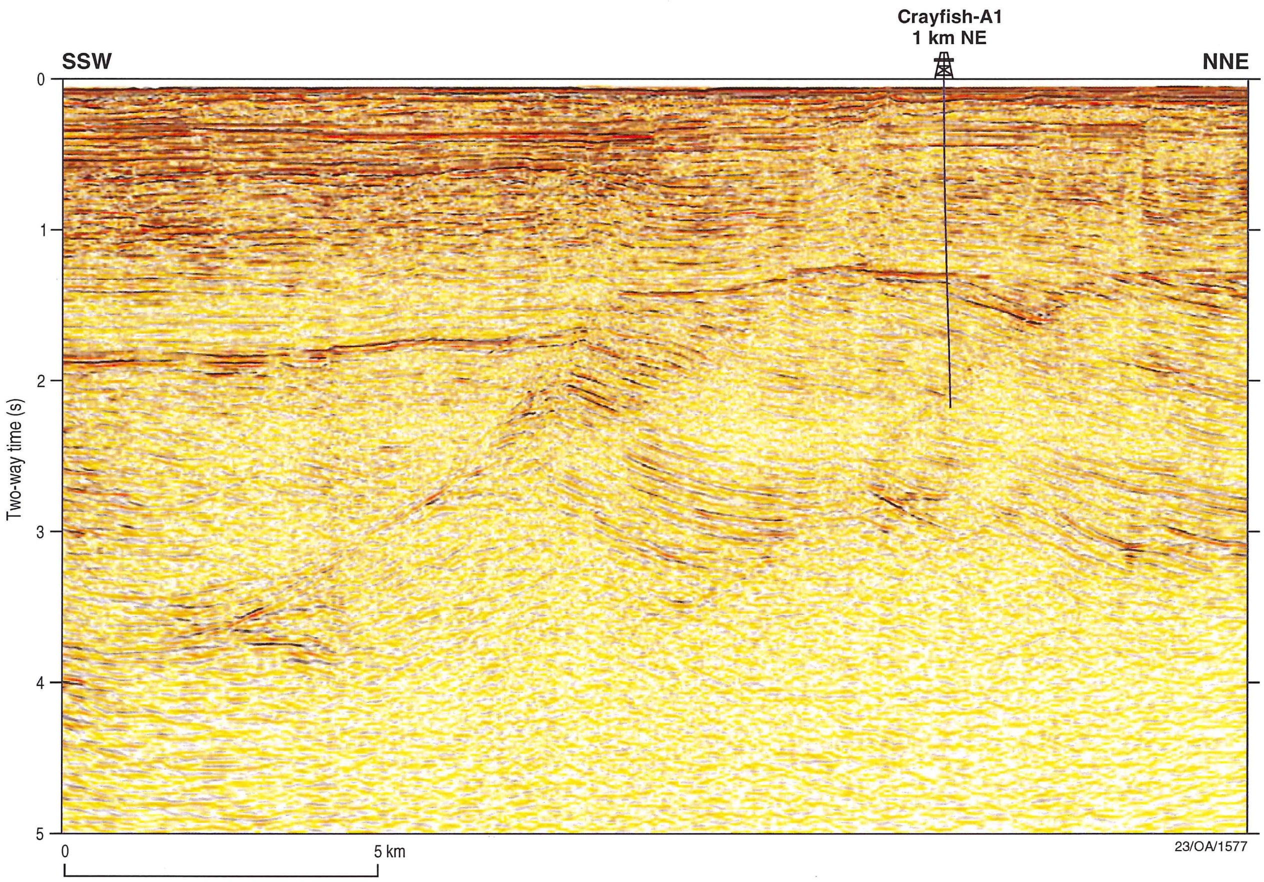

Figure 6. Seismic section showing location of Crayfish-A1.

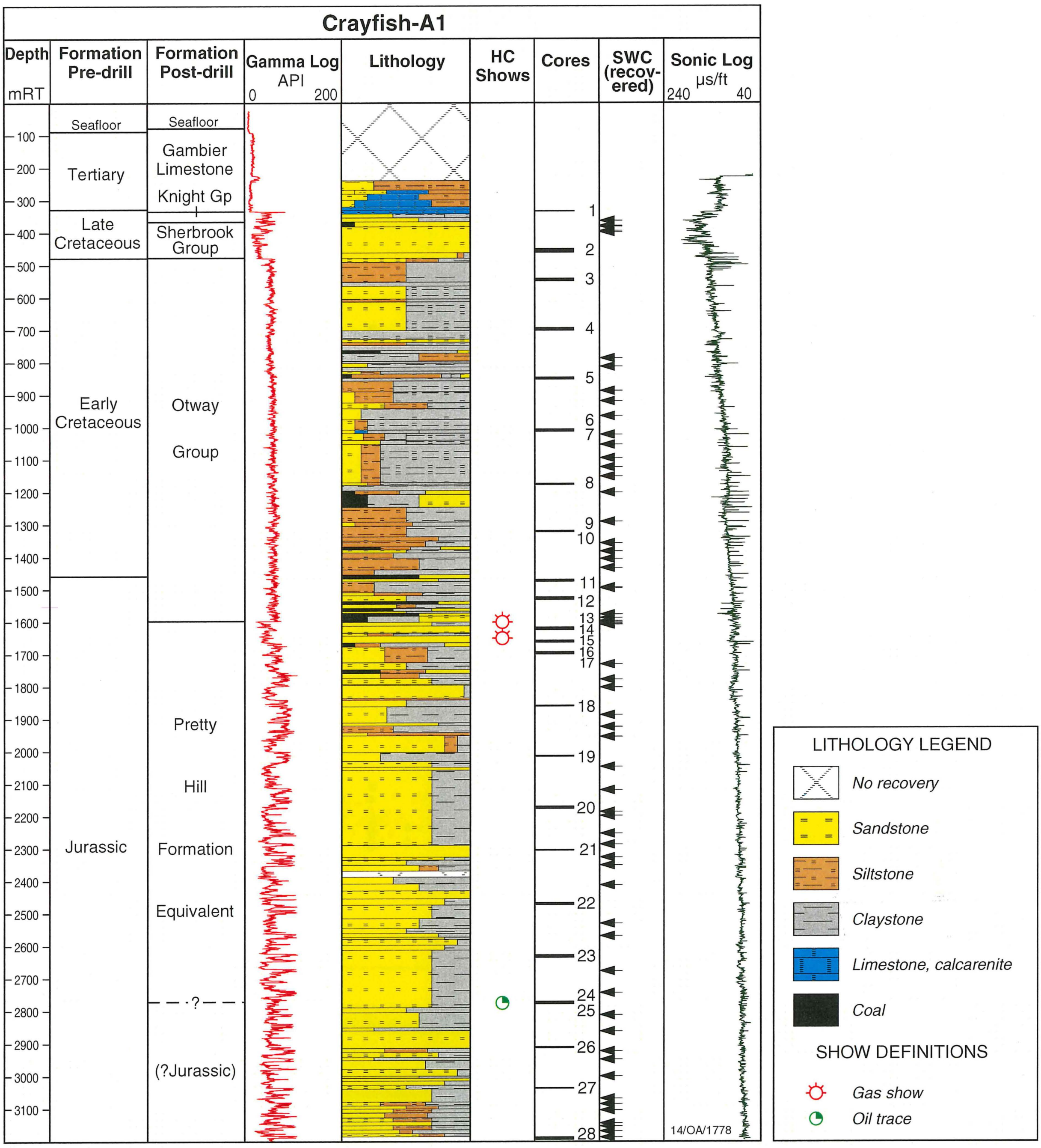

Figure 7. Crayfish-A1 well composite.

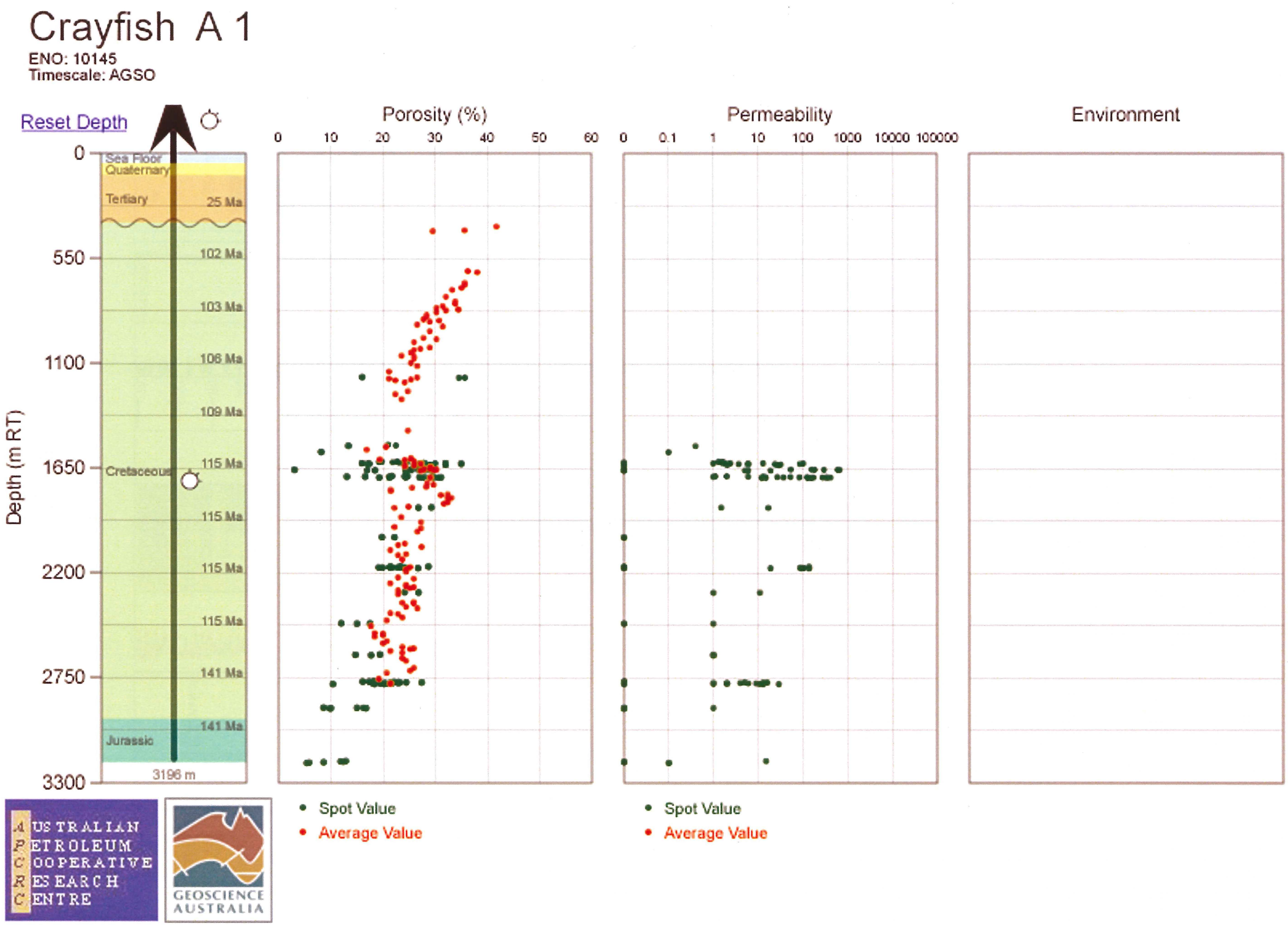

Figure 8. Porosity and permeability measurements recovered from Crayfish-A1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

Neptune-1

WELL SUMMARY

Operator	Esso Exploration and Production Australia Inc
Date Spudded	27 December 1973
TD Date	8 January 1974
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No significant shows encountered
UNO	W5730013
Permit	EPP2
Latitude	37° 18' 12.987" S
Longitude	139° 44' 8.538" E
Reference datum	Not provided in WCR
Projection	Not provided in WCR
KB (m) datum	9.75 m
Water Depth	35.4 m
TD (mKB)	2436 m
Age at TD	Early Cretaceous
Primary Objective	Pretty Hill Formation sandstones
Secondary objective	None stated
Play/Trap Type	Fault block
Reason for failure	Lack of mature source and migration

DATA SUMMARY

Palynology:

The original palynological analysis was undertaken by Stover, L.E., (1974). "*Palynological interpretations for Neptune-1, Otway Basin, Australia*". The report is in the WCR as Appendix 4. The palynological analysis was based on 24 SWCs, of which 16 yielded good assemblages. Stover's examination predates the description of many taxa useful in subdividing the Cainozoic.

A revised analysis based on the range chart and text of the original report was performed by Macphail, M.K. (1998). "*Revised age determinations based on palynological data of Stover (1974)*" This report is appended to the WCR.

Micropalaeontology:

No micropalaeontological analysis was done on this well.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments (Core recovery %)
Core-1	1553.9	1559.3	5.8	90% recovery
SWC	755.9	2429.3	29 of 30	97% recovery
Cuttings	180	2436.0		3–10 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table.

Run	Tool string	Interval (mKB)	Comments
1 & 2	ISF–SONIC	165.0–2436.3	Suite-1, 165–720 mKB
1 & 2	CAL	165.2–2437.5	
2	GR	695.0–2437.5	Suite-2, 695–2437.5 mKB
2	FDC–CNL	1356.4–2437.5	
2	HDT	1356.4–2437.5	

Velocity Survey:

A velocity survey was run over the interval 781.5–2404.6 mKB. A total of 6 levels were surveyed with records reported to be good. The report can be found in Appendix 5 of the WCR.

Well Tests:

No wireline FITs, DSTs or Production Tests were carried out.

PRIMARY OBJECTIVE

Neptune-1 was planned to test a high-side fault closure within a horst block. The target interval were sandstones of the Pretty Hill Formation, sealed by mudstones and shales of the overlying Eumeralla Formation.

SECONDARY OBJECTIVE

None stated in the WCR.

STRUCTURE

Neptune-1 was located over a faulted regional high (Fig. 9). Much of the structuring was interpreted as Neocomian to Aptian (synrift) aged, followed by a period of erosion, giving rise to an angular unconformity at the top Pretty Hill Formation, located at ~1.5 s at the well trace (Fig. 9; Eyles, 1975). Neptune-1 was slightly downdip from the crest at the unconformity and was therefore, a good test of the structure (Fig. 9). If intra-Pretty Hill Formation seals were developed below the unconformity, the well would test the shallowest of these in a crestal position.

Cross-sections in the WCR show the faults controlling the horst die out into the overlying proposed sealing interval of the Eumeralla Formation (Eyles, 1975). The throw on the controlling fault to the south is approximately 180 m, significantly less than the thickness of the Eumeralla Formation (900 m; Fig. 10). The WCR provides a map that shows a well defined robust structural closure (Eyles, 1975). The top of the Pretty Hill Formation well came in ~46 m deep to prognosis. As this was interpreted to be due to velocity variations from the tie at Crayfish-A1, it does not affect the validity of the structure (Eyles, 1975).

SOURCE ROCKS

Two source intervals were examined (Appendix 1), the Early Cretaceous Eumeralla and Pretty Hill formations. The Eumeralla Formation, down to approximately 1400 mKB, has TOC values typically <1%, with a slight increase in the coaly lower quarter of the interval. HIs indicate a gas prone source. Maturity levels from VR data show the interval to be immature for oil (VR <0.5%). The high scatter in the PI and Tmax data most likely arises from measurement error in the very lean source rocks. The Pretty Hill Formation, below 1400 mKB, has higher TOC values typically between 1 and 1.6%, with HIs <100 mg HC/g TOC indicating a very poor quality gas prone source. Maturity levels from VR data show the interval is not quite mature for oil at the well TD.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Potential reservoir intervals from the Late Cretaceous Sherbrook Group occur in the shallow penetrated sequence.

No direct porosity/permeability measurements are available from Neptune-1 in the Early Cretaceous Eumeralla Formation, however, the interval is expected to have limited reservoir development in this area from analyses in Crayfish-A1. This lithologically immature interval shows a very rapid decrease in porosity down through the section. This is driven by diagenetic alteration with increasing depth and temperature of the abundant volcaniclastic material. In the west of the basin, there is a general increase in the amount of quartzose sands present in the Eumeralla Formation.

Reservoir quality for the Pretty Hill Formation similar to that seen in Crayfish-A1 was expected in this well, i.e., a moderate to good quality reservoir with porosity 20-30% and permeability 1-1000 mD, decreasing slowly downsection (Fig. 8). However, core taken from the Pretty Hill Formation (Fig. 10), had relatively poor reservoir characteristics with porosity typically between 7 and 15%, and very low permeability (Fig. 11). Inspection of logs show the core was not located in good reservoir sands.

SEAL

The primary seal proposed for this target was the Eumeralla Formation, an interbedded claystone, siltstone, sandstone and coaly interval (Fig. 10). This interval and its stratigraphic equivalents have been demonstrated to act as a seal in the onshore Otway and offshore Gippsland basins. Across both basins, the high proportions of volcaniclastic sediments altered rapidly with burial producing very low porosity and permeability rocks. The Eumeralla Formation was likely to provide a top and cross fault seal for the underlying Pretty Hill Formation reservoir sequences. In this western area of the basin, however, there are better quality reservoir intervals present within the Eumeralla Formation because of an increase in the amount of quartzose sands that entered the basin. This is likely to restrict seals to the more argillaceous intervals in this formation. Cross-fault mapping of Eumeralla Formation seal and sand units on the Neptune structure would be required before the cross-fault seal question could be answered confidently.

Within the Pretty Hill Formation, there are many potential thin intraformational seals. No quantitative data are available on their quality.

SHOWS

No significant hydrocarbon indications or shows were recorded in this well.

RESULTS

Neptune-1 probably tested a valid trap, with an adequate seal developed over the Pretty Hill Formation target. However, from the geochemical analysis and the lack of significant shows it is considered that the likely reason for failure is lack of adequate mature and expelling source rocks within the drainage area of the trap.

The timing of any hydrocarbon generation and migration here, from a deeper unknown source section, was probably around the middle Cretaceous. As such, any traps need to be relatively undisturbed to preserve older accumulations. There appears little chance of late migration through late loading with only 450 m of Tertiary and Late Cretaceous present.

REFERENCES

EYLES, D.R., 1975. Neptune No.1, S.A., Well Completion Report. Esso Exploration and Production Australia Inc (unpublished).

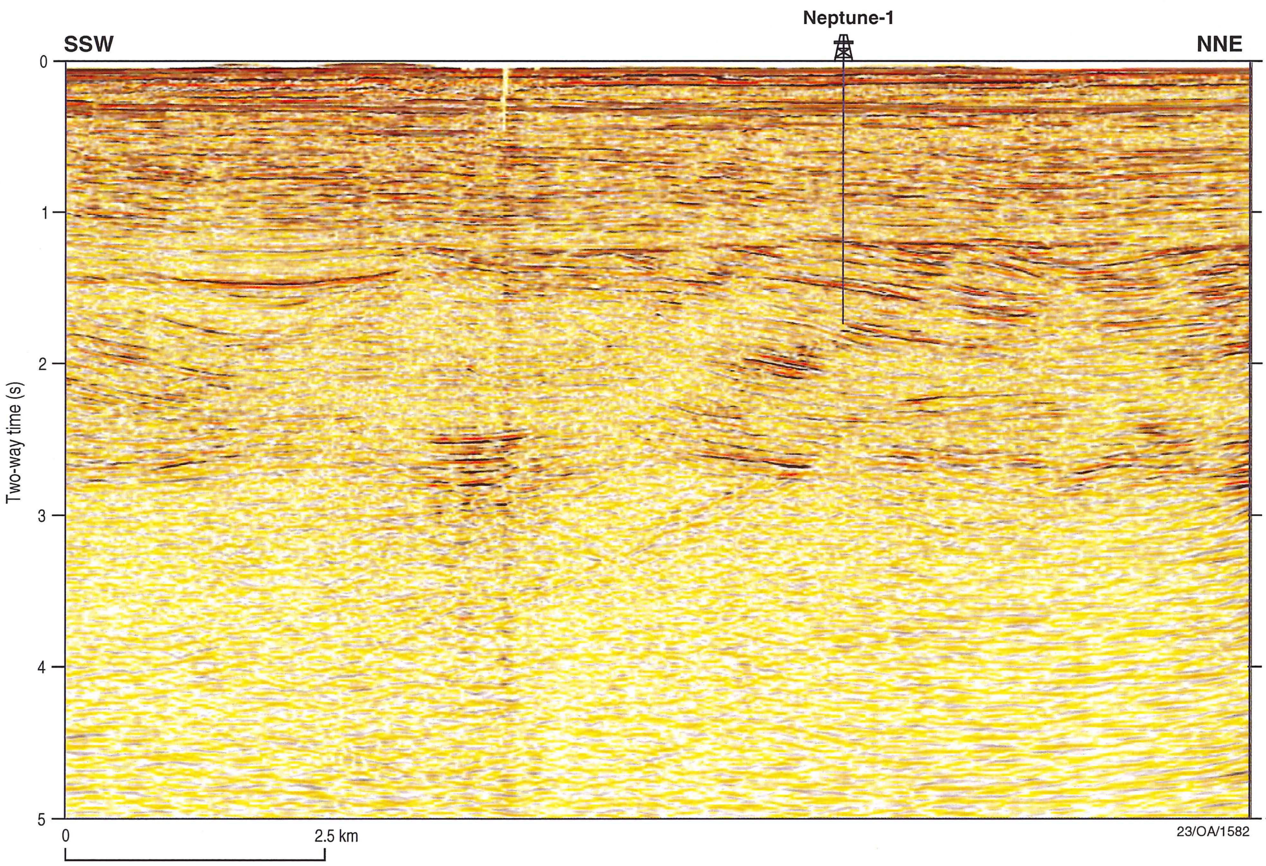

Figure 9. Seismic section showing location of Neptune-1.

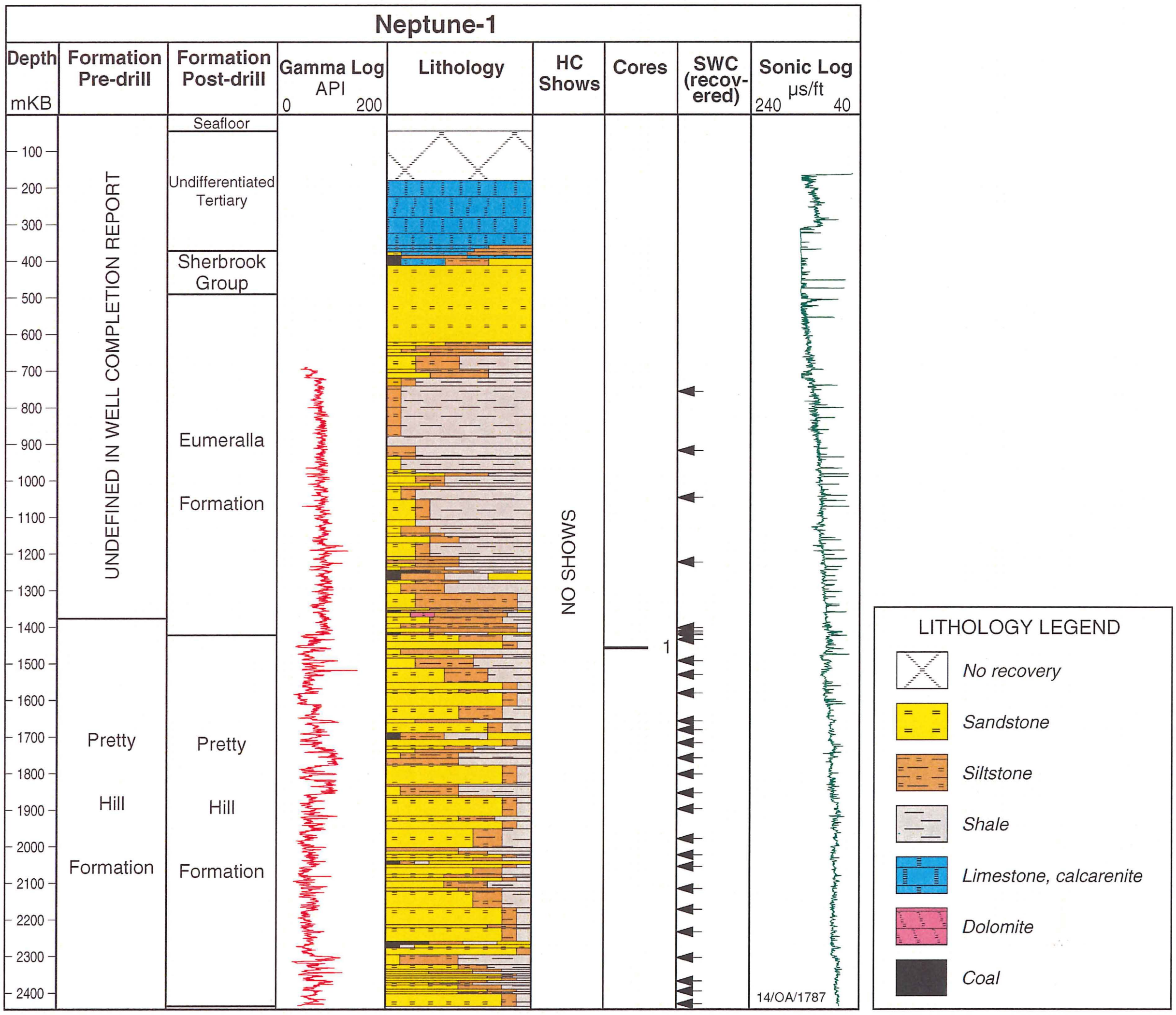

Figure 10. Neptune-1 well composite.

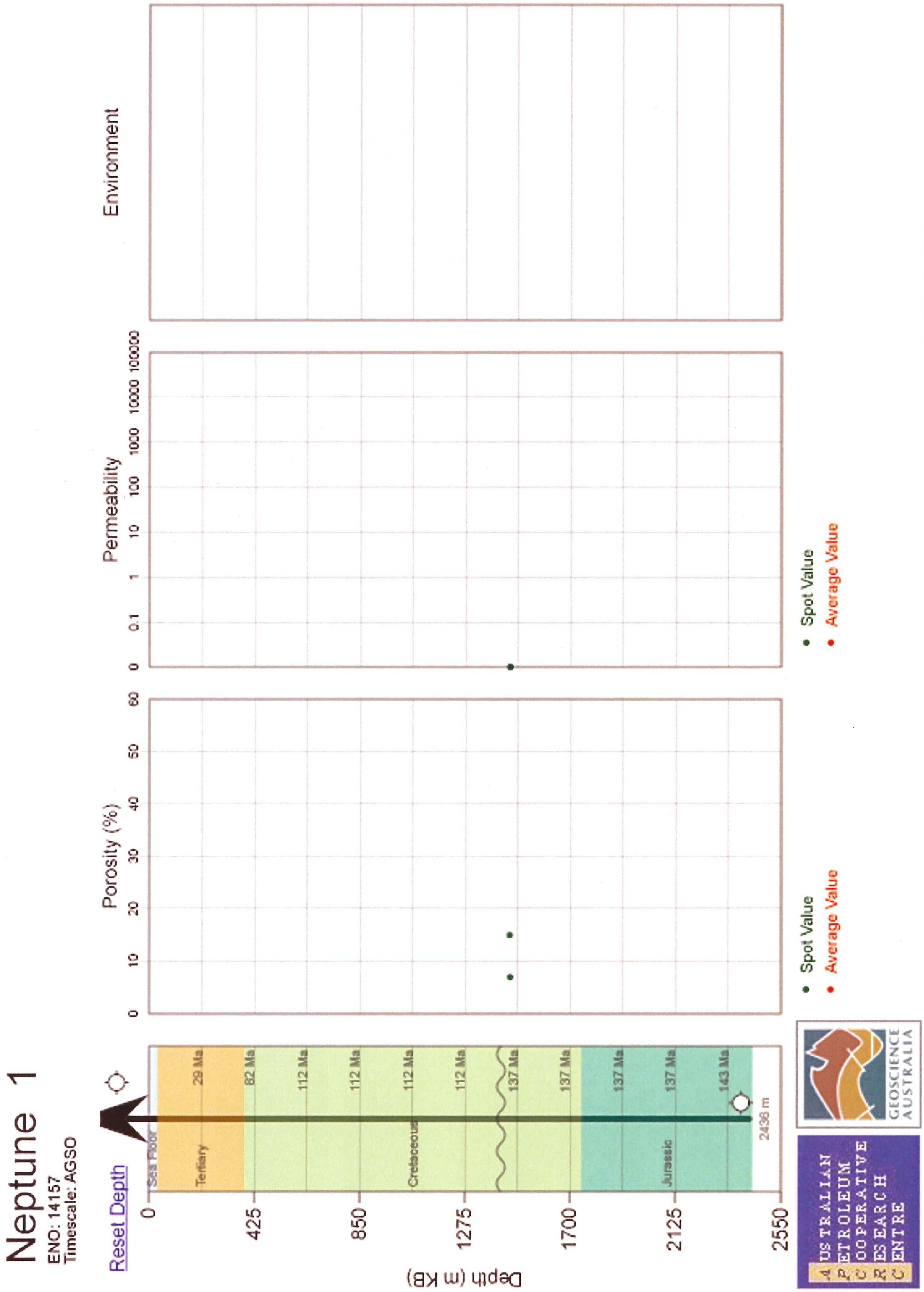

Figure 11. Porosity and permeability measurements recovered from Neptune-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003

Troas-1/ST1

WELL SUMMARY

Operator	BHP Petroleum Pty Ltd
Date Spudded	17 November 1992
TD Date	6 January 1993
Type	Exploration
Status	Plugged and abandoned
Shows	Gas shows
UNO	W5920027 W5920044 (ST1)
Permit	EPP24
Latitude	37° 22' 01.77" S
Longitude	139° 23' 22.34" E
Reference datum	AGD84,Central Meridian 141° E
Projection	Transverse Mercator
RT (m) datum	25 m
Water Depth	86 m
TD (mRT)	1430 m, Troas-1
Sidetrack kickoff point (mRT)	1230 m
TD (mRT)	3506 m, Troas-1/ST1
Age at TD	Early Cretaceous
Primary Objective	Early Cretaceous Crayfish Sub-group sandstones (Pretty Hill Formation)
Secondary objective	Shipwreck Group sandstones (Waarre Formation equivalent)
Play/Trap Type	Tilted fault block
Reason for failure	Poor quality cross-fault seal - non commercial gas discovery

DATA SUMMARY

<u>Palynology:</u>

The original palynological analysis, contained within Appendix 1 of the WCR, was undertaken by Morgan, R., and Hooker, N., (1993). "*Palynology of Troas-1, offshore Otway Basin, South Australia*". Sidetrack samples are included in this report.

Additional analyses were performed by:
Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report, 1996/5.

Macphail, M.K., (1998). "*Revised age determinations based on palynological data of R. Morgan & N. Hooker (1993)*" and is appended to the Troas-1/ST1 WCR.

and Stoian, L.M., (2002). "*Late Cretaceous–Late Eocene palynofloras from drillhole Troas 1, offshore Otway Basin*", South Australia, Department of Primary Industries and Resources. Report Book, 2002/010.

<u>Micropalaeontology:</u>

The original work was undertaken by Rexilius, J.R., (1993). "*Micropalaeontological analysis, Troas-1, Permit EPP-24, Otway Basin*". This report is contained in Appendix 1 of the Troas-1/ST1 WCR. Sidetrack samples were not examined in these analyses.

Additional analyses were performed by:
White, M.R., (1995). "*Micropalaeontological analysis of 26 petroleum wells in the Gambier Basin, South Australia*". South Australia, Department of Mines & Energy, Report Book 95/6.

and Macphail, M.K., (1998). "*Revised age determinations based on micropalaeontological data of J.R. Rexilius (1993)*", appended to the Troas-1/ST1 WCR.

Cores and cuttings:

Sample Type	Top (mRT)	Base (mRT)	Recovered (mRT)	Comments
Core				No conventional cores cut
SWC	375	3506	236 of 270	
Cuttings	370 725 1235 2370	725 1430 2370 3506		Troas-1 3 m samples Troas-1 10 m samples Troas-1/1ST 5 m samples Troas-1/1ST 3 m samples

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mRT)	Comments
OPEN HOLE WIRELINE LOGS - TROAS-1				
1	1	DLL–MSFL–AS–GR–SP–CAL–AMS–GPIT	360–666	GR to seafloor
2	1	Zero offset VSP	400–1322	
	2	CST–GR	375–1315	60 shot
	2	DLL–MSFL–SDT–GR–SP–CAL–AMS–GPIT	580–1337	
3	1	FPIT–BACKOFF	300–1385	
OPEN HOLE WIRELINE LOGS – TROAS-1/ST1				
3	1	FMS–LDL–CNL–GR–AMS	1188–2365	
	2	Zero offset VSP	742–2360	
	2	CST–GR		60 shot
	3	DLL–MSFL–AS–GR–AMS–SP	1188–2362	
4	1	RFT–GR–HP	2357–2906	Pretests
	2	RFT–GR–HP	2805.5	Sample
	2	FMS–LDL–CNL–GR–AMS	2300–2921	
	3	Zero offset VSP	742–2925	
	3	CST–GR	2503.5–2926	60 shot
	4	DLL–MSFL–AS–GR–AMS–SP	2300–2926	
	4	CST–GR	2304.5–2498.5	30 shot
5	1	DLL–MSFL–GR–CAL–AMS–LDT–CNL	2900–2992	
6	3	FMS–LDT–CNL–GR–AMS	2987–3506	60 shot
	4	Zero offset VSP	2320–3500	
	5	CST–GR	2999–3506	
	5	DLL–MSFL–GR–CAL–SDT–AMS	2987–3506	
CASED HOLE WIRELINE LOGS (TROAS-1/ST1)				
6	1	CDL–VDL	2200–2987	
7	1	RFT–GR–HP	2615–2621.5	
	2	RFT–GR–HP	2635.5–2648.5	
	3	RFT–GR–HP	2698–2968	
	4	RFT–GR–HP	2698–2901	

Velocity Survey:

Four velocity surveys (VSPs) were completed in Troas-1 and Troas-1/ST1. In Troas-1 a total of 25 VSP levels were recorded. In Troas-1/ST1, a further 130 VSP levels were recorded, providing a total of 155 levels over the interval 400–3500 mRT. The velocity report is located in volume 2, Appendix 3 of the basic data portion of the WCR.

Well Tests:

Extensive RFT programs were run in open hole and through casing. The pretests and sampling confirm the presence of gas over the interval 2696 to 2699 mRT, and at 2805, 2699 and 2698 mRT. The presence of gas below 2400 mRT is inferred from petrophysical analysis of the porous and permeable sands, however, the valid pretest pressures lie on, or close to, a water gradient indicating that no significant hydrocarbon columns are present in the interval. The gas is contained in thin sands probably isolated both vertically and laterally. Three of the RFT samples contained gas confirming some moveable hydrocarbons.

Gas water contacts have been interpreted from logs in several sands at 2514 mRT, 2530 mRT, 2623 mRT and 2704 mRT confirming the pressure data interpretation.

PRIMARY OBJECTIVE

The primary objective of the well was to test the hydrocarbon potential of Crayfish Sub-group sandstones in a tilted fault block structure. The overlying claystones of the Eumeralla Formation were predicted to act as top and cross-fault seals on this fault controlled structure.

SECONDARY OBJECTIVE

Secondary targets were in the Late Cretaceous Shipwreck Group sands.

STRUCTURE

Troas-1 was located on one of a series of downstepped faulted terraces on the Crayfish Platform (Figs. 1 and 3). The Troas structure was interpreted to have three-way dip closure plus fault closure provided by a major bounding fault down thrown to the southwest (Pickavance and Oke, 1994). The throw on this fault at the top of the Crayfish Sub-group (Fig. 12) is approximately 600 m, juxtaposing the Eumeralla Formation seal and Crayfish Sub-group reservoir across the fault. The feature has a mapped closure height of 230 m, with a dip leak point against the next major fault to the northeast. The structure developed initially during the Barremian with evidence of structuring continuing to as late as the Paleocene (Pickavance and Oke, 1994).

SOURCE ROCKS

The significant gas column intersected in the Crayfish Sub-group indicates that a mature source rock exists within the drainage area of the Troas1/ST1 well (Pickavance and Oke, 1994). The initial prognosis was that the Eumeralla Formation Coal Measures (EFCM) would provide the source for the hydrocarbons in Troas-1/ST1; the cross-fault juxtaposition providing direct access to the source rocks across the southwest bounding fault (Pickavance and Oke, 1994). The Eumeralla Formation shows lean gas prone source characteristics with HIs <100 mg HC/g TOC in the upper portion (Appendix 1). Below 2050 mRT, in the lower EFCM, source quality of the carbonaceous shales and coals improves with HI values typically above 300 mg HC/g TOC, indicating an oil prone character. Maturity at these levels shows this section to be well within the oil window. Assuming a similar maturity gradient and a fault throw of 600 m, the maturity of the downthrown, lower EFCM source interval would be in the late oil to mid gas maturity range.

At Troas-1/ST1, the Tertiary is approximately 400 m thick, and as such little additional late maturation and expulsion is expected, although this cannot be confirmed without full thermal modelling.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

The Crayfish Sub-group sandstone porosities range between 6 and 17%, averaging 13%, with permeabilities from RFTs ranging between 10 and 340 mD (Fig. 13). The sands through the hydrocarbon bearing Crayfish Sub-group sandstone interval were deposited in a marginal marine–lacustrine setting, and are interpreted to be of limited areal extent and discontinuous based on log character, net to gross ratios and pressure data.

SEAL

The prognosed seal was the Eumeralla Formation with the basal coal measures providing a top seal and the greater Eumeralla Formation (approximately 900 m thick) providing a cross-fault seal (Pickavance and Oke, 1994). The Eumeralla Formation is comprised generally of interbedded claystones, siltstone, sandstones and coals. There is a predominance of volcaniclastic material, which commonly comprises 85% or more of the sand and finer grained material. Diagenetic and compactional processes usually resulted in rapid porosity and permeability reduction in these rocks, to a point that they could act as effective seals. Only in units where a higher proportion of quartz sand exists, or at unconformities, is there any porosity and permeability preserved or generated. Thin intraformational Crayfish Sub-group seals are present, based on the postdrill results (Pickavance and Oke, 1994).

The Eumeralla Formation is unlikely to provide a continuous, effective cross-fault seal at Troas 1/ST1 due to texturally mature, sandy interbeds within the succession. At Troas-1/ST1, 98 m of Heathfield Sandstone Member is preserved. Here the proportion of volcaniclastic material is significantly lower with a corresponding increase in quartz. Porosities are around 20% with a net to gross of sandstone of 41%. The Eumeralla Formation above and below the Heathfield Sandstone Member also contains many other thin sand interbeds with average porosities measured between 10 and 13%. The small hydrocarbon columns identified probably developed from the limited juxtaposition of thinner seals on the downthrown side of the fault (Pickavance and Oke, 1994).

SHOWS

Good gas shows were observed in the Early Cretaceous Crayfish Sub-group sandstones. Log interpretation shows the well intersected a total 1140 m of gross gas hydrocarbon column from 2350–3490 mRT. The net hydrocarbon column was calculated to be 97.7 m with a net to gross ratio of 9%. This 97.7 m net consists of a number of small columns in thin discontinuous sands.

RESULTS

Troas-1/ST1 intersected a sub-commercial gas column within thin, discontinuous and unconnected sands within the Crayfish Sub-group. No large trap was present as a result of the low potential of the Eumeralla Formation to provide an effective cross-fault seal, particularly if the fault throw exceeds 500 m (Pickavance and Oke, 1994).

From a regional perspective it is interesting to note what appears to be an improvement in the reservoir characteristics of the Eumeralla Formation in the west of the basin. Palynological evidence shows that for the interval 1887 to 2022 mRT, there is a change in depositional environment to a more brackish to very nearshore environment. There is consistent identification of dinoflagellates and algal acritarchs including the occurrence of *Botryococcus* suggesting lacustrine influence. It may be the case that in this setting reworking and winnowing contributed to better reservoir development in the Eumeralla Formation, and a corresponding reduction in the formation's sealing characteristics.

Lack of adequate cross-fault seal appears to be the main contributing factor for the failure of this well to intersect commercial quantities of hydrocarbons.

REFERENCES

PICKAVANCE, D. & OKE, B., 1994. Troas-1/ST1, Well Completion Report. BHP Petroleum Pty Ltd (unpublished).

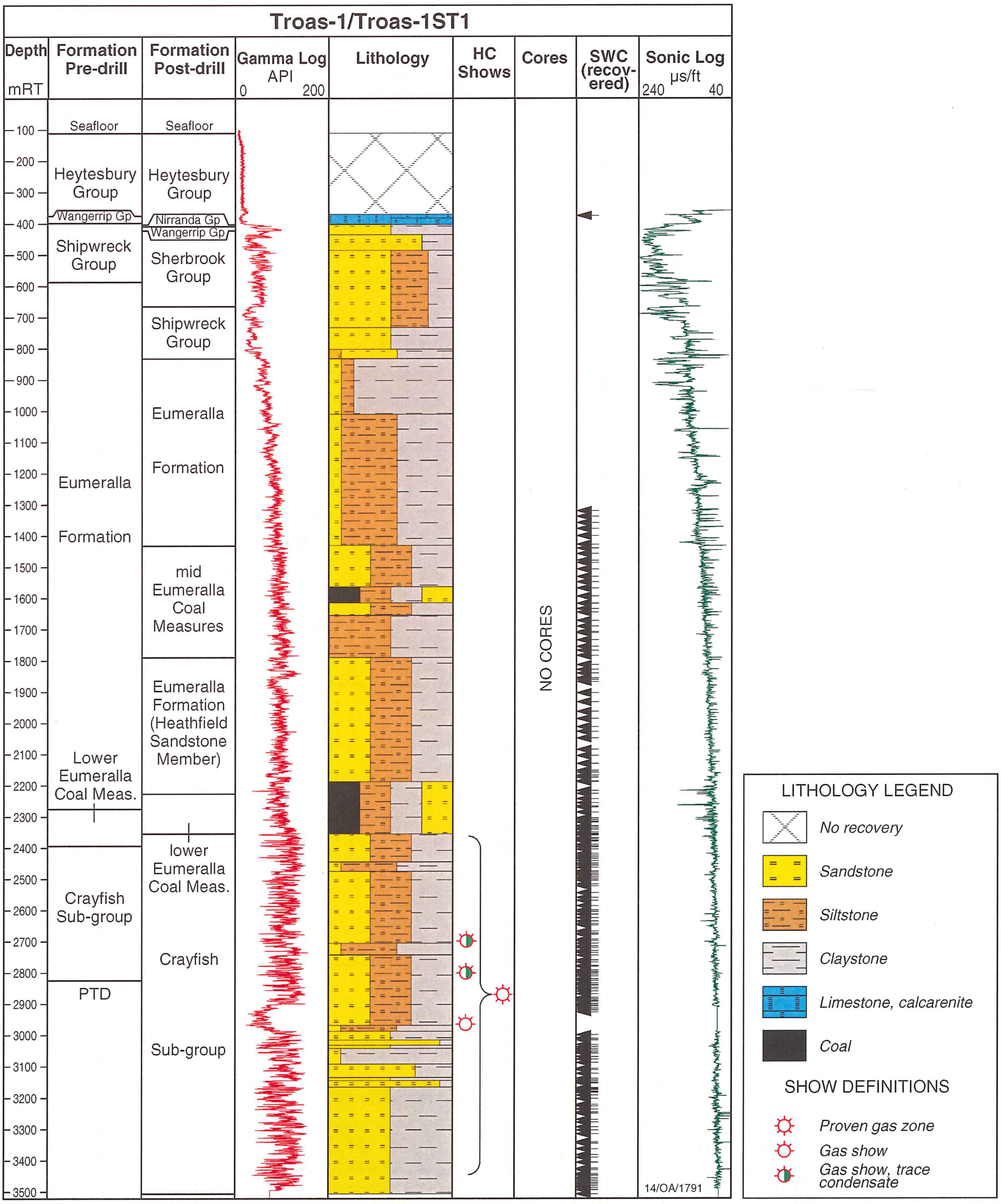

Figure 12. Troas-1/ST1 well composite.

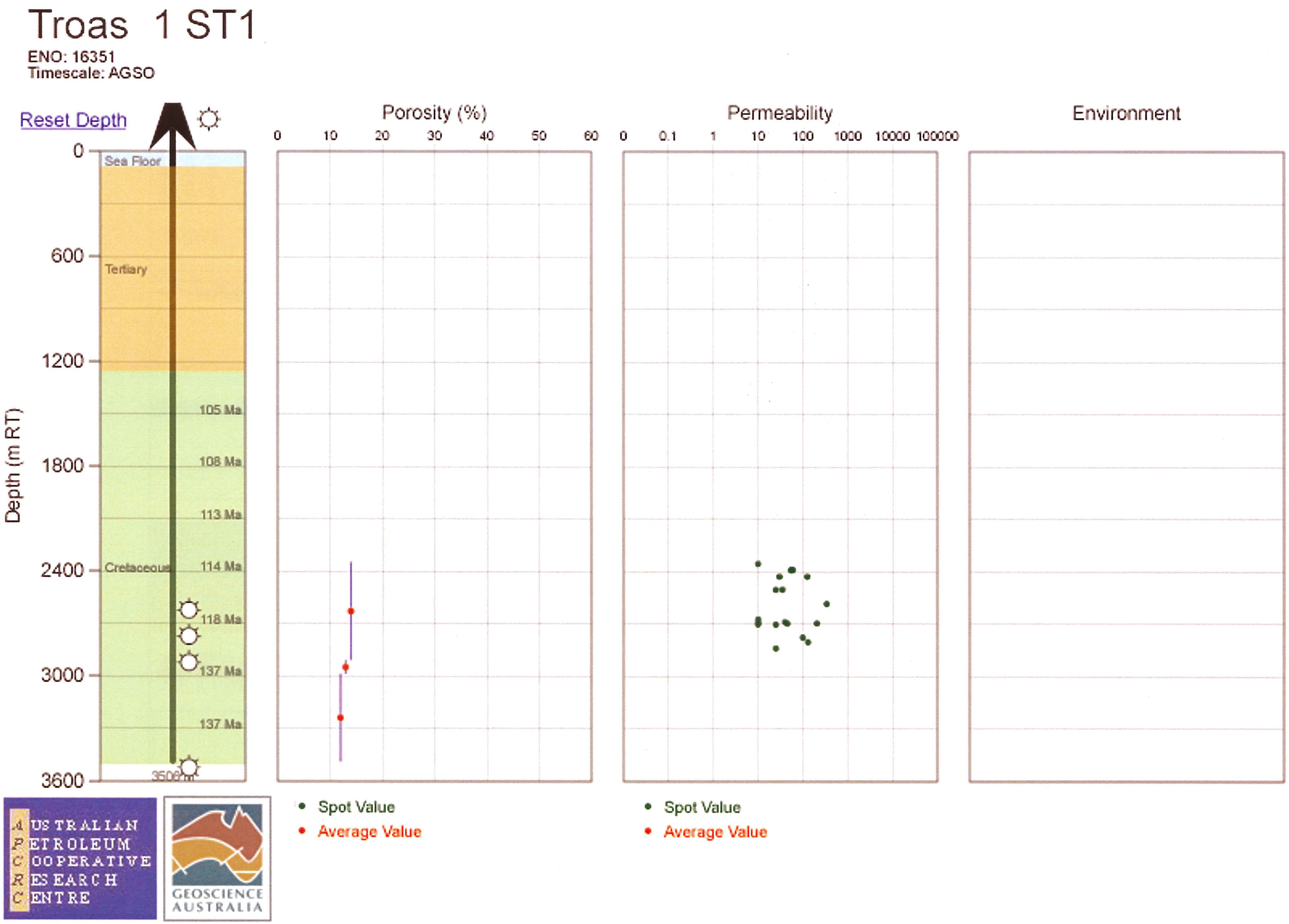

Figure 13. Porosity and permeability measurements recovered from Troas-1/ST1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

3.2 Morum Sub-basin

The Morum Sub-basin, located seaward of the Tartwaup–Mussel fault zone, is characterised by major growth of the Late Cretaceous Sherbrook Group section. Along strike, the Tertiary section thins to the west to less than 400 m at Morum-1. The Late Cretaceous Sherbrook Group maintains a fairly uniform thickness in the wells investigated with a marked trend of increased sand and silt content toward the west. This suggests a much stronger coarse clastic sediment supply at the western end of the basin during this period. Stratigraphic variation between the wells is quite pronounced suggesting that both local variations in sediment supply and syndepositional structuring, particularly in the earlier Late Cretaceous period, have influenced reservoir and seal development. Resolution of the early structural configuration may be masked in part by the latest Cretaceous to early Tertiary faulting.

The risks associated with this stratigraphic complexity can be addressed with adequate quality data, both biostratigraphic and seismic. Generalisations about reservoir or seal quality trends can be misguiding. For example, the Belfast Mudstone does work as a seal in the Caroline gas accumulation onshore, a generally very proximal setting. Here, local conditions were clearly adequate to develop the seal. The seal may have been deposited in an interdistributary setting away from the main sediment access points at this time.

Morum-1

WELL SUMMARY

Operator	Esso Exploration and Production Australia Inc
Date Spudded	1 May 1975
TD Date	2 June 1975
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No shows
UNO	W5750002
Permit	EPP2
Latitude	37° 30' 09.017" S
Longitude	139° 14' 07.763" E
Reference datum	AMG zone 54
Projection	Not provided in WCR
KB (m)	8.53 m
Water Depth	277.4 m
TD (mKB)	2439 m
Age at TD	Late Cretaceous
Primary Objective	Late Cretaceous Waarre Formation
Secondary objective	Late Cretaceous Paaratte Formation
Tertiary Objective	Early Cretaceous Pretty Hill Formation sandstones
Play/Trap Type	Faulted anticline play
Reason for failure	Fault seal-juxtaposition to sandy section

DATA SUMMARY

Palynology:

The original analysis was undertaken by Partridge, A.D., (1975). "*The palynology of the Late Cretaceous sequence in Morum-1, Otway Basin*" and is contained in Appendix 6 of the WCR.

Additional analysis was performed by Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report, 1996/5.

Micropalaeontology:

The original micropalaeontological analysis was done by Taylor, D. (1975). "*Micropalaeontological examination, Morum-1, Palaeontological Report 1975/11*". This report is included in the WCR as Appendix 5. Analysis was initially based on 15 SWCs between 1082 mKB and 2361 mKB. No foraminifera were found. Other SWCs were examined visually and found to be inadequate for analysis. Cuttings between 436.7 and 814 mKB were then also examined and again found to be inadequate for evaluation due to the sandy low clay lithologies present offering little potential for foraminiferal occurrence and preservation.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments
Core-1	1493.2	1503.0	9.75	100% recovery
SWC	1082	2433.8	78 of 82	
Cuttings	436.7	1503		9.1 m sample interval
	1503	1847		6.1 m sample interval
	1847	1893		9.1 m sample interval
	1893	1951		6.1 m sample interval
	1951	2439		3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string and some tools were turned off to minimise overlap with previous runs.

Run	Tool string	Interval (mKB)	Comments
1	ISF–SONIC	424.3–1076	
	FDC-GR	424.3–1077	GR to 295.6 mKB
2	ISF–SONIC	1058.3–2075	
	FDC–GR–CNL	1058.3–2073.8	
	HDT	1058.3–2074.1	4 arm
3	ISF– SONIC	1920.2–2433	
	FDC–GR–CNL	1844–2435.4	
	HDT	1828.8–2435	4 arm

Velocity Survey:

A velocity survey was undertaken during the second logging run. A total of 11 stations were surveyed between 1070.5 and 2064 mKB, with good data quality reported. The velocity survey report is in Appendix 8 of the WCR.

Well Tests:

No testing by RFT, DST or other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of the well was to evaluate the hydrocarbon potential of the Morum structure at the Waarre Formation level. Critical to the primary and secondary objectives of the well was the development of a thick Belfast Mudstone interval to provide the necessary hydrocarbon source, and in the case of the primary objective, the necessary seal.

SECONDARY OBJECTIVE

The secondary objective of the well was to evaluate the hydrocarbon potential of the Morum structure at the Paaratte Formation level. An additional deep tertiary target was the Early Cretaceous Pretty Hill Formation sandstone. Structural closure at the Pretty Hill Formation level was considered somewhat speculative because of the poorer quality of the seismic data at depths >3300 m (Esso Australia Ltd, 1975).

STRUCTURE

Morum-1 was drilled near the crest of a gently tilted fault block with faulting down to the basin (southwest). The controlling fault has expression at the seafloor with a well developed scarp ~700 m south of the well site (Fig. 14). Faults on adjacent blocks do not appear to breach the seafloor. Any significant hydrocarbon accumulations are likely to have been tested by the well. However, late faulting increased the chance of leakage of any early-trapped hydrocarbons.

The Morum structure comprises a large, complexly faulted anticlinal nose. The predrill prognosis interpreted that shear processes had played a role in the development of the mapped broad anticlinal reversal. The feature measures approximately 65 km between bounding synclines, with a structural relief of greater than 2100 m. Postdrill analysis of the well confirms the structural interpretation (Esso Australia Ltd, 1975).

The Tertiary succession is very thin, ~200 m, at the well (Fig. 15). Recent work by Duddy et al. (2003) on the thermal history of this well provides good evidence for a major period of uplift and erosion above the Tertiary /Cretaceous boundary, effectively uplifting and eroding a thick Wangerrip Group section. Duddy et al. (2003) proposed that up to 1500 m of Tertiary Wangerrip Group section has been removed by erosion in the area surrounding Morum-1.

SOURCE ROCKS

Source rock development in this well section is very poor (Appendix 1). Rock Eval analysis on the Waarre Formation shows TOCs <1.0% and HI values all <100 mg HC/g TOC, indicating a poor gas prone source rock. From Tmax and VR data, this shale is not mature for oil (VR maximum <0.5%).

At Morum-1, the Tertiary is approximately 200 m thick, as compared with 1200 m to 1600 m for wells peripheral to the eastern Voluta Trough with trapped gas. It is thus considered unlikely that source rock reactivation has occurred.

The comments above clearly refer to the source potential of the immediate well section and have not taken into account the regional setting of the well. Morum-1 is located on the shelf break to the Morum Sub-basin where thicker Late Cretaceous and Tertiary section is preserved to the southeast of the well. Here the Eumeralla Formation may be mature and expelling hydrocarbons.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Excellent quality reservoirs exist throughout the Cretaceous section, with porosities around 20% near the TD of the well (Fig. 16). Analysis of the core cut from 1493 mKB shows porosities in the range 26.2 to 32.6%. Permeability ranges from 2.8 to 469 mD (Fig. 16). These sands are nearshore shallow marine sands.

SEAL

The principal seal, the Belfast Mudstone, is very poorly developed at this location and comprises a sandy siltstone. Paaratte Formation seals are also poorly developed comprising silty claystones at best. The well is located in a proximal part of the depositional systems for both intervals. It is likely that better seals are developed seaward of this location, or away from the sediment input points.

SHOWS

No shows were recorded in the well.

RESULTS

The failure of this well can be attributed firstly to the lack of fault trap development and, the poor development of any appropriately thick seals in the drilled section. Top and cross-fault seals are required in the fault block plays mapped at Morum-1, and to provide laterally continuous migration surfaces within the migration fetch area of the structure. The very recent timing of fault movement also introduces the additional risk of trap leakage. This is a more critical issue where no late migration and charge is occurring.

Charge modelling in the deeper water Morum Sub-basin by Duddy et al. (2003) suggests that any Eumeralla Formation source rocks in the sub-basin are currently expelling hydrocarbons. The thermal model appears moderately well constrained. However, source quality and quantity assumptions are only based on regional trends.

This analysis suggests that the way forward for exploration in this area may be to look for more subtle traps less affected by late stage faulting, and in locations where adequate seals are developed providing both sealed traps and migration conduits.

REFERENCES

ESSO AUSTRALIA LTD, 1975. Morum No.1, S.A., Well Completion Report. (unpublished).

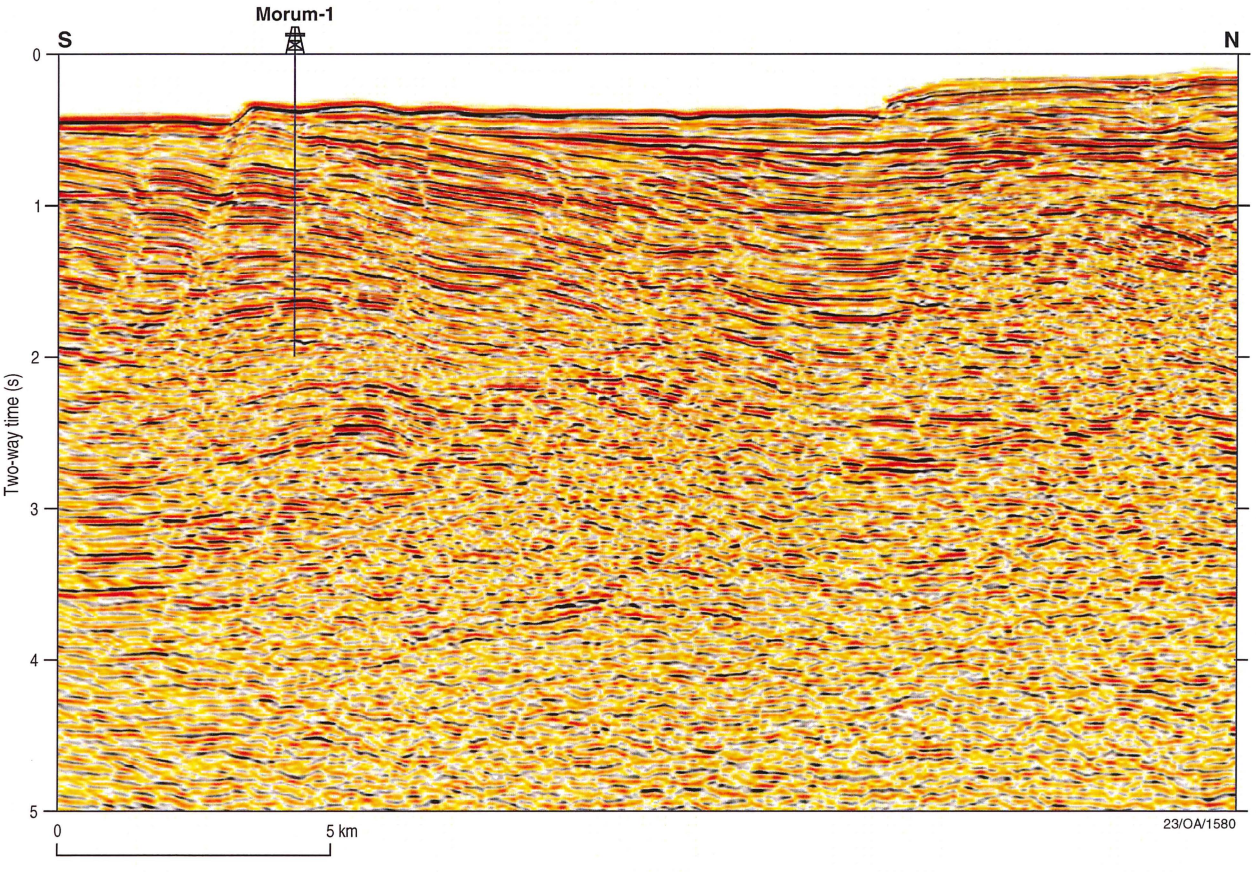

Figure 14. Seismic section showing location of Morum-1. Seismic reproduced with permission of Fugro MCS.

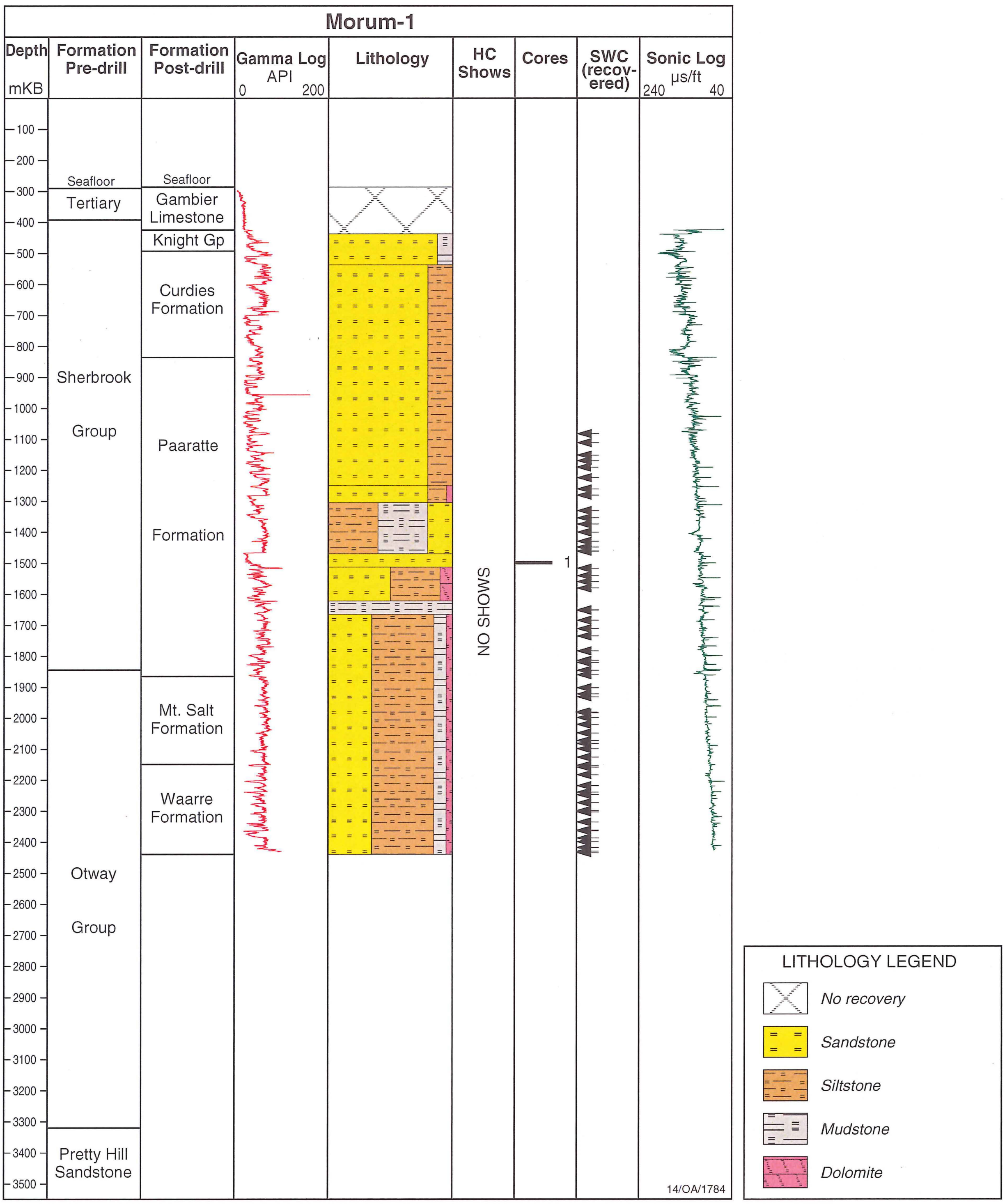

Figure 15. Morum-1 well composite.

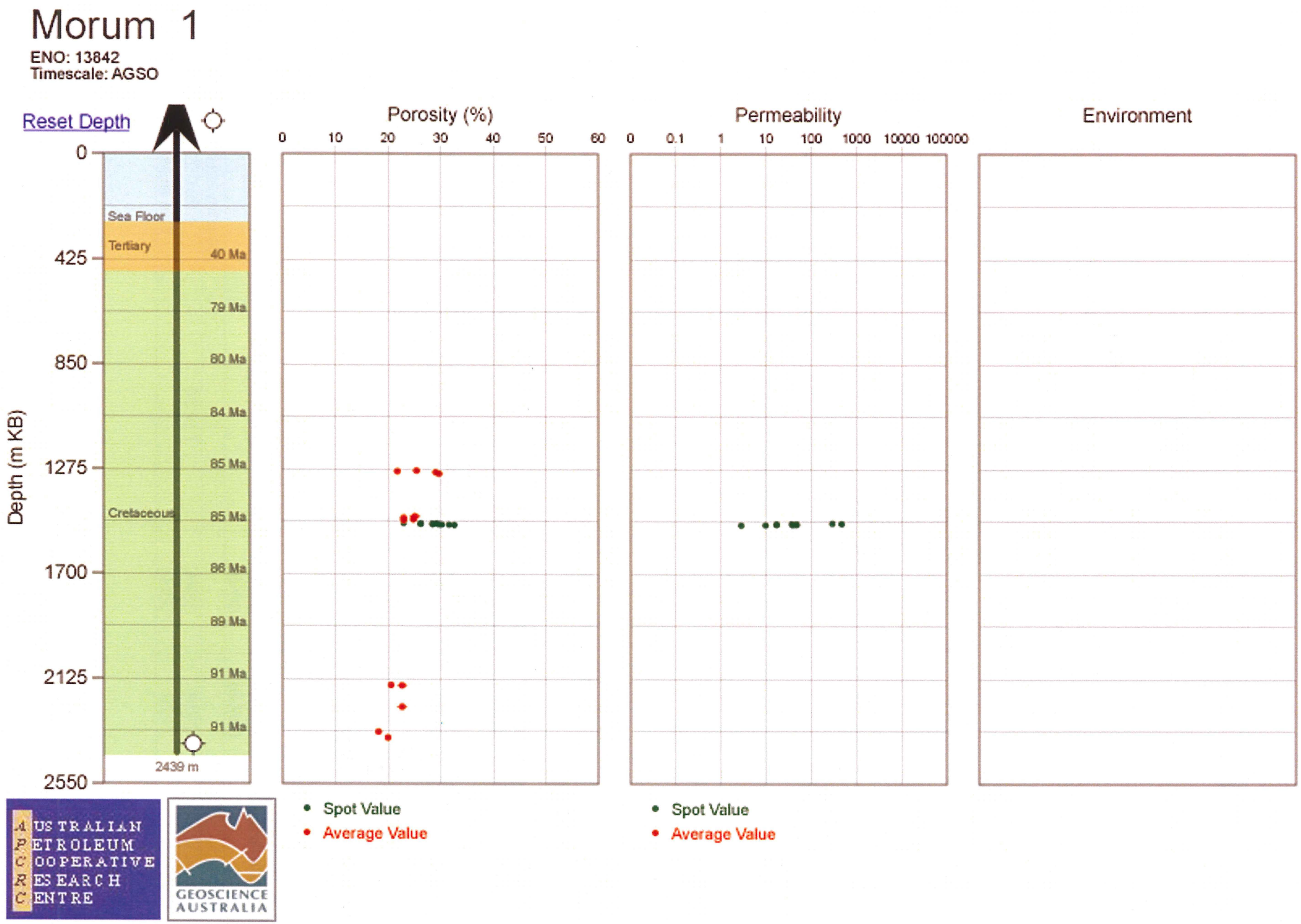

Figure 16. Porosity and permeability measurements recovered from Morum-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: June, 2003.

Copa-1

WELL SUMMARY

Operator	Cultus Petroleum (Australia) NL
Date Spudded	16 December 1989
TD Date	16 January 1990
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No significant shows encountered
UNO	W5890055
Permit	EPP23
Latitude	37° 41' 18.274" S
Longitude	139° 45' 22.034" E
Reference datum	Australian National A.G.D.1966 Central Meridian 141° E
Projection	Universal Transverse Mercator
KB (m) datum	28.7 m
Water Depth	92.3 m
TD (mKB)	3850 m
Age at TD	Early Cretaceous
Primary Objective	Waarre Sandstone
Secondary objective	Flaxmans and Paaratte formations, and Timboon Sandstone
Play/Trap Type	Fault block
Reason for failure	Unfavourable cross-fault juxtaposition

DATA SUMMARY

Palynology:

The original palynological analysis was undertaken by Macphail, M.K. & Hos, D.P.C., (1990). "*Palynology report on Copa-1, Otway Basin*". The report, located in Appendix 3 of the WCR, is based on 7 SWC and 34 cuttings samples.

Additional analyses were performed by:
Morgan, R., (1991). "*Review of palynology of Copa-1*". Morgan re-examined the original sample material.

and Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report, 1996/5

Micropalaeontology:

No micropalaeontological analysis was undertaken on this well.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered	Comments
Core				No conventional cores cut
SWC	2788	3844	7 of 30	1 lost, 22 misfires
Cuttings	420	3850		5 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mKB)	Comments
1	1	DLL–BHC–GR–SP	408–1031.5	
2	2	DLL–MSFL–BHC–GR–SP LDL–CNL–GR SAT (VSP)	1023.5–2428.5 1023.5–2432 410–2420	
3	2	SAT (CHECKSHOTS)	775–3657	
4	3	DLL–MSFL–BHC–SP–LDL–CNL–GR CST	2423–3844 2440.5–3844	

Velocity Survey:

The Copa-1 velocity survey was completed in two parts that were later combined in the processing. A VSP survey was undertaken as part of log suite 2, with 52 levels recorded. Log suite 3 comprises a checkshot survey, with 29 levels recorded. The report is located in Appendix 4 of the WCR.

Well Tests:

No testing by RFT, DST or other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of the well was to evaluate the hydrocarbon potential of the Waarre Sandstone in a seismically defined, large, northwest-oriented faulted anticline.

SECONDARY OBJECTIVE

The secondary objectives were to confirm the presence of reservoir rocks in the Timboon Sandstone, Paaratte and Flaxmans formations.

STRUCTURE

Copa-1 was drilled on a horst-like structure within a broad, faulted anticline (Fig. 17). The structure is northwest-oriented, with seismic lines and a map at the top Waarre Sandstone level provided in the WCR showing the well is positioned on the downthrown side of a fault dissecting the anticlinal feature (Priest and Luxton, 1990). On the upthrown side, seismic quality was poor such that no mapping was attempted at this level. On the flank of the feature where data for the upthrown Waarre Sandstone are provided, a fault throw estimate of between 120 m and 150 m has been made as a guide to the general throw on this fault at this level. Due to poor data quality, there is no evidence from maps that the broader faulted anticline is closed. The anticline was interpreted to be controlled by the underlying Early Cretaceous morphology. Large listric faults were predicted to act as migration pathways between the deeper source rocks (Eumeralla Formation and Pretty Hill Sandstone) and Late Cretaceous reservoirs (Waarre and Timboon sandstones and Flaxmans and Paaratte formations; Fig. 18)(Priest and Luxton, 1990).

Postdrill, the anticline appeared to be a robust structure. However, with regard to mapping, the poor quality seismic data only supports the well as a test of one downthrown closure where upthrown cross-fault juxtaposition of an effective seal is required to create a trap. The seismic section in the WCR indicates that it is possible the well drilled through the fault into the footwall sequence. Faults related to the structure show evidence of significant movement at the base Tertiary, with little or no movement above this level (Priest and Luxton, 1990). This indicates that pre-Tertiary traps had an increased risk of leakage during this structural episode. The absence of evidence for further reactivation through the Tertiary indicates that any Tertiary accumulations may have a better chance of maintaining trap integrity to the Present.

SOURCE ROCKS

The ~500 m thick Belfast Mudstone is immature for oil with Tmax <440°C (Appendix 1). TOC and HI data indicate a moderate to poor quality gas prone source rock. Surrounding wells indicate very similar source potential with overall poor oil and gas source character for the Belfast Mudstone. The well penetrated the Eumeralla Formation/Pretty Hill Sandstone, intersecting silty sandstones and claystones. No maturity levels were measured.

At Copa-1, the Tertiary is approximately 400 m thick, as compared with 1200 m to 1600 m for wells peripheral to the eastern Voluta Trough where there are commercial gas accumulations in five significant fields (i.e., Minerva, La Bella, Thylacine, Geographe and Geographe North). Without further study it is not known if the 800 m of Tertiary loading was sufficient to reinitiate generation and migration in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Potential reservoirs exist in the Tertiary, Paaratte Formation, intra-Belfast Mudstone, Flaxmans Formation and Waarre Sandstone intervals (Fig.18). Porosities estimated from wireline log interpretation range between 6 and 20% in the sands down to the top of the Otway Supergroup. No cores were available to measure permeability. Available data are presented in Figure 19.

SEAL

The principal and thickest seal, the Belfast Mudstone is 501 m thick with two significant interbedded sands. It was expected to form an adequate seal, although no quantitative data are available. With only poor mapping data in the WCR (Priest and Luxton, 1990) at the top Waarre Sandstone level, the fault throw at the critical point of the structure is not known. Importantly, above the top Waarre Sandstone horizon there is no significant seal developed. Rather, there is 600 m of the highly interbedded Flaxmans Formation, where the thickest shales/siltstones are less than 30 m (Fig. 18).

Sand and shale interbeds are very thin beneath the Belfast Mudstone. The sealing potential of any of the Flaxmans or Paaratte formations intraformational seals is not known. However, it is expected that reasonable seals are developed that may prove effective.

SHOWS

Only minor gas shows were seen during drilling. These occurred through the Flaxmans Formation between 3005–3508 mKB (C_1~ 0.3%) and 3667–3677 mKB (C_1~ 0.1%), and at 3708 mKB (trace C_1) in the Otway Supergroup.

RESULTS

At the Waarre Sandstone level, there is a very good case that the mapped downthrown structure was not an effective trap due to the absence of effective cross-fault seal. The thick overlying interbedded Flaxmans Formation provides insufficient seal thickness to create effective seals across the 120–150 m throw of the fault as mapped. For the greater faulted anticlinal closure (if present), fault breaching of thin seals would also be the most obvious reason for failure.

The form of the structure at the base Belfast Mudstone level is not known. However, if similar to the top Waarre Sandstone, the well would have penetrated the seal farther downdip on the broad faulted anticlinal structure. With the 501 m thick seal, the likelihood of an effective trap being present is increased. It is within the Flaxmans Formation that minor shows were recorded which might support this argument. Therefore, is there an updip accumulation in the Flaxmans Formation? Additional risks are: 1) only 800 m of Tertiary section exists resulting in a lower chance of source reinitiation, and 2) faults may have been active in the Tertiary so any early formed traps may have leaked and not been recharged.

It is difficult to quantify if and what volumes of hydrocarbons have migrated through this area and at what time. However, where sufficient Tertiary loading has occurred (e.g., Minerva-1 and La Bella-1), all valid traps appear to have trapped hydrocarbons. This provides reasonable evidence that the bulk of the Eumeralla Formation, regionally, has sufficient quality and quantity of source rocks to expel economic volumes of hydrocarbons. Migration fetch area also needs to be considered as a risk element where multiple fault block traps are developed in an area. In this area, the fault spacing and probably migration fetch areas are not large relative to the structure size.

REFERENCES

PRIEST, P. AND LUXTON C., 1990. Copa-1, Well Completion Report. Cultus Petroleum (Australia) NL. (unpublished).

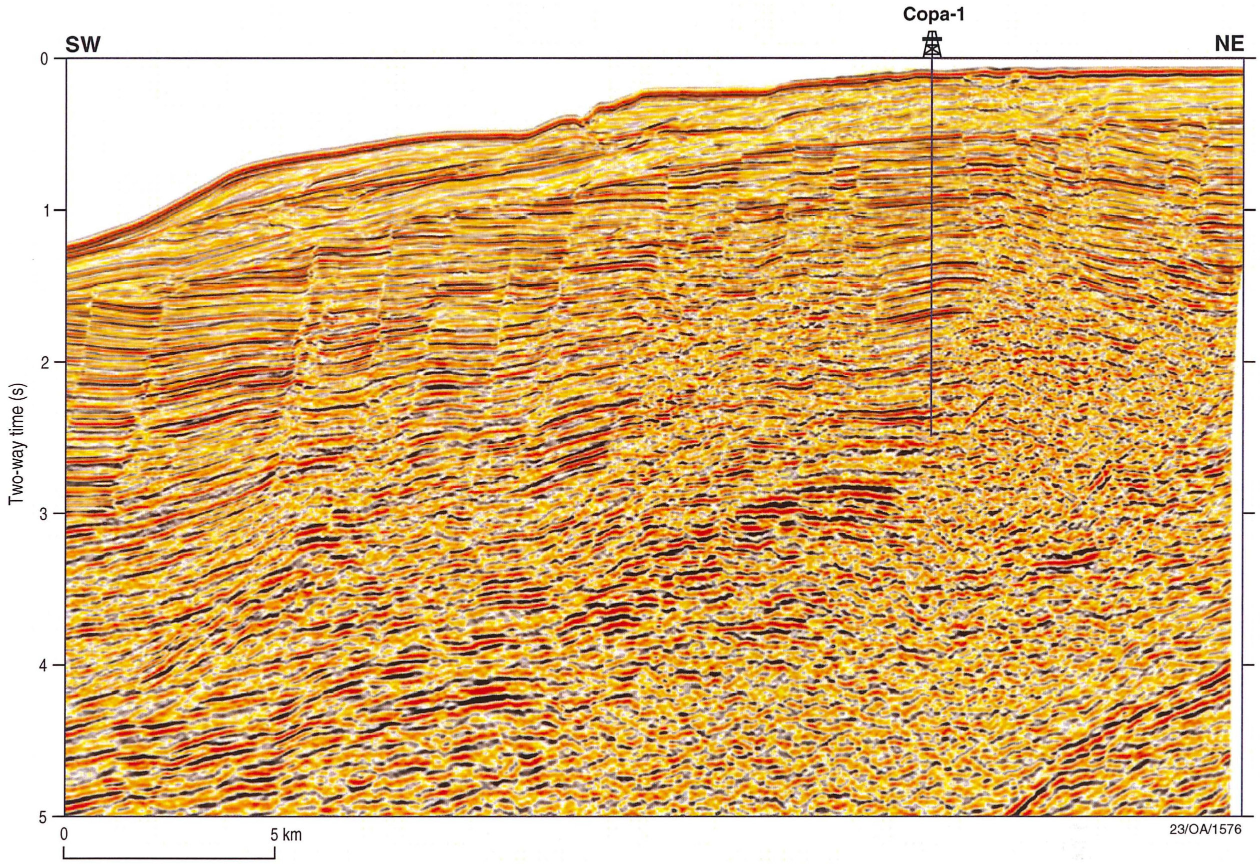

Figure 17. Seismic section showing location of Copa-1. Seismic reproduced with permission of Fugro MCS.

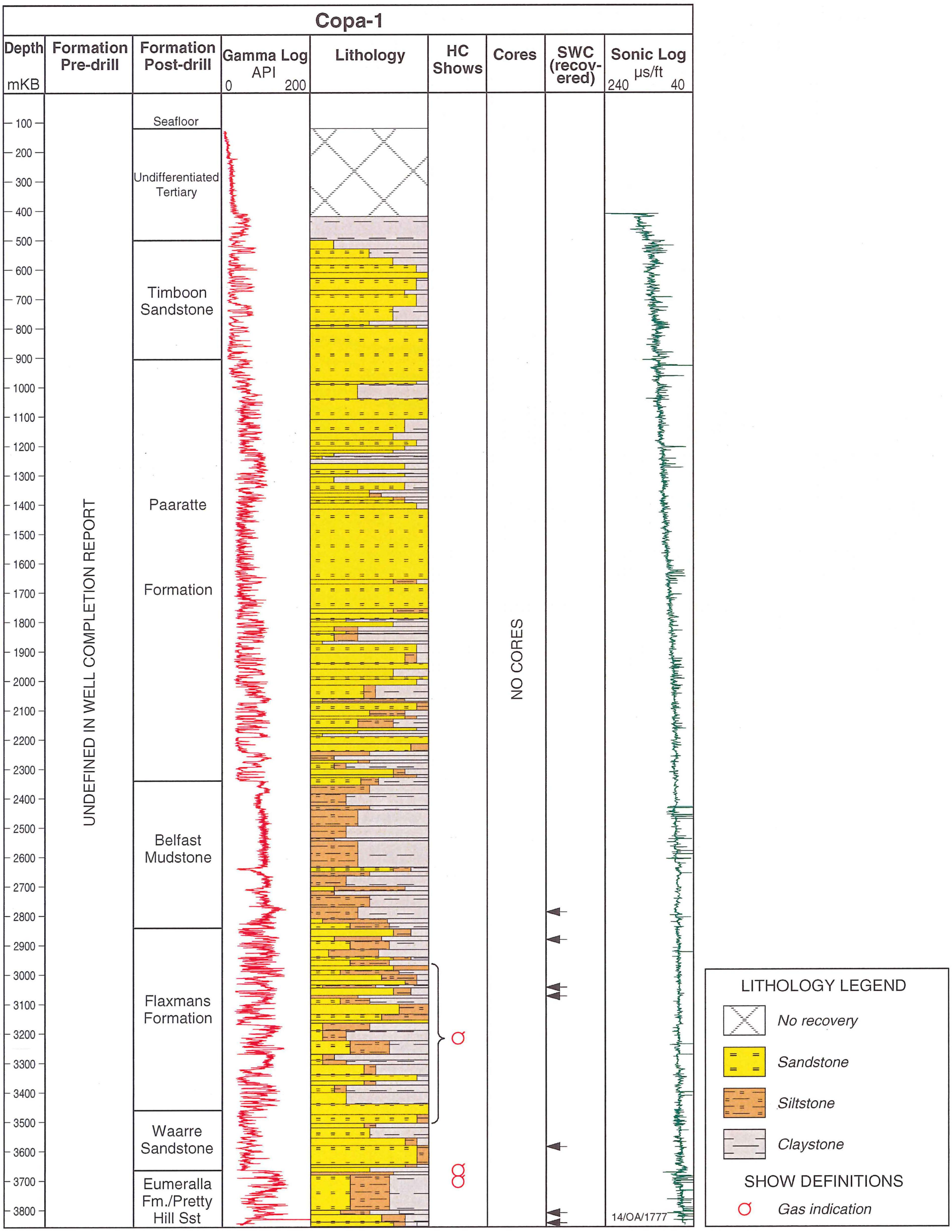

Figure 18. Copa-1 well composite.

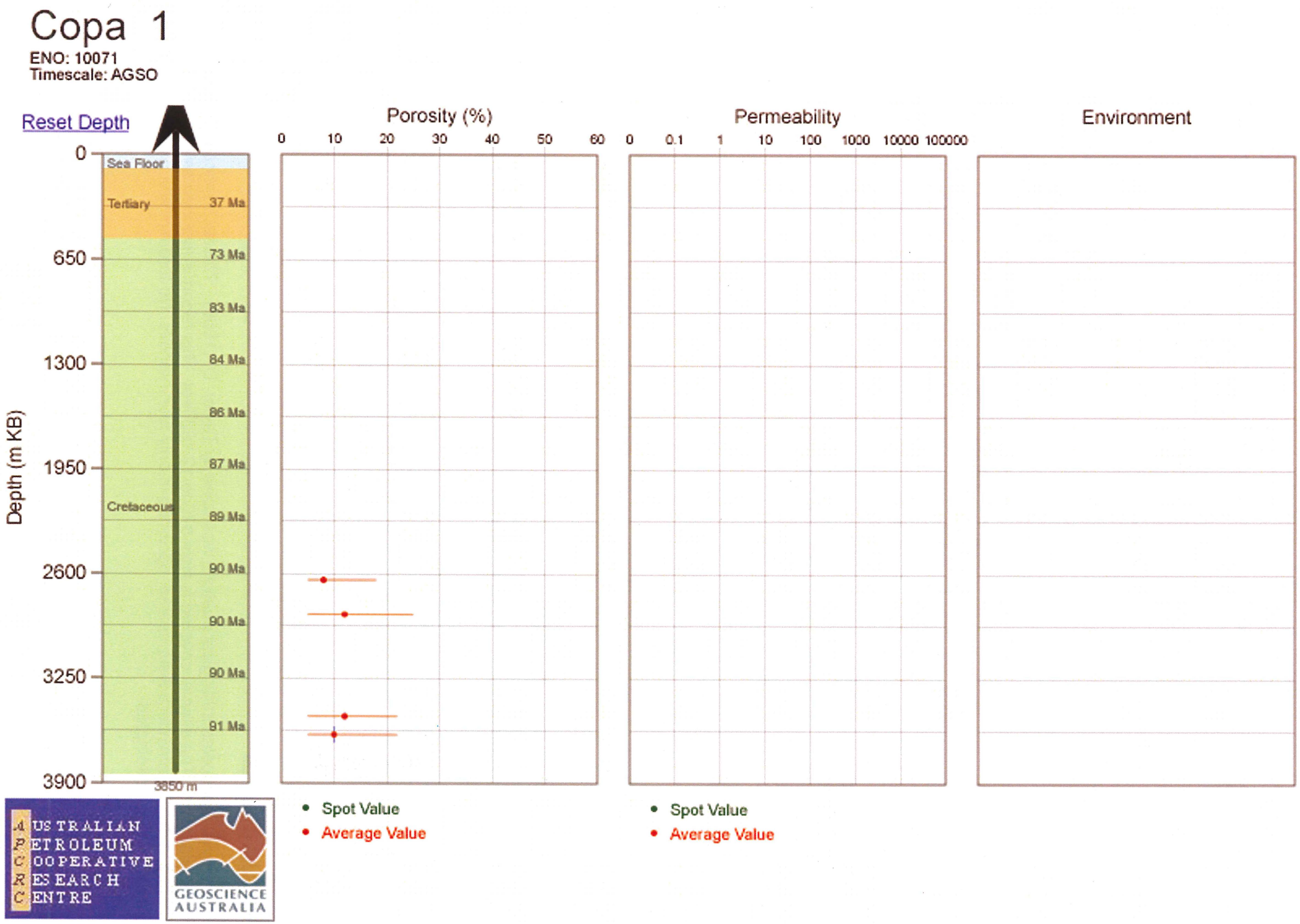

Figure 19. Wireline log porosity measurements recovered from Copa-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

Argonaut-A1

WELL SUMMARY	
Operator	Esso Exploration and Production Australia Inc
Date Spudded	14 May 1968
TD Date	29 June 1968
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No shows
UNO	W5680002
Permit	OEL49
Latitude	37° 58' 17.668" S
Longitude	140° 15' 52.934" E
Reference datum	Central Meridian 146° E
Projection	Transverse Mercator, Belt-7
KB (m)	28.3 m
Water Depth	77.1 m
TD (mKB)	3707 m
Age at TD	Late Cretaceous
Primary Objective	Late Cretaceous including Waarre Sandstone
Secondary objective	Sealing conditions at the Base Tertiary level
Play/Trap Type	Fault block play
Reason for failure	Fault seal juxtaposition to sandy section

DATA SUMMARY

Palynology:

The original palynological analysis was undertaken by Dettmann, M. E., (1968). "*Palynological report on Argonaut A-1 intervals 2210–2595 feet and 9972–12,163 feet*". This report is included as part of Appendix 1 in the WCR.

Additional analyses were performed by:
Morgan, R., (1985). "*Palynology of Argonaut No. 1, Otway Basin, Australia. Report for Ultramar Australia.*" This is the most comprehensive analysis and is based on 50 samples examined in detail and 20 rapidly scanned samples.

Alley, N.F., (1984). "*Palynostratigraphy of Argonaut-A1, Lake Bonney-1 and Kalangadoo-1 wells, Otway Basin.*" Department of Mines and Energy, SA Report Book No. 84/100; Biostrat Report No. 11/84. This report has the *N.senectus* Zone as deep as 1628 mKB but is not accepted at Geoscience Australia as it is inconsistent with spore pollen assemblages recorded by Morgan (1985).

and, Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells.*" Biostrata Report 1996/5.

Micropalaeontology:

The original micropalaeontological analysis was done by Taylor, D. (1968). "*The occurrence of foraminifera in Argonaut A-1*". The interval covered is from 870 to 12,163 feet. This report is included as part of Appendix 1 in the WCR. Foraminifera were sparse, occurring in only four intervals. No foraminiferal biostratigraphic breakdown was attempted.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments
Core-1	640	647	4.9	17 cores. Total 95.1 m recovered 37.6 m (39.5%)
Core-2	805	813	1.1	
Core-3	981	989	0.9	
Core-4	1143	1152	1.7	
Core-5	1305	1311	0.8	
Core-6	1472	1475	1.1	
Core-7	1638	1646	1.8	
Core-8	1805	1808	1.4	
Core-9	2226	2227	0.6	
Core-10	2474	2477	3.0	
Core-11	2733	2740	7.6	
Core-12	3039	3046	4.0	
Core-13	3198	3202	0.1	
Core-14	3449	3454	2.9	
Core-15	3553	3561	4.6	
Core-16				No recovery
Core-17	3669	3707	4.3	
SWC	523	3688	69 of 85	
Cuttings	268	3707		10 ft sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string and some tools were turned off to minimize overlap with previous runs. Net result was a full log suite for the hole below 248 m.

Run	Tool string	Interval (mKB)	Comments
1	IES DT–GR	248–507 248–503	
2	IES Fm Density–GR DT–SP Dipmeter	491–1810 491–1810 491–1808 491–1808	
3	IES DT–GR	1790–2990 1790–2988	
4	IES Fm Density–GR DT–SP Dipmeter	2926–3705 1790–3705 2926–3701 1772–3698	

Velocity Survey:

Two velocity surveys were conducted after wireline logging runs 2 and 4. Following Run-2 the geophones were set at 3 depths between 509 and 884 mKB with good to fair results. On Run-4 the geophones were set at 5 depths between 1898 and 3521 mKB with fair to poor results reported. The tool was irretrievably stuck in the hole at 1524 m, such that the lower survey was not extensive enough to link with the shallower survey. The velocity survey report is included as Appendix 6 of the WCR.

Well Tests:

No testing by RFT, DST or other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of Argonaut-A1 was to evaluate the hydrocarbon potential of the fault bounded structure. The initial concept was that the proportion of shale in the Late Cretaceous would increase basinward (from onshore well penetrations), creating a favourable setting where a number of thick interbedded shales and sands would contribute to the development of fault traps down through the Late Cretaceous section in the fault block, including the Waarre Sandstone. This structure was viewed as representative of similar structures in the area. More broadly the well was planned to determine favourable reservoir, sand/shale pairs, and source rock potential of the Late Cretaceous rocks in the offshore Otway Basin. The Late Cretaceous section proved to be much thicker and sandier than prognosed (James, 1968). To meet well objectives, it was decided to continue drilling and test the Waarre Sandstone below the Belfast Shale.

SECONDARY OBJECTIVE

To determine if a seal was present at the base of the Tertiary.

STRUCTURE

Argonaut-A1 was drilled on a gently tilted fault block, with faulting generally down to the basin to the southwest (Fig. 20). Beds dip gently to the north, with the well located in a crestal position such that any significant accumulations of hydrocarbons were likely to be intersected. The gentle northerly dips were supported by dipmeter data (James, 1968). The Argonaut fault block also has a small fault throwing down to the northeast. The well penetrated the horizons progressively farther downdip from the crest with depth, leaving increasingly larger untested potential traps updip. At the Waarre Sandstone level (Fig. 21), based on the near top Otway Group map in the Breaksea Reef-1 WCR, the well was located on a downthrown block that is part of the broad Argonaut structure (Ultramar Australia Inc, 1984). The south bounding fault has a displacement of 280 ms TWT that, with an interval velocity of 3960 m/s, equates to ~555 m. The same fault has a throw at the Belfast Shale level >480 m, sufficient to breach the fault trap at this level (James, 1968). Postdrill analysis suggested that the well was a valid test of the Late Cretaceous Curdies–Paaratte formations structure (James, 1968). The north bounding fault has a throw of approximately 200 m, using the same velocities, likely juxtaposing Waarre Sandstone on either side of the fault (James, 1968). As a downthrown fault test the trap is very probably breached at this level.

Faults from the northeast edge of the seismic line to just southwest of Argonaut-A1 continue through to, or near, the seafloor (Fig. 20), suggesting very late movement, which increases the chance of leakage of any earlier trapped hydrocarbons. Importantly, southwest of Argonaut-A1 faults do not appear to have as significant a late reactivation and may present better settings for the preservation of fault trapped hydrocarbons.

SOURCE ROCKS

The Belfast Shale is approximately 480 m thick in Argonaut-A1 and is the only possible source rock intersected in the well. It has TOCs <1.5% and HI values <100 mg HC/g TOC, indicating that the Belfast Shale, at least in the Argonaut-A1 location, is a lean, gas prone source rock (Appendix 1). From HI, Tmax and VR data, this shale is within the oil window (VR <1%). With this poor quality gas prone source profile and low maturity, the section is unlikely to have produced oil or gas in the vicinity of the well.

At Argonaut-A1, the Tertiary is approximately 620 m thick, compared to greater than 1200 m for wells peripheral to the Voluta Trough, where there are commercial gas accumulations in five significant fields. Without further study, it is not known if the 620 m of Tertiary loading was sufficient to reinitiate generation and migration of hydrocarbons in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Far more potential reservoir sands were penetrated through the Late Cretaceous than prognosed (Fig. 21). Reservoir quality is generally good in the primary objective, the Paaratte/Curdies formations. At depths between 2400 and 3000 mKB, porosities range between 12 and 20% with permeability's up to 3000 mD (Fig. 22). Moderately thick potential seals are present above this level.

At the Waarre Sandstone level, reservoir sands are interbedded with shales. Reservoir quality is less than that seen in shallower onshore wells. Core porosities measured from the Waarre Sandstone range between 8 and 15%, with permeabilities between 2 and 25 mD. The porosity vs. permeability plot (Fig. 22) shows the variation in reservoir quality through the section. This poorer quality reservoir probably resulted from well advanced diagenetic processes at these depths and temperatures. The Waarre Sandstone was deposited in a shallow marine environment above the top Eumeralla Formation unconformity surface, and can provide good primary quality reservoirs in the right setting.

SEAL

Many thin (1-25 m) shales exist within the Curdies–Paaratte formations. Towards the base of the sequence (below 2300 mKB), there are thicker 10–20 m shales above good quality reservoirs, offering the potential for trap development in four-way closures or where fault throws are small. The potential Base Tertiary seal, the secondary target, is poorly developed, comprising interbedded silts, claystones and sands of the Knight Group (James, 1968). The principal seal, the Belfast Shale, is approximately 480 m thick and is breached by the controlling fault on the southwestern side of the structure where the throw is approximately 555 m (James, 1968; Ultramar Australia Inc, 1984). This shale is likely to be effective as a top and cross-fault seal in structures that have controlling fault throws less than the seal thickness.

SHOWS

No significant shows were recorded in the well.

RESULTS

Argonaut-A1 was plugged and abandoned as a dry hole. In the context of the broad structural closure, Argonaut-A1 is located well downdip (300 ms) from the trap crest at the Waarre Sandstone level, and was therefore, not a valid test of the structure. Additionally, fault throws at the Waarre Sandstone level exceeded the thickness of the seal provided by the Belfast Shale. Consequently, reservoir sands are juxtaposed on either side of the fault (James, 1968). In addition, the potential of the overlying base Tertiary seal, the Knight Group, is also low, with a much sandier interval than prognosed intersected. Additional risks are derived from the late reactivation of the control fault, reducing the chance of preservation of early-trapped hydrocarbons.

With the very low source potential of the Belfast Shale at this location, oil and gas gas accumulation in this area is probably dependent on the Eumeralla Formation source intervals below TD. Peak generation and migration of hydrocarbons from the Eumeralla Formation is interpreted as occurring in the mid Cretaceous, with little or no charge expected after the very late stage fault reactivation. This analysis suggests that the way forward for exploration in this area may be to look for subtle traps not affected by late stage faulting, potentially preserving early trapped hydrocarbons.

REFERENCES

JAMES, E.A., 1968. Argonaut A-1, South Australia, Offshore, Well Completion Report. Esso Exploration and Production Australia Inc (unpublished).

ULTRAMAR AUSTRALIA INC, 1984. Breaksea Reef No.1, Well Completion Report. (unpublished).

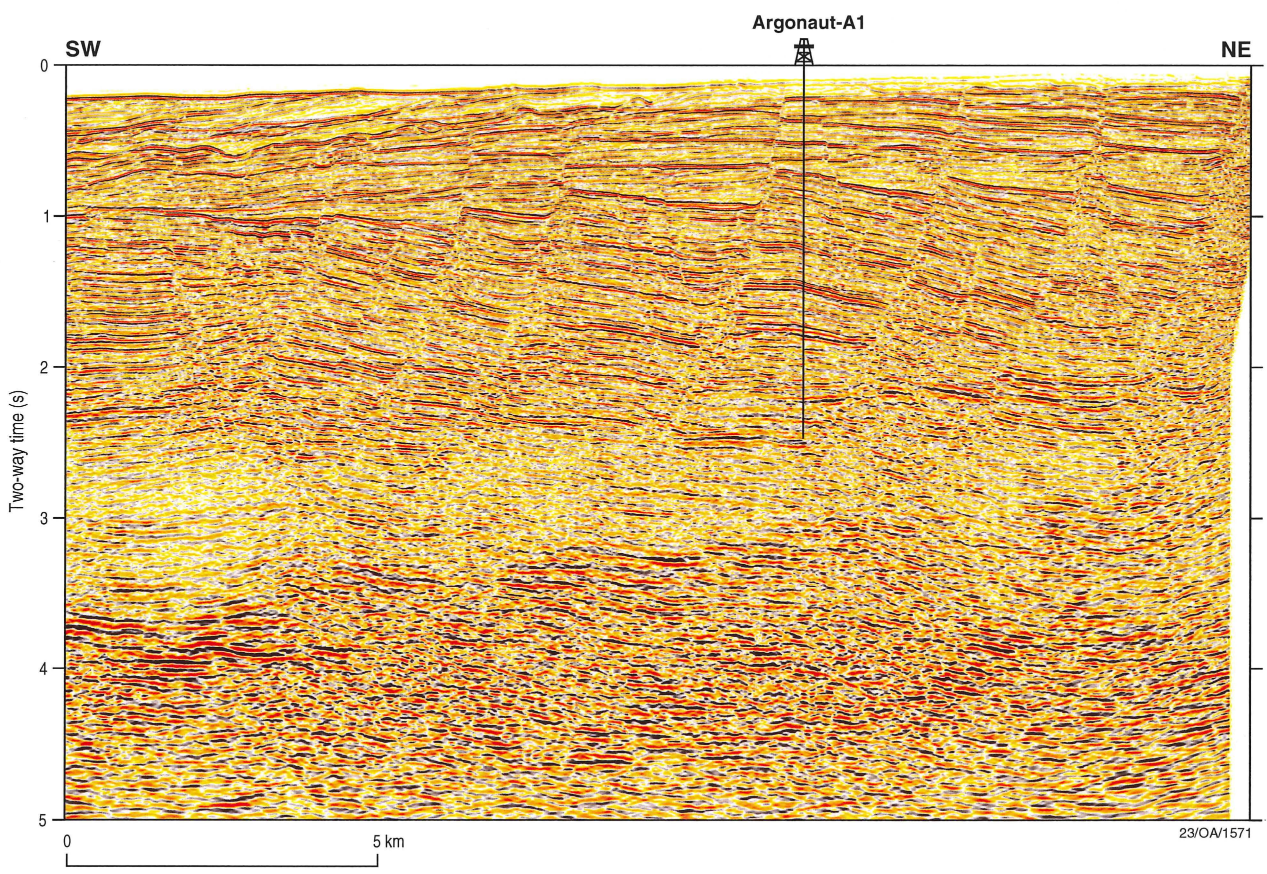

Figure 20. Seismic section showing location of Argonaut-A1.

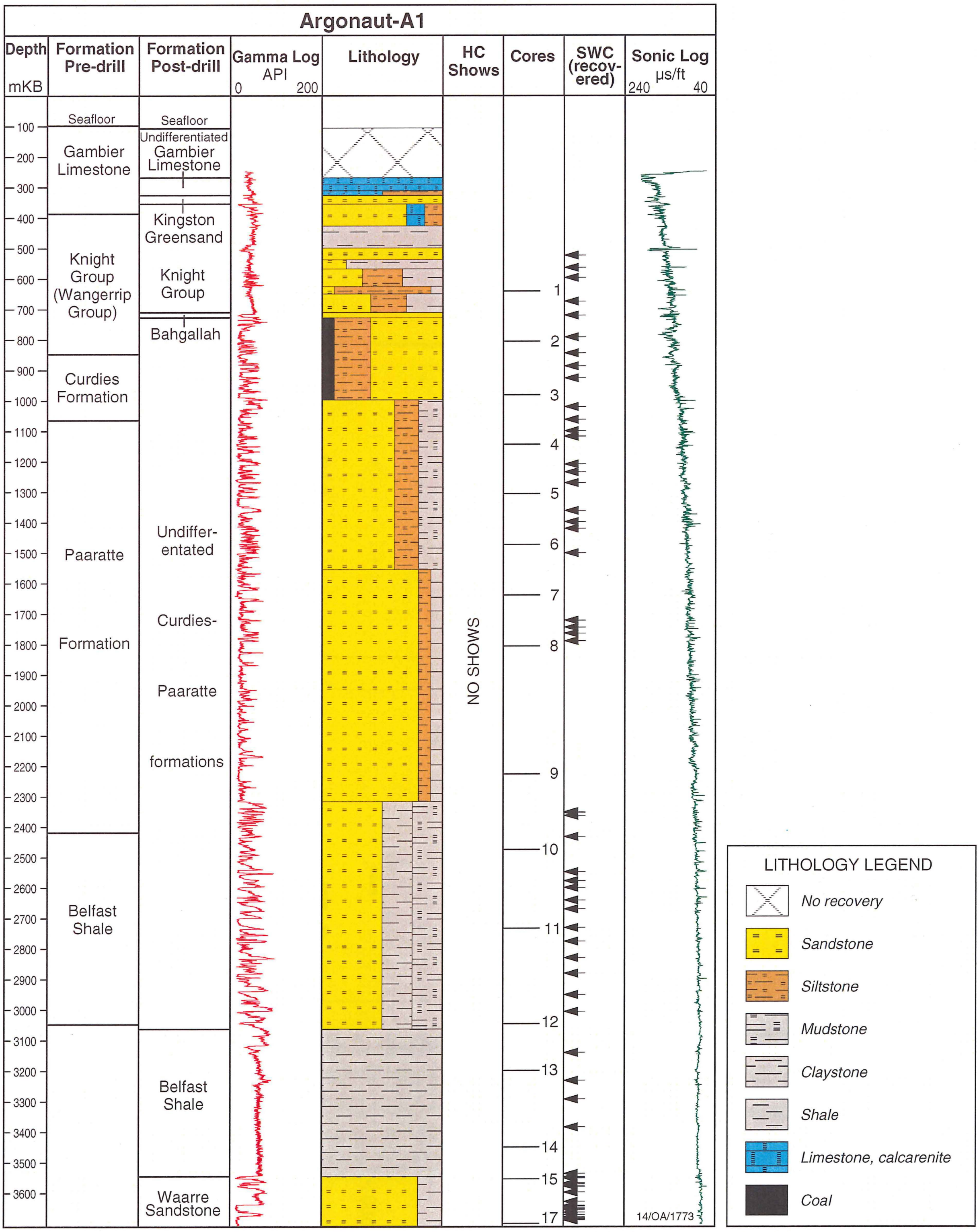

Figure 21. Argonaut-A1 well composite

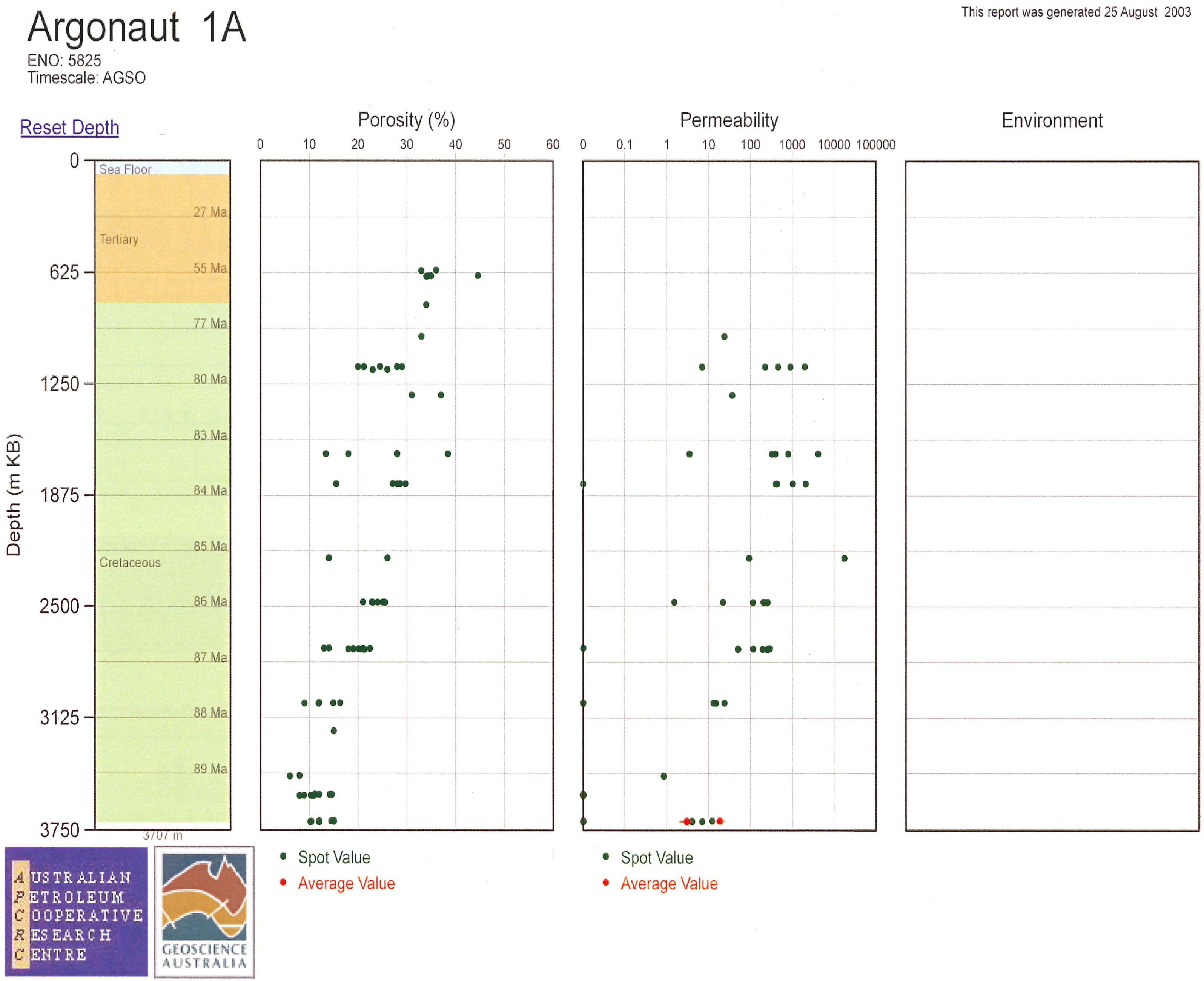

Figure 22. Porosity and permeability measurements recovered from Argonaut-A1. Source: www.ga.gov.au/oracle/apcrc. Acce sse d : August, 2003.

Breaksea Reef-1

WELL SUMMARY

Operator	Ultramar Australia Inc
Date Spudded	22 Dec 1983
TD Date	18 May 1984
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	Mud log gas & residual oil shows
UNO	W5830001
Permit	EPP18
Latitude	38° 09' 30.875" S
Longitude	140° 36' 44.397" E
Reference datum	Central Meridian 141° E
Projection	AGD66
KB (m)	22.0 m
Water Depth	67.0 m
TD (mKB)	4468 m
Age at TD	Late Cretaceous
Primary Objective	Waarre Formation
Secondary objective	Curdies–Paaratte formations and intra-Belfast Mudstone sands
Play/Trap Type	Faulted anticlinal structure / tilted fault block
Reason for failure	Fault seal breaching and lack of subsequent charge

DATA SUMMARY

Palynology:

The original palynological analysis was undertaken by Morgan, R., (1984). "*Palynology and visual geochemistry of Ultramar Breaksea Reef No. 1, Otway Basin*". The report is contained in Appendix D in the WCR with analysis of 84 SWC and 8 cuttings samples.

Additional analysis was also done by Partridge, A. D., 1996. "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells.*" Biostrata Report 1996/5.

Micropalaeontology:

No micropalaeontological analysis has been performed.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments
Core-1	4429.7	4436.8	0.0	Not recovered due to hole problems
SWC	771	4178	75 of 102	2 Runs, 24 empty, 2 mudcake,1 lost
Cuttings	246 2190	2190 4468		5 m sample interval 3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Run	Tool string	Interval (mKB)	Comments
1	DIL–BHCS–GR–CAL–SP HDT	246–757 246–757	
2	DIL–SLS–GR–CAL–SP HDT FDC–CNL–GR	764–2978 764–3192 3178–4175	
2A	DIL–SLS–GR–SP LDL–CNL–GR	2900–3192 764–3192	
3	DIL–SLS–GR–SP HDT	3178–4192 3178–4203	
4	DIL–SLS–GR–SP VSP	4190–4289 1052–4200	
1 (in 7" casing)	CBL–VDL	3025–4147	

Velocity Survey:

A VSP survey was run in Breaksea Reef-1, with a total of 29 check levels shot, three of which were later rejected. The general data quality was described as fair, although the majority of the levels were affected by high frequency noise. The VSP report is included in the WCR as Appendix H.

Well Tests:

No testing by RFT, DST or other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of Breaksea Reef-1 was to evaluate the hydrocarbon potential of the Waarre Formation in a seismically defined Early Cretaceous high with a vertical relief of 120 m and areal closure of 20 km^2. The structure was mapped as dip closed, except to the south, where the down-faulted Belfast Mudstone was interpreted to provide a seal (Ultramar Australia Inc, 1984).

SECONDARY OBJECTIVE

The secondary objectives were the Curdies–Paaratte formations and intra-Belfast Mudstone sands where fault controlled closures, similar to that mapped at the Waarre Formation level, were also defined (Ultramar Australia Inc, 1984).

STRUCTURE

The structural setting of Breaksea Reef-1 (Fig. 23) was very similar to that for Argonaut-A1 (Fig. 20). Breaksea Reef-1 was located on one of a series of gently tilted fault blocks with the major faults down to the basin to the southwest (Fig. 23). The Breaksea Reef fault block was also controlled by antithetic faults down to the northeast between ~1.0 and 2.0 s. Bed dips are very low, with the well located in a crestal position such that any significant accumulations of hydrocarbon were likely to be observed in Breaksea Reef-1. The well penetrated the horizons in near crestal positions at all levels, and appears to be a valid test.

Similar to Argonaut-A1, faults from the northeast edge of the seismic line to just southwest of Breaksea Reef-1 continue through to, or near, the seafloor (Fig. 23), suggesting very late movement, which increases the chance of leakage of any earlier trapped hydrocarbons. Importantly, southwest of Breaksea Reef-1 faults do not appear to have as significant late reactivation and may present better settings for the preservation of fault trapped hydrocarbons.

SOURCE ROCKS

The thick Belfast Mudstone (>1000 m), is interpreted as the only possible source rock in the well. It has TOCs <3.2%, with fair source richness as indicated by potential hydrocarbon yields of 2–6 kg/ton. All the shallower shales and silts evaluated have yields of <2 kg/ton. HI values are in the range 110–180 mg HC/g TOC, higher than those seen in Argonaut-A1. HI, Tmax (highly variable) and VR data show that this shale is gas prone, within the oil window (VR <1%), and as such is unlikely to have produced oil or gas in the vicinity of the well (Appendix 1).

Organic petrographic analysis identifies widespread occurrence of free oil and bitumen in siltstones from the Belfast Mudstone. These were only seen during the organic petrographic analysis of prepared side wall core samples for VR determination. This may explain the erroneously large S_2 peaks and the anomalous spread of Tmax values seen. The free oil and bitumen has been observed optically below 3275 mKB and is interpreted as migrated oil and reservoir bitumen (Ultramar Australia Inc, 1984). A low grade or residual oil leg is interpreted in the intra-Belfast Mudstone sand interval between 3638 and 3677 mKB (Ultramar Australia Inc, 1984).

At Breaksea Reef-1, the Tertiary is approximately 1000 m thick (Fig. 24), as compared with 1200 m to 1600 m for wells peripheral to the eastern Voluta Trough. Without further study it is not known if Tertiary loading was sufficient to restart generation and migration in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Many potential reservoir sands with porosities >30% were penetrated in the highly interbedded Late Cretaceous interval (Figs. 24 and 25). In the intra-Belfast Mudstone sands, porosity values range between 9 and 13%. No permeability data are available (Fig. 25). At the Waarre Formation level, reservoir sands are interbedded with shales, and with poor or no wireline log data, reservoir porosities could not be quantitatively determined. Cuttings lithology based estimates range between 10 and 20%. Palynological data indicate a shallow marine setting.

SEAL

The principal seal, the Belfast Mudstone, is approximately 1050 m thick, divisible into a lower 600 m thick seal interval below the intra-Belfast Mudstone sands, and an upper 400 m thick shale. The fault throw at the trap crest is estimated to be 330 m, and as such there is a reasonable case that both the upper and lower Belfast Mudstone seals are in juxtaposition against reservoir sands across the faults on the southwestern side of the structure. The Belfast Mudstone is silty at this location, which does raise some concerns about its sealing ability. There is also some geopressuring in the Belfast Mudstone (Ultramar Australia Inc, 1984). If the formation pressures are greater than those in underlying reservoirs then the sealing potential of the interval is enhanced. On a regional scale, from analysis of a series of well logs with more modern log suites, there is a clear trend of increasing silt content towards the west.

Through the Paaratte and Curdies formations there are many thin shales, generally 1–25 m thick, above good quality reservoirs, offering the potential for trap development in four-way closures or where fault throws are low. The Breaksea Reef structure with relatively high fault throws is not a favourable setting for the development of traps involving these thinner seals.

SHOWS

There are interesting shows in the well below 3276 mKB in the Belfast Mudstone and Waarre Formation intervals. In the intra-Belfast Mudstone sands and silts good gas shows, oil coatings and bitumen were observed. A low grade oil leg was interpreted. Petrophysical evaluation interpreted these sands to be water bearing. Good gas shows were recorded in the Waarre Formation; however, wireline logs are not available over the entire Waarre Formation interval.

Oil coatings and oil filling of pore spaces were observed during the VR and petrology study of mounted and polished sidewall cores detailed in Appendix E of the WCR (Ultramar Australia Inc, 1984). All the sidewall cores were shot prior to the running of the 7-inch liner. Close inspection of the well history show that no diesel was added to the mud prior to this point. During the subsequent drilling of the 6 inch hole, diesel pills were added at ~4386 m. As such there is a good case that these shows are not a diesel contamination product. However, care should be taken with any inferences made.

Top (mKB)	Base (mKB)	Source	Show type	Lithology	Comments
3635.2	3640.8	mudlog	G1	Sandstone	High gas peaks-no hydrocarbon column from petrophysics
3646.3	3655.6	mudlog	G1	Sandstone	As above
3663.8	3673.9	mudlog	G1	Sandstone	As above
4362	4369	mudlog	G1	Sandstone	Best gas readings-no logs
3276		CST	L2	sandy siltstone	Oil and bitumen identified form maceral analysis
3310		CST	L2	sandy siltstone	Oil appears as coatings on quartz grains
3328		CST	L2	sandy siltstone	As above
3351		CST	L2	sandy siltstone	As above
3477		CST	L2	Siltstone	As above
3494		CST	L2	Siltstone	As above
3516		CST	L2	sandy siltstone	As above
3570		CST	L2	sandy siltstone	As above
3613.1		CST	L2	sandy siltstone	As above
3630		CST	L2	sandy siltstone	Oil occurs in pore spaces interstitial to quartz grains as well as coatings
3751		CST	L2	Siltstone	Oil occurs as coatings on quartz grains
3799		CST	L2	Siltstone	Oil occurs as coatings on quartz grains
3868		CST	L2	Siltstone	Oil occurs as coatings on quartz grains
4027.1		CST	L2	Siltstone	Oil occurs as coatings on quartz grains
4075		CST	L2	Siltstone	Oil occurs as coatings on quartz grains
4173		CST	L2	Siltstone	Oil occurs as coatings on quartz grains
4468		Cuttings	L2	Siltstone	Crush cut fluorescence

RESULTS

It is interpreted that this structure is probably adequately sealed at both the intra-Belfast Mudstone sands and Waarre Formation levels, although no quantitative data on Belfast Mudstone seal quality is available. It is thought likely that oil and gas have migrated through the section and may have accumulated in the structure at these deeper levels. If traps had been developed and filled, the late reactivation of the controlling fault would have greatly increased the preservation risk. Therefore, the oil and gas shows are possibly residual after late trap breaching. For traps above the thick Belfast Mudstone, migration from the Eumeralla Formation source rocks is considered a significant risk. Detailed mapping may demonstrate a clear pathway and reduce this critical risk element.

With over 1000 m of Tertiary loading, the potential for later Eumeralla Formation sourced hydrocarbons is increased (relative to the Argonaut-A1 setting). Without quantitative analysis it is not possible to determine if a late charge has occurred and what volumes were available at this location. The observation of at least two types of oil and bitumen may support a multiple phase migration history. Migration fetch area also needs to be considered as a risk element where multiple fault block traps with small drainage areas are developed, restricting the volumes of hydrocarbons available for trapping.

This analysis suggests that the way forward for exploration in this area is to look for more subtle traps not affected by late stage faulting, potentially preserving early trapped hydrocarbons and trapping later stage migrating hydrocarbons. Sufficiently large migration fetch areas are also required.

REFERENCES

ULTRAMAR AUSTRALIA INC, 1984. Breaksea Reef No.1, Well Completion Report. (unpublished).

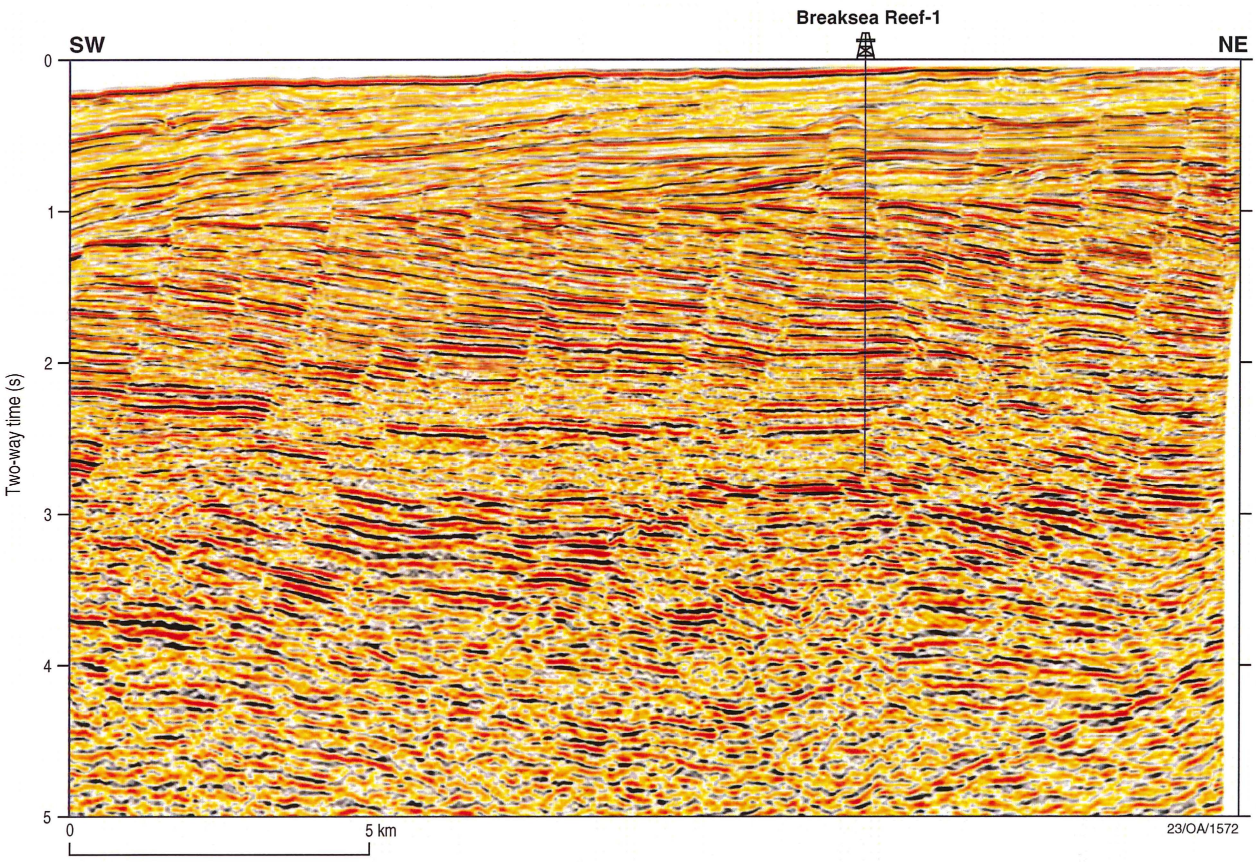

Figure 23. Seismic section showing location of Breaksea Reef-1. Seismic reproduced with permission of Fugro MCS.

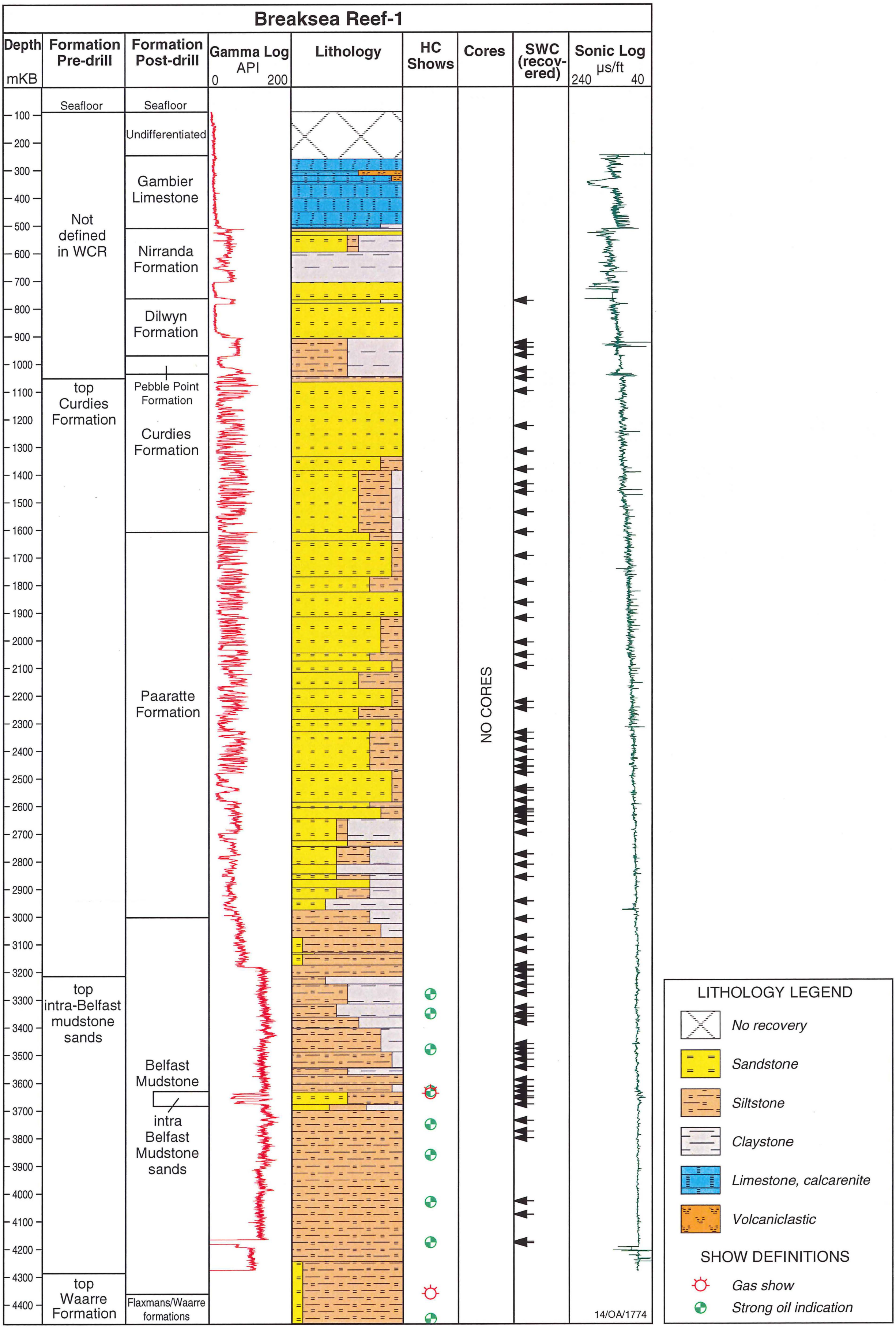

Figure 24. Breaksea Reef-1 well composite.

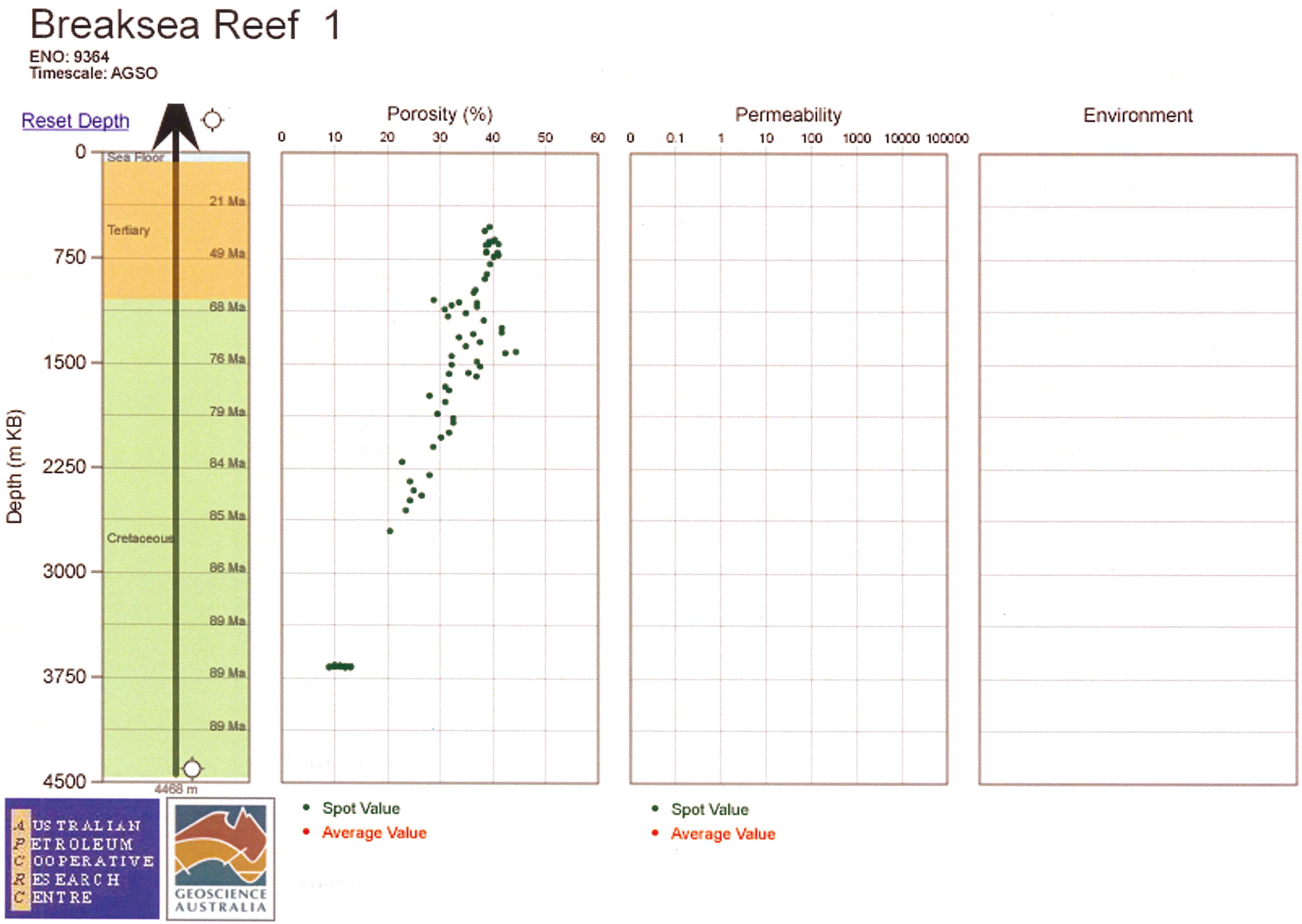

Figure 25. Porosity and permeability measurements recovered from Breaksea Reef-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

3.3 Discovery Bay High

The Discovery Bay High area is located central to the Otway Basin and seaward of the Tartwaup–Mussel fault zone. The boundaries of this approximately northnortheast–southsouthwest trending structural high are poorly defined, but it is likely that it is continuous with the onshore Merino High and Dartmoor Ridge (Moore et al., 2000). Offshore, the Discovery Bay High is characterised by major growth of the Late Cretaceous Sherbrook Group section across the Tartwaup–Mussel fault zone. As with the Morum Sub-basin, resolution of the early structural configuration may be masked in part by the latest Cretaceous to early Tertiary faulting.

The Tertiary section is significantly thicker than in the Morum Sub-basin; typically greater than 1200 m in the wells investigated. The Late Cretaceous Sherbrook Group maintains a fairly uniform thickness in the wells investigated with a better developed and less silty Belfast Mudstone.

Discovery Bay-1

WELL SUMMARY	
Operator	Phillips Australian Oil Company
Date Spudded	21 September 1982
TD Date	12 October 1982
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No hydrocarbon indications
UNO	W3820013
Permit	VIC/P14
Latitude	38° 24' 42.9030" S
Longitude	141° 04' 21.1006" E
Reference datum	Australian National Spheroid, Zone 54 Central Meridian 141° east
Projection	Universal Transverse Mercator
KB (m)	23 m
Water Depth	97 m
TD (mKB)	2776 m
Age at TD	Late Cretaceous
Primary Objective	Curdies and Paaratte formations sands with Tertiary seal
Secondary objective	Belfast Formation sands
Play/Trap Type	Complex faulted structure
Reason for failure	Poor seal - unfavourable cross-fault juxtaposition

DATA SUMMARY

Palynology:

An initial report was prepared by Harris, W.K., (1983). "*Discovery Bay No.1 Well, Otway Basin. Palynological Examination and Kerogen Typing of Sidewall Cores*". The palynological analysis was based on 75 SWCs between 774 and 2776 mKB. The report is included as Appendix 7 of the WCR.

Additional analysis was undertaken by Partridge, A. D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells.*" Biostrata Report 1996/5.

Micropalaeontology:

The initial analysis was undertaken by Taylor, D., (1982). "*Foraminiferal sequence in Discovery Bay #1*", and is contained in Appendix 6 of the WCR. The analysis was based on 56 SWCs and 4 cuttings samples between 434 and 2772 mKB. Foraminifera were recovered between 434 to 795 mKB and 1013 to 1594 mKB.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments
Core				No conventional cores were cut
SWC	434	2776	108 of 152	
Cuttings	438	2776		5 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table.

Run	Tool string	Interval (mKB)	Comments
1	DIL–SLS–GR CST	423–1210 423–1210	
2	DIL–SLS–GR–LDL–CNL HDT CST	1199–2778 1199–2778 1199–2778	

Velocity Survey:

A velocity survey was completed at 27 levels over the interval 300 to 2737 mKB at TD. The report can be found in Addendum 3 of the WCR.

Well Tests:

No testing by RFT, DST or other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of Discovery Bay-1 was the Late Cretaceous fluvio-deltaic sandstones of the Curdies and Paaratte formations. The expected seal was the Early Tertiary shale and siltstone overlying the Late Cretaceous unconformity surface. These targets were interpreted to be present in a complex faulted anticlinal closure mapped at the top Cretaceous horizon (Phillips Australian Oil Company, 1983).

SECONDARY OBJECTIVE

The secondary targets were reservoirs within the Belfast Formation.

STRUCTURE

Discovery Bay-1 was drilled near the crest of a fault block at top Late Cretaceous level (~1.2 s; Fig. 26) within what is interpreted to be a partially collapsed anticlinal structure. With increasing depth, the well was positioned progressively farther downdip from the fault trap crest. Minor fault reactivation was observed above ~1.2 s, introducing some chance of leakage of any earlier trapped hydrocarbons. This faulting does not appear to continue above ~1.0 s for faults related to the Discovery Bay-1 structure.

Maps provided in the WCR for the top of the Sherbrook Group and intra-Paaratte Formation, indicates that the Discovery Bay structure has closure on a major complex northwest–southeast anticlinal trend (Phillips Australian Oil Company, 1983).

SOURCE ROCKS

The interbedded deltaic shales and claystones of the Curdies and Paaratte formations have TOCs <2% and HI values typically <100 mg HC/g TOC, indicating poor quality, gas prone source rocks. Maturity levels increase to just mature (VR ~ 0.66%) for oil at TD (Appendix 1). As such, it is highly unlikely that these potential source rocks have produced any significant volumes of hydrocarbons.

At Discovery Bay-1, the Tertiary is approximately 1200 m thick. This is comparable to the 1200 m to 1600 m observed for wells peripheral to the eastern Voluta Trough where commercial gas accumulations are identified (e.g., Minerva, La Bella, Thylacine, Geographe and Geographe North fields). It is therefore considered likely that Tertiary loading may be sufficient to restart generation and migration, if the source rocks are adequately developed in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Many potential reservoir sands were penetrated through the highly interbedded Late Cretaceous interval (Fig. 27). Porosity degrades fairly uniformly down the section with 30 to 35% at 800 mKB in the Tertiary, and 17 to 20% at the base of the Paaratte Formation (Fig. 28).

SEAL

The expected argillaceous seal above the top of the Sherbrook Group was not present. The Pember Mudstone here comprised siltstone with thinly interbedded sandstones, with little or no sealing potential.

Within the deeper Curdies and Paaratte formations, there are many thin argillaceous intervals that may offer some seal potential. These are typically <15 m thick and often very silty. With the relatively uniform interbedded characteristics present throughout the whole drilled Sherbrook Group section, the potential for any significant sealed fault traps is considered quite low. However, there are no quantitative data on these seals.

The deeper Belfast Formation, not penetrated in this well, is expected to be hundreds of metres thick and a good seal. This interval is likely to be a barrier to hydrocarbons migrating from the underlying Eumeralla Formation source interval.

SHOWS

Only very minor gas shows were recorded through the whole well section.

RESULTS

Lack of seal at the primary target level resulted in the absence of an effective trap at this location. The deeper intra-Sherbrook Group intraformational seals are not likely to be continuous over significant areas and are also required to provide cross-fault seal for the tilted fault block play present at this level. With the well located downdip from the fault trap crest within the Paaratte Formation, the well is unlikely to have any possible small accumulation developed at the trap crest. A clear migration pathway from the Eumeralla Formation source, through the thick Belfast Formation, combined with an adequate migration fetch area, are all required to make successful plays in this setting.

This analysis suggests that the way forward for exploration in this area is to look for more subtle traps with smaller faults and thicker, better developed seals, unaffected by late stage faulting, in an effort to locate possible early-trapped hydrocarbons. Critically, a migration window providing access to source rocks through the Belfast Formation needs to be identified.

REFERENCES

PHILLIPS AUSTRALIAN OIL COMPANY, 1983. Discovery Bay No. 1, Well Completion Report. Phillips Australian Oil Company. (unpublished).

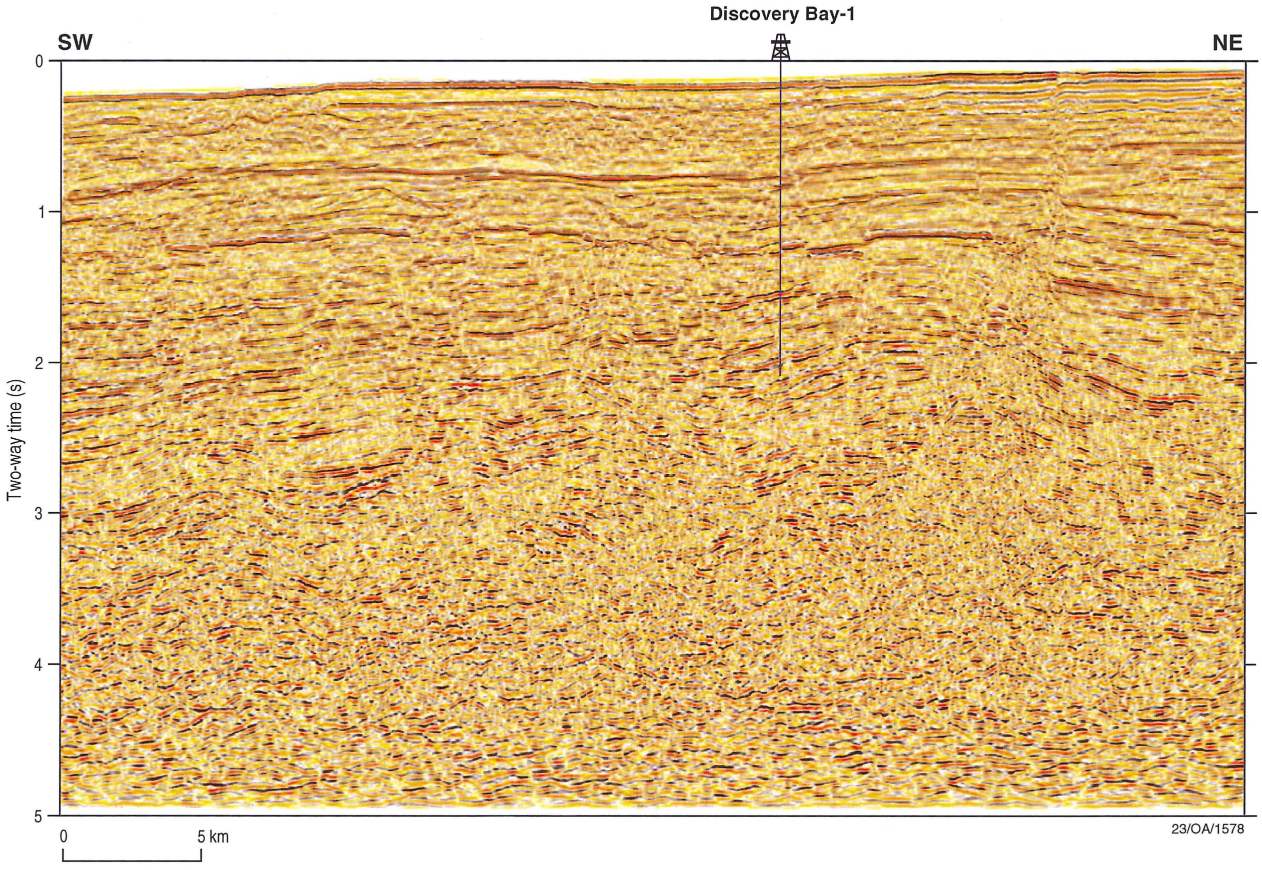

Figure 26. Seismic section showing location of Discovery Bay-1.

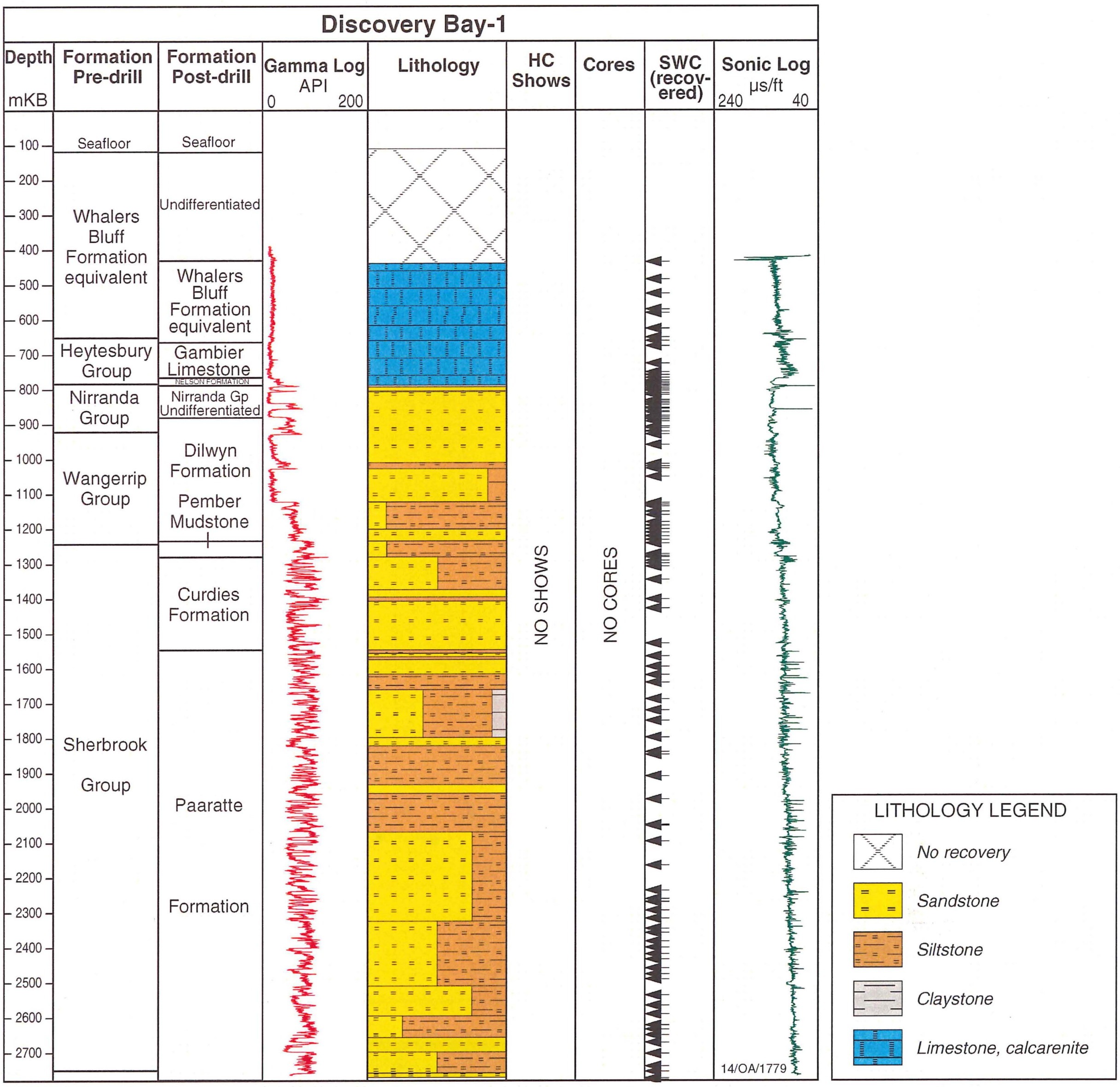

Figure 27. Discovery Bay-1 well composite.

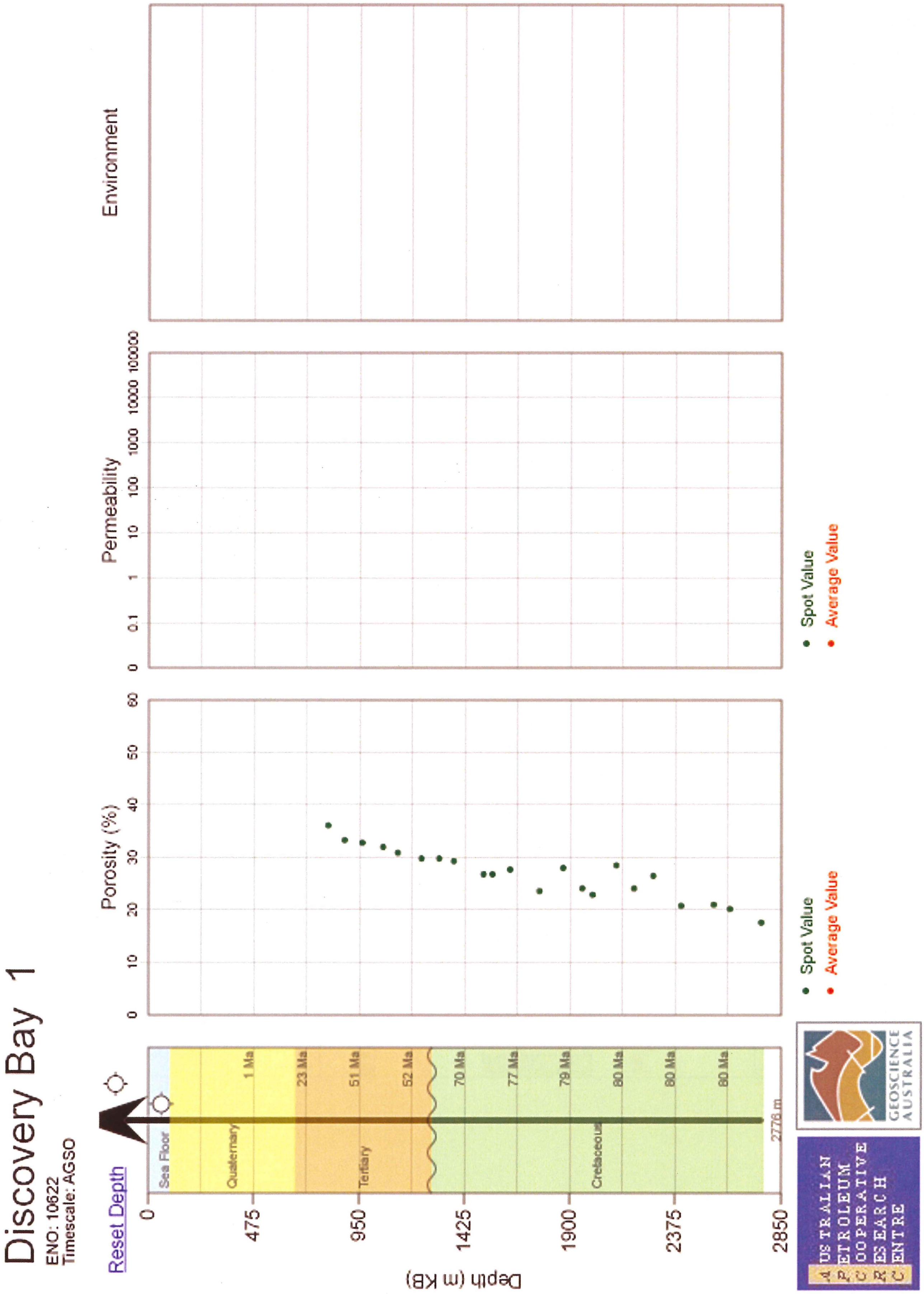

Figure 28. Porosity and permeability measurements recovered from Discovery Bay-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

Voluta-1

WELL SUMMARY

Operator	Shell Development Australia Pty. Ltd.
Date Spudded	25 August 1967
TD Date	8 December 1967
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No hydrocarbon indications
UNO	W3670003
Permit	PEP22
Latitude	38° 25' 46.66" S
Longitude	141° 18' 47.53" E
Reference datum	ATM Zone-6
Projection	Universal Transverse Mercator
DF (m)	34.1 m
Water Depth	91.75 m
TD (mDF)	3973.7 m
Age at TD	Late Cretaceous
Primary Objective	lower Sherbrook Group (Waarre Formation)
Secondary objective	sands in the upper Sherbrook and Wangerrip groups
Play/Trap Type	Faulted anticlinal structure
Reason for failure	Failed to reach primary target

DATA SUMMARY

Palynology:

The original analysis was performed by Dettmann, M.E., (1968) "*Palynological report on Voluta-1 well 4151 feet –13,020 feet.*", located in Appendix 6 of the WCR. The palynological analysis is based on 35 SWCs, 26 core, 2 junk samples and 1 cuttings sample, between 1265 mDF and 3965 mDF. Palynological samples below 2713 mDF contain assemblages with low concentrations of poorly preserved palynomorphs. The low diversity species lists recorded provide only the broad age range of *T.apoxyexinus* to *P.mawsonii Zones*.

Additional analysis was also done by Partridge, A. D., 1996. "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells.*" Biostrata Report 1996/5.

Micropalaeontology:

The micropalaeontological analysis was conducted in the Shell Development (Aust.) Pty Ltd, Geological Laboratory (1968), "*Palaeontology Report, Voluta-1 well*", and is included as Appendix 5 in the WCR. The analysis is based on cuttings examined at 100 ft intervals between 294 and 3974 mDF (966 and 13037 ftDF) supplemented by cores and sidewall cores.

Cores and cuttings:

Sample Type	Top (mDF)	Base (mDF)	Recovered (%)	Comments
Core-1	810.8	814.7	85	
Core-2	905.3	914.4	85	
Core-3	1016.5	1024.7	0	
Core-4	1100.9	1109.2	0	
Core-5	1411.2	1417.0	57	
Core-6	1508.8	1516.7	35	
Core-7	1670.3	1676.4	23	
Core-8	1792.2	1799.8	79	
Core-9	1913.2	1920.9	100	
Core-10	2036.1	2041.3	73	
Core-11	2160.7	2168.4	0.68	
Core-12	2315.6	2320.1	100	
Core-13	2459.4	2468.6	100	
Core-14	2626.5	2629.5	0.85	
Core-15	2672.2	2675.2	90	
Core-16	3034.0	3040.4	82	
Core-17	3191.9	3194.9	82.5	
Core-18	3323.2	3326.3	65	
Core-19	3468.0	3471.1	0	
Core-20	3508.6	3512.2	100	
Core-21	3653.9	3657.3	73	
SWC	301.5	2713	133 of 189	4 runs
Cuttings	294.4	3973.7		3.0 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table.

Run	Tool string	Interval top (mDF)	Interval base (mDF)	Comments
1	LL7	294.1	806.2	
1	BSGRC	294.1	602.9	
1	MLC	294.4	621.2	
1	CBL	286.5	799.8	
1	IES–SP	799.8	1919.0	
1	FDC	799.8	1919.0	
1	SNP	799.8	1919.0	
1	CDM	799.8	1917.8	
2	MLC	294.1	807.1	
2	CBL	609.6	1927.9	
2	BSGRC	630.9	804.7	
2	IES–SP	1924.8	2937.0	
2	FDC	1924.8	2937.0	
2	CDM	1924.8	2653.6	
3	BSGRC	799.8	1915.4	
3	IES–SP	2895.6	3784.4	
3	CBL	1859.3	1929.4	
4	CBL	1859.3	1932.4	
4	BSGRC	1924.8	2933.7	
5	BSGRC	2895.6	3767.3	

Velocity Survey:

A velocity survey was completed over the interval 457.2 to 1914.1 mDF. Nine shots were made with velocity data obtained for three mapped horizons. The report can be found in Appendix 7 of the WCR.

Well Tests:

No testing by RFT, DST or other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of Voluta-1 was to evaluate the hydrocarbon potential of the Late Cretaceous Sherbrook Group, the main target being the basal Sherbrook Group sands observed onshore (Waarre Formation equivalent). These were mapped to be in a broad closure at this location. The Sherbrook Group penetrated was found to be much thicker than predicted, with the well not reaching the primary objective of the Waarre Formation or the Early Cretaceous Eumeralla Formation.

SECONDARY OBJECTIVE

The secondary objectives were the sands of the upper Sherbrook and Wangerrip groups.

STRUCTURE

Voluta-1 was located near the crest of a broad closed anticline at ~1 s (Fig. 29). The anticline trends northeast–southwest and has a vertical closure of approximately 330 m (Shell Development Australia Pty Ltd, 1968). No maps were provided in the WCR. The Belfast Mudstone is at least 1810 m thick at this location (Fig. 30), and is thus likely to provide a cross-fault seal on the drilled structure. The structural interpretation was validated in the postdrill analysis. Low dipmeter measurements at the Sherbrook Group confirmed the well was located near the crest (Shell Development Australia Pty Ltd, 1968).

SOURCE ROCKS

The interbedded deltaic shales and claystones of the Curdies and Paaratte formations have TOCs <2% and low HI values typically <100 mg HC/g TOC, indicating poor, gas prone source rocks. Maturity indications from Tmax and VR data show this upper section of the well to be immature for oil (Appendix 1).

At Voluta-1, the Belfast Mudstone has TOC values between 1 and 2% and HI values <100 mg HC/g TOC, indicating a poor quality, gas prone source rock. Maturity indications from Tmax and VR data show this silty mudstone section of the well to be mature for oil below approximately 3000 mDF. This is supported in part by a slight increase in mud gas C_1, C_2 and C_3 seen down through this section.

At Voluta-1 the Tertiary is approximately 1300 m thick, comparing favourably with 1200 to 1600 m for wells peripheral to the Voluta Trough. There appears to be a reasonable chance that Tertiary loading here may be sufficient to have restarted generation and migration in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Excellent reservoir sands exist in the Wangerrip Group, Curdies and Paaratte formations (Fig. 30), with calculated log porosities typically between 20 and 39% (Fig. 31). 21 cores were cut, however, no core porosity or permeability analysis was performed. No visible porosity was observed from cuttings of sandstones below ~3800 m.

SEAL

The Belfast Mudstone is over 1810 m thick, and is the formation in which the well reached TD; it is likely to be an effective top and cross-fault seal. Lithologic descriptions indicate the presence of a dark silty mudstone with minor very thin sand and dolomite stringers. Lithologic and petrophysical comparisons need to be made against working Belfast Mudstone seals before a more informed opinion can be reached. The Belfast Mudstone is likely to be a barrier to hydrocarbons migrating from the underlying Eumeralla Formation source interval, particularly if no large faults breach the seal within the drainage area of the structure.

Within the deeper Curdies and Paaratte formations, there are many thin argillaceous intervals that may offer some seal potential. These are typically <15 m thick and often very silty. Importantly, there are no quantitative data on these seals and very limited analogs or calibration points in the basin to better assess their potential.

SHOWS

Only very minor gas shows were recorded through the whole well section. A slight increase in mud gas C_1, C_2 and C_3 was observed through the Belfast Mudstone section.

RESULTS

The well failed to reach its primary target of the Late Cretaceous lower Sherbrook Group below the Belfast Mudstone. Critical horizons were mispicked due to poor seismic quality and limited well control at the time of interpretation. The shallower secondary targets of the Paaratte and Curdies formations in the upper Sherbrook Group may have tested a valid closure. However, with no significant shows and the thickness of the underlying Belfast Mudstone, any traps developed at these levels may not have had access to migrating hydrocarbons sourced from the Eumeralla Formation. In addition, if there are any significant faults at the shallower target levels, the thin seals may well have been breached. In the absence of any mapping data these comments are somewhat speculative.

REFERENCES

SHELL DEVELOPMENT (AUSTRALIA) PTY LTD, 1968. Voluta No.1, Offshore Victoria, Well Completion Report. (unpublished).

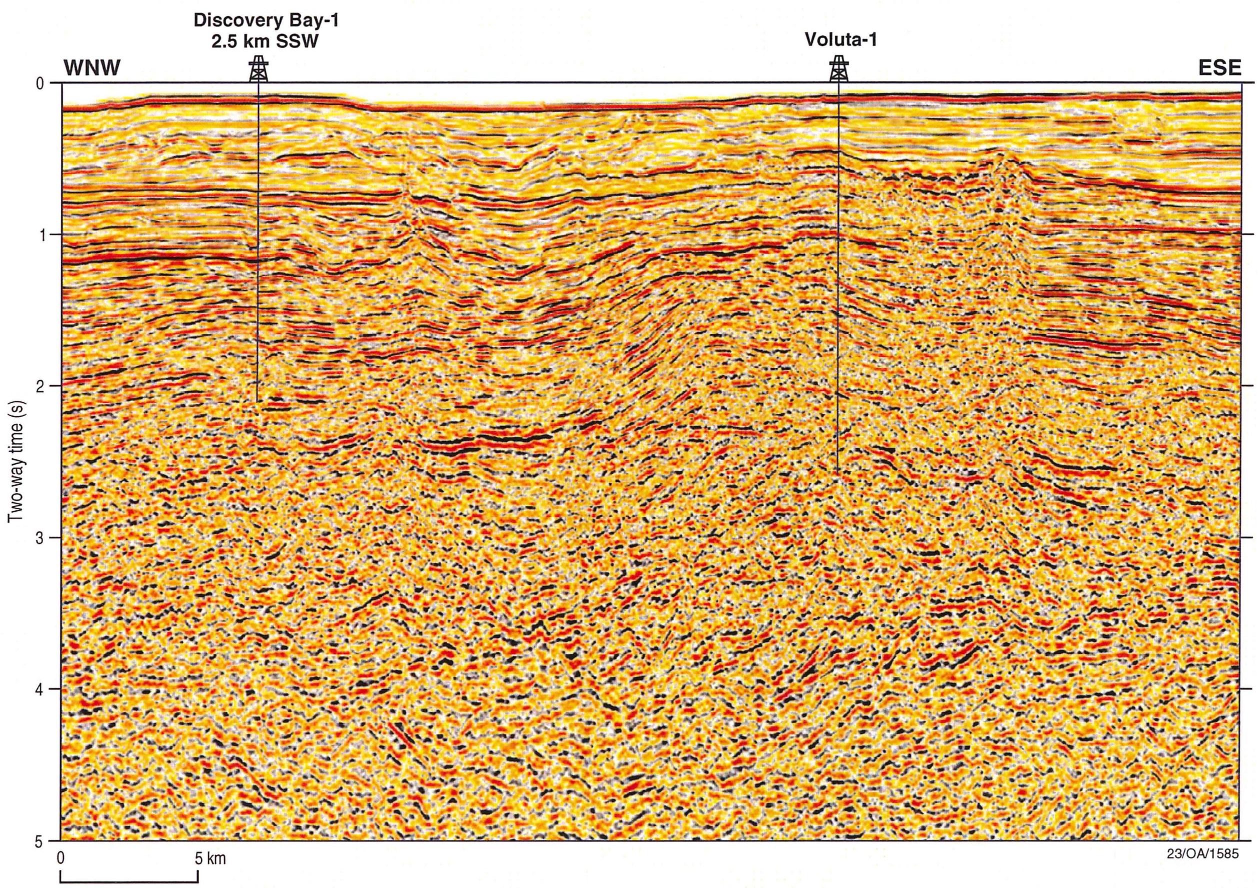

Figure 29. Seismic section showing location of Voluta-1 and Discovery Bay-1. Seismic reproduced with permission of Fugro MCS.

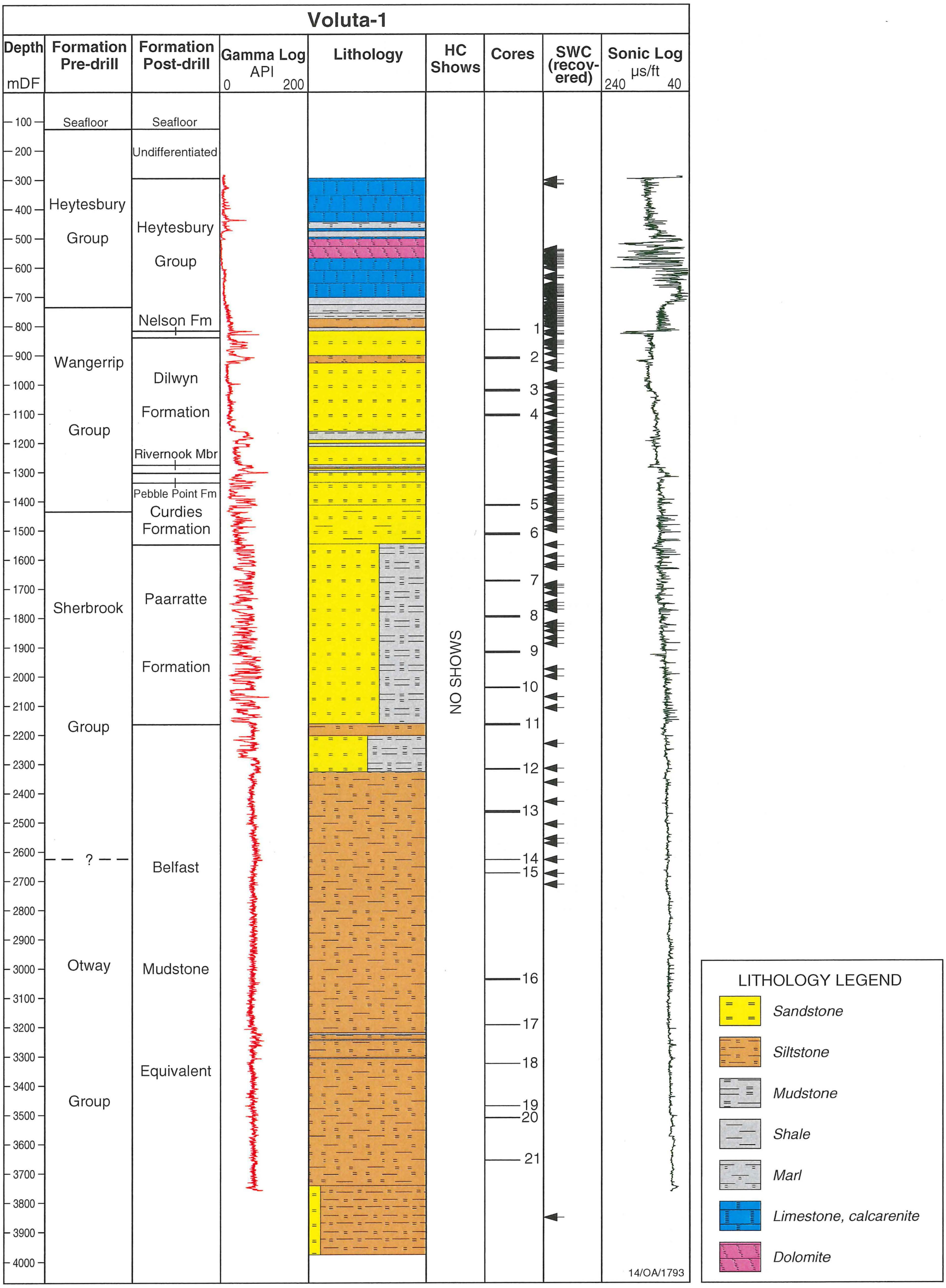

Figure 30. Voluta-1 well composite.

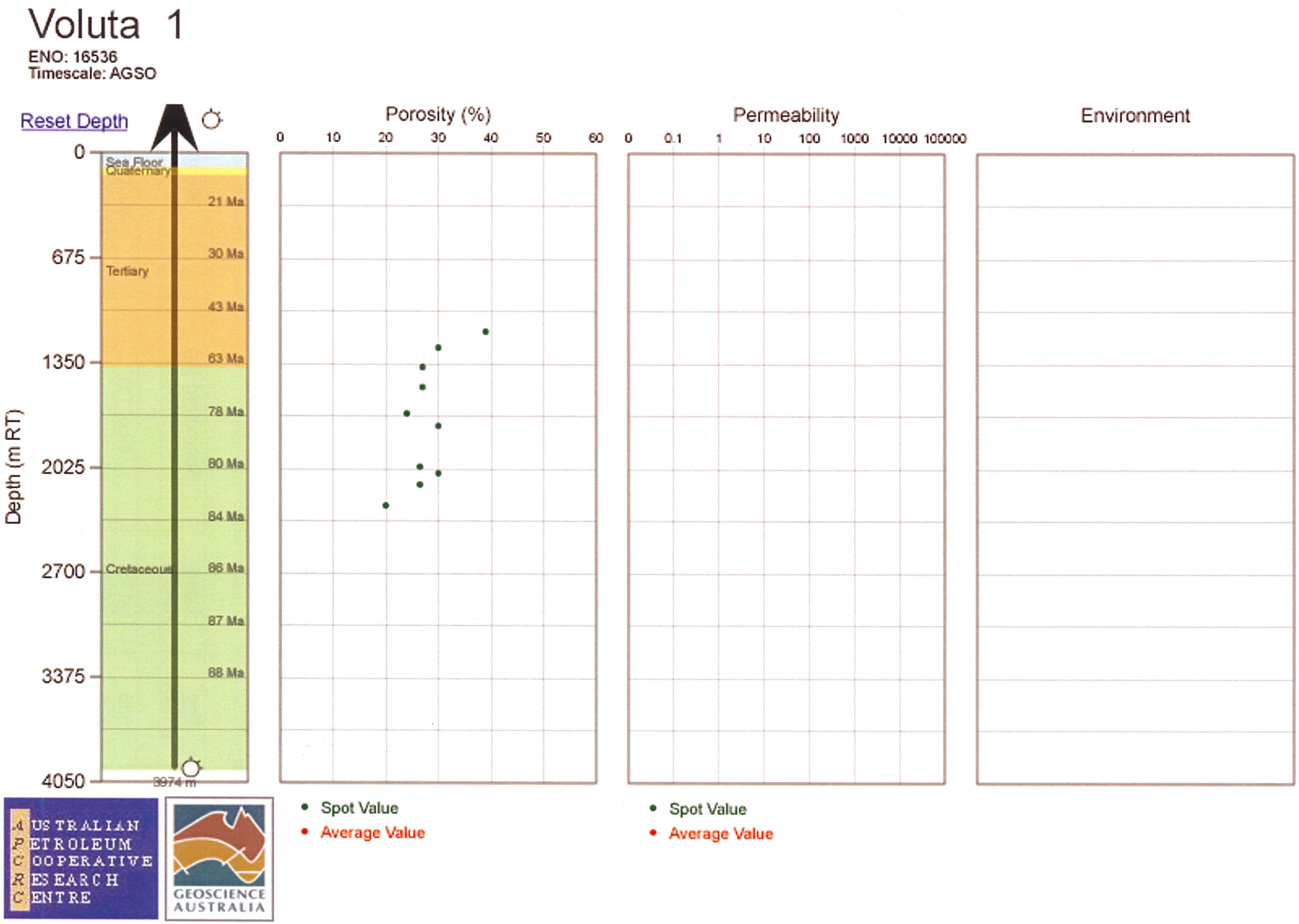

Figure 31. Log derived porosity measurements recovered from Voluta-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

Bridgewater Bay-1

WELL SUMMARY

Operator	Phillips Australian Oil Company
Date Spudded	15 September 1983
TD Date	2 December 1983
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	Minor gas shows
UNO	W3830008
Permit	VIC/P14
Latitude	38° 32' 25.9689" S
Longitude	141° 21' 47.9468" E
Reference datum	Australian National Spheroid, Zone 54 Central Meridian 141° E
Projection	Universal Transverse Mercator
KB (m)	22 m
Water Depth	109 m
TD (mKB)	4200 m
Age at TD	Late Cretaceous
Primary Objective	Waarre Formation
Secondary objective	sands at near base Paaratte or near top Belfast formations
Play/Trap Type	Fault block
Reason for failure	Well 35 m downdip on low relief closure Poor seal - unfavourable cross-fault juxtaposition

DATA SUMMARY

Palynology:

The original palynological analysis was undertaken by Martin, A. H., (1984), "*The stratigraphic palynology of Bridgewater Bay-1, Otway Basin*", and is included in Appendix 6 of the WCR. The analysis was based on 74 SWC between 887 and 4098 mKB.

Additional analyses were performed by:
Partridge, A. D., (1996), "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells.*" Biostrata Report 1996/5.

and Partridge, A. D., (1997), "*Palynological age and environmental analysis of cuttings samples from Bridgewater Bay-1, offshore Otway Basin.*"

Micropalaeontology:

The original micropalaeontological analysis was done by Taylor, D. (1984), "*Foraminiferal sequence in Bridgewater Bay-1, Otway Basin*", and is included in the WCR as Appendix 5

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments
Core				
SWC	550	4175	89 of 111	80.2% recovery
Cuttings	505 1505	1505 4200		10 m sample interval 5 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mKB)	Comments
1	1	DIL–SLS–GR	493–1602	
	2	BGL	493–1602	
	3	CST	550–1593	30 attempted 28 recovered
2	1	DIL–SLS–GR	1594–3533	
	2	LDL–CNL–GR	1594–3533	
	3	HDT	1594–3533	
	4	CST	1613–3335	51 attempted 39 recovered
3	1	DIL–SLS–GR	3519–4199	
	2	LDL–CNL–GR	3900–4139	
	3	HDT	3850–4138	
	4	CST	3560–4175	30 attempted 22 recovered
	5	Velocity Survey	477–4157	23 levels

Velocity Survey:

A velocity survey was completed with 23 levels over the interval 477–4157 mKB. The report can be found in Addendum 3 of the WCR.

Well Tests:

No testing by RFT, DST or other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of the well was to evaluate the hydrocarbon potential of the Waarre Formation in a seismically defined Early Cretaceous faulted anticlinal structure mapped at the top of the Otway Group.

SECONDARY OBJECTIVE

The secondary objectives were Late Cretaceous sands mapped within the near top Belfast or near base Paaratte formations. At this level, the structure comprised a significant faulted anticlinal feature.

STRUCTURE

Bridgewater Bay-1 was drilled near the crest of a broad faulted anticline (Fig. 32). Predrill mapping interpreted a lightly faulted, domal structure at top Otway and intra-Sherbrook groups, with more than 100 m of vertical closure predicted at the Waarre Formation level (Phillips Australian Oil Company, 1984). The Waarre Formation was intersected ~1100 m deep to prognosis (Fig. 33). Therefore, predrill maps were representative of shallower horizons. Postdrill, the structure at the Waarre Formation target level was reduced to a broad, shallow relief, anticlinal closure on a terrace between two major down to the basin faults, with very little closure. It was also interpreted in the WCR that Bridgewater Bay-1 penetrated the Waarre Formation approximately 35 m downdip from the trap crest (Phillips Australian Oil Company, 1984). At this level, the well was positioned at approximately the same depth that the top Waarre Formation contacts the northern controlling fault, 2 km to the northeast (fault spill point), juxtaposing sandstones from the Waarre Formation probably against the Eumeralla Formation. Postdrill maps included in the WCR indicated that south of the well, the structure was cut by a fault with approximately 2000 m throw (Phillips Australian Oil Company, 1984). Seismic evidence suggests that the Belfast Formation expanded over this fault, juxtaposing it against the Waarre Formation at about the same depth as the well.

Near the top Belfast Formation, the structure appears to be robust with crestal faults having throws between 75 and 100 m near the well. At the base of the Belfast Formation (~1400 m thick), the structure has low relief with little closure. This structure was not mapped reliably due to the poorer quality of the seismic available at the time (Phillips Australian Oil Company, 1984).

Faulting was generally minor in the Tertiary (above ~ 1 s at the well trace; Fig. 32). However, Late Cretaceous deformation of the bounding fault may have occurred beneath the Tertiary channel axis ~4 km to the northeast. Nonetheless, there is a decreased chance of leakage of any earlier trapped hydrocarbons, particularly compared with wells farther to the west where there was increased Tertiary faulting and a slightly siltier Belfast Formation.

SOURCE ROCKS

The Belfast Formation is approximately 1400 m thick, and is interpreted as the only possible source rock in the well. The upper Belfast Formation is marginally mature for oil and is interpreted to have overall poor oil and gas source character (TOCs <3.5%; HI values <150 mg HC/g TOC; Appendix 1). Rocks below 3550 mKB were potentially contaminated with an oil based mud additive which has affected TOC and pyrolysis results (Phillips Australian Oil Company, Pty Ltd, 1984; Edwards, 1997).

At Bridgewater Bay-1, the Tertiary is approximately 1100 m thick (Fig. 33) as compared with 1200 to 1600 m for wells peripheral to the eastern Voluta Trough. Therefore, Tertiary loading may be sufficient here to restart generation and migration of hydrocarbons, if the source rocks are adequately developed in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Many potential reservoir sands were penetrated through the highly interbedded Late Cretaceous to Tertiary interval. In the Paaratte Formation, there is a higher proportion of shale and poorer quality sands than in equivalent well sections to the west (Fig. 33). Log derived porosity values decrease fairly uniformly down the section with 26 to 44% at the Pebble Point Formation, 17 to 19% in selected sand units of the basal Paaratte Formation, 10 to 22% in the upper Belfast Formation, and <2% in the Waarre Formation (Fig. 34). The Waarre Formation comprises interbedded sandstone, claystone and siltstone with a fine to very fine grainsize range.

SEAL

The principal seal, the Belfast Formation, is approximately 1400 m thick with no significant interbedded sands (Fig. 33). It is expected to be an adequate seal, although no quantitative data are available. Mapped fault throws at the top Waarre Formation are approximately 700 m for the bounding fault to the north and 2000 m for the bounding fault to the south (Phillips Australian Oil Company, 1984). On the northern fault, the Eumeralla Formation, comprising diagenetically altered volcaniclastic fluvial sands, shales and coals with very low porosities and permeabilities, is juxtaposed against the downthrown Waarre Formation. In the Gippsland Basin, equivalent rocks provide effective seals (e.g., the Longtom gas field), and may therefore work across this northern fault. The Belfast Formation thickens dramatically across the downthrown block of the southern fault and is therefore expected to provide an effective seal.

Within the Pebble Point, Curdies and Paaratte formations, there are many thin shales and silty shales, generally 1 to 25 m thick, above moderate to good quality reservoirs (Phillips Australian Oil Company, 1984). Therefore, potential exists for trap development in four-way closures or where fault throws are low. Mapping at this level shows a faulted domal closure with fault throws of 75 to 100 m at the trap crest. Within this setting, seal risk is viewed as high.

SHOWS

Only minor gas shows were recorded with a gas peak in the lower portion of the Belfast Formation. Only very minor C_1 gas shows were seen in the Waarre Formation

Top (mKB)	Base (mKB)	Source	Show type	Lithology	Comments
4050	4053	mudlog	G1	Silty shale	Gas peak-no hydrocarbon column from petrophysics

RESULTS

Bridgewater Bay-1 came in approximately 1100 m deep to prognosis, penetrating the primary target of the Waarre Formation ~35 m downdip from the trap crest, near the level of the fault leak position (Phillips Australian Oil Company, 1984). Consequently, small accumulations on the structure may not have been intersected, and hydrocarbons may be present updip. The northern bounding fault has a mapped down to the basin throw of ~ 700 m. It is therefore likely that the Eumeralla and Waarre formations are juxtaposed, making sealing on this fault possible. However, Late Cretaceous and possible Tertiary movement on this fault may have resulted in leakage. In addition, the quality of the Waarre Formation reservoir penetrated is very poor and identifies a risk for similar prospects.

At intra-Paaratte Formation levels, the fault throws are sufficient (75 to 100 m) to breach the generally thin potential seal interval. Lithology descriptions indicated that many of these potential seals were silty. They may therefore have limited sealing capacity. It is important to note that there are no data on seal quality through this potentially prospective interval. Migration from the Eumeralla Formation source rocks up through the Belfast Formation is a significant issue for the targets proposed above the Belfast Formation. Here, the fault throw is less than the seal thickness, so no clear migration path is evident. The optimum setting would involve a significant area of cross fault juxtaposition of late mature Eumeralla Formation with the Paaratte Formation sands.

It is possible that some late generation and migration of hydrocarbons has occurred in this area given the 1100 m of Tertiary section intersected in the well. In this area, the fault spacing, and therefore probable migration fetch areas, are greater than to the west.

This analysis suggests that the way forward for exploration in this area is to use better quality modern seismic techniques before drilling wells like this in crestal structural positions. The updip Bridgewater Bay structure may be an example of the 'more subtle traps with smaller faults not affected by late stage faulting discussed in other well analyses in this area.

REFERENCES

PHILLIPS AUSTRALIAN OIL COMPANY, 1984. Bridgewater Bay No.1, Well Completion Report. (unpublished).

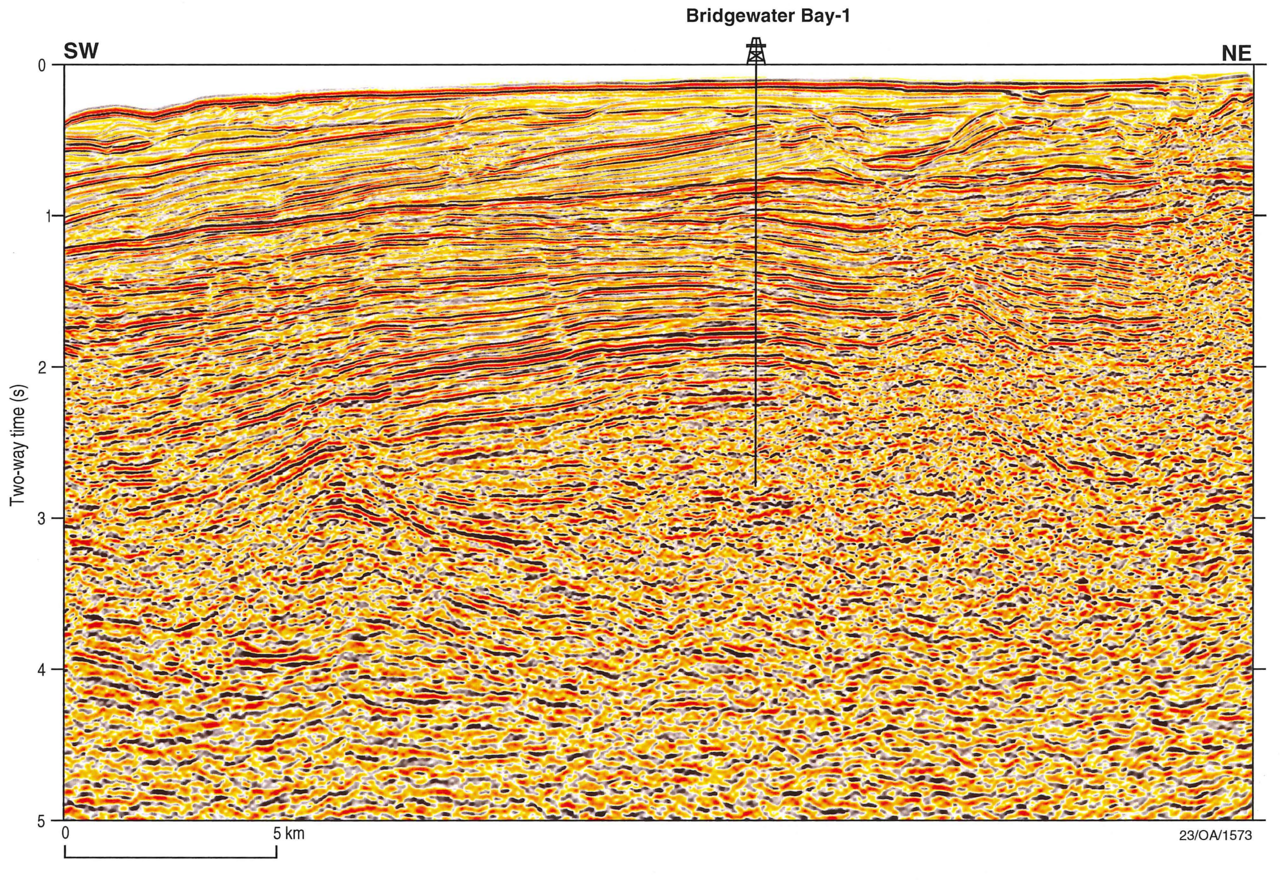

Figure 32. Seismic section showing location of Bridgewater Bay-1. Seismic reproduced with permission of Fugro MCS.

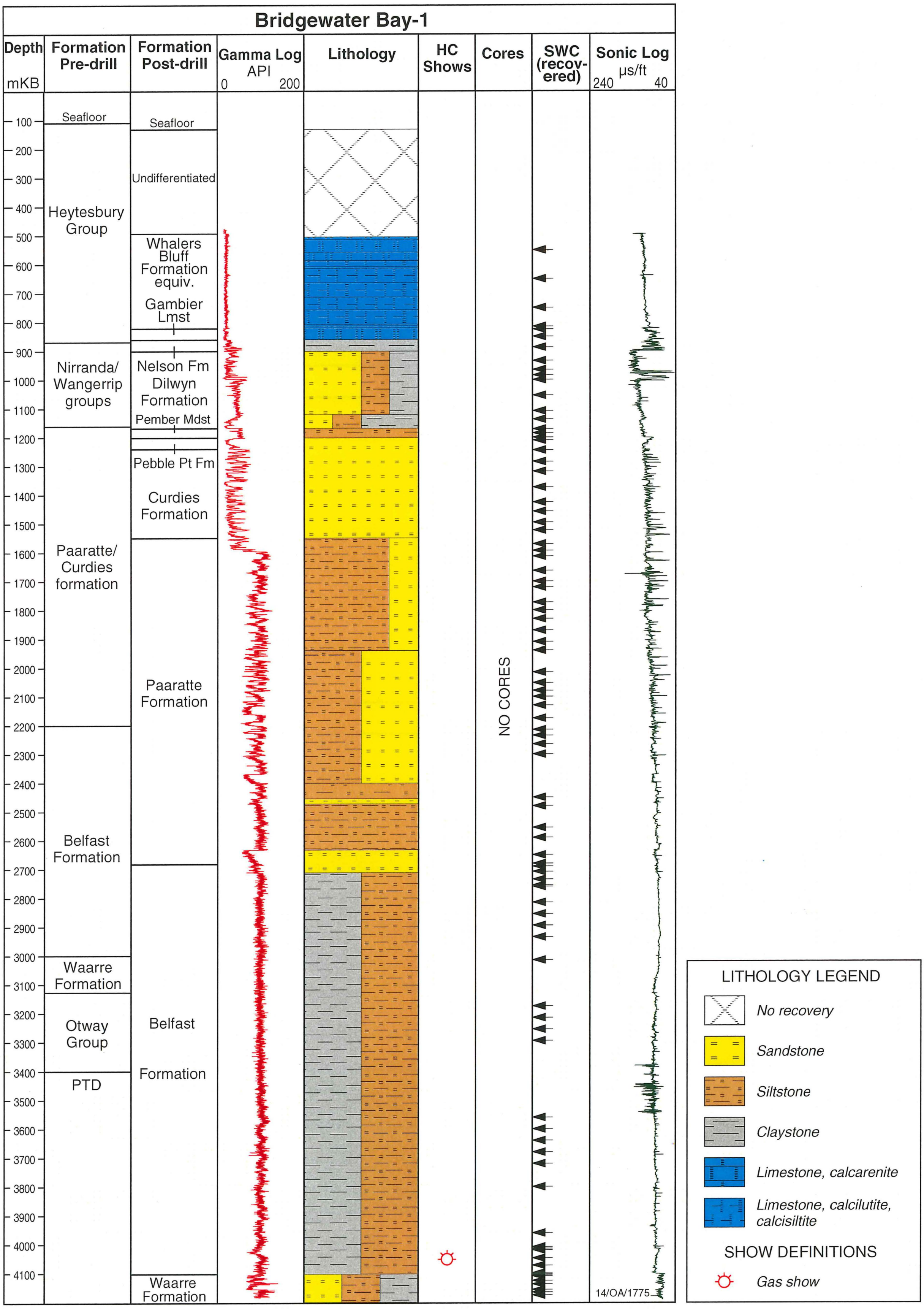

Figure 33. Bridgewater Bay-1 well composite.

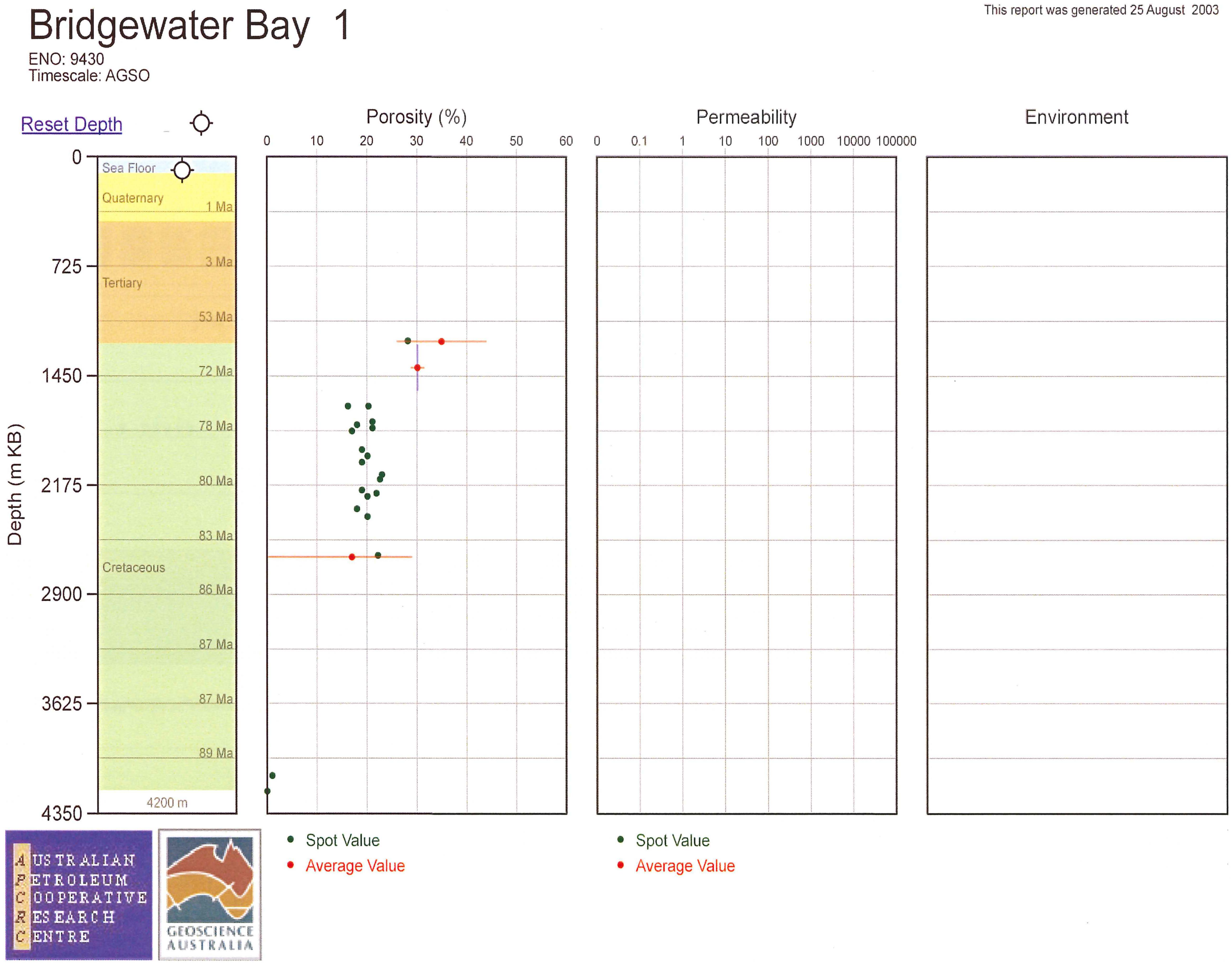

Figure 34. Porosity and permeability measurements recovered from Bridgewater Bay-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: August, 2003.

3.4 Mussel Platform

The Mussel Platform is a broad faulted and lightly folded area characterised by a relatively thin Late Cretaceous section compared with the Morum Sub-basin and Discovery Bay High areas. This contributed to the preservation of the Waarre Formation targets at prospective depths (generally <2800 m). Tertiary cover is similar to the Discovery Bay High area to the west.

The Belfast Mudstone is thick and well developed, with only minor interbedded silts and sands. Even at the proximal Minerva wells, seal characteristics of the Belfast Mudstone are good. Structural controls related to the development of the west Tasmanian wrench margin, resulted in restricted coarse clastic input on the terrace during this time.

The upper Shipwreck Sub-group (Waarre Formation equivalents) hydrocarbon bearing sands are dominated by quartzarenites, while the lower Shipwreck Sub-group sands are dominated by litharenites. This change reflects a shift in provenance from predominantly locally derived reworked Eumeralla Formation sediments, to transported cratonic sourced sediments in the upper Shipwreck Sub-group.

Recent work by Duddy and Erout (2001), based on fission track analysis from Shipwreck Sub-group sandstones and VR data in Mussel-1, has produced strong evidence for kilometre scale uplift and erosion on the Mussel Platform. The interpreted most likely timing for this major event is 'near' the Cretaceous–Tertiary boundary where there is good regional evidence for a structural event and some erosion. The Wangerrip Group is absent at La Bella-1 and thin at Mussel-1, supporting this hypothesis. In addition, seismic data show a gross thinning of the Sherbrook Group interval towards Mussel-1. However, truncation at the top of the Sherbrook Group implies only 200 to 300 m of lost section. It is difficult to resolve the variations in these observations with the currently available data.

Minerva-1

WELL SUMMARY

Operator	BHP Petroleum Pty Ltd
Date Spudded	8 March 1993
TD Date	4 April 1993
Type	Exploration
Status	Gas discovery-cased and suspended
Shows	Three gas columns intersected
UNO	W3930004
Permit	VIC/P31
Latitude	38° 42' 12.23" S
Longitude	142° 57' 12.34" E
Reference datum	AGD84, AMG Zone 54 Central Meridian 141° E
Projection	Universal Transverse Mercator
RT (m) datum	25.3 m
Water Depth	57 m
TD (mRT)	2425 m
Age at TD	Early Cretaceous
Primary Objective	Late Cretaceous Shipwreck Group (Waarre Formation equivalent)
Secondary objective	Sherbrook, Wangerrip and Nirranda groups
Play/Trap Type	Faulted anticline
Reason for failure	Successful test.

DATA SUMMARY

Palynology:

The original palynological analysis was done by Morgan, R. and Hooker, N., (1993). "*Final Palynology of BHP Petroleum Minerva-1, Offshore Otway Basin*". This was an unpublished palynological report for BHP Petroleum Pty. Ltd. based on assemblages recorded from 50 SWCs, 4 core and 29 cuttings samples. It is included as Appendix 1 in the WCR.

Additional analyses were performed by:
Morgan, R., (1994). "*Palynology of 6 new samples from Minerva-1, Otway Basin, Australia*". Unpublished report for BHP Petroleum Pty Ltd.

and Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report 1996/5.

Micropalaeontology:

No micropalaeontological analysis was performed on this well.

Cores and cuttings:

Sample Type	Top (mRT)	Base (mRT)	Recovered (m)	Comments
Core-1	1821	1828	3.04	34% recovery
Core-2	1828	1842.5	13.3	92% recovery
Core-3	1842.5	1847	4.5	100% recovery
SWC	635	2730	121 of 127	
Cuttings	560	1100		5 m sample interval
	1100	2425		3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mRT)	Comments
1	1	DLL–MSFL–AS–GR–SP–CAL–AMS	549–1204	GR to seafloor
	1	CSI(VSP)	150–1189	33 levels, 25 m shot spacing
	1	CST–GR	563–1193	46 shot, 46 recovered
2	1	LDL–CNL–GR–AMS	1189–2024	
	1	FMS–GR–AMS	1189–2024	
	1	RFTB–GR–HP–AMS	1649–1992	
	2	DLL–MSFL–AS–GR–SP–CAL–AMS	1189–2024	
	2	CSI(VSP)	920–2017	42 levels, 20 m shot spacing
3	2	CST–GR	1195–2101	60 shot, 57 recovered
	3	DLL–MSFL–AS–GR–SP–CAL–AMS	1800–2103	
4	1	CBL–VDL–GR	1088–2109	7 inch liner
	1	USIT cement map	1088–2109	
	2	LDL–CNL–GR–AMS	2109.5–2424	
	2	FMS–GR–AMS	2109.5–2424	
	3	CSI(VSP)	1992–2420	21 levels, 20 m shot spacing
	3	CST–GR	2120–2420.5	21 shot, 18 recovered
	4	DLL–MSFL–AS–GR–SP–CAL–AMS	2109.5–2424	
5	1	Perf & packer record	1800–1838	
MWD		DPR	1240–2107	

Velocity Survey:

Three velocity surveys were completed surveying at a total of 96 VSP levels over the interval 150–2420 mRT. 8 check shot levels were also recorded as part of the first VSP run above 1189 mRT. The velocity surveying is discussed in section 4.4 of the basic data volume of the WCR.

Well Tests:

An RFT program was run in the well to evaluate the three gas and water bearing sands in the upper Shipwreck Group. Three RFT runs were made with 33 pretests attempted, 28 of which were successful. Samples at 1649.8, 1931 and 1942.5 mRT recovered gas, condensate and water.

The two shallower gas sands, called the top upper Shipwreck Group 1 sand (1648.8–1652 mRT) and top upper Shipwreck Group 2 sand (1661–1668 mRT) may have separate gas columns. The top upper Shipwreck Group 1 sand was underpressured and had an estimated GWC at 1912.8 mSS (1938.1 mRT) giving a gross gas column of 289.3 m. The top upper Shipwreck Group 2 sand has an estimated GWC at 1920 mSS (1945.3 mRT) giving a gross gas column of 284.3 m, and appeared slightly overpressured. Segregated sample composition in the top upper Shipwreck 1 sand included 0.6% carbon dioxide and 89% methane.

The main reservoir sand section (1816–1995 mRT) contained a gross 98.7 m gas column with a GWC at 1914.7 mSS (1940 mRT; Locke, 1994). If the depths to the top reservoir sand and GWC are correct, this indicates a gross column of 124 m not the 98.7 m stated in the WCR. Two samples taken from the main reservoir had a segregated composition including 1.7% carbon dioxide and 90.5% methane.

A DST in the main reservoir, through perforated 7 inch liner was made over the interval 1816 m to 1821 mRT and 1825 to 1827.5 mRT, flowing gas at a rate of 28.4 MMcf/d with a condensate to gas ratio (CGR) of 2 stb/MMcf.

PRIMARY OBJECTIVE

The primary objective of the well was to test the hydrocarbon potential of sands contained within the Late Cretaceous lower Shipwreck Group within a tilted fault block. The overlying mudstones of the upper Shipwreck Group were predicted to act as top and cross-fault seals.

SECONDARY OBJECTIVE

Secondary targets were interpreted to exist throughout the Late Cretaceous Sherbrook, Wangerrip and Nirranda groups. Mapping at all these levels show anticlinal closure with only minor fault dependence.

STRUCTURE

Minerva-1 was drilled on a faulted anticline (Fig. 35). The anticline is dissected by two main northwest–southeast trending rotated fault blocks, with Minerva-1 testing the northern block. Each of the fault blocks has three-way dip closure in combination with fault closure (Locke, 1994).

The structure developed initially at the end of the Early Cretaceous with continued episodic development through the Late Cretaceous. It experienced very little growth during the early Tertiary until the Oligocene and more recent times when significant anticlinal growth occurred. Two distinct phases of normal faulting are evident. The Early to Late Cretaceous faults cease in the Sherbrook Group mudstones, while the Late Cretaceous–Early Tertiary faults that sole out in the upper Shipwreck Group mudstones continue to the seafloor (Locke, 1984). This later set appears to be anticlinal collapse faults around Minerva-1.

Unlike La Bella-1 where the entire Wangerrip Group is missing, palynological analysis in Minerva-1 confirms a nearly continuous section through the Tertiary into the Late Cretaceous. Therefore, the kilometre scale uplift and erosion proposed by Duddy and Erout (2001) along the Mussel Platform appears to be localized and not as evident at Minerva-1.

SOURCE ROCKS

Significant thicknesses of Sherbrook and Shipwreck groups mudstones and siltstones are developed at this location (Fig. 36). The Sherbrook and upper Shipwreck groups mudstones are all immature for oil generation, with source characteristics showing gas prone low yield source rocks (Appendix 1). 123 m of Eumeralla Formation sands, shales and minor coals were penetrated.

Tertiary and Late Cretaceous loading has resulted in the late generation and expulsion from the intra-Eumeralla Formation source rocks to provide the gas for this accumulation. At Minerva-1, the Tertiary is approximately 700 m thick and is located within the Shipwreck Trough. The Tertiary thickens significantly away from the structure, still within the drainage area of Minerva-1.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Upper Shipwreck Group gas reservoir sands are of good quality with average porosities of 18% (Fig. 37). For the main reservoir (1816–1995 mRT), permeabilities ranged between 10 and 1800 mD. Well production tests indicate permeabilities of 1000–2000 mD. Sands are deltaic to shallow marine. The upper Shipwreck hydrocarbon bearing sands are dominated by quartzarenites. The lower Shipwreck sands are dominated by litharenites. The top upper Shipwreck Group 1 and 2 sands, 1648.8–1652 mRT and 1661–1668 mRT respectively, have an average porosity of 14%. From RFT data, the permeabilities in these two upper sands were in the order of 20 to 30 mD. These sands are shallow marine in origin. A thin gas bearing sand is also observed in the Sherbrook Group below ~1170 m, with an average porosity of 11%.

SEAL

The combined seal interval of the upper Shipwreck Group and lower Sherbrook Group mudstones are over 600 m thick. From maps at the top of the main reservoir level, the critical fault is to the south of Minerva-2 with approximately 640 m of throw at the trap crest (Locke, 1994). The downthrown seal interval is interpreted to increase in thickness across the fault providing an effective cross-fault seal, resulting in trapped hydrocarbons at Minerva-1 (Locke, 1994). A small gas column was observed in the interbedded sand within the Sherbrook Group. This provides evidence that these shallower seals can be effective in the right setting.

SHOWS

Gas bearing sands were encountered within both the Sherbrook Group in the interbedded sand and shale section midway through the section (secondary target), and in the Shipwreck Group sandstones (Fig. 36). A total of 0.2 m of net gas is interpreted in the Sherbrook Group over a 25 m gross interval below 1170 m with an average porosity of 11% and an average water saturation of 65%. In the upper Shipwreck Group, two gas zones with 2.9 m (top upper Shipwreck Group 1 and 2 sands) and 118.5 m (main reservoir) of net gas sand were penetrated with excellent mudlog gas shows. Below 1821 mRT, minor (indirect) fluorescence was seen in many of the samples. On sampling, condensate was reported from both intervals.

RESULTS

Minerva-1 discovered possibly three separate gas bearing sands within the upper Shipwreck Group. Whilst separated by significant shales, it is not possible with the quality of the RFT data to confidently say they are entirely separate columns. The economically significant lower sand has excellent reservoir characteristics, proven by the production test flowing gas at a rate of 28.4 MMcf/d, with a CGR of 2 stb/MMcf.

This accumulation demonstrates that valid traps can be developed on structures where fault throws are less than the seal thickness of the Sherbrook and upper Shipwreck groups. The general character of these seals appears to change, becoming siltier in the wells to the west. However, without quantitative data across the basin, it is difficult to know whether hydrocarbons can be trapped basin wide. There is evidence from basin modelling that late hydrocarbon charge has occurred at Minerva-1. This is supported by the close match between the southeastern dip spill depth and the interpreted gas water contacts. The presence of a small and fairly convincing gas accumulation in the interbedded sands and shales of the upper Sherbrook Group is also significant, demonstrating that this play can work if a migration route through the thick seal below is present.

The comments in the WCR regarding the timing of faulting episodes and the implied lack of linking of these fault sets (Locke, 1994) suggested a migration problem through the Late Cretaceous claystones to upper plays in this area. In addition, this observation may have implications on mapping and migration elsewhere in the basin. Farther to the west, the trends and character of the controlling faults for the Waarre Sandstone plays may not be evident as they could be masked by the Late Cretaceous–Early Tertiary fault sets.

REFERENCES

LOCKE, A., 1994. Minerva-1, Well Completion Report. BHP Petroleum Pty Ltd. (unpublished).

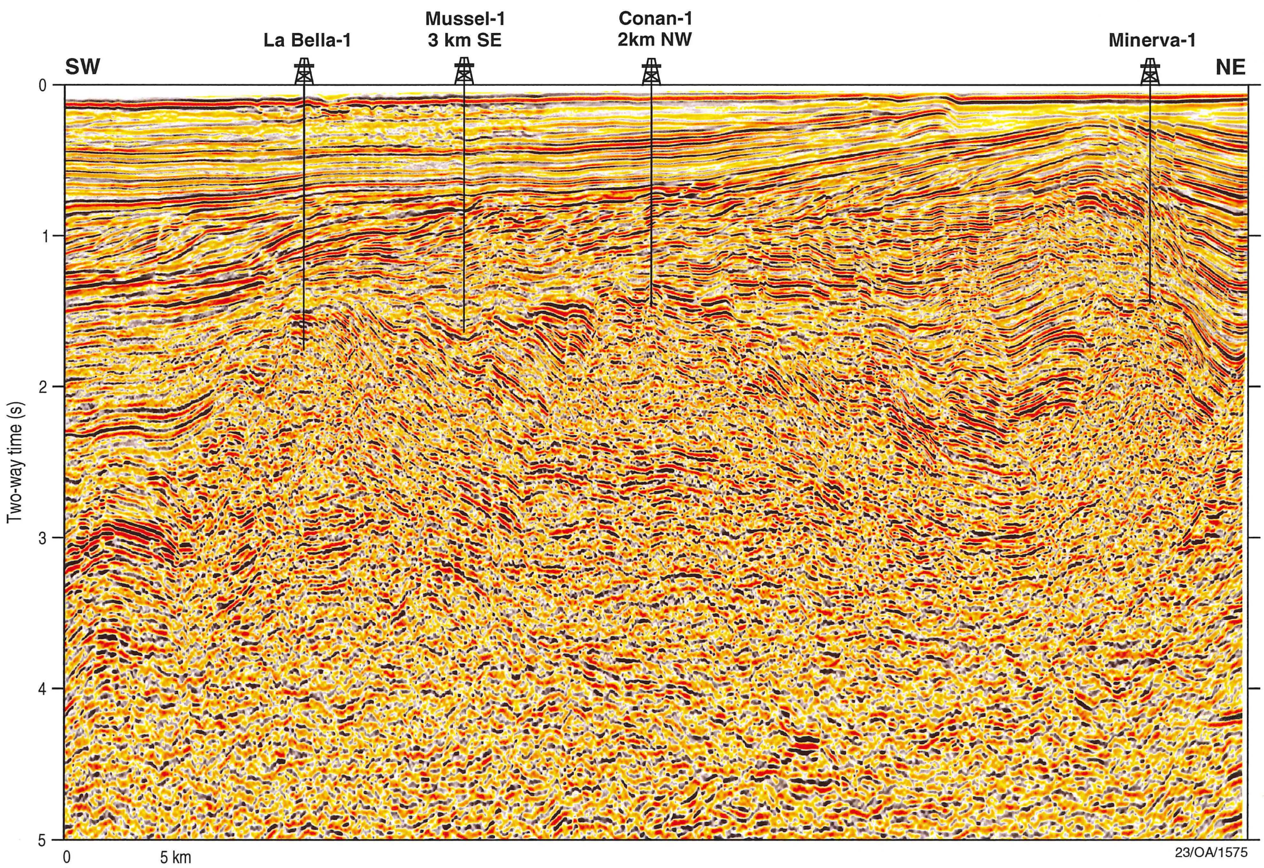

Figure 35. Seismic section showing location of Conan-1, La Bella-1, Minerva-1 and Mussel-1. Seismic reproduced with permission of Fugro MCS.

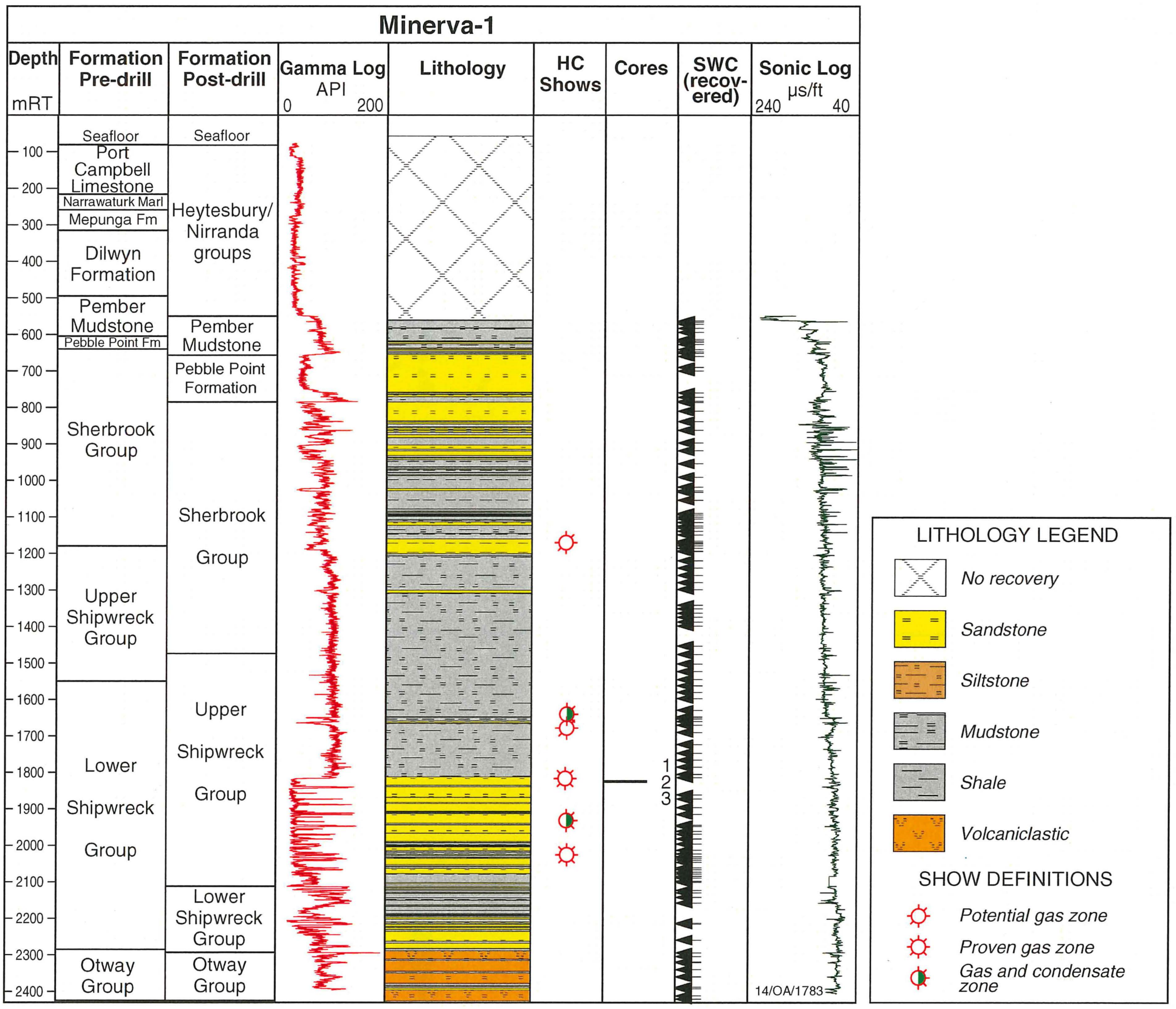

Figure 36. Minerva-1 well composite.

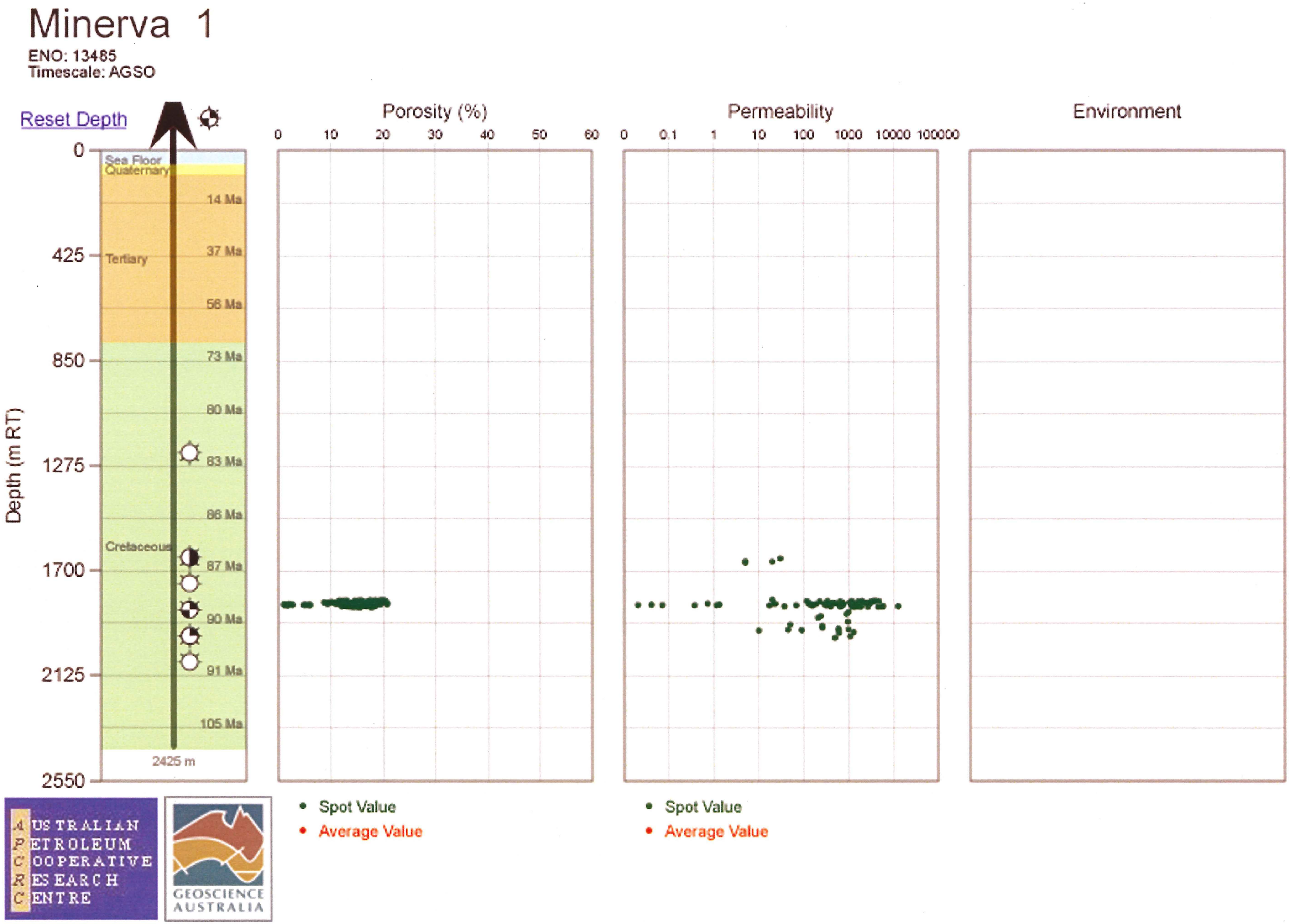

Figure 37. Porosity and permeability measurements recovered from Minerva-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: June, 2003.

Conan-1

WELL SUMMARY

Operator	BHP Petroleum Pty Ltd
Date Spudded	24 July 1995
TD Date	31 July 1995
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	Minor
UNO	W9350025
Permit	VIC/P31
Latitude	38° 52' 14.953" S
Longitude	142° 46' 52.224" E
Reference datum	Australian National Spheroid, AGD Zone 54, Central Meridian 141° E
Projection	Universal Transverse Mercator
RT (m) datum	25 m
Water Depth	70 m
TD (mRT)	1985 m
Age at TD	Late Cretaceous
Primary Objective	Waarre Sandstone
Secondary objective	None stated
Play/Trap Type	Fault block
Reason for failure	Unclear: No late generation from source rock &/or unfavourable cross-fault juxtaposition

DATA SUMMARY

Palynology:

The original palynological analysis was done by Morgan, R., (1995). "*Palynology of BHPP Conan-1, Offshore Otway Basin*". This report is located in the WCR as Appendix 2.

Additional analysis was done by Partridge, A. D., (1998). "*Biostratigraphy and interpreted stratigraphy of Champion-1 and Conan-1 from open file basic data*". Petroleum Development unpublished report 1998/01, Biostrata Pty. Ltd.

Micropalaeontology:

No micropalaeontological analysis was undertaken on this well.

Cores and cuttings:

Sample Type	Top (mRT)	Base (mRT)	Recovered (m)	Comments
Core				No conventional cores cut
SWC	1539	1959	29 of 30	
Cuttings	150 1710	1710 1985		10 m sample interval 5 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mRT)	Comments
1	1	AS–MSFL–GR–DLL–AMS	95–1957	
1	2	CSI–VSP	600–1955	
1	3	FMI (IMAGES)	1675–1949	
1	3	LDL–CNL–GR–AMS	1539–1950	
1	4	CST–GR	1539–1950	30 shot, 29 recovered
MWD		DPR–GRAM	1208–1985	

Velocity Survey:

A velocity survey was completed with 54 levels over the interval 600–1955 mRT. The report can be found in the basic data volume of the WCR.

Well Tests:

No testing by RFT, DST or other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of the well was to evaluate the hydrocarbon potential of the Minerva and La Bella formations (Waarre Sandstone equivalents) in a seismically defined Early Cretaceous faulted structure.

SECONDARY OBJECTIVE

No secondary objective defined in the WCR.

STRUCTURE

Conan-1 was drilled near the crest of a broad horst block just below 1.5 s (Fig. 35). The horst structure was defined by a 1x1 km 2D seismic grid prior to drilling (Ellis, 1996). Closure measured approximately 11 km by 4 km and 220 m vertically at the base of the Sherbrook Group mudstones (Belfast Formation). The Sherbrook Group and younger intervals dip gently to the southwest (basinward). The underlying Waarre Sandstone equivalent reservoirs (La Bella and Minerva formations) dip gently to the northeast as a result of earlier fault rotation (Ellis, 1996). Angular truncation on the flanks of the horst structure was reported from seismic observations in the WCR (Ellis, 1996). The well came in approximately 151 m high to prognosis at the top Minerva Formation reservoir, 362 m high at the top La Bella Formation and at least 492 m high at the top Otway Group (Fig. 38). The WCR states that the predicted versus actual depth variations at the top Minerva Formation level were due to velocity variations in the Late Cretaceous and Tertiary sections from those in the control wells. However, no postdrill mapping was undertaken because neither the structure nor well position were expected to vary significantly due to these velocity variations (Ellis, 1996).

The Conan horst appears to be a robust structure. However, the large disparity between predicted and actual depths, even after taking out shallower velocity variations, indicates problems exist with carrying the horizons from the nearby well control at Mussel-1 (10 km distant) and La Bella-1 (16 km distant). This problem relates to the seismic line spacing, quality and the presence and complexity of the faults. Although the structural form at the top of the horst is thought to be well represented by the predrill maps, fault throws may be in serious error. Therefore, the potential fault seal risk is poorly understood. For example, as the Otway Group is intersected at least 492 m (341 m after velocity adjustment) higher than prognosed, throw on the controlling faults may be much greater than predicted, potentially breaching the 528 m thick Belfast Formation.

Faulting related to the Conan structure does not appear to continue in the late Tertiary above ~ 1 s (Fig. 35). This decreases the chance of leakage of any earlier trapped hydrocarbons. There is significant late folding immediately to the east at Minerva-1, however, its impact at Conan-1 appears to be minor.

SOURCE ROCKS

The Belfast Formation has a thermal maturity VR <0.5% (Appendix 1). No source rock data have been collected for this interval in the well. Surrounding wells show very similar lithologies with poor source properties; such properties are thought to be replicated in Conan-1.

At Conan-1, the Tertiary is approximately 1200 m thick. This compares favourably with the 1200 to 1600 m intersected in wells peripheral to the eastern Voluta Trough where commercial gas accumulations exist (i.e., Minerva, La Bella, Thylacine, Geographe and Geographe North). Without further study, it is difficult to quantify the extent of late hydrocarbon generation here. However, it is considered likely that Tertiary loading was sufficient to restart generation and migration from the sources if they are adequately developed in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Potential reservoirs exist in the Tertiary (from mudlog and regional data) and Late Cretaceous Waarre Formation equivalents (La Bella and Minerva formations, Fig. 38). The La Bella Formation (thickness 57 m) is a transgressive non-marine to shallow marine sand/shale sequence deposited on the top Otway Group unconformity surface. The Minerva Formation (thickness 84 m) unconformably overlies the La Bella Formation and comprises basal silty claystone and progradational delta sequence. The Minerva Formation was deposited in a nearshore environment, with the presence of freshwater algae indicating a significant lacustrine influence (Ellis, 1996).

La Bella Formation sands have porosity values generally <10% with an 18 m interval having porosity values averaging approximately 14.5% (Fig. 39). Porosity values are low due to a high argillaceous and lithic grain content. Sands from the Minerva Formation are better quality with 37.5 m of clean quartzose sands having porosity values ranging from 15 to 24%, averaging 18.9% (Fig. 39). Although these formations have significant porous intervals, the permeability values are likely to be quite low due to the presence of unstable lithics, particularly volcanilithics derived from the eroding Eumeralla Formation (Ellis, 1996). No quantitative permeability data are available.

SEAL

The principal seal, the Belfast Formation, is 528 m thick with no significant interbedded sands. As such, it is expected to be an adequate seal, although no quantitative data are available. The lower portion of the Minerva Formation comprises a 36 m interval of grey brown claystone and dark siltstone. This is likely to be an effective seal, although again no quantitative data are available. By analogy, there are stacked gas columns in the nearby La Bella field, separated by seals of similar lithology.

SHOWS

No fluorescence, shows, or significant ditch cuttings gas peaks were seen during drilling.

RESULTS

Postdrill interpretation suggested that Conan-1 did not intersect significant hydrocarbons due to either lack of source rocks, or that the source rock interval was ineffective, i.e., no late generation (Ellis, 1996). However, the Conan structure is located immediately updip from the Shipwreck Trough and probably has a large migration fetch area at the base of the Belfast Formation. Therefore, it is considered likely that late generation and migration may have occurred somewhere within the migration drainage area.

Alternatively, the sealing Belfast Formation may be breached by faulting. Given the seismic mispicks, throws on the bounding faults may be greater than those initially mapped. In addition, this region is also interpreted to be influenced by a Late Cretaceous structural event resulting in kilometre-scale uplift and erosion across the Mussel Platform (Duddy and Erout, 2001). Therefore, it is difficult to predict when the major throw on the faults occurred. However, if the majority of the displacement occurred early, then the Belfast Formation may have syn-depositional growth and thus thicken across the fault to provide a cross-fault.

The reason for failure at Conan-1 is not clear. It may be source and migration related, or seal breach related. Other wells in the area located on similar broad highs and involving multiple faults have been successful in trapping hydrocarbons (e.g., Pecten-1). A more extensive review is required, incorporating post well mapping to solve this problem.

REFERENCES

ELLIS, C., 1996. Conan-1, VIC/P31, Well Completion Report. BHP Petroleum Pty Ltd (unpublished).

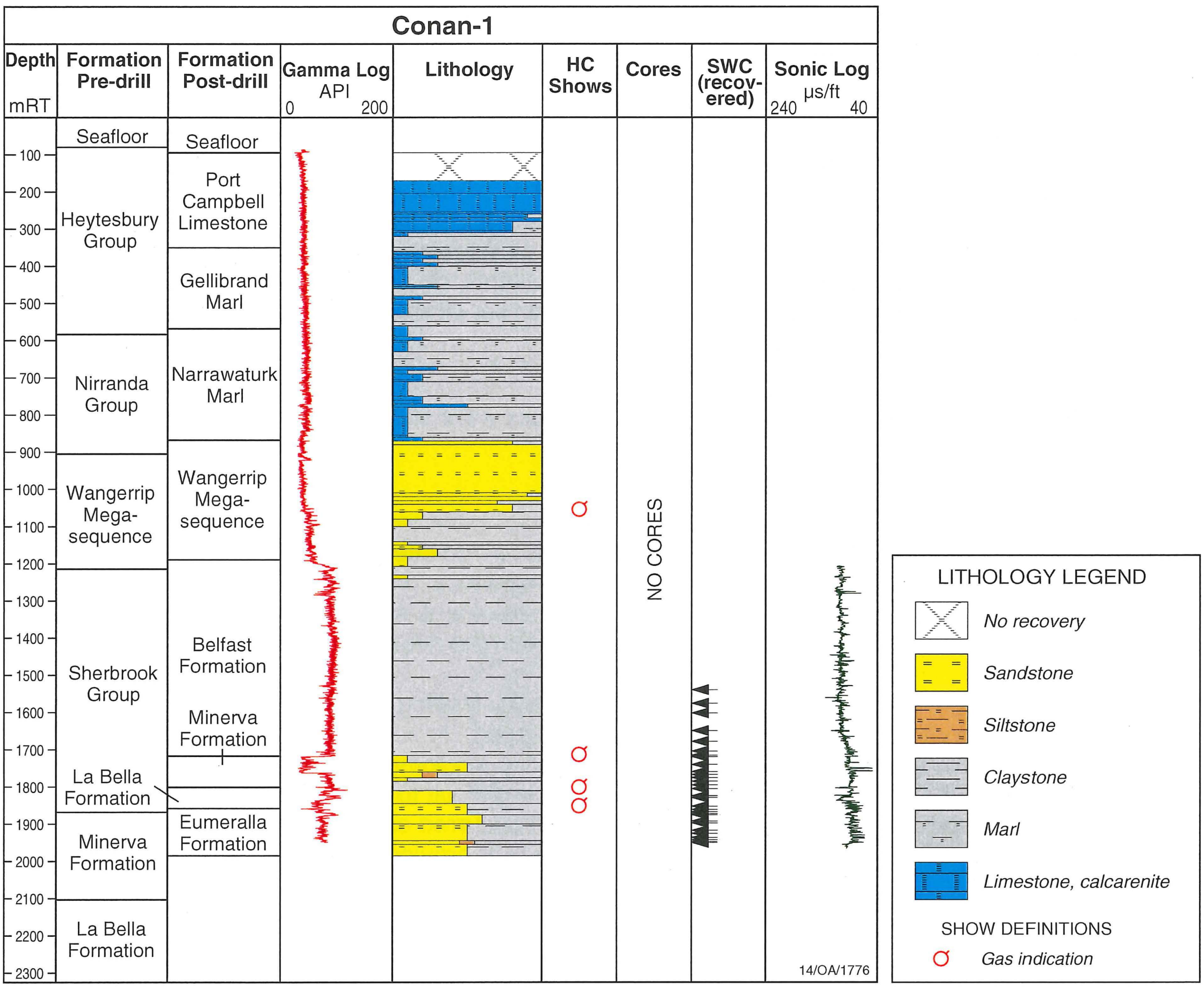

Figure 38. Conan-1 well composite.

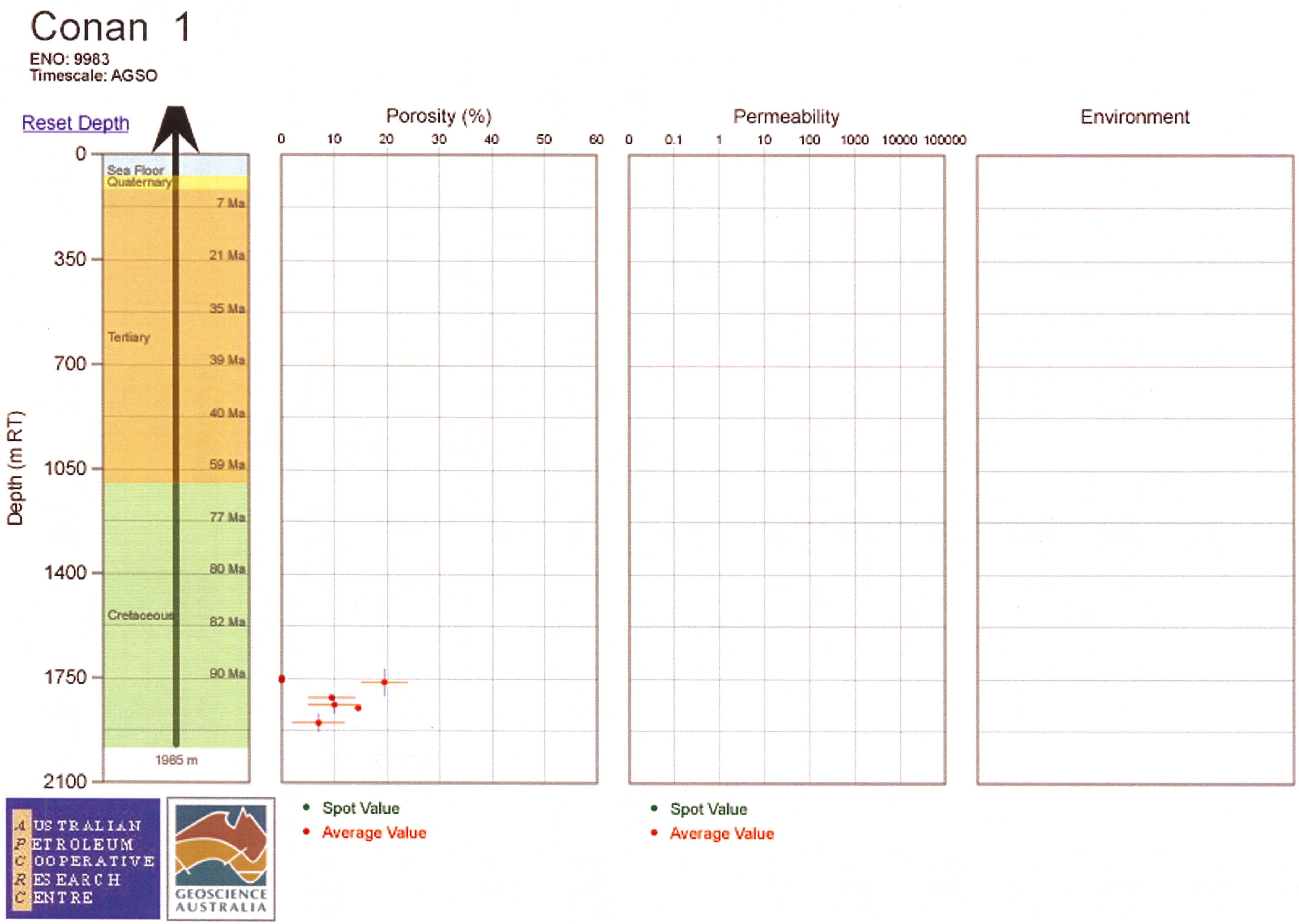

Figure 39. Porosity and permeability measurements recovered from Conan-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: June, 2003.

Mussel-1

WELL SUMMARY

Operator	Esso Exploration and Production Australia Inc
Date Spudded	18 August 1969
TD Date	7 September 1969
Type	Exploration
Status	Dry hole - Plugged and abandoned
Shows	Minor gas shows
UNO	W3690002
Permit	PEP40
Latitude	38° 57' 45.993" S
Longitude	142° 46' 21.676" E
Reference datum	None provided in WCR
Projection	None provided in WCR
RT (m) datum	30.2 m
Water Depth	85.3 m
TD (mRT)	2450 m
Age at TD	Late Cretaceous
Primary Objective	Late Cretaceous Waarre Formation
Secondary objective	Eocene Mepunga and Dilwyn formations
Play/Trap Type	Tilted fault block
Reason for failure	Well downdip from trap crest, possibly outside closure

DATA SUMMARY

Palynology:

The original palynological analysis included in the WCR was undertaken by Evans, P.R. and Mulholland, R.D., (1969). "*Palynological report on Esso Mussel No.1, Otway Basin*". EAL Palaeo. Rept. 1969/17. The palynological analysis is based on 17 SWCs, 3 core and 7 cuttings samples between 1245 mRT and 2441 mRT. Below 2254 mRT, only cuttings are available for analysis. These poor quality samples contained no new microflora and were badly contaminated by caving. The most likely age at TD was estimated as *P.mawsonii*.

Later analyses can be found in:
Morgan, R. (1992). "*New Palynology of Mussel 1 Otway Basin, Australia*". This unpublished report was prepared by Morgan Palaeo Associates for BHP Petroleum Pty Ltd.

and in Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report 1996/5.

Micropalaeontology:

No micropalaeontological analysis was performed on this well.

Cores and cuttings:

Sample Type	Top (mRT)	Base (mRT)	Recovered (m)	Comments
Core-1	2097.3	2104	5.18	78% recovery
Core-2	2104	2119.6	0	0% recovery
Core-3	2235.7	2242	2.74	44% recovery
SWC	283.16	2282.9	60 of 61	
Cuttings	320	2450		3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Run	Tool string	Interval (mRT)	Comments
1	IES–BHCS–GR FDC–GR	269–685 669.6–2234.8	GR to surface
2	IES–BHCS–GR FDC–GR BHCS–SP CDM	669.6–2286 2194.6–2286 669.6–2286 669.6–2287	 3 arm

Velocity Survey:

A velocity survey was completed with 15 levels being surveyed. The results are summarised in Figure 4 of the WCR.

Well Tests:

No well testing by RFTs, production tests or by any other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of Mussel-1 was to test the hydrocarbon potential of sands contained within the Late Cretaceous Waarre Formation at its highest structural position in a large fault block.

SECONDARY OBJECTIVE

Secondary objectives targeted the sands of the Eocene Mepunga and Dilwyn formations.

STRUCTURE

Mussel-1 was located over a rotated fault block with beds dipping to the north below ~1.5 s (Fig. 35). The well location in Fig. 35 is extrapolated ~3 km to the seismic section and does not illustrate its crestal position adequately. However, pre- and postdrill interpretive cross-sections in the WCR suggested the well was located on the crest of the fault block (Lunt, 1970). The throw on the controlling fault was interpreted to be approximately 550 m (Lunt, 1970). Over 600 m of good quality Belfast Formation (Fig. 40) overlies the reservoir section, providing an adequate top and cross-fault seal. At the secondary target level in the Tertiary, there is a minor closure, with an estimated maximum height of 60 m. This closure developed as a result of differential erosion of the Mepunga Formation reservoir sands, just prior to the deposition of the Narrawaturk Formation marls.

Faults do not extend into the Tertiary section around Mussel-1 and La Bella-1. However, with almost the entire Wangerrip Group at the base of the Tertiary absent, evidence for Early Tertiary faulting commonly seen in more landward areas may not be preserved. Recent work by Duddy and Erout (2001) has produced strong evidence for kilometre scale uplift and erosion during the Paleocene in this area. Based on regional faulting history and the magnitude of the uplift indicated, it is considered likely that a considerable portion of the net displacement seen on the controlling fault at Mussel developed in the Early Tertiary.

SOURCE ROCKS

A significant thickness of Sherbrook Group shales (Belfast and Flaxmans formations) is developed at Mussel-1 (Fig. 40). The Sherbrook Group is mostly immature for oil except for the lower approximately 100 m. Source characteristics show gas prone low yield source rocks just in the oil mature window at the well (Appendix 1).

The Eumeralla Formation possibly occurs below the TD of the well. Generally, it has a variable distribution and quality of coaly source rocks and is likely to be mature to over mature (Mehin & Link, 1995). Based on the amount of late loading seen here, it is considered likely that the 1400 m of Tertiary loading was sufficient to restart generation and migration, if the source rocks are adequately developed in this area.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Good quality reservoirs occur through the Sherbrook Group. Core analysis revealed porosities of 8 to 25.5%, and permeabilities between 1 and 3300 mD (Fig. 41).

SEAL

Good quality, thick seals are present in the Sherbrook Group at this location, with over 600 m of continuous Belfast Formation developed above the Waarre Formation reservoir interval. The interpreted fault displacement of 550 m (Lunt, 1970) is therefore insufficient to breach the thick seal, and the trap is likely to be valid. Similar seals within the same formations work effectively in tilted fault blocks at the La Bella field.

SHOWS

Only very minor mud gas indications were recorded in this well with no significant shows.

RESULTS

Lunt (1970) interpreted that Mussel-1 failed to intersect hydrocarbons due to a lack of adequate source in the drainage area or timing of the structure relative to hydrocarbon migration, assuming that it is at the trap crest. However, the well is located near the edge of the Mussel Platform adjacent to the Voluta Trough, and is updip from the La Bella field. Therefore, access to migrating hydrocarbons is considered quite likely at Mussel-1. There also appears to be little difference in seal quality at La Bella-1.

More recent seismic data suggests that the well may be located downdip and southeast from the trap crest. It is possible that the well intersected the reservoirs at or below the limit of closure of this trap. Given the apparent robustness of the trap seal and a good migration setting, this explanation for well failure is favoured.

REFERENCES

LUNT, K.L., 1970. Mussel-1, Well Completion Report. Esso (unpublished).

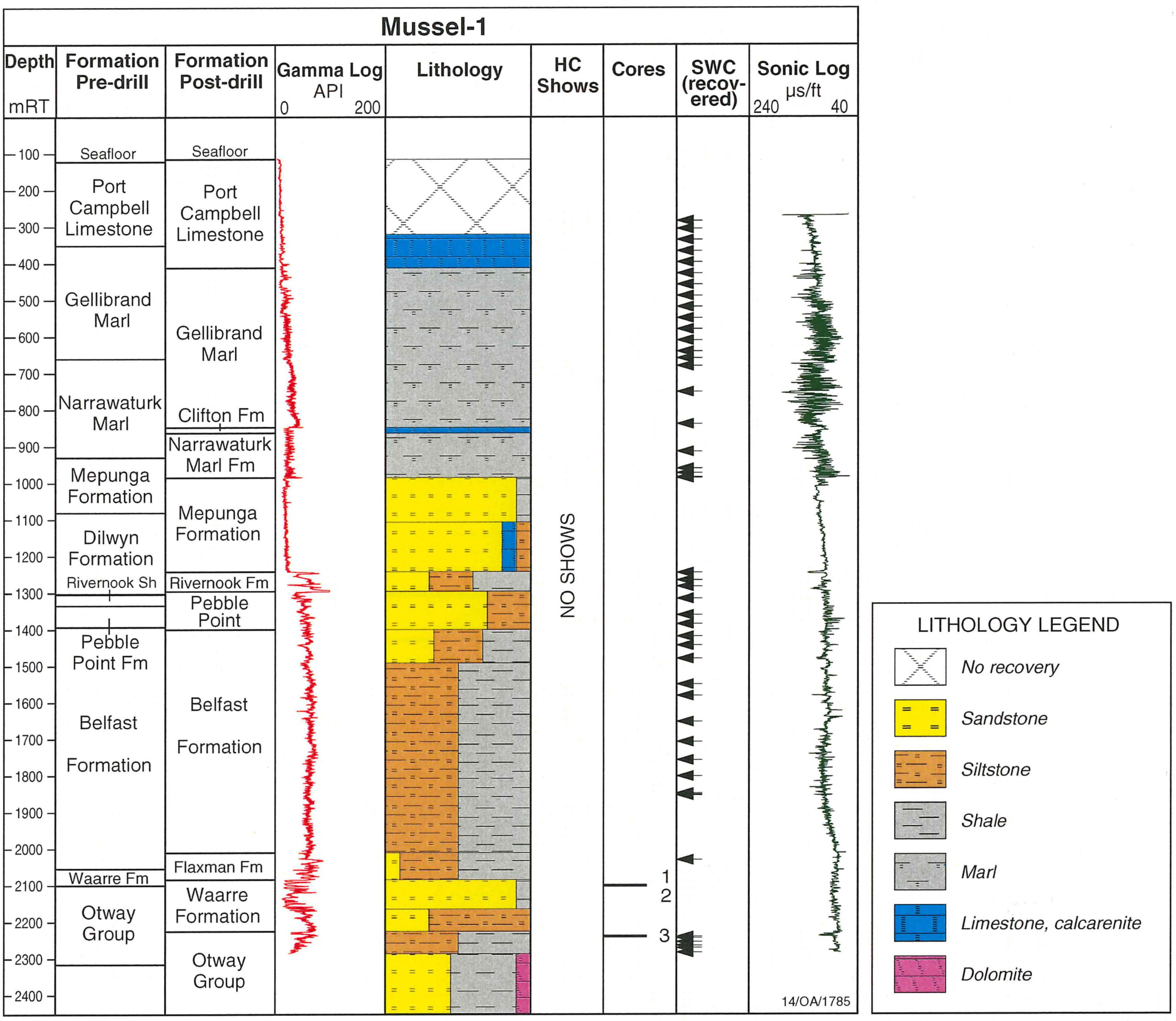

Figure 40. Mussel-1 well composite.

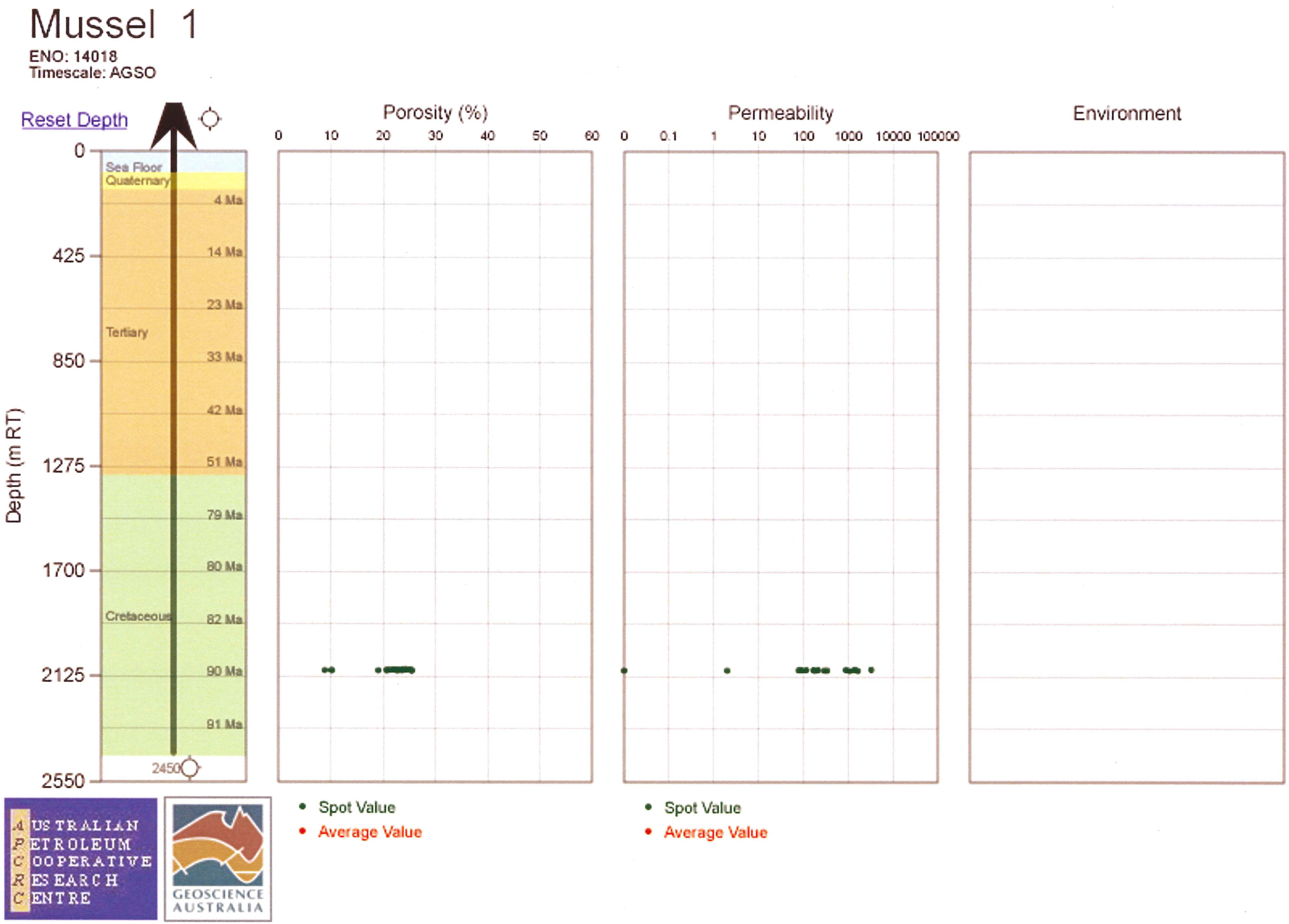

Figure 41. Porosity and permeability measurements recovered from Mussel-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

La Bella-1

WELL SUMMARY

Operator	BHP Petroleum Pty Ltd
Date Spudded	22 January 1993
TD Date	8 February 1993
Type	Exploration
Status	Gas discovery - Plugged and abandoned
Shows	Gas columns intersected
UNO	W3930001
Permit	VIC/P30
Latitude	39° 00' 14.19" S
Longitude	142° 41' 42.93" E
Reference datum	AGD84, AMG Zone 54 Central Meridian 141° E
Projection	Universal Transverse Mercator
RT (m) datum	25.3 m
Water Depth	94.2 m
TD (mRT)	2735 m
Age at TD	Late Cretaceous
Primary Objective	Late Cretaceous Shipwreck Group (Waarre Sandstone equivalent)
Secondary objective	None stated
Play/Trap Type	Tilted fault block
Reason for failure	Successful test

DATA SUMMARY

Palynology:

The original palynological analysis was done by Morgan, R., and Hooker, N., (1993), "*Final Palynology of BHPP La Bella 1*", and is located in Appendix 2 of the WCR. The palynological analysis was based on 71 SWCs, 3 cores and 9 cuttings between 635–2735 mRT.

Additional analyses are presented in Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report, 1996/5.

Micropalaeontology:

The original micropalaeontological analysis was performed by Rexilius, J.P., and Powell, S.L., (1993), "*Micropalaeontological Analysis*", and can be found in Appendix 1 of the WCR. Micropalaeontological analysis was performed on 15 SWCs between 635 mRT–1364 mRT. Samples below 1151 mRT were barren of calcareous microfossils.

Cores and cuttings:

Sample Type	Top (mRT)	Base (mRT)	Recovered (m)	Comments
Core-1	2071	2098.65	27.65	100% recovery
SWC	635	2730	136 of 150	
Cuttings	628 1800	1800 2735		5 m sample interval 3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mRT)	Comments
1	1	DLL–MSFL–AS–GR–SP–CAL–AMS	120–1787	GR to seafloor
	1	CSI (VSP)	200–1770	
	1	CST–GR	638.7–1765	60 shot, 56 recovered
2	1	DLL–MSFL–GR–SP–CAL–AMS	1785.5–2733	
	1	LDL–CNL–SDT–GR–AMS	1785.5–2728	
	1	FMS–GR–AMS	1785.5–2736.5	
	1	RFT–GR–HP	2068.3–2624	
	2	CSI (VSP)	1520–2734	
	2	CST–GR	2146.1–2730	)
	3	CST–GR	1810.1–2141.5	) 90 shot, 77 recovered
MWD		DPR	628–2735	

Velocity Survey:

Two VSP surveys comprising a total of 102 levels over the interval 200–2734 mRT were completed with an average shot spacing of 20 m. 12 check shot levels were recorded with the first suite above 1770 mRT, with an average shot spacing of 50 m. The report can be found in the basic data portion of the La Bella-1 WCR.

Well Tests:

An RFT program was run in the well to evaluate the upper Shipwreck-1 (2068–2073.1 mRT), and upper Shipwreck-2 (2100–2190 mRT) sands. A total of 34 pretests were attempted over the interval 2068.3–2624 mRT, with 28 successful. Two segregated samples were taken at 2072.8 and 2160.5 mRT.

Three valid pretests were obtained in the upper Shipwreck-1 sand but no reliable gradient could be fitted because the spacing between the points was less than 1 m. A 51 m gas column was interpreted from analysis of RFT pressure gradients in the gas column and underlying water filled sands. Pretests obtained in the upper Shipwreck-2 sand established a gas gradient of 0.24 psi/m in a 42.9 m gas column. The pressure differential between these two sands is approximately 33 psi, with these sands possibly in separate pressure regimes. Below 2143 mRT, a water gradient of 1.42 psi/m was recorded with overpressuring of approximately 200 psi for this section. Pretests below 2250 mRT show increased overpressuring; 550 psi above normal for this deeper section (Locke, 1994).

PRIMARY OBJECTIVE

The primary objective of the well was to test the hydrocarbon potential of sands contained within the Late Cretaceous Shipwreck Group. The overlying mudstones and siltstones of the Sherbrook Group were expected to act as both a vertical seal and lateral seal (Locke, 1994).

SECONDARY OBJECTIVE

No secondary objective was defined in the WCR.

STRUCTURE

La Bella-1 was drilled at the crest of a rotated fault block basinward of Mussel-1 (Fig. 35). The La Bella structure is a northeast–southwest trending faulted anticline and has been broken into four rotated fault blocks by northwest–southeast trending normal faults (Locke, 1994). Each of the fault blocks has three-way dip closure in combination with fault closure to the southeast. An east–west compressional event occurring after the deposition of the Shipwreck Group appears to have created the anticlinal relief of the structure (Locke, 1994). Dipmeter analysis indicates there is an angular unconformity between the Shipwreck and Sherbrook groups; the Shipwreck Group reservoir dips to the northeast, and the overlying Sherbrook Group (Belfast Mudstone) dips to the south, generally agreeing with seismic observations (Luxton et al., 1995).

Faults do not extend into the Tertiary section around La Bella-1 (Locke, 1994). However, the entire Wangerrip Group at the base of the Tertiary, and part of the Sherbrook Group are absent (Fig. 42). This suggests evidence for Early Tertiary faulting, as commonly seen in more landward areas (e.g., near Minerva-1; Fig. 35) is not preserved here. Based on regional faulting history and the magnitude of the uplift suggested by AFTA results (Duddy and Erout, 2001), it is considered likely that at least a portion of the net displacement seen on the controlling faults at La Bella-1 has developed in the Early Tertiary.

SOURCE ROCKS

Significant thicknesses of Sherbrook and Shipwreck groups shales and siltstones are developed at this location (Fig. 42). The Sherbrook Group is mostly immature for oil, except for the lower approximately 100 m. Source characteristics show gas prone low yield source rocks. The intra-Shipwreck Group shales have similar poor source characteristics with these rocks just in the oil mature window at the well (Appendix 1).

La Bella-1 is located on the flank of the Voluta Trough and the Tertiary section is approximately 1500 m thick (Fig. 42). Therefore, it is considered highly likely that late stage generation and migration has occurred in the vicinity of La Bella-1, providing late charge to the traps.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Good quality reservoirs occur through the Shipwreck Group (Fig. 42). The upper sand contains 4.1 m net gas over a 15 m gross interval (2060–2075 mRT), with an average porosity of 14% (Fig. 43) and an average water saturation of 46%. The lower sand contains 28.6 m net gas over a 68 m interval (2100–2168 mRT), with an average porosity of 20% and an average water saturation of 31%. Permeabilities measured and calculated from the RFT tool pretest data over the reservoir interval lie between 20 and 1740 mD in the cleaner sands. From limited core data, only the top metre of core was in good reservoir. Here, porosity ranged between 17.6 and 22.5% with permeability between 137 and 6775 mD (Fig. 43).

The upper Shipwreck Group hydrocarbon bearing sands are dominated by quartzarenites. The lower Shipwreck Group sands are dominated by litharenites. This change reflects a shift in provenance from predominantly locally derived sediments, reworked Eumeralla Formation to transported cratonic sourced sediments in the upper Shipwreck Group.

SEAL

Seals in the Shipwreck and Sherbrook groups are variably developed in this predominantly marine shelfal depositional environment. Trapped hydrocarbons provide clear evidence that marine intraformational seals of the Shipwreck Group (Waarre Sandstone equivalent) are effective cross-fault seals. Geopressured compartments in deeper sands separated by marine shales indicate the presence of other, at least partially sealing intervals. The working cross-fault sealing unit at La Bella-1 is the Sherbrook Group (Belfast Mudstone).

SHOWS

Only minor hydrocarbons were recorded down to 2060 mRT in the well. In the Shipwreck Group reservoir, up to 7% gas was recorded. No direct fluorescence was recorded through these sands. Two segregated fluid samples at 2072.8 and 2160.5 mRT, derived from gas bearing intervals in La Bella-1, were composed of gas, condensate and filtrate (Locke, 1994). The interval below 2168 mRT is interpreted to be 100% water saturated.

RESULTS

There is a clear demonstration at La Bella-1 that marine intraformational seals of the Shipwreck Group (Waarre Sandstone equivalent) and deeper intervals are capable of providing multiple effective seals in faulted settings. The Sherbrook Group (Belfast Mudstone) provides an effective cross-fault seal at La Bella-1 and Minerva-1.

Results of this well located on the edge of the Mussel Platform, indicated that the adjacent Voluta Trough section is likely significantly geopressured over a large area. This has positive implications for current day source and migration from deeper and more mature Belfast Mudstone and Eumeralla Formation source rocks within the Voluta Trough. The geopressuring of any source rocks likely provides a mechanism for improving expulsion in the Voluta Trough. Other traps in similar settings on or near the edge of the Mussel Platform are likely to be favourably positioned for the timely accumulation and preservation of hydrocarbons.

REFERENCES

LOCKE, A., 1994. La Bella-1, Well Completion Report. BHP Petroleum Pty Ltd (unpublished).

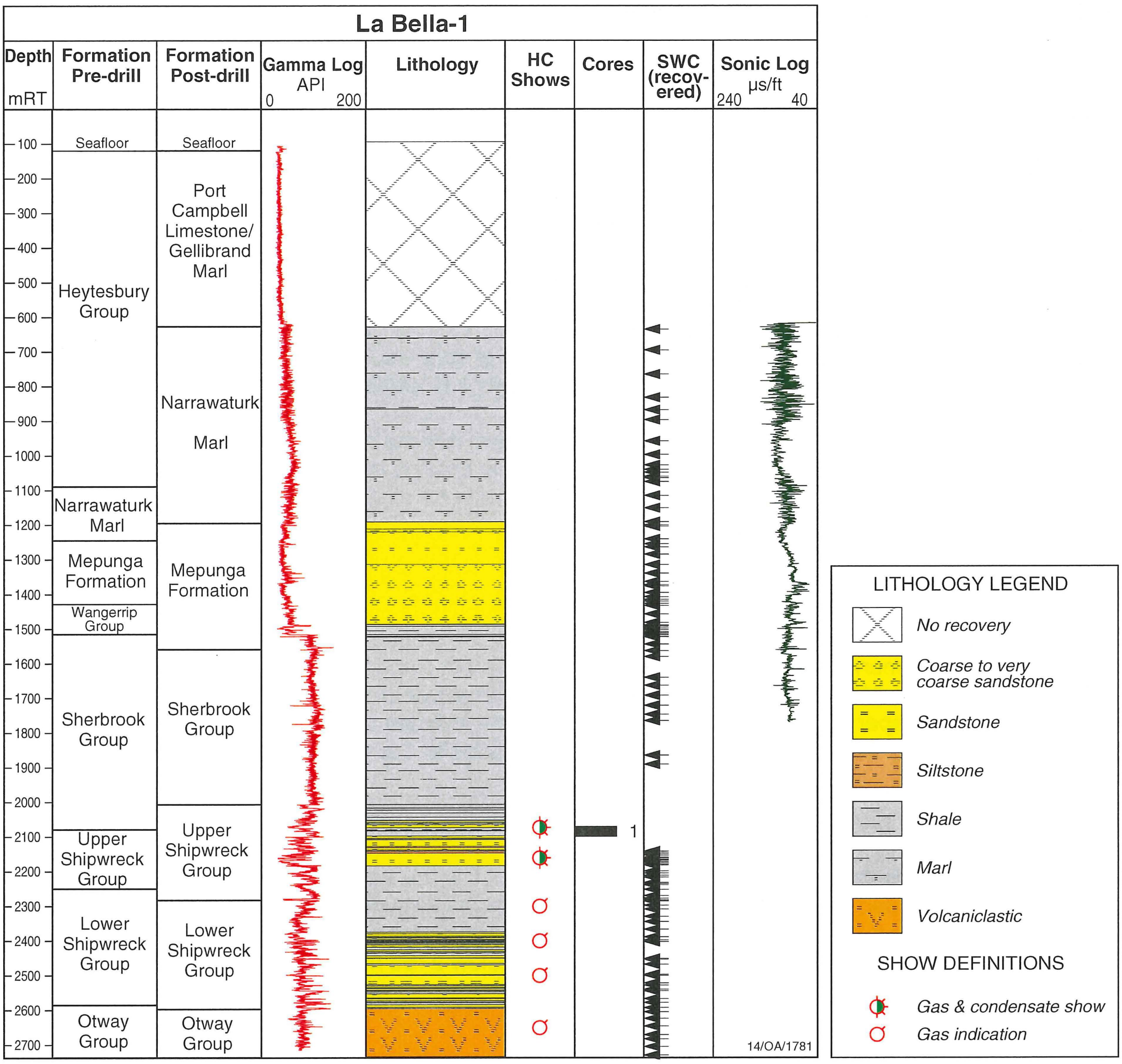

Figure 42. La Bella-1 well composite.

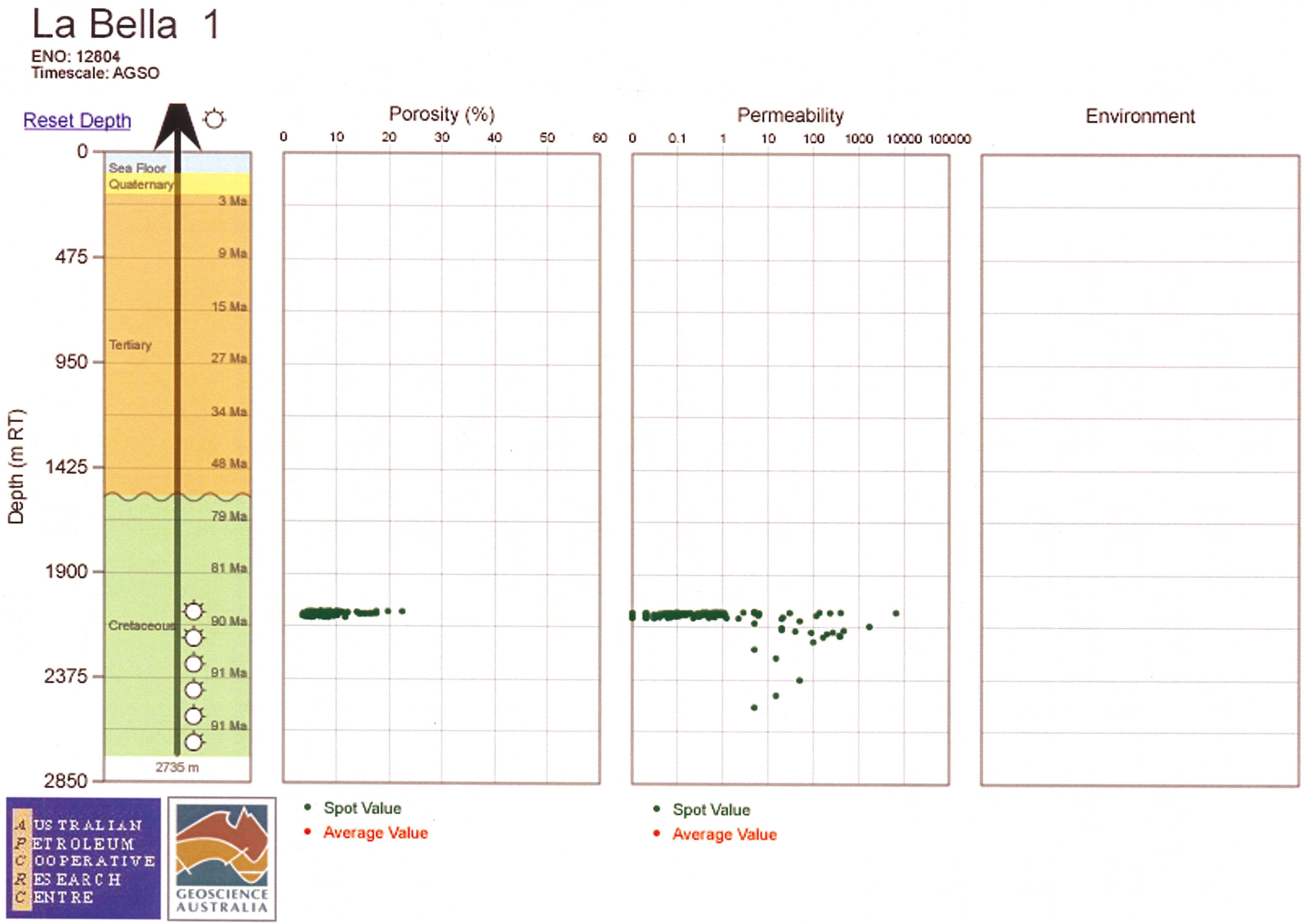

Figure 43. Porosity and permeability measurements recovered from La Bella-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: June, 2003.

3.5 Eastern Voluta Trough

The eastern Voluta Trough is located seaward of the Mussel Platform and is characterised by an expanded Late Cretaceous and Tertiary section. From the limited seismic data, it appears less intensely faulted than the Mussel Platform. Similar to some wells from the adjacent Mussel Platform, Nautilus-A1 and Triton-1/ST1 intersected an unconformity with both the Wangerrip and Nirranda groups missing. Therefore, in this area sedimentation does not recommence, or is not preserved, until the Oligocene. As a result, evidence for Early Tertiary faulting in rocks of the same age in more landward areas, e.g., Minerva-1, is not preserved here. The recent AFTA work by Duddy and Erout (2001) has produced strong evidence that there has been kilometre scale uplift and erosion most likely in the Paleocene in the adjacent Mussel Platform. The extent of uplift is constrained by AFTA, however, the error bars on the timing of the event(s) are broad covering the bulk of the Late Cretaceous and the Early Tertiary. Consequently, there is uncertainty in the structural and thermal history in this area.

Prospectivity of any Waarre Sandstone targets appears to be limited by preservation of reservoir porosity. The Belfast Mudstone is geopressured and the interpreted Eumeralla Formation source rocks are likely to have undergone significant late generation and expulsion during the Tertiary. The two wells drilled on the flank of the eastern Voluta Trough provide some information on the potential for deeper basin play types. The sands seen at the top of the Late Cretaceous may represent the proximal end of deepwater reservoir systems.

Nautilus-A1

WELL SUMMARY

Operator	Esso Exploration and Production Australia Inc
Date Spudded	13 April 1968
TD Date	5 May 1968
Type	Exploration
Status	Dry hole - Plugged and abandoned
Shows	Minor gas indications
UNO	W3680001
Permit	PEP49
Latitude	38° 58' 40.972" S
Longitude	142° 32' 45.744" E
Reference datum	None provided in WCR
Projection	None provided in WCR
KB (m) datum	28.3 m
Water Depth	85.3 m
TD (mKB)	2011 m
Age at TD	Late Cretaceous
Primary Objective	Early Oligocene fan shaped sandstone wedge.
Secondary objective	None stated
Play/Trap Type	Eroded and sealed sand wedge
Reason for failure	Sandstone absent in wedge and poor top seal

DATA SUMMARY

Palynology:

Palynology was not undertaken as part of the original work plan. The earliest palynological analysis was done by Partridge, A.D. (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report 1996/5.

Micropalaeontology:

The original micropalaeontological analysis was done by Taylor, D.J. (1968). "*Foraminiferal sequence Nautilus A-1 well, Otway Basin*". This report is included as Appendix 1 in the WCR. The micropalaeontological analysis is based on 29 SWCs, 8 cores, and cuttings at 50ft intervals, between 305 mKB and 2010 mKB. The diverse foraminiferal fauna recorded from Late Cretaceous between 1743 mKB to 2010 mKB are assigned to Otway Basin benthic foraminiferal zones XA from 1768 mKB to 1864 mKB and XB from 1945 mKB to 2010 mKB. Late Cretaceous benthic zones are not given datums in STRATDAT as their age limits are currently uncertain. In part, the assemblages are facies indicators rather than time indicators.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments
Core-1	845	847	2.4	100% recovery
Core-2	847	856	6.1	66.6% recovery
Core-3	952	961	9.1	44% recovery
Core-4	1114	1119	4.9	100% recovery
Core-5	1260	1265	4.9	100% recovery
Core-6	1414	1423	9.1	100% recovery
Core-7	1577	1672	7.9	87% recovery
Core-8	1729	1735	1.4	28% recovery
Core-9	1860	1864	4.6	100% recovery
Core-10	2003	2011	7.6	100% recovery
SWC	304.5	1943.7	50 of 60	
Cuttings	304.8	2011		3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Run	Tool string	Interval (mKB)	Comments
1	IES	290–673	
1	SGRC	290–671	
1	FDC	651–2001	
1	CDM	651–1999	
2	IES–SGRC	651–2001	

Velocity Survey:

A checkshot velocity survey was completed with 4 shots recorded between 798 and 1957 mKB. The results are summarised in Enclosure 5 of the WCR.

Well Tests:

No well testing by RFTs, production tests or by any other means was performed in this well.

PRIMARY OBJECTIVE

The primary objective of Nautilus-A1 was to test the hydrocarbon potential of a discrete fan shaped wedge, which was believed from seismic amplitude and frequency to contain an interbedded sand shale sequence. These sands were predicted to pinch-out updip. Above and below the wedge, the seismic character indicated enclosure by more homogeneous rocks, possibly fine grained sediments, to provide a seal.

SECONDARY OBJECTIVE

No secondary objectives were stated in the WCR.

STRUCTURE

Nautilus-A1 was drilled on a small domal structure near the updip end of a "fan shaped' wedge located at TD (Fig. 44). The well was designed to test the ~30–40 m of closure and potential of the underlying Tertiary wedge (Lunt and James, 1968). Interpretation of the structure at the base of the wedge was complicated by erosional topography. However, analysis of the dip log (CDM), show low angle dips to the north at the base of the Gellibrand Marl Formation and regional dips to the southwest. This dip reversal supports the presence of a domal structure (Lunt and James, 1968).

According to Lunt and James (1968), three large channel systems eroded into the wedge. One cuts 150 m into the wedge, with the prognosed tight channel-fill facies providing seal. An analogy is made with the Gippsland Basin Marlin Field, where the incised channel fill seal greatly extends the size of the trap (Lunt and James, 1968).

Minor faulting extends into the Tertiary section south of Nautilus-A1 and Triton 1/ST1. There is a major hiatus near the top of the Belfast Shale Formation with only a thin basal Tertiary sand present and the entire Wangerrip and Nirranda groups missing (Fig. 45). The Oligocene–Miocene Gellibrand Marl Formation makes up approximately 1300 m of the 1700 m Tertiary succession. The minor faulting seen here is therefore post Oligocene, with no early Tertiary section preserved to show evidence of older Tertiary faulting.

SOURCE ROCKS

The upper 267 m of the Belfast Shale Formation penetrated in this well (Fig. 45) is immature for oil (VR <0.5%). Source characteristics show gas prone low yield source rocks for the one source sample with a full Rock Eval data set at 1966 mKB (Appendix 1). This point sample has a low TOC relative to other samples which have values up to 2.5%. These TOC values are higher than for the equivalent section seen in wells on the Mussel Platform and may indicate some improvement in source quality toward the basin centre.

At Nautilus-A1, the Tertiary is approximately 1650 m thick and the well is located on the flank of the eastern Voluta Trough. It is considered very likely that this Tertiary section provided late loading which was sufficient to restart generation and migration. The La Bella Field updip from this well provides good evidence to support this model.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

The only potential reservoir penetrated was the base Tertiary sand, which is 20.4 m thick below 1723 mKB. It is very fine to medium grained, clayey, unconsolidated with glauconite. Log calculations indicate 25 to 30% porosity in the upper 6 m of this sand (Lunt and James, 1968). However, the section is considered impermeable, based on sample descriptions and more subtle E-log character (Lunt and James, 1968). However, given the lack of direct porosity/permeability measurements, and insufficient data provided by Lunt and James (1968), the issue of reservoir quality is considered unresolved. Lunt and James (1968) consider the age of this sand as questionable. It could be either a Paleocene distal Pebble Point Formation sand, a Late Cretaceous or Eocene aged unit (Lunt and James, 1968).

SEAL

The seal above the Tertiary sands comprises interbedded calcareous shales and limestones. Where any later structural deformation occurs, more brittle carbonate-rich seals often fail. A good quality thick seal is well developed in the penetrated upper section of the Belfast Shale Formation at the base of the well Fig. 45).

SHOWS

Only very minor mud gas indications were recorded in this well with no evidence of hydrocarbons from the core and cuttings samples.

RESULTS

The targeted 'wedge' was found to contain interbedded calcareous shales and limestone, rather than the interbedded sands and shales predicted from predrill seismic interpretation. Interpretation of the base Tertiary sand by Lunt and James (1968) suggests that this well intersected the sands near their distal pinchout edge. Alternatively, the basal Tertiary sand intersected at Nautilus-A1 may represent the most proximal end of extensive fans containing eroded sands and shales. This scenario is supported by the location of the well just basinward of the Mussel Platform, which may have undergone massive uplift and erosion of the more proximal Late Cretaceous sequences (Duddy and Erout, 2001).

Given the presence of the La Bella gas field updip from this well, and the evidence of migration from deeper areas southwest of the Mussel Platform, four reasons for failure are possible (Duddy and Erout, 2001). First, it is possible that a trap has not been tested by the well at this Base Tertiary level. Second, a thick Belfast Shale Formation may have prevented migration into these sands. Third, the carbonate-rich top seal has fractured during the frequent structural episodes through the Tertiary to the present. Fourth, the reservoir quality is so poor that hydrocarbons could not penetrate them.

REFERENCES

LUNT, C.K. & JAMES, E.A., 1968. Nautilus A-1, Well Completion Report. Esso Exploration and Production Australia Inc (unpublished).

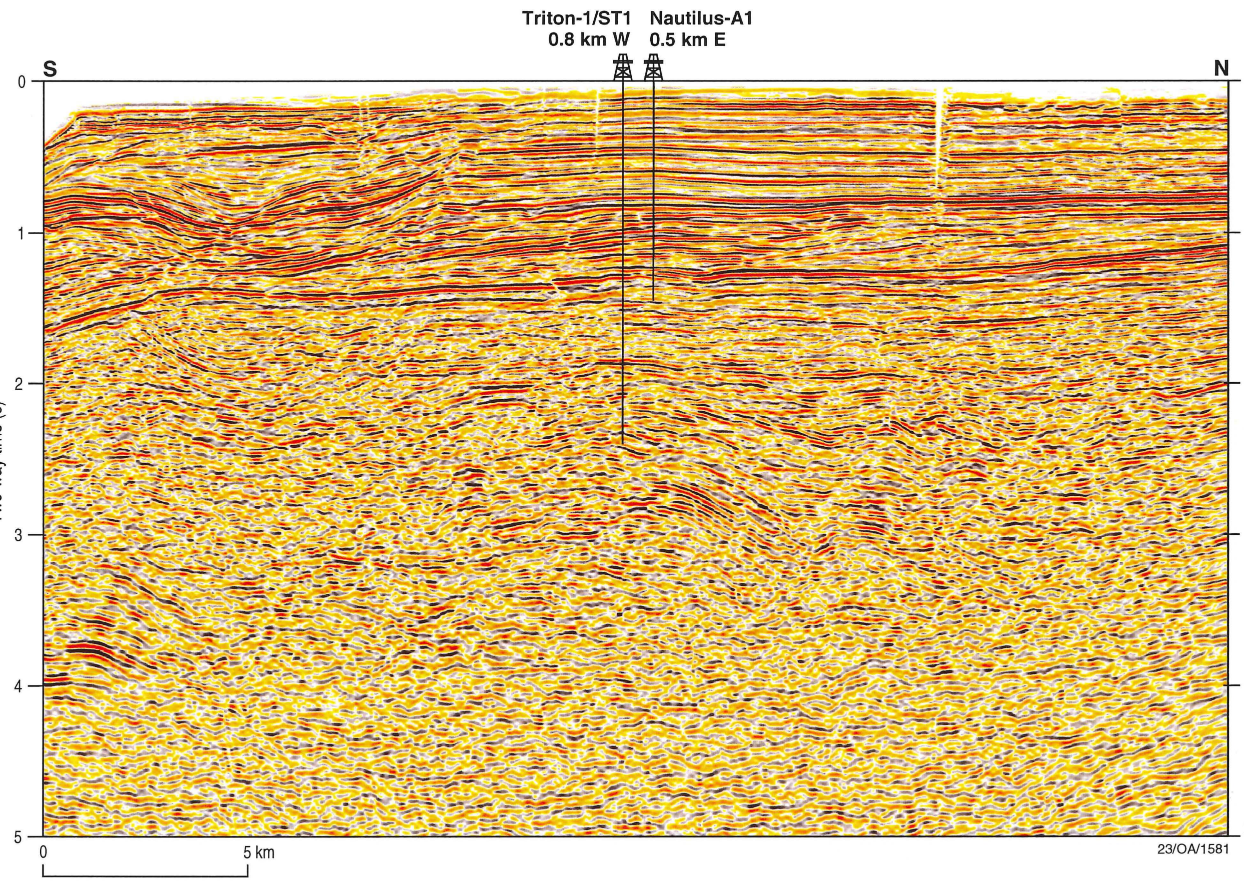

Figure 44. Seismic section showing location of Nautilus-A1 and Triton-1/ST1. Seismic reproduced with permission of Fugro MCS.

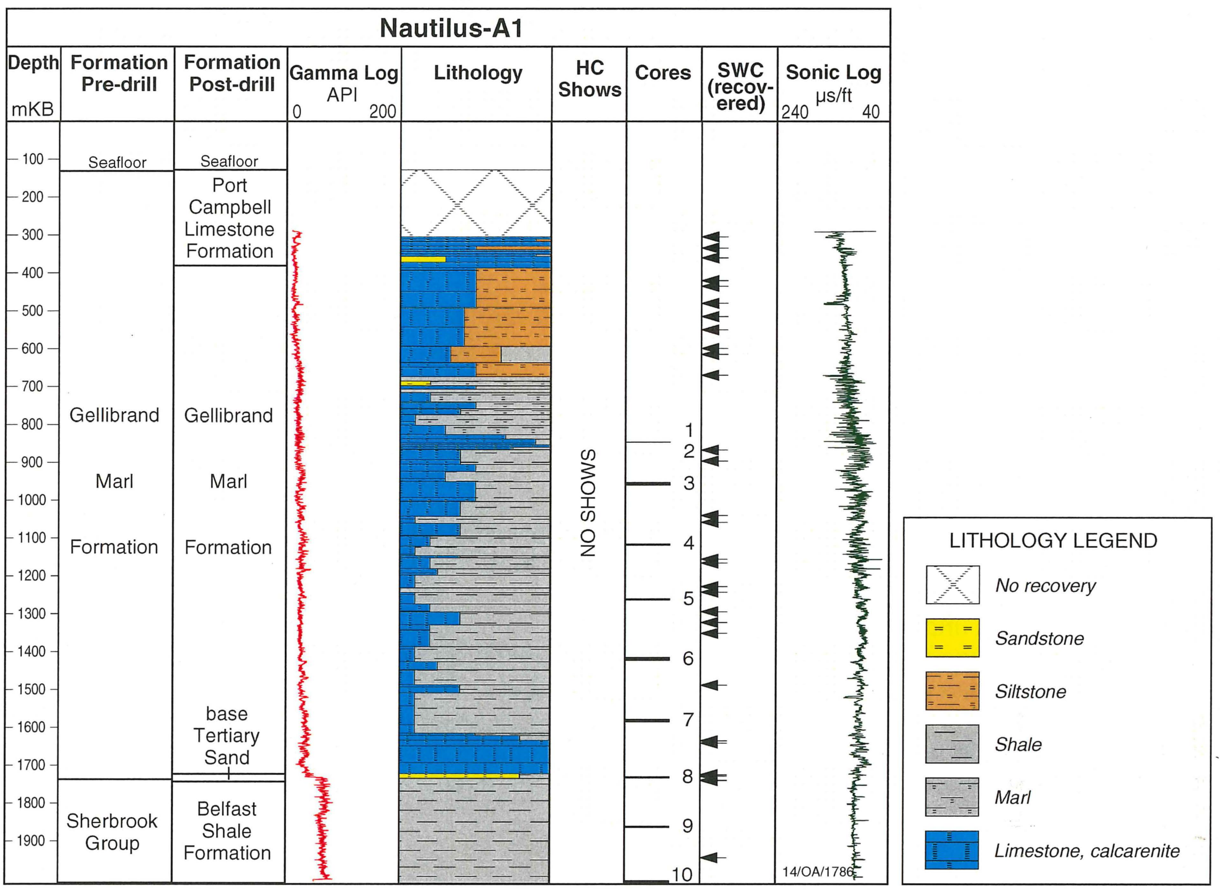

Figure 45. Nautilus-A1 well composite.

Triton-1/ST1

WELL SUMMARY

Operator	Esso Australia Ltd.
Date Spudded	24 January 1982
TD Date	17 April 1982
Type	Exploration
Status	Dry hole - Plugged and abandoned
Shows	Minor gas shows
UNO	W3820002 W3820006 (ST1)
Permit	VIC/P15
Latitude	38° 58' 59.95" S
Longitude	142° 31' 48.94" E
Reference datum	Central Meridian 141°
Projection	AMG Zone 54
KB (m) datum	21 m
Water Depth	100 m
TD (mKB)	2803 m, Triton-1
Sidetrack kickoff point (mKB)	1467 m
TD (mKB)	3537.85 m, Triton-1/ST1
Age at TD	Late Cretaceous
Primary Objective	Waarre Formation
Secondary objective	None stated
Play/Trap Type	Faulted anticline
Reason for failure	No migration into very poor reservoir.

DATA SUMMARY

Palynology:

The original palynological analysis by Stacy, H.E. (1982). "*Palynological analysis of Triton-1 and Triton-1 Sidetrack, Otway Basin*", can be found in Appendix 5 of the WCR.

Additional analysis was undertaken by:
Morgan, R. (1992). "*New palynology of Triton-1 offshore Otway Basin, Australia*". This unpublished report was performed by Morgan Palaeo Associates for BHP Petroleum.

and Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report, 1996/5.

Micropalaeontology:

The original micropalaeontological analysis was done by Rexilius, J.P., (1982), "*Foraminiferal analysis of Triton-1 and Triton-1 Sidetrack, Otway Basin*", and appears in Appendix 4 of the WCR.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments
Cores				No cores cut
SWC	2840	3533.5	37 of 51	
Triton-1, Cuttings	250 810	810 2803		10 m sample interval 5 m sample interval
Triton-1/ST1, Cuttings	1475	3545		5 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

	Suite	Tool string	Interval (mKB)	Comments
Triton-1	1	DIL–BHC–GR	120–1051	
	2	DIL–BHC–CAL–GR	1042–2450	
Triton-1/ST1	3	DLL–MSFL–GR–SP	1000–3540	
	3	BHC–GR—SP	2810–3542	
	3	LDL–CNL–GR	2810–3542	
	3	HDT	3300–3545	
	3	CST	2840–3533.5	51 shot, 37 recovered
	3, Run 1	VELOCITY SURVEY	333–2785	13 Levels
	3, Run 2	VELOCITY SURVEY	608–3540	12 Levels

Velocity Survey:

A checkshot velocity survey was completed with 25 levels being surveyed between 333 and 3540 mKB. The results are presented in Appendix 10 of the WCR.

Well Tests:

A total of 8 RFT pretests were performed between the 3468 and 3532 mKB, all of which were unsuccessful due to the formation sample points being tight. An RFT sample recovery was unsuccessfully attempted at 3419.5 mKB recovering 8.5 litres of mud. Failure was because of tight formation and inadequate sealing of tool.

PRIMARY OBJECTIVE

The primary objective of the well was to test the hydrocarbon potential of the Waarre Formation in a lightly faulted anticlinal structure.

SECONDARY OBJECTIVE

No secondary objectives were stated in the WCR.

STRUCTURE

Triton-1/ST1 targeted the crest of a lightly faulted anticlinal structure at ~2 s (Fig. 44). The anticline was interpreted to trend southwest and approximately 3 km south of the bounding fault of the Mussel Platform (Priest, 1982). Northwest trending normal faults dissect the anticline, and are downthrown to the southwest in a series of rotated fault blocks. Reactivation of the faults during the Late Cretaceous to Early Tertiary modified the closure (Priest, 1982).

Minor faulting extends into the Tertiary section south of Nautilus-A1 and Triton-1/ST1 (Fig. 44). A major hiatus occurs at the top of the Belfast Mudstone, with both the Wangerrip and Nirranda groups missing (Fig. 46). The Oligocene–Miocene Gellibrand Marl makes up approximately 1100 m of the 1700 m Tertiary succession. The minor faulting seen here is therefore post Oligocene, and similar to wells on the Mussel Platform. No Paleocene section is preserved to show the early Tertiary faulting events.

SOURCE ROCKS

The Belfast Mudstone section penetrated in Triton-1/ST1 is immature for oil generation down to approximately 2400 mKB (VR <0.6%; Appendix 1). This agrees with the maturity profile of the sidetrack well. Source characteristics show a gas prone, low yield source, with low TOCs that decrease with depth. These TOC values are slightly higher than for the equivalent section seen in wells on the Mussel Platform and may indicate some improvement in source quality of this interval toward the basin centre.

The lower 600 m of the section is well within the oil mature zone with VR values just <1%. These Belfast Mudstone rocks are shown to be lean from TOC analysis, however, there are no further Rock Eval data to describe this interval more fully. It is interesting to note that the VR profile shows a marked change in gradient between approximately 2850 and 3250 mKB in the lower portion of the Belfast Mudstone.

At Triton-1/ST1, the Tertiary is approximately 1700 m thick and is located on the flank of the Voluta Trough. It is considered highly likely that late stage generation and migration has occurred in the vicinity of Triton-1/ST1 providing the potential for charge to any traps.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

The Waarre Formation has low porosities, with values all <7% based on petrophysical interpretations (3406 mKB; Fig. 47). The sands at this location have well developed illite films and a high proportion of detrital sedimentary or metamorphic rock fragments. Porosity is reduced from both compactional deformation of the rock fragments, and the presence of authigenic kaolin, carbonate and minor quartz overgrowths (Priest, 1982). The basal Tertiary sand seen in Nautilus-A1 occurs as a more silty and shaly sand interval in Triton-1/ST1.

SEAL

The thick Belfast Mudstone in Triton-1/ST1 has very similar lithologic and petrophysical characteristics to that seen in the La Bella field where it is an effective top and cross-fault seal. Fault displacements, as shown on the WCR map (Priest, 1982), are around 100 m and, therefore, would not breach the 1100 m thick Belfast Mudstone.

Results from the Abnormal Pressure Report, located in Appendix 7 of the WCR, indicate that the Belfast Mudstone is slightly geopressured from its top at approximately 1770 mKB to 3545 mKB (MWE ~14 to 15.7 ppg). This amount of geopressuring is likely to enhance seal effectiveness. The underlying Waarre Formation is interpreted as likely not to be geopressured, although this is uncertain in the absence of direct pressure data.

SHOWS

Minor gas indications were recorded throughout the well section increasing in the Belfast Mudstone. Priest (1982) interprets that the gas is associated with the abnormally pressured zones. No fluorescence was seen in any of the sands and petrophysical analysis indicated 100% water saturation.

RESULTS

The well appears to be a valid test of a structure, based on the map by Priest (1982). However, it should be noted that seismic data quality is poor at this level, and no clear definitive structural interpretation is possible with this data set. There is often significant discordance between the form of horizons within the lower Belfast Mudstone and those at the top of the Waarre Formation reservoir over short distances. This is the case at La Bella-1 where significant dips in these respective intervals are 180^{o} apart (Luxton et al., 1995). There appears to be a significant risk at Triton-1/ST1 that, whilst located on an anticlinal structure, the well may not have been positioned to test it optimally. More broadly, the well was positioned on an anticlinal nose plunging into the Voluta Trough. Source and migration appear to be low risk elements, given that the La Bella gas field is located updip. The favoured failure mechanism for Triton-1/ST1 is that migrating hydrocarbons may not have had sufficient pressure to enter the poor quality, geopressured reservoirs (i.e., cap seal entry pressures too high).

REFERENCES

PRIEST, P., 1982. Triton-1, Well Completion Report. Esso Australia Limited (unpublished).

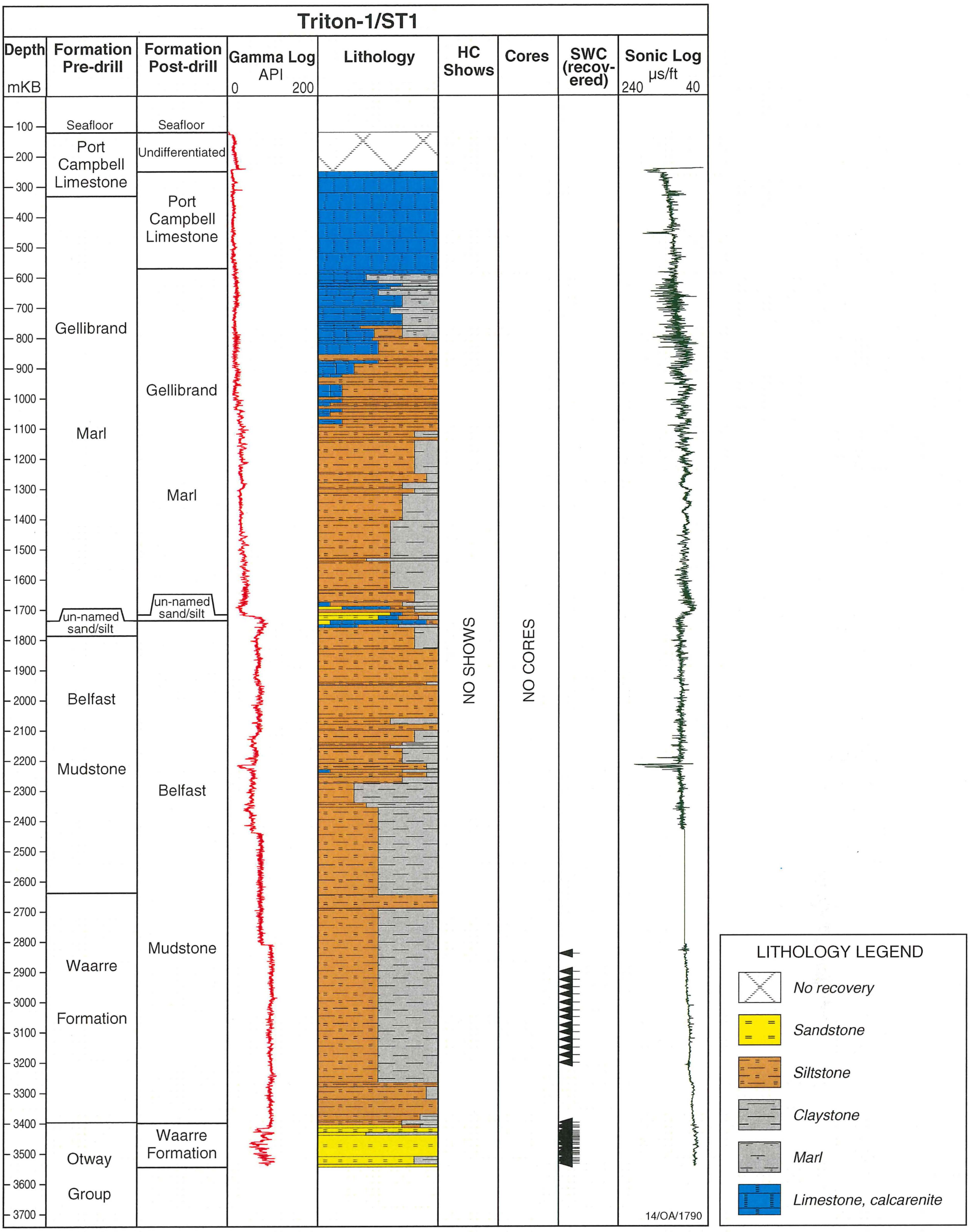

Figure 46. Triton-1/ST1 well composite.

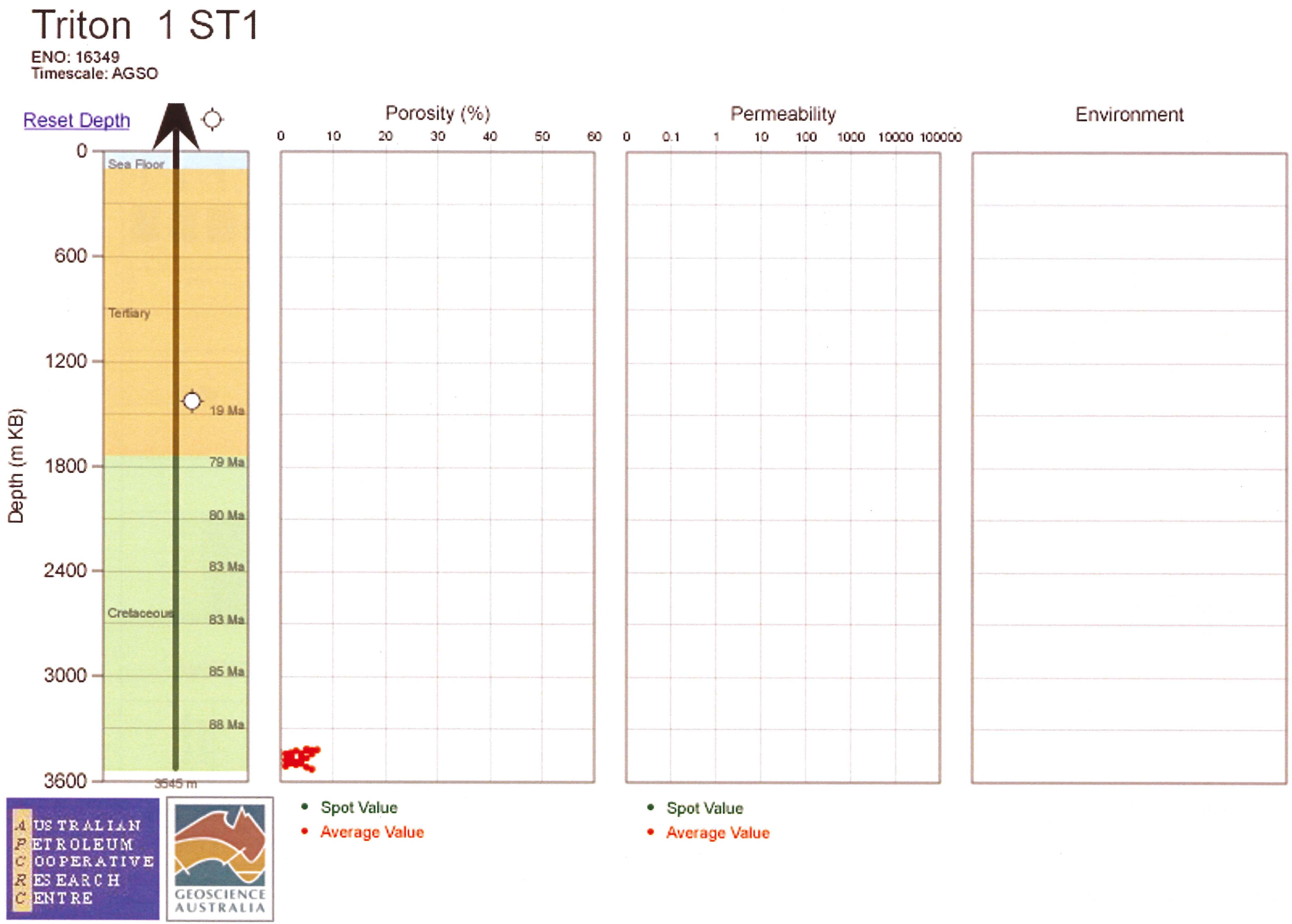

Figure 47. Porosity and permeability measurements recovered from Triton-1/ST1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

3.6 Prawn Platform

The Prawn Platform lies northeast of the Mussel Platform and the Shipwreck Trough. It is characterised by a northeasterly thinning wedge of Late Cretaceous and Tertiary section. The Late Cretaceous Belfast Mudstone equivalent section becomes increasingly interbedded and sand rich to the northeast. Structurally, the Prawn Platform becomes increasingly faulted and folded to the northeast. This structuring has occurred episodically throughout the Late Cretaceous and Tertiary. Both down to the basin normal faults and wrench couple related faults and folds fragment the Late Cretaceous section in this area. The Prawn Platform lies over the north-trending basement boundary between the Lachlan Fold Belt and the Delamerian basement rocks. This boundary accommodated the development of the west Tasmanian Margin from early Late Cretaceous times.

Eric the Red-1

WELL SUMMARY	
Operator	BHP Petroleum Pty Ltd
Date Spudded	17 February 1993
TD Date	26 February 1993
Type	Exploration
Status	Dry hole - Plugged and abandoned
Shows	Minor gas indications
UNO	W3930002
Permit	VIC/P31
Latitude	39° 00' 45.440" S
Longitude	143° 10' 51.450" E
Reference datum	AGD84, AMG Zone 54, Central Meridian 141° E
Projection	Universal Transverse Mercator
RT (m) datum	25.3 m
Water Depth	75.2 m
TD (mRT)	1875 m
Age at TD	Late Cretaceous
Primary Objective	Shipwreck Group
Secondary objective	None stated
Play/Trap Type	Fault block
Reason for failure	Unfavourable cross-fault juxtaposition & thin seals.

DATA SUMMARY

Palynology:

The original palynological analysis was done by Morgan, R., and Hooker, N., (1993). "*Final Palynology of BHPP Eric the Red-1 offshore Otway Basin*". This unpublished report prepared for BHP Petroleum by Morgan Palaeo Associates Pty. Ltd., is located in Appendix 1 of the WCR. The palynological analysis is based on assemblages from 41 SWC and 7 cuttings samples. Spore-pollen assemblages between 1749.5–1813.5 mRT, although diverse (>40 species total), lack key index species. They are tentatively assigned to the Eumeralla Formation, on the absence of younger index species.

Additional analyses can be found in:
Morgan, R., (1994). "*Palynology of two followup SWC from BHPP Eric the Red-1 Otway Basin*". This unpublished report is also included in Appendix 1 of the WCR.

and Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report 1996/5

Micropalaeontology:

The original analysis by Rexilius, J.P., 1993. *Micropalaeontological analysis, Eric the Red 1, permit VIC-P31, Otway Basin*", is unpublished report located in Appendix 2 of the WCR. Micropalaeontological analyses were performed on 3 SWCs between 373.5 and 467 mRT. All samples were barren of foraminifera and nannofossils.

Cores and cuttings:

Sample Type	Top (mRT)	Base (mRT)	Recovered (m)	Comments
Core				No conventional cores cut
SWC	373.5	1813	74 of 90	
Cuttings	364 1017	1017 1875		5 m sample interval 3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mRT)	Comments
1	1	DLL–MSFL–SDT–GR–SP–CAL–AMS	355–1010.5	GR to seafloor
		CSI (VSP)	175–1005	
		CST–GR	373.5–1010	30 shot, 21 recovered
2	1	DLL–MSFL–SDT–GR–SP–CAL–AMS	1007–1871	
		LDL–CNL–FMS–GR–AMS	1007–1825	
		RFT–GR–HP	1058.5–1790	
		CST–GR	1029–1813.5	
		CSI (VSP)	900–1820	60 shot, 53 recovered
MWD		DPR	364–1875	

Velocity Survey:

Two VSP surveys were completed with 79 levels over the interval 175 to 820 mRT. The report can be found in the Eric the Red-1 WCR, Basic Data Volume 2, Appendix 7.

Well Tests:

One RFT tool run was performed in the well. Ten pretests were made with six successful over the interval 1058.5–1785 mRT. No fluid samples were collected.

A fluid pressure gradient of 1.41 psi/m was measured in the lower Shipwreck Group sands, which appear to be in communication on a common aquifer. These sands have the same pressures and gradients as seen in the Pecten-1 well. The pressures in the La Bella-1 well in the same formation are 550 psi higher (Locke, 1994).

PRIMARY OBJECTIVE

The primary objective of Eric the Red-1 was to evaluate the hydrocarbon potential of the quartzose sandstones of the Late Cretaceous Shipwreck Group within a faulted anticline.

SECONDARY OBJECTIVE

No secondary objective defined in the WCR.

STRUCTURE

Eric the Red-1 was drilled on a rotated fault block, near the crest of a faulted anticlinal structure (Fig. 48). Extensional faults intersect the targeted anticline to form a series of fault blocks with dip closure in an east–west direction (Wong, 1994). Although the broader structure was interpreted to have significant closure in the dip direction, closure of the fault block along strike relied on an effective cross-fault seal against the Sherbrook Group to both the north and south. Rollover in the strike direction was caused by several east–west compressional events from the end of the Cretaceous and through the Tertiary to near present times (Wong, 1994).

Faults related to the drilled structure exist in the shallower section (Tertiary) above ~0.5 s (Fig. 48). Therefore, there is increased risk of leakage of any earlier trapped hydrocarbons. More intense folding and faulting at this level occurs directly to the east (Fig. 48).

SOURCE ROCKS

The interbedded shales of the Sherbrook and Shipwreck groups are not well developed at this location. The section is immature except for the lowermost drilled section that is just mature for oil (Appendix 1). Source quality from HI and TOC data indicate poor to fair gas prone source rocks.

At Eric the Red-1, the Tertiary is approximately 550 m thick (Fig. 49) as compared with 1200 to 1600 m for wells peripheral to the eastern Voluta Trough. Without further study, it is not known if the 550 m of Tertiary loading was sufficient to restart generation and migration in this area. It is, however, considered unlikely.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Good quality reservoirs occur throughout the Shipwreck Group (Fig. 49) with porosities ranging from 16 to 26% in this interval (Fig. 50). Permeabilites determined from RFT analysis were reported as ranging from <100 to 3300 mD (Note: permeability values of <10 mD do exist but qualitative log inspection indicates permeabilities are far greater than the RFT suggests; Wong, 1994). Depositional facies interpretation, guided by palynostratigraphic interpretation, indicates that the reservoir interval was predominantly deposited in a proximal marine setting with occasional non-marine facies.

SEAL

Seals in the Shipwreck and Sherbrook groups are not well developed in the generally shallow or proximal sand-rich depositional environments that are observed throughout the Sherbrook Group (Fig. 49). If seals are present they are likely to be thin. The potential for effective cross-fault seals on the highly faulted structures is greatly reduced, particularly considering the high net sand in the interval.

SHOWS

Only very minor gas indications were recorded throughout the Shipwreck Group.

RESULTS

There is a strong case that no effective traps were developed on the Eric the Red structure due to insufficient seals. Sealing was dependent on the development of adequate cross-fault seals, however, the section proved to be sandier than prognosed. It is also questionable whether any late charge had occurred after the time of final significant structural development.

REFERENCES

WONG, D.H. 1994. Eric the Red-1, Well Completion Report. BHP Petroleum Pty Ltd. (unpublished).

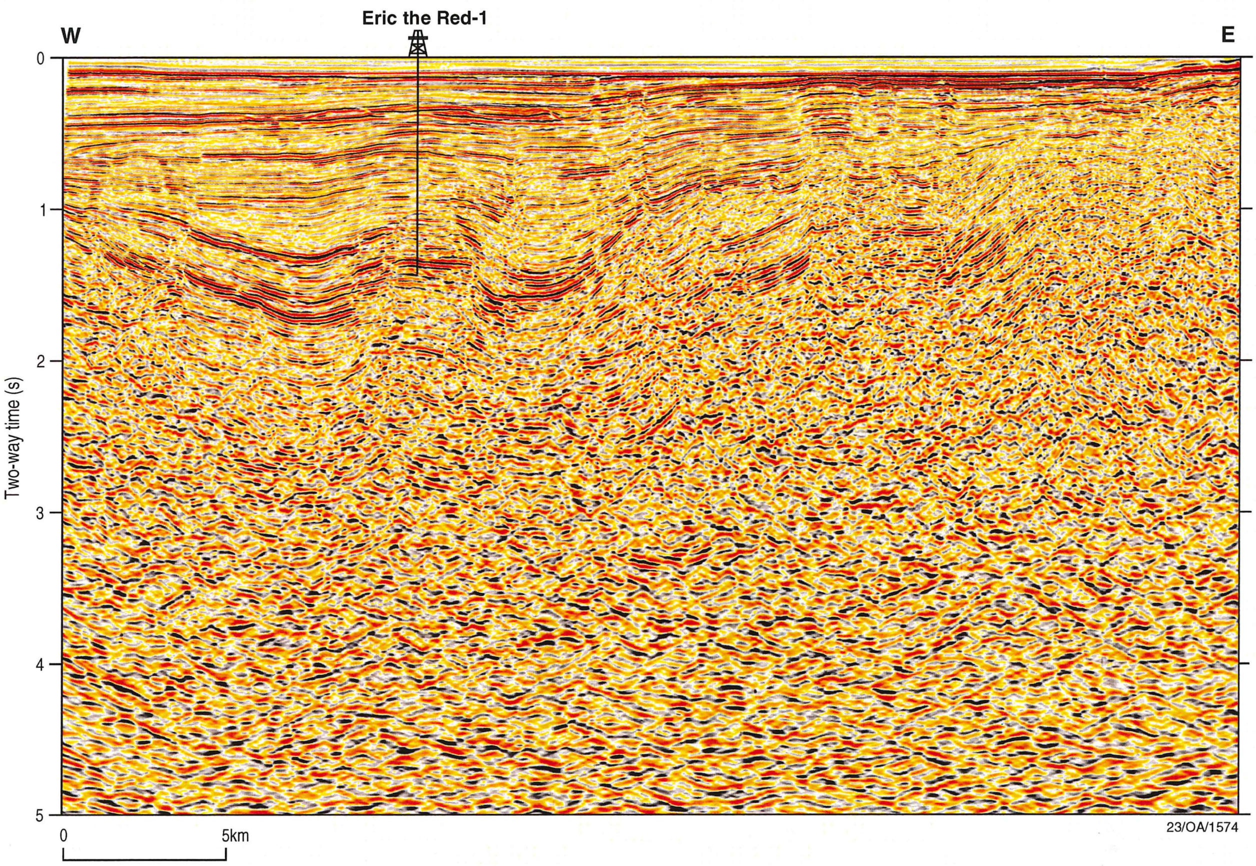

Figure 48. Seismic section showing location of Eric the Red-1.

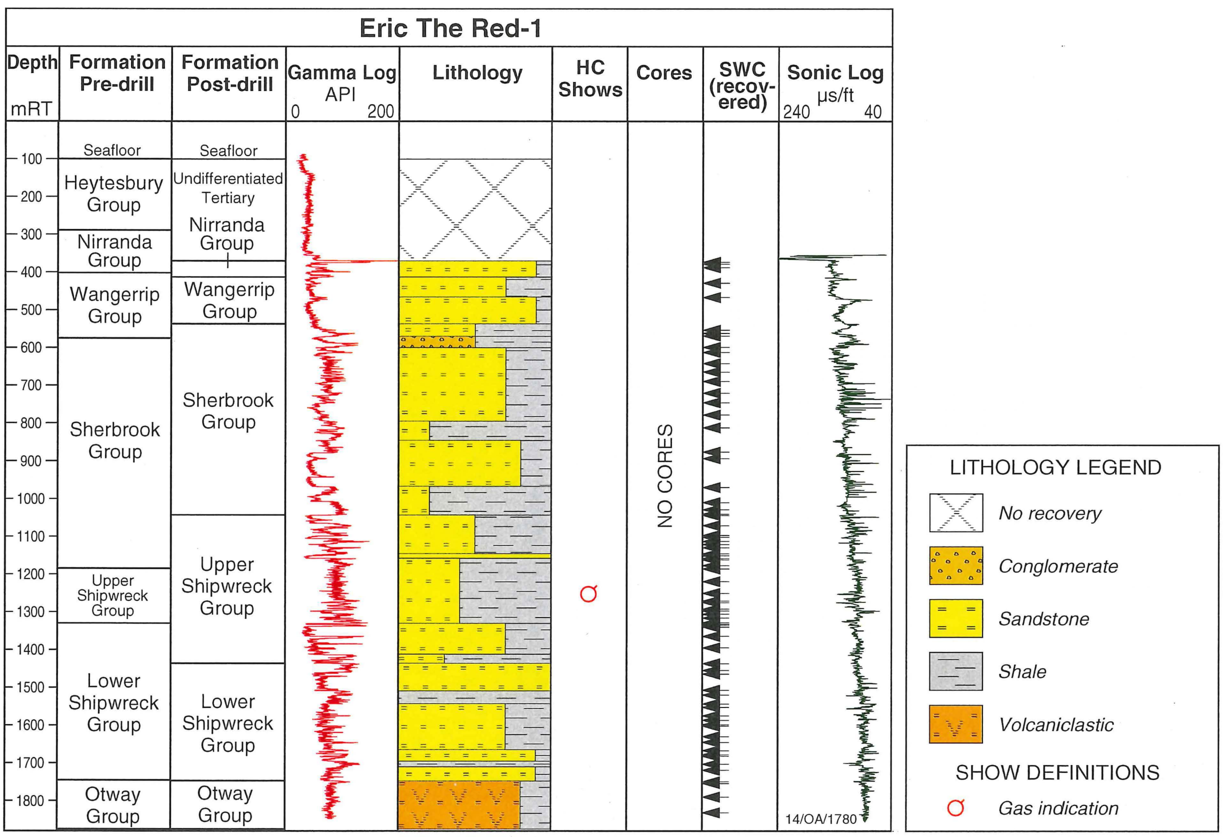

Figure 49. Eric the Red-1 well composite.

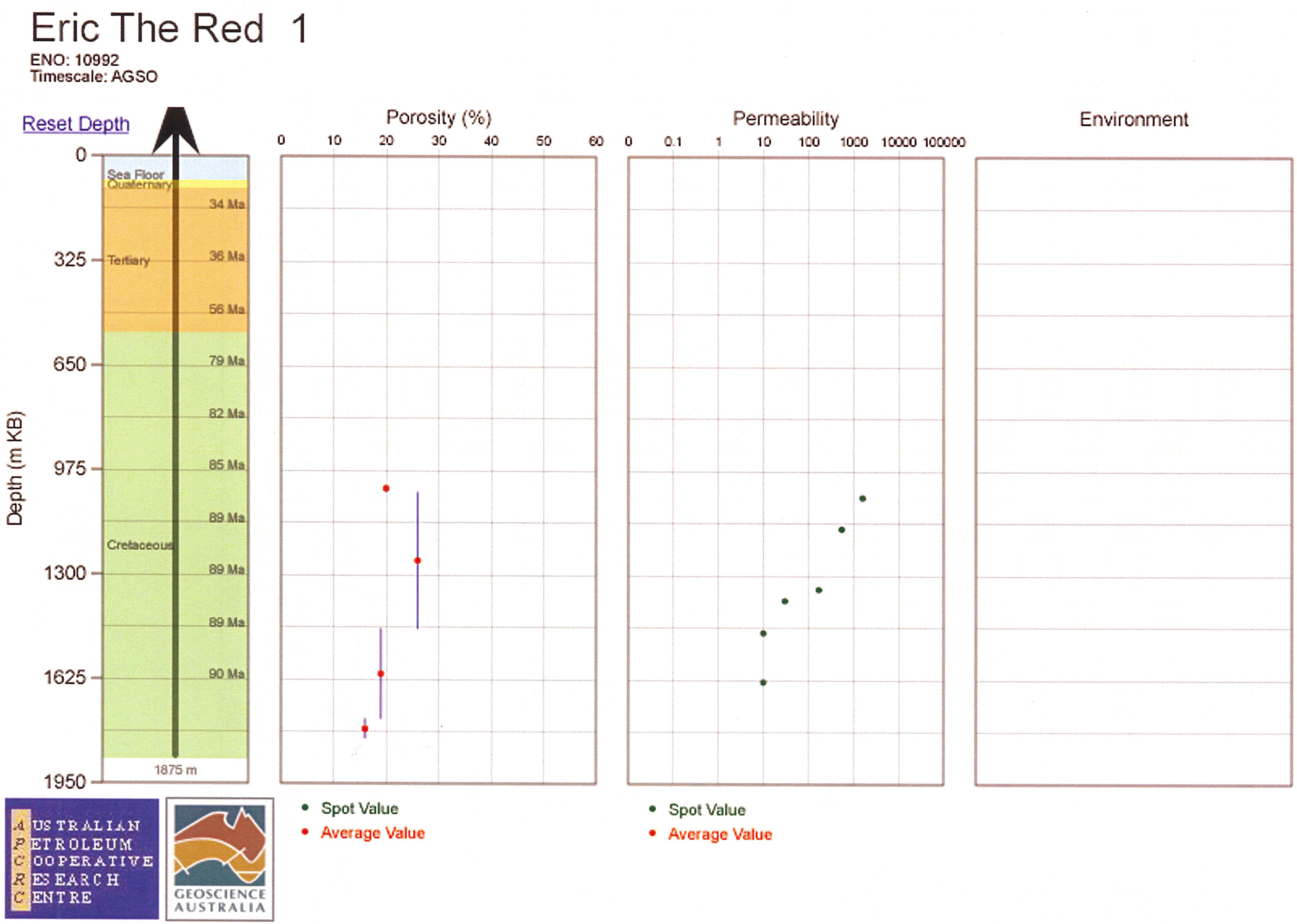

Figure 50. Porosity and permeability measurements recovered from Eric the Red-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: June, 2003.

Loch Ard-1

WELL SUMMARY

Operator	BHP Petroleum Pty Ltd
Date Spudded	19 October 1993
TD Date	27 October 1993
Type	Exploration
Status	Dry hole - Plugged and abandoned
Shows	Minor gas indications
UNO	W3930014
Permit	VIC/P31
Latitude	38° 55' 54.717" S
Longitude	143° 10' 55.156" E
Reference datum	AGD84, AMG Zone 54, Central Meridian 141° E
Projection	Universal Transverse Mercator
RT (m) datum	25.3 m
Water Depth	74.7 m
TD (mRT)	1397 m
Age at TD	Early Cretaceous
Primary Objective	Upper Shipwreck Group 'B' sand
Secondary objective	Upper Shipwreck Group 'A' sand Sherbrook Group 'B' sand
Play/Trap Type	Faulted anticline
Reason for failure	Unfavourable cross-fault juxtaposition & thin seals.

DATA SUMMARY

Palynology:

The original palynological analysis by Morgan, R., (1994), "*Palynology of BHPP Loch Ard 1*", is located in Appendix 2 of the Loch Ard-1 WCR.

Additional work was undertaken by Partridge, A.D., (1996). "*Review of palaeontology data and preparation of STRATDAT datums for selected Otway Basin wells*". Biostrata Report 1996/5.

Micropalaeontology:

No micropalaeontological analysis was performed.

Cores and cuttings:

Sample Type	Top (mRT)	Base (mRT)	Recovered (m)	Comments
Core				No conventional cores cut
SWC	402.5	1329	60 of 60	
Cuttings	395 945	945 1397		5 m sample interval 3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mRT)	Comments
1	1	DLL–MSFL–AS–GR–SP–CAL–AMS	100–942	GR to seafloor
	1	FMS–GR–GPIT–AMS	383–942	
	1	CST–GR	402.5–927	30 shot, 30 recovered
2	1	DLL–MSFL–SDT–GR–SP–CAL–AMS	929–1395	
	1	LDL–CNL–FMS–GR–CAL–AMS	929–1395	
	1	CST–GR	954–1329	30 shot, 30 recovered
	1	VSP	100–1380	
MWD		DPR	393–1397	

Velocity Survey:

A velocity survey was completed at TD. The velocity survey was submitted separate to the WCR. It was conducted over 480–1380 mRT, with 47 levels.

Well Tests:

No well tests were performed on the well.

PRIMARY OBJECTIVE

The primary objective of the well was to evaluate the hydrocarbon potential of the upper Shipwreck Group 'B' sand.

SECONDARY OBJECTIVE

The secondary objective was to evaluate the upper Shipwreck Group 'A', and Sherbrook Group 'B' sands.

STRUCTURE

Loch Ard-1 was drilled near the crest of an anticlinal structure with very late anticlinal growth (Fig. 51). The structure was defined predrill from seismic data as a faulted anticline with fault dependant closure. The anticline and syndepositional faulting were interpreted from isopach maps to form during a localised transpressional event in the late Campanian (Mustica, 1984). Subsequently, episodic inversion from the late Campanian to Late Miocene reactivated the structure. With such a complex structural history and very significant late movement, it is not known when structural closure was developed and if the crest has shifted through time.

SOURCE ROCKS

The interbedded shales of the Sherbrook and Shipwreck groups (Fig. 52) are not well developed at this location and the entire well section is immature. No geochemical analysis has been done on samples from this well (Appendix 1).

The well penetrated the top of the Otway Group (Eumeralla Formation), intersecting silty sandstones and claystones. Maturity levels were measured at a maximum VR of 0.65%. Below the TD of the well, the Eumeralla Formation, comprising variable quality and a variable distribution of coaly source rocks, is likely to be mature to over mature (Mehin & Link, 1995).

At Loch Ard-1, the Tertiary is approximately 350 m thick and is located on the flank of the Shipwreck Trough. It is therefore considered unlikely that late stage generation and migration has occurred.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Good quality reservoirs occur though the Shipwreck Group (Fig. 52) with porosities ranging from 10 to 30% (Fig. 53). No permeability data are available. Depositional facies interpretation, guided by palynostratigraphic interpretation, indicates predominantly proximal marine with occasional non-marine facies present in the reservoir interval.

SEAL

Seals in the Shipwreck and Sherbrook groups were not well developed in the generally shallow or nearshore depositional environments that are observed throughout. If seals are present, they are likely to be thin and within an interval of high net sands. Therefore, there is low potential for cross-fault seals to develop on the highly faulted structures in this area. As no maps are available in the WCR the relationships between fault throws and seal interval cross-fault juxtaposition are not known.

SHOWS

No hydrocarbon shows of any significance were observed in this well. Only minor mudlog gas indications were recorded.

RESULTS

The primary target, the upper Shipwreck Group 'B' sands were found to be water wet, exhibiting a porosity of 14%. The secondary targets, the upper Shipwreck Group 'A' and Sherbrook Group 'B' sands were also water wet with an average porosity of 19 and 30% respectively. There is a strong case that no effective traps were developed on the Loch Ard structure due to lack of sufficiently thick and adequate cross-fault seals at this location, with a generally sandier than expected section intersected. It is also questionable whether any late charge occurred after the time of the final significant structural development of the potential trap.

REFERENCES

MUSTICA, A., 1984. Loch Ard-1, Well Completion Report. BHP Petroleum Pty Ltd (unpublished).

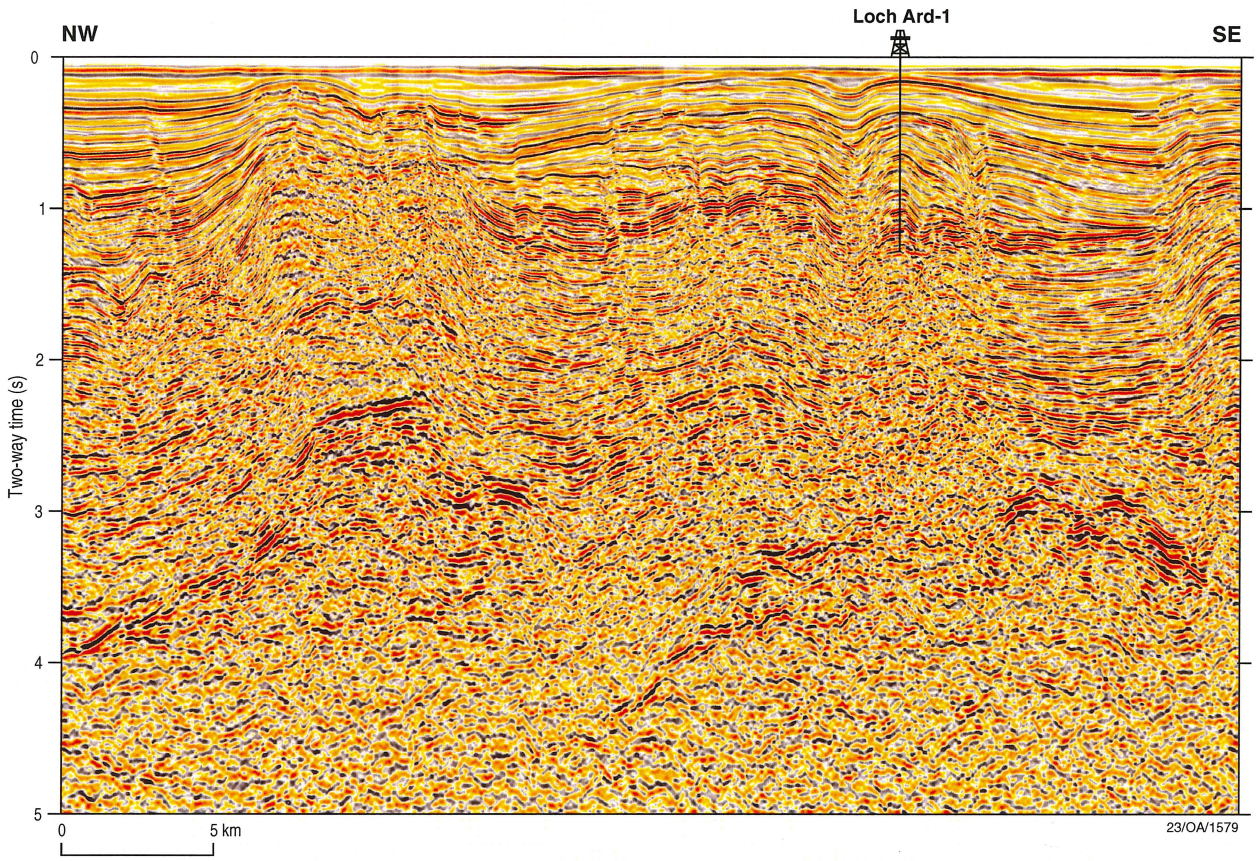

Figure 51. Seismic section showing location of Loch Ard-1. Seismic reproduced with permission of Fugro MCS.

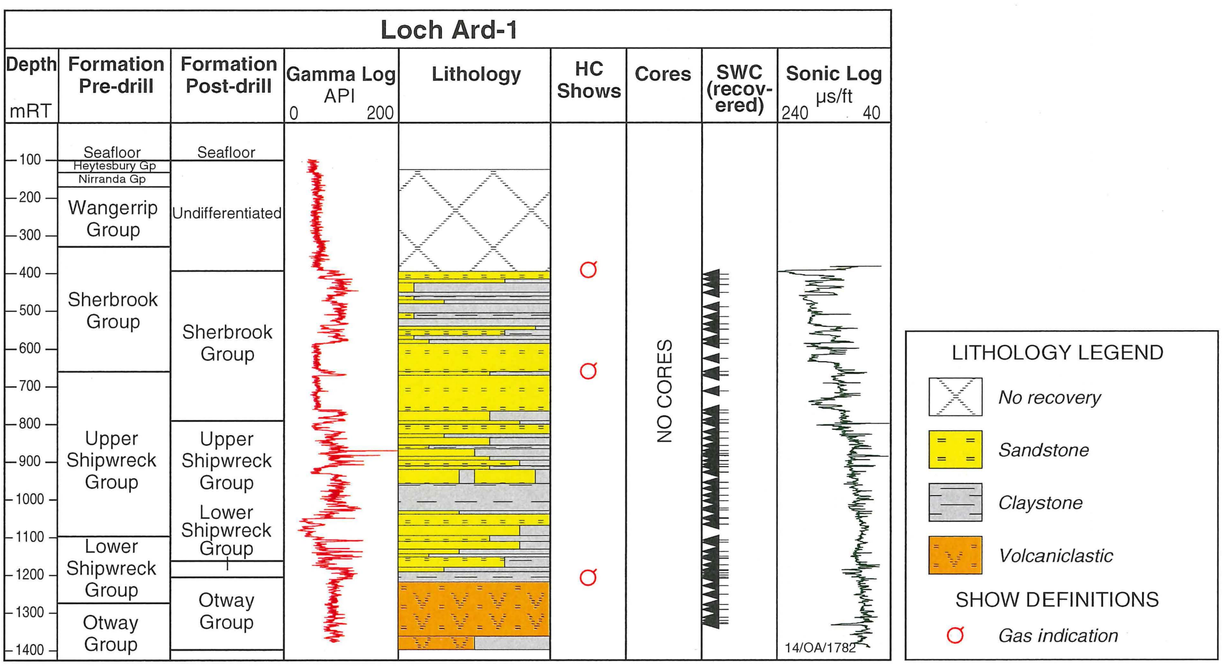

Figure 52. Loch Ard-1 well composite.

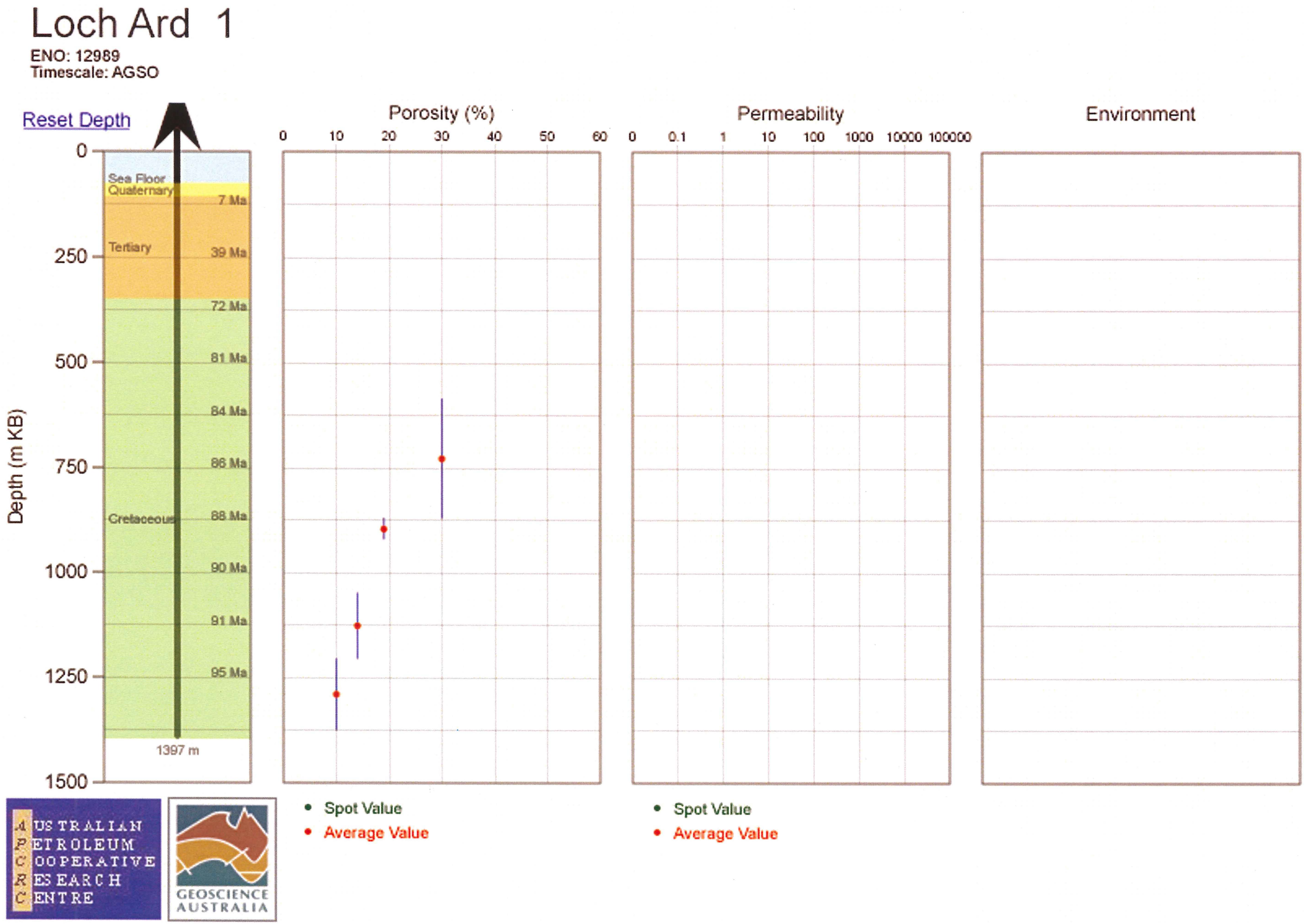

Figure 53. Porosity and permeability measurements recovered from Loch Ard-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

3.7 Torquay Sub-basin

The Torquay Sub-basin is a northeast trending structural element characterised by a thin Late Cretaceous section. There is a major hiatus between the Early Cretaceous Eumeralla Formation and a nearly complete and comparably thick (1200 m) Tertiary section. A broad, two-fold subdivision is apparent in the basin-fill of the Torquay Sub-basin. The lower part of the basin-fill comprises rift-related, fluvio-lacustrine, Late Jurassic to Early Cretaceous sediments of the Otway Supergroup. The upper part of Torquay Sub-basin stratigraphy relates to the Bass Basin. This section comprises Late Cretaceous to Early Tertiary, coal-prone, fluvio-lacustrine sediments of the Eastern View Group, Eocene to Oligocene siliciclastic sediments of the Demons Bluff Group, and Oligocene to Miocene marine carbonates of the Torquay Group. The distinct change in sediment fill relates to mid-Cretaceous uplift in the Otway Ranges which effectively isolated the sub-basin from the remainder of the Otway Basin (Trupp et al., 1994).

The sub-basin is east of the north trending basement boundary between the Lachlan Fold Belt and Delamerian Fold Belt basement rocks. This boundary accommodated the development of the west Tasmanian Margin from early Late Cretaceous times, leaving the Early Cretaceous basin as a failed arm of the rift. Significant structuring comprising episodes of uplift and folding has occurred mainly late in the Tertiary.

Snail-1

WELL SUMMARY

Operator	Hematite Petroleum Pty. Ltd.
Date Spudded	26 November 1972
TD Date	7 December 1972
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	No significant shows encountered
UNO	W3720003
Permit	VIC/P6
Latitude	38° 53' 50" S
Longitude	144° 18' 02" E
Reference datum	Not provided in WCR
Projection	Not provided in WCR
KB (m) datum	9.75 m
Water Depth	81.1 m
TD (mKB)	1234.7 m
Age at TD	Early Cretaceous
Primary Objective	Eastern View Coal Measures (EVCM)
Secondary objective	Otway Group
Play/Trap Type	Lightly faulted anticline
Reason for failure	Lack of migration into late structure.

DATA SUMMARY

Palynology:

The original (unpublished) palynological analysis, included as part of Appendix 2 in the WCR was done by Harris, W.K., (1973), entitled "*Snail 1 — Torquay Embayment Otway Basin, Victoria Palynological examination of cores and side wall cores*".

Additional analysis was undertaken by Macphail, M.K., (1989). "*Palynological analysis of samples from Snail 1, Torquay Sub-basin*", as an unpublished report for the Shell Company of Australia Ltd.

Micropalaeontology:

The original analysis was by Taylor, D., (1973). "*Foraminiferal Biostratigraphy Hematite Snail 1 Well, Otway Basin*" is also included in Appendix 2 of the WCR as an unpublished report for Hematite Petroleum Pty Ltd.

Cores and cuttings:

Sample Type	Top (mKB)	Base (mKB)	Recovered (m)	Comments / (Core rec. %)
Core-1	791.9	797	0	0
Core-2	812.9	822.65	7.01	72
Core-3	960.73	968.95	7.77	94
SWC	272.7	1228.6	29 of 30	
Cuttings	243.8	582.2		9.14 m sample interval
	582.2	618.7		6.1 m sample interval
	618.7	1234.7		3.05 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mKB)	Comments
1	1	SP–ISF–S	215.5–554.7	
2	2	SP–ISF–S	546.8–1234.1	
1	1	GR–CAL–FDC	215.5–556.6	
2	2	GR–CAL–FDC–CNL	546.8–1234.1	
2	1	HDT	546.8–1231.7	
2	1	CAL–PML	546.8–1231.4	

Velocity Survey:

A velocity survey was run at TD over the interval 572.1–1231.4 mKB. A total of 7 levels were surveyed with good quality records reported. The report can be found in Appendix 5 of the Snail-1 WCR.

Well Tests:

No formation or production tests were conducted.

PRIMARY OBJECTIVE

Snail-1, the second well drilled in the offshore Torquay Sub-basin, was drilled to test the hydrocarbon potential of the Eastern View Coal Measures (EVCM). The well was located on a broad low relief structure with closure mapped at the top of the EVCM (Hodgson and Mellins, 1973).

SECONDARY OBJECTIVE

The secondary objective was to investigate the nature of the expected Otway Group immediately below the EVCM to obtain stratigraphic and reservoir information (Hodgson and Mellins, 1973).

STRUCTURE

Snail-1 was drilled near the crest of a structural terrace developed on the southeast side of the Torquay Sub-basin (Fig. 54). The Snail structure is a small tilted fault block on a broader terrace. A considerably reduced section of EVCM (Fig. 55) was penetrated than prognosed (based on Nerita-1) as the Late Cretaceous portion is absent. Postdrill mapping confirmed the presence of a robust structure with 50 m of relief (Hodgson and Mellins, 1973).

SOURCE ROCKS

Source rocks have been sampled through most of the drilled section (Fig. 55). The entire sequence including the Otway Group (Eumeralla Formation) is immature for oil. There are some good TOC values but low HI values through the EVCM indicating a gas prone source (Appendix 1). Significantly, there is only very minor coal development in this well. This is supported by seismic amplitude and character, where the coaly, bright discontinuous coal signature is restricted to the deeper basin area around Nerita-1. It is also interesting to note that the EVCM section here appears to be more marine than at Nerita-1, with the presence of dinoflagellate cysts and acritarchs noted (Hodgson and Mellins, 1973).

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Two cores were cut in the EVCM (Fig. 55). Sands were of excellent quality and friable to unconsolidated, making them unsuitable for core analysis. One tight sand was measured for porosity and permeability and is shown on the plot (Fig. 56). However, this result it is not considered representative of the section (Hodgson and Mellins, 1973).

A core was also cut in the Otway Group (Eumeralla Formation) (Fig. 55). Core analysis shows quite good porosity and permeability ranges despite the generally poor reservoir characteristics of the interval. Porosities range between 34 and 36%, with permeabilities between 90 and 710 mD (Fig. 56). Petrographic analysis of core through the Otway Group (Eumeralla Formation) indicates a massive, friable lithic sandstone with a dark grey to green colour. Thin section work identifies the main component as lithic fragments (85%), quartz (5%), plus minor feldspars, mica and clay minerals. Alteration is extensive with interstitial clays and deformation from compaction of lithics and micas (Hodgson and Mellins, 1973).

It is noted here that the petrographic description is characteristic of the Otway Group (Eumeralla Formation) sandstones, and it strongly suggests that reservoir characteristics would be poor. It is difficult to reconcile the disparity between this petrographic description and core analysis results. It is possible that late structuring has produced some fracture porosity in these rocks.

SEAL

The 136 m thick Demons Bluff Formation (Fig. 55) provides the best regionally developed potential seal interval in the sub-basin. At Snail-1, it comprises a monotonous silty glauconitic claystone. Given that the underlying EVCM was deposited in a more marine setting, it is likely that the Demons Bluff Formation here was also deposited in a more distal marine setting. This may indicate that seal potential for this unit improves to the southeast. There are very few intraformational shales and thus little seal potential within the underlying EVCM.

The Otway Group (Eumeralla Formation) does work as a top and cross-fault seal in the Gippsland and Otway basins. Care should be taken, however, in assuming that all of the formation seals. Potential reservoirs are developed where more quartz-rich sand intervals are preserved, and at the top of the sequence where leaching has produced secondary porosity.

SHOWS

The WCR reports that no significant shows were recorded in this well. Petrophysical interpretation indicated all sands have 100% water saturation (Hodgson and Mellins, 1973).

RESULTS

Interpretation of seismic and biostratigraphic data indicates that a large part of the Snail structural closure developed predominantly during the Miocene. The Demons Bluff Formation looks, from a quick evaluation, to be a reasonable seal, and from palynological evidence is a more distal facies than that seen at Nerita-1. A more quantitative review is required to confirm this. The absence of shows at this level casts some doubt as to the seal quality.

Geochemical data show that the entire section is immature for oil. Deeper Otway Group (Eumeralla Formation) or other source rocks may be present, with some higher amplitude intervals on seismic data possibly indicating coaly source rocks. The timing of any generation from these, based on regional thermal data and modelling, is likely to be early in the Late Cretaceous and Miocene corresponding with maximum Tertiary burial. Both possible generation and migration events pre-date final structuring, introducing a significant timing risk for this structure (Messent et al., 1999).

The thickness of the Tertiary section here is approximately 900 m (and much greater in the surrounding troughs), suggesting that a late generation and expulsion phase from any Otway Group (Eumeralla Formation) source may be possible. This needs to be modelled carefully. There are also well documented gas seeps occurring on the sea bed near the coast (Bishop et al., 1992), which at least support the presence of migrating gas in the sub-basin either through structural disturbance of older traps with recent tectonics, or from renewed generation arising from the Tertiary loading.

In brief, the reasons for failure of Snail-1 are not clear. The most likely reason may be the very late structuring, as traps may not have been present for any commercially significant Tertiary hydrocarbon charge. There is also considerable uncertainty in the quality of seals in this section.

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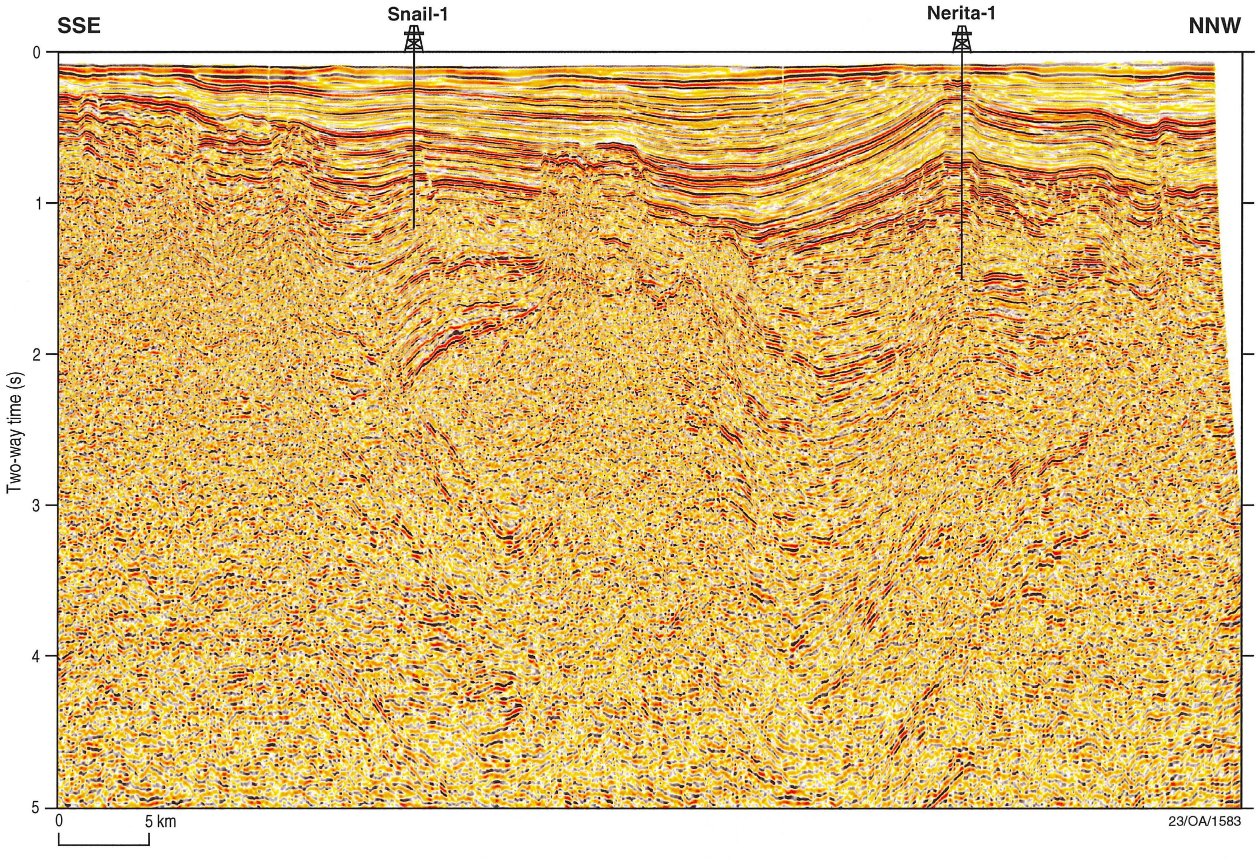

Figure 54. Seismic section showing location of Nerita-1 and Snail-1. Seismic reproduced with permission of Fugro MCS.

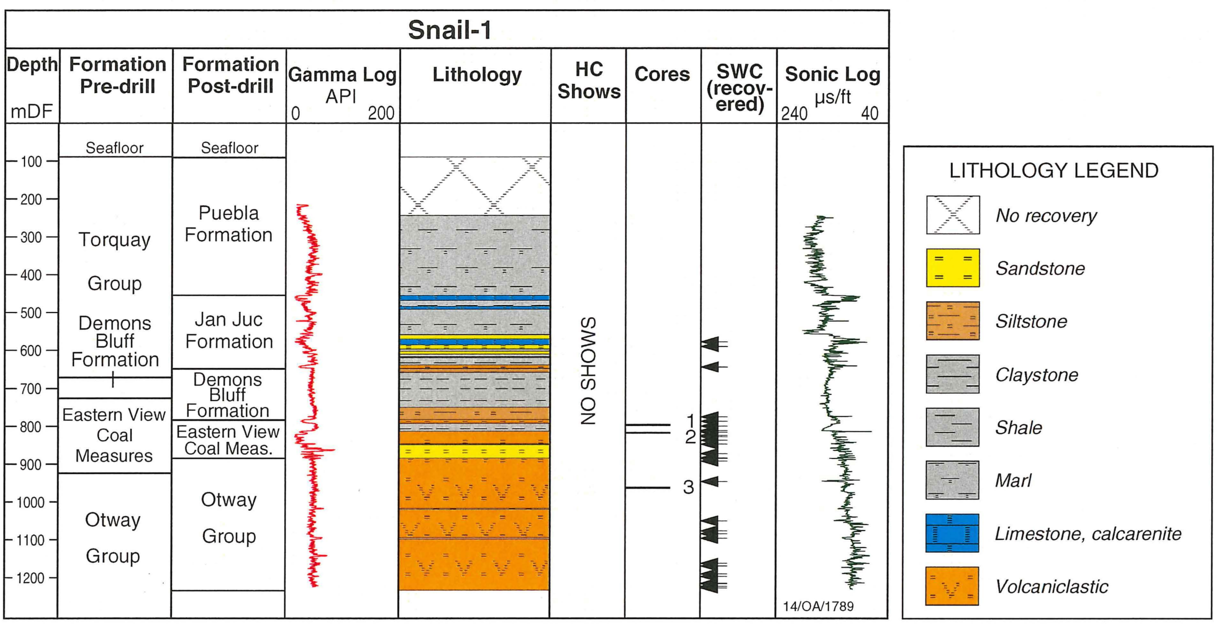

Figure 55. Snail-1 well composite.

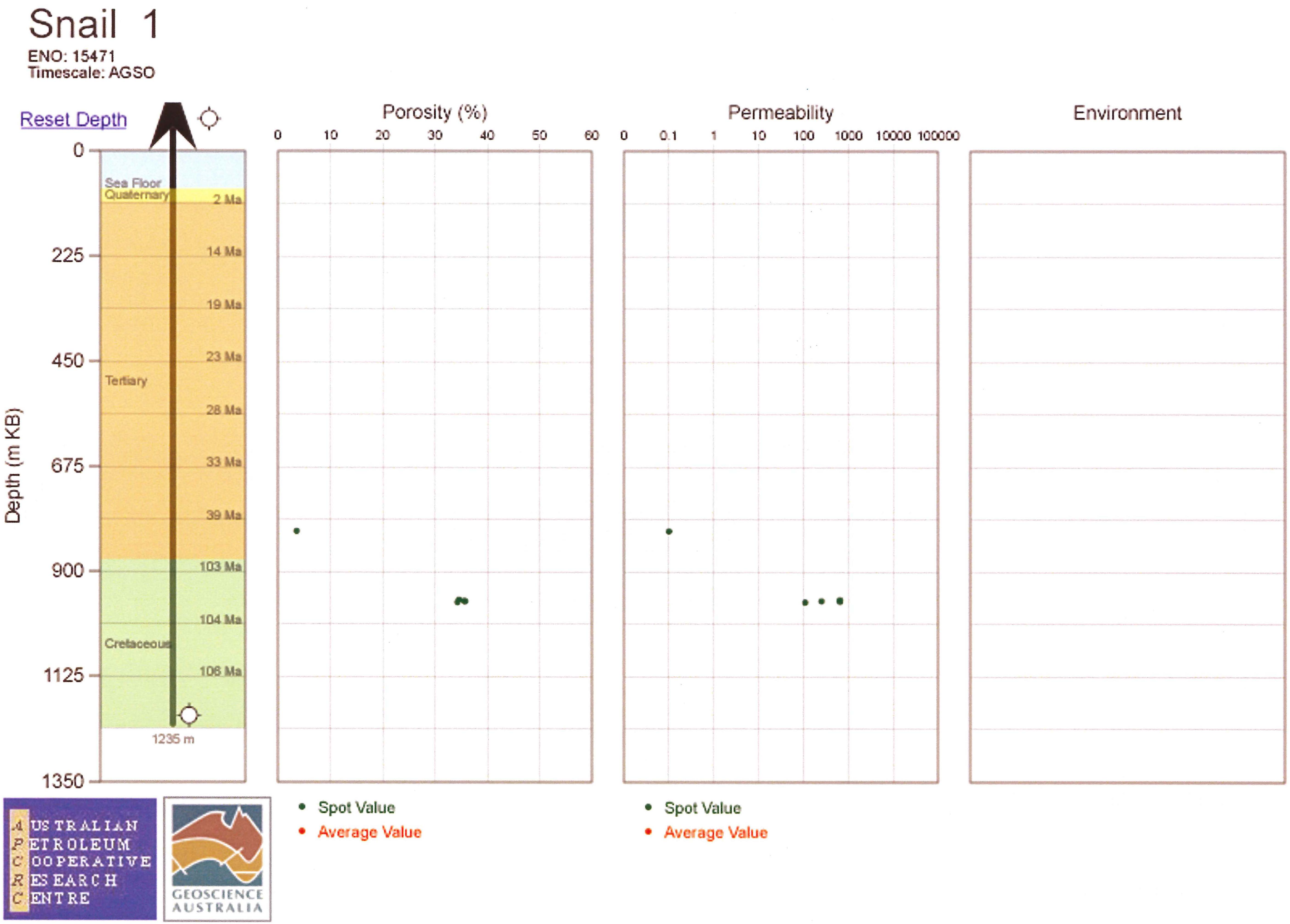

Figure 56. Porosity and permeability measurements recovered from Snail-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

Nerita-1

WELL SUMMARY	
Operator	Shell Development (Australia) Pty. Ltd.
Date Spudded	1 July 1967
TD Date	30 July 1967
Type	Exploration
Status	Plugged and abandoned dry hole
Shows	Good mud gas shows encountered
UNO	W3670002
Permit	PEP22
Latitude	38° 37' 43.19" S
Longitude	144° 13' 44.83" E
Reference datum	ATM (Zone-7)
Projection	Not provided in WCR
DF (m) datum	34.1 m
Water Depth	74.7 m
TD (mDF)	2042 m
Age at TD	Early Cretaceous
Primary Objective	Multiple targets Tertiary to Early Cretaceous
Secondary objective	None specifically stated
Play/Trap Type	Lightly faulted anticline
Reason for failure	Lack of good seals and possibly timing of migration into late structure.

DATA SUMMARY

Palynology:

The original palynological analysis was undertaken by Dettmann, M.E. (1967), "*Palynological Report on Shell Nerita No. 1 Well, 2106-6456 feet*", and is contained in the WCR as Appendix 6.

A second palynological report from BIPM, The Hague (1967), "*Palynological interpretation of Tertiary samples from well Nerita-1, Otway Basin*", is included in the WCR as Appendix 7.

Additional analysis was performed by:
Morgan, R., (1987), "*Review of Palynology of Nerita-1 Torquay Embayment, Bass Basin, Australia*" for Amoco Australia (unpublished).

and Macphail, M.K., (1989). "*Palynological analysis of samples from Nerita 1A Torquay Sub-basin*" for the Shell Company of Australia (unpublished).

Micropalaeontology:

The original micropalaeontological analysis done by the S.D.A. Geological Laboratory, (1967), "*Palaeontological Report Nerita 1 Well*", is an unpublished report included as Appendix 5 in the WCR.

Additional analysis was done by Siesser, W.G., (1979), entitled "*Oligocene-Miocene calcareous nannofossils from the Torquay Basin, Victoria, Australia*", Alcheringa, v. 3(3-4), p159-179.

Cores and cuttings:

Sample Type	Top (mDF)	Base (mDF)	Recovered (m)	Comments / (Core rec. %)
Cores				No conventional cores cut
SWC	421	2025	73 of 90	
Cuttings	191	2042		3 m sample interval

Wireline logging:

Gross logging run intervals are shown in the following summary table. Individual tools' first readings vary depending on position in the string.

Suite	Run	Tool string	Interval (mDF)	Comments
1	1	IES–SP	188–396.3	
2	2	IES–SP	395–708.4	
3	3	IES–SP	981–2035.8	
1	1	BSGRC	188–390	
2	2	BSGRC	395–978	
3	3	BSGRC	987–2031	
2	1	FDC	395–982.7	
3	2	FDC	980.2–2035	
2	1	MLC	608.4–982.6	
3	2	MLC	980.2–2035.7	
1	1	CBL	104.2–395	
2	2	CBL	210.3–980.2	
1	1	CDM	188.1–392.3	
2	2	CDM	395–981.5	
3	3	CDM	981.5–2034.5	
3	1	SNP	980.2–2035.4	

Velocity Survey:

A velocity survey was run over the interval 990.6–2027 mDF. A total of 5 levels were surveyed with records reported to be good. The report can be found in the Nerita-1 WCR, Appendix 8.

Well Tests:

Four FIT/FTT formation tests were carried out and the results were as follows:

Formation test-1 at 1118.6 mDF - mechanical failure
Formation test-2 at 1118.6 mDF - recovered 20 litres of water and 0.2 litres of mud.
Formation test-3 at 1456 mDF - recovered 20 litres of water.
Formation test-4 at 732.7 mDF - in casing, recovered 5 litres of water.

PRIMARY OBJECTIVE

Nerita-1 was the first well drilled in the offshore Torquay Sub-basin. As such, the lithological units described in the predicted section were for simplicity considered as equivalents of the major units in the rest of the Otway Basin. The well was sited on an elongate northeast–southwest trending anticlinal structure where the entire section from the Tertiary to the Early Cretaceous could be tested (Shell Development, Australia, 1974).

SECONDARY OBJECTIVE

None specifically stated in WCR.

STRUCTURE

Nerita-1 was drilled at the crest of a tight monoclinal fold or uplifted fault block northwest side of the Torquay Sub-basin (Fig. 54). The Nerita structure is an elongate northeast–southwest trending anticlinal structure (Shell Development, Australia, 1974). Interpretation of seismic sparker data indicates two anticlinal features are present, with the southern anticline tested by this well. These data also confirm that the anticlinal structure is present in the Early Miocene strata that outcrop on the seabed (Shell Development, Australia, 1974). A slight angular unconformity at seismic horizon B indicates the presence of an initial structure prior to the main deformation in the Early Miocene (Shell Development, Australia, 1974).

SOURCE ROCKS

Source rocks have been sampled from 350 mDF to TD in the well. The entire sequence drilled, including the Otway Group (Eumeralla Formation), is immature for oil (Appendix 1). Good TOC and HI values through the coaly intervals of the EVCM and the Boonah Formation (Fig. 57) indicate gas and oil prone coastal plain sequences similar to that seen in the Bass and Gippsland basins.

See Appendix 1 for analyses extracted from Geoscience Australia's ORGCHEM database.

RESERVOIR

Good to excellent reservoirs, with porosities up to 31% (Fig. 58) are present in the shallower sequences above the Otway Group (Eumeralla Formation) (Fig. 57). Porosity decreases significantly within the volcaniclastic dominated Otway Group (Eumeralla Formation). At some locations near the top Eumeralla Formation unconformity, secondary leaching porosity has resulted in moderate to poor quality reservoir rocks (Fig. 58). A medium to fine-grained, argillaceous, slightly permeable sandstone within the Otway Group (Eumeralla Formation) had good gas shows with up to 18% C_1 recorded. Potential reservoirs are also indicated between 1926 and 1996 mDF from the mud log gas peaks with up to 8% recorded on drilling (Messent et al., 1999). With late structuring at Nerita-1, mechanical deformation of these usually tight rocks may have produced fracture porosity in this interval.

SEAL

The 277 m thick Demons Bluff Formation (Fig. 57) provides the best regionally developed potential seal interval in the sub-basin. It comprises interbedded silty clays and claystones, shales, quartz sand and dolomite streaks. More information and analysis is required before its seal quality can be assessed. Within the underlying Boonah Formation and EVCM, there is the potential for good quality thinner intraformational seals to be developed. The working analog for this is the Latrobe Group siliclastic sequences of the Gippsland Basin where many hydrocarbon trapping horizons are developed in very similar sequences. The main issue of concern here is the lateral continuity of the thin seals over any significant structures.

The Otway Group (Eumeralla Formation) does work as a top and cross-fault seal in the Gippsland and Otway basins. Care should be taken, however, in assuming that all of the formation acts as a seal.

SHOWS

No significant shows were recorded in this well, with only minor mudlog gas shows recorded in the vicinity of the coals and within the Otway Group (Eumeralla Formation)(Shell Development, Australia, 1974). Petrophysical interpretation indicated all sands have water saturation of 100%. However, from looking at the shows in detail, up to 18% gas (C_1 to C_3) was recorded. In the EVCM, the gas shows are generally associated with coaly intervals. In the Otway Group (Eumeralla Formation), the high gas readings are associated with slightly more permeable sandstone intervals. The EVCM gas shows are predominantly associated with coals, except for a tight sandstone over the interval 1262 to1274 mDF which had up to 5% C_1 against a background of around 0.1%. In the Otway Group (Eumeralla Formation), there are several tight sands, each generally <5 m thick, with gas shows up to about 14% total gas. While a significant number of these shows are associated with coals between 1810 to 1829 mDF, a medium to fine grained, argillaceous sandstone with relatively more permeable intervals and no associated coal, has significant gas peaks of up to 18% (C_1 18%, C_2 0.15% and C_3 0.08%). Gas peaks up to 8% are also present in tight sandstones, from about 1926 m to 1996 mDF (Messent et al., 1999).

During the late 1980s to early 1990s, Geoscience Australia (formerly BMR and AGSO) carried out seabed-geochemical sniffer surveys in the Torquay Sub-basin (Bishop et al., 1992). A total of six bottom water hydrocarbon anomalies were detected in the 1992 survey. One of these seeps is located just north of Nerita-1 (near SP 300 on seismic line 12-7-A). Eight vibrocores were retrieved near seep pockmarks. Geochemical analysis from these cores indicates the presence of thermogenic hydrocarbons in the sediments (Bishop et al., 1992).

RESULTS

There is strong evidence that the Nerita structure developed predominantly during the Miocene. There is, however, no mapping data available in the WCR so no comments can be made about the closure. The Demons Bluff Formation looks, from a quick evaluation only, to be a reasonable seal. A more quantitative review is required to confirm this, as the absence of shows at this level casts some doubt as to the seal quality. Intraformational seals within the EVCM are likely to be present, and given that good gas shows occur deeper in this interval, minor amounts of gas may be trapped here. Seismic data show that the deeper part of the section is faulted, increasing the seal risk to preserve a significant hydrocarbon column.

Geochemical data indicates the entire section is immature for oil. Deeper Otway Group (Eumeralla Formation) or other source rocks may be present, with some higher amplitude intervals on the seismic data possibly indicating coaly source rocks. The timing of any generation from these coals, based on regional thermal data and modelling, is likely to be mid Cretaceous and/or Miocene corresponding with maximum Tertiary burial. Both possible generation and migration events predate structuring, introducing a significant timing risk for this structure (Messent et al., 1999).

The thickness of the Tertiary section here is approximately 1400 m, suggesting that a late generation and expulsion phase from any Otway Group (Eumeralla Formation) source may be possible. This needs to be modelled carefully. There are also well documented gas seeps occurring on the sea bed near the coast that provide supporting evidence for the presence of migrating gas in the sub-basin, either through structural disturbance of older traps during recent tectonic events, or from renewed generation arising from the Tertiary loading.

In brief, the reasons for failure here are not clear and require further work. The most likely reason may be that structuring occurred very late after the last significant hydrocarbon charge in the Tertiary. There is also considerable uncertainty about the quality of seals in this section. Clearly defined gas seeps provide good evidence that potentially significant volumes of gas may be moving through the basin.

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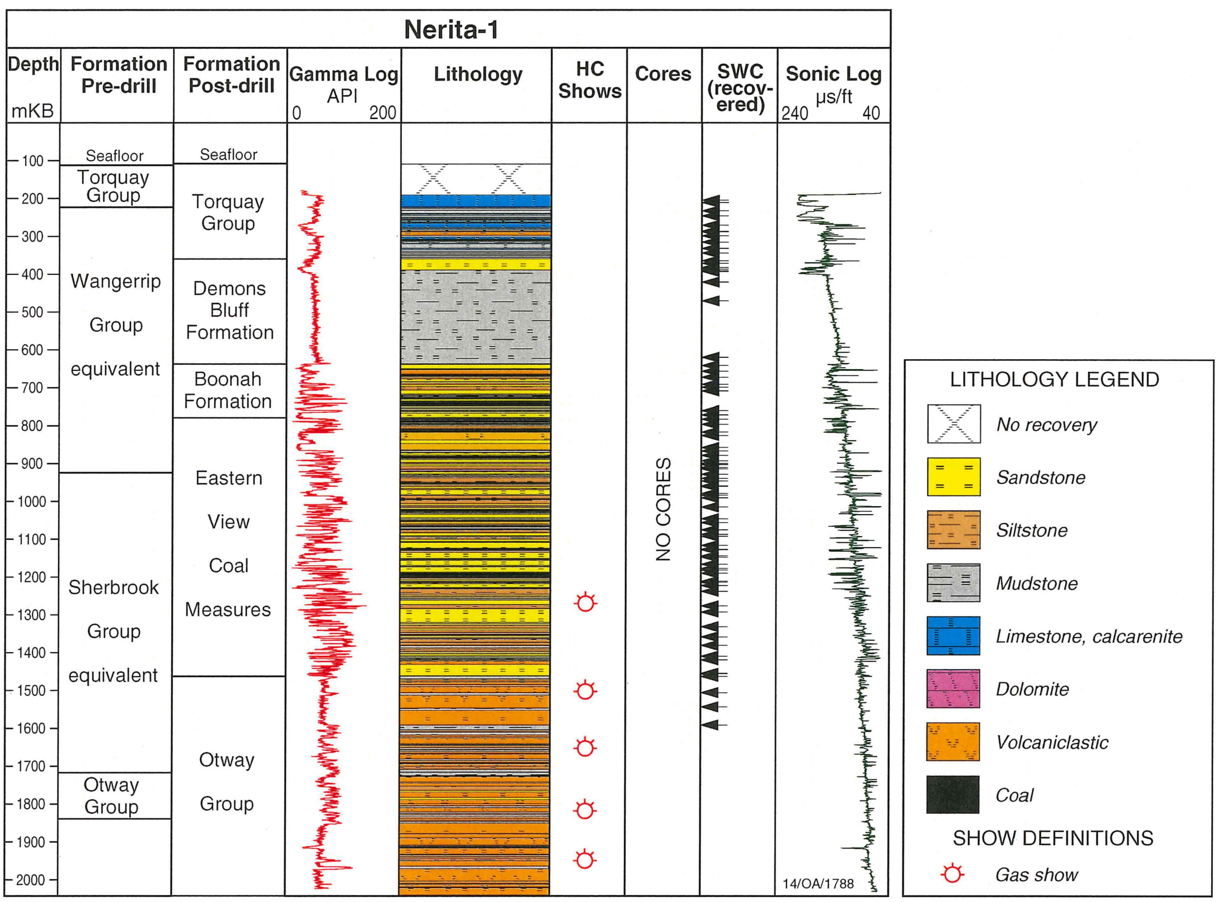


Figure 57. Nerita-1 well composite.

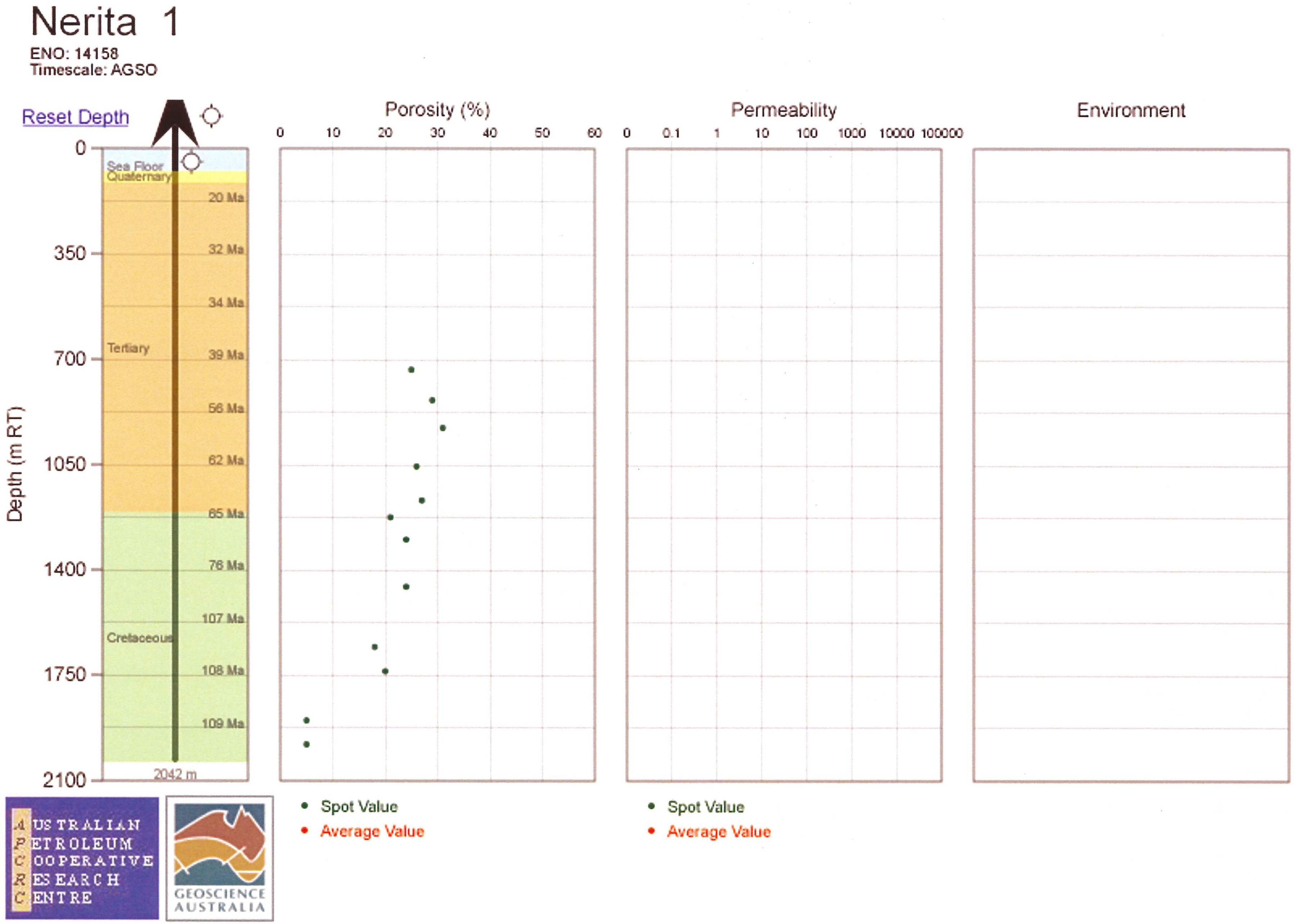


Figure 58. Porosity and permeability measurements recovered from Nerita-1. Source: www.ga.gov.au/oracle/apcrc. Accessed: April, 2003.

4. SUMMARY AND DISCUSSION OF THE RESULTS

4.1 Structural Validity

The main play in the offshore Otway Basin involves sandstones of the Waarre Sandstone overlain by seals from the Belfast Mudstone. Structures are typically faulted, involving syndepositional growth of Belfast Mudstone seals over their control faults. Latest Cretaceous/Early Tertiary faulting often obscures the deeper form of the structure. In many cases the shallower faults do not link up with the older prospect controlling faults. The older wells in the Morum Sub-basin and on the Discovery Bay High area, Argonaut-A1 and Voluta-1, both were invalid tests as a result of poor quality seismic data and little well control. Therefore, one key to successful exploration in this play clearly involves the quality and quantity of seismic data applied to resolve structures at this prospective level. Modern seismic data is vastly superior to that used for these wells.

Structural validity is difficult to establish at either end of the basin (Morum Sub-basin and Prawn Platform) and within the Paaratte and younger formations, where the plays involve thinner seals at Waarre Sandstone level. Firstly, from existing well data it is difficult to determine which units are effective seals. Secondly, there are only limited hydrocarbon field analogs to base models on. Thirdly, it is difficult to map thin seals seismically because of resolution limits and the likely limited continuity of individual seals. For these reasons, the seal quality ratings presented in the summary chart for those areas with thins seals (e.g., Morum Sub-basin and Prawn Platform-Waarre Sandstone and Paaratte Formation levels) have been given a “caution” rating (Table 1).

The timing of the faulting and trap development within the Paaratte and Curdies formations occurred during the latest Cretaceous to Early Tertiary. This may introduce an added risk element depending on the precise timing of any late stage generation and migration. Perhaps simplistically, the faults that are required to provide migration access to deeper sourced hydrocarbons also need to be sealed in any shallower traps. Evidence from seismic data shows that the timing of late movement on faults is variable, and as such it is possible that lower risk traps may be present. From the data available, the intensity of late faulting appears greatest at either end of the basin in the Morum Sub-basin and on the Mussel Platform. This observation is reflected in the timing risk and the migration risk (Table 1).

4.2 Source Maturity and Hydrocarbon Charge

Source

There is a general consensus that the primary source rocks in the offshore part of the basin is the Eumeralla Formation. The general stratigraphy indicates a fairly consistent distribution of coals through this interval, with variability in quality seen in the onshore control wells. Modelling of the offshore Eumeralla Formation source is not well constrained, and is dependent on extrapolation from onshore wells via seismic interpretation. It cannot be assumed that an effective Eumeralla Formation source is universally present in the offshore. The assumption made in this report and reflected in the summary table ratings is that it is effectively uniformly developed. This assumption should be treated with caution. As an example, Conan-1 on the Mussel Platform appears to have all petroleum system elements present, yet it is dry.

The Casterton Formation source rocks, documented and proven to exist onshore, are likely to have also developed in offshore rift grabens. On the Crayfish Platform, Trumpet-1 appears to be a valid structural test of an intra-Pretty Hill Formation four-way dip closure. Neptune-1 also appears to be a valid structural test. With these wells being dry, the source risk for both is shown to be high (Table 1). However, there are probably insufficient well data to conclude that source risk is high over the whole of the Crayfish Platform.

Other sources are possible, the most likely being the Belfast Mudstone where there is some evidence in more restricted and deeper water settings for a viable oil or gas source. This may be the case in the eastern Voluta Trough.

Maturity and timing

Maturity levels for the principal source, the Eumeralla Formation, are fairly well constrained across the basin with sufficient wells and data sets to provide a good indication of current day maturity levels. An accurate understanding of the optimum late loading conditions that restarts generation and expulsion is critical to exploration success, given the unusual thermal history of the basin with the maturation of the Eumeralla Formation ‘turned off’ at the mid Cretaceous in some areas. Duddy (1997) highlights the importance of Late

Cretaceous and, more importantly Tertiary loading, to the generation of a late charge in the basin. Where these conditions are met, for example, in the vicinity of the eastern Voluta Trough, five significant discoveries (Minerva, La Bella, Geographe, Thylacine and Casino fields) in the Waarre Sandstone are recorded.

Migration

Migration from the Eumeralla Formation into the Waarre Sandstone is very direct with no significant intervening seals. For the potential targets above the Belfast Mudstone, there is an increased migration risk. Hydrocarbons need migration routes through the thick Belfast Mudstone to shallower traps. Optimally, fault throws in the prospect drainage areas need to be greater than the Belfast Mudstone thickness for these plays to be successful. Once through the Belfast Mudstone the traps would ideally be four-way closures to work in a 'thin seal setting'. Significant migration risks have been given to those areas where the primary and secondary targets are above a thick Belfast Mudstone and there are no large faults to provide clear migration pathways. This higher migration risk element has been assigned to the eastern Morum Sub-basin, the Discovery Bay High and Mussel Platform. Evidence contradicting this interpretation is the small gas column seen in the basal Paaratte Formation in Minerva-1. Here there are excellent thick working Belfast Mudstone seals present, and relatively minor late Tertiary faulting. This serves to emphasise the need to acknowledge the limits of this type of broad analysis, and the complexity of the actual basin geology.

4.3 Reservoir

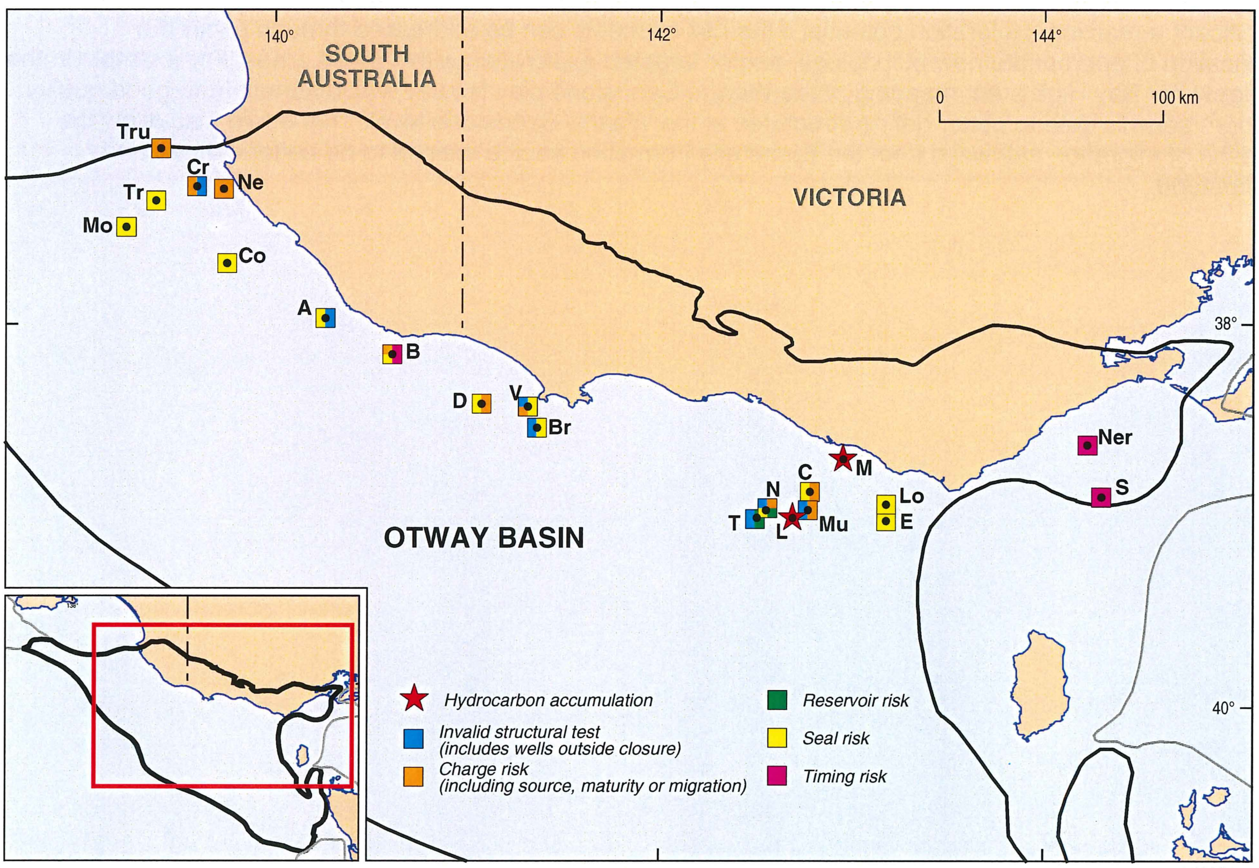
There is considerable variability in reservoir quality within the Waarre Sandstone as a function of depositional facies, provenance, thermal history and depth of burial. Deposition of the Waarre Sandstone was on an irregular and structured surface with localised sediment input points (e.g., through the Shipwreck Trough). A thorough analysis is required before the distribution of sands in the Waarre Sandstone can be predicted with reasonable confidence. In general, if the Waarre Sandstone reservoir sands are buried deeper than 3000 m, then reservoir quality is very poor. Examples of deeply buried, poorly developed reservoirs in the Waarre Sandstone occur in Argonaut-A1, Bridgewater Bay-1 (2% porosity at 4100 m), and Triton-1/ST1. Reservoir preservation risk exists in all deep Waarre Sandstone wells across the Morum Sub-basin, Discovery Bay High and the eastern Voluta Trough (Table 1; Fig. 59).

Shallower targets above the Belfast Mudstone generally have good to excellent reservoir characteristics, which are controlled more by depositional facies than thermally induced diagenetic processes. The issue for exploration here is finding settings where good sands are interbedded with adequately thick seals in a structural setting that has little or no faulting associated with the trap. Traps must also be within a drainage area that provides access through the thick Belfast Mudstone to migrating hydrocarbons from the Eumeralla Formation. With the current offshore well spacing and the variable stratigraphy, it is not possible to accurately map reservoir quality in detail.

4.4 Seal and Trap Integrity

The principal seal, the Belfast Mudstone is generally a thick silty prodelta mudstone. In the wells examined, it is best developed in the Shipwreck Trough/Mussel Platform and Discovery Bay High area where it is thick and log characteristics show a high Gamma Ray and good Neutron-Density separation, i.e., reasonable indicators of seal potential. Importantly, the fields in the Mussel Platform area provide a calibration for these seals. In wells to the west there is a general reduction in the Neutron-Density separation suggesting a reduction in seal quality, probably because most of these wells are located in slightly more proximal positions relative to the delta complexes. Equally good seals are expected to be developed seaward of these western wells. The seal quality rating for the Waarre Sandstone and Paaratte Formation is reduced increasingly to the west, reflecting the general increase of silt in the seals (Table 1; Fig. 59). The Prawn Platform area also has been given a reduced rating based on the more proximal silty claystones seen there.

For the Paaratte and Curdies formations, there are numerous thin potential interbedded seals. These are highly variable; their deltaic setting suggests they are unlikely to be developed over significant areas. The only calibration point in the offshore is the seal above the thin gas column near the base of the Paaratte Formation in Minerva-1. From the limited examination of these seals in this study it is considered very likely that many of these seals are capable of trapping hydrocarbons in the right setting.



A - Argonaut A1
B - Breaksea Reef 1
Br - Bridgewater Bay 1
C - Conan 1
Co - Copa 1
Cr - Crayfish A1
D - Discovery Bay 1
E - Eric the Red 1
L - La Bella 1
Lo - Loch Ard 1
M - Minerva 1
Mo - Morum 1
Mu - Mussel 1
N - Nautilus 1/A1
Ne - Neptune 1
Ner - Nerita 1
S - Snail 1
T - Triton 1
Tr - Troas 1
Tru - Trumpet 1
V - Voluta 1

Figure 59. Ma pshow ingthe geographic spread of well risk elements in the Otw ay Basin.

5 CONCLUSIONS

The primary focus of this report has been a review of key wells in the Otway Basin. The summary integration and distillation analysis of these wells has identified well constrained patterns in the petroleum systems characteristics of the areas in which these wells have been drilled (Table 1; Fig. 59).

With the nearly forty year spread in the vintage of the wells, the real commercial impact of improved technology and concepts can be seen. The first observation here is that if the old wells are removed as invalid tests, the well spacing in this offshore basin is very sparse. The second observation is that all the significant discoveries have been made since 1995. This is clearly a result of the application of high quality seismic acquisition, processing and interpretation, and, arising from better quality data sets, basin models and concepts that have been refined and improved to a commercially relevant level.

This work clearly identifies the Mussel Platform area as having all the required petroleum systems elements in place at the right time to develop commercial hydrocarbon accumulations. In the other areas, there is significant remaining exploration potential if the risk elements can be addressed through either the application of appropriate new technology, and/or targeted exploration within these areas. For example in the Bridgewater Bay High area, mapping of the Waarre Sandstone play fairway would benefit from good quality modern seismic data to better define structures at the Waarre Sandstone level. This would also allow the location of migration pathways from the Eumeralla Formation source interval to be better defined and understood.

6 ACKNOWLEDGEMENTS

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APPENDIX 1—SUMMARY GEOCHEMISTRY PLOTS – CD IN BACKPOCKET

ORGCHEM, Geoscience Australia's Oracle-based geochemical database (www.ga.gov.au/oracle/apcrc), is the source of the bulk Rock Eval pyrolysis and vitrinite reflectance (VR) shown in this Appendix. Sample ages were estimated using age-depth curves generated from Geoscience Australia's STRATDAT Oracle-based biostratigraphic database, and later verified against current well log interpretations. The geochemistry and biostratigraphic data in Geoscience Australia's databases were compiled from WCRs submitted under the Petroleum Submerged Lands Act (PSLA) 1967 and destructive analysis reports.

The open-file geochemistry plots shown in Appendix 1 were captured from the Geoscience Australia ORGCHEM database in April 2003. Please note that Geoscience Australia continues to upgrade and populate these corporate databases as new information is available or becomes open-file. It is therefore recommended that the reader query these on-line databases via the URL, www.ga.gov.au/oracle/apcrc, to insure access to the most recent information.

For contents of Appendix 1 as originally released on CD, see separate PDF.

APPENDIX 2—LOG MNEMONICS

A

AMS	Auxiliary Measurement Sonde

B

BGL	Borehole Geometry Log
BHC	Borehole Compensated Sonic
BHCS	Borehole Compensated Sonic
BSGRC	Borehole Compensated Sonic, Gamma Ray and Sonic

C

CAL	Caliper
CBL	Cement Bond Log
CDL	Compensated Density Log
CDM	Continuous Dipmeter
CNL	Compensated Neutron Log
CSI	Combinable Seismic Imager Tool
CST	Core Sample Taker

D

DIL	Dual Induction Log
DLL	Dual Laterolog
DPR	Dual Propagation Resistivity
DT	Sonic

F

FDC	Compensated Formation Density Log
FMI	Formation Micro-Imager
FMS	Formation Micro Scanner
FPIT	Free Point Indicator Tool

G

GPIT	General Purpose Inclinometry Tool
GR	Gamma Ray
GRAM	Natural Gamma Ray

H

HDT	High Resolution Dipmeter Tool
HP	Pressure (HP Quartz Gauge)

I

IES	Induction Electric Log
ISF	Induction Spherically Focussed

L

LDL	Litho Density Log
LDT	Litho Density Tool
LL7	Resistivity Wireline Log

M

MLC	Micro Log
MLL	Microlaterolog Resistivity
MSFL	Micro Spherical Focused Log

P

PML	Proximity Micro Log

R

RFT	Repeat Formation Tester
RFTB	Repeat Formation Tester

S

SAT	Seismic Acquisition Tool
SDT	Sonic Digital Tool
SGRC	Borehole Compensated Sonic Log - Gamma Ray Caliper
SLS	Sonic Long Spaced
SNP	Sidewall Neutron
SP	Spontaneous Potential

U

USIT cement map	Ultrasonic Imaging Tool

V

VDL	Variable Density Log
VSP	Vertical Seismic Profile

APPENDIX 3—GENERAL ABBREVIATIONS

A

AFTA	Apatite Fission Track Analysis
AGD	Australian Geodetic Datum
AGSO	Australian Geological Survey Organisation
API	Unit of radioactivity defined by the American Petroleum Institute for natural gamma ray logs

B

bcf	Billion cubic feet (billion = one 10^9)
boe	Barrels of oil equivalent

C

cc	Cubic centimetres
CGR	Condensate to gas ratio
Cu.ft	Cubic feet
°C	Degrees celcius

D

D	Darcy
DF	Derrick floor
DOM	Dispersed organic matter
DST	Drill stem test

E

E	East
EFCM	Eumeralla Formation Coal Measures
EVCM	Eastern View Coal Measures

F

FTT	Formation testing tool
FIT	Formation interval test
ft	Feet

G

GA	Geoscience Australia
GIP	Gas in place
GWC	Gas water contact

H

HC	Hydrocarbons
HC/g	Hydrocarbons per gram
HI	Hydrogen index

K

KB	Kelly bushing
km	Kilometre
km^2	Square kilometres

M

m	Metre
mD	Millidarcy
mg	Milligrams
mmboe	Million barrels of oil equivalent
MMcf/d	Millions of cubic feet of gas per day
μs/ft	Microseconds per foot
ms	Milliseconds
m/s	Metres per second
MWE	Mud weight equivalent

O

OI	Oxygen Index

P

PI	Production index
ppg	Pounds per gallon
psi	Pounds per square inch
psi/m	Pounds per square inch per metre
PSLA	Petroleum Submerged Lands Act
PTD	Projected total depth

R

RFT	Repeat formation tester
RT	Rotary table

S

s	Seconds
S	South
SP	Shotpoint
SS	Subsea
stb/MMcf	Stocktank barrels (of condensate) per million cubic feet (of gas)
SWC	Sidewall core

T

TD	Total depth
TOC	Total organic carbon

U

UNO	Unique number

V

VR	Vitrinite reflectance

W

WCR	Well Completion Report

APPENDIX 4—SHOW ABBREVIATIONS

Code	Description	Comment
C1	Condensate Indication	Rich gas and no shows or milky liquid in acetone test
C2	Strong Condensate Indication	Anomalous rich gas and milky liquid in acetone test and no shows
C3	Condensate Show	Condensate flowed on test
C4	Potential Condensate Zone	Condensate show with convincing log anomaly or other indication
C5	Proven Condensate Zone	Sustained condensate flow on test or RFT & log anomaly or pressure data proving an accumulation (no economic implications)
G0	Gas Traces	Trace to high gas reading.
G1	Gas Indication	Anomalously high gas reading
G2	Strong Gas Indication	Anomalously high gas reading and other indication. eg from core logs or shakers
G3	Gas Show	Gas flowed on test
G4	Potential Gas Zone	Gas show with convincing log anomaly or other indication
G5	Proven Gas Zone	Sustained gas flow on test or RFT & log anomaly proving an accumulation (no economic implications)
L0	Oil Traces	Stains of dead oil no fluorescence no cut or was not able to differentiate between oil fluorescence and mineral fluorescence
L1	Oil Indication	Fluorescence or cut
L2	Strong Oil Indication	Fluorescence or cut & other oil indication. eg log anomaly
L3	Oil Show	Oil recovered from core, test, mud.
L4	Potential Oil Zone	Oil show with convincing oil anomaly
L5	Proven Oil Zone	oil flow on test or RFT & log anomaly proving an accumulation (no economic implications)
DHI	Direct Hydrocarbon Indicator - undifferentiated	Undifferentiated DHI reported from seismic.
DHIB	Direct Hydrocarbon Indicator - bright spot	Seismic shows amplitude anomaly over well
DHIC	Direct Hydrocarbon Indicator - chimney	Seismic shows shallow gas indication.
DHIF	Direct Hydrocarbon Indicator - flat spot	Seismic shows flat spot.
NC	No Condensate Show	No condensate show / no condensate show for entire well.
NG	No Gas Show	No gas show for entire well.
NO	No Oil Show	No oil show for entire well.
NR	No Returns	No returns - lost circulation.
NS	No Shows	No show over entire well.
OOO	Out of Order	Equipment out of order.
UHC	Undifferentiated Hydrocarbon Shows	Undifferentiated hydrocarbon shows.

Instructions for the CD-ROM

An audit of selected offshore petroleum exploration wells in the Otway Basin, southeastern Australia: Appendix 1

This CD-ROM contains the above-titled document as geoscienceaustraliarecord2003_21_appendix1.pdf, an appendix to Geoscience Australia Record 2003/21, An audit of selected offshore petroleum exploration wells in the Otway Basin, southeastern Australia.

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