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HYDROCARBON PROSPECTIVITY OF THE WEST BARROW VACANT AREA

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SUMMARY

The West Barrow Vacant Area has been surveyed by a broad reconnaissance grid of seismic surveying as well as detailed and semi-detailed seismic surveying. There has been no seismic surveying in the West Barrow Vacant Area since 1985. Three wells, West Barrow 1A, West Barrow 2 and Robot 1A have been drilled in the Area. West Barrow 1A and 2 encountered hydrocarbon shows but were not tested, and the three wells were plugged and abandoned.

Significant petroleum and gas discoveries surrounding the West Barrow Vacant Area highlight the hydrocarbon potential of the region, which contains reservoir, seal and generative source rocks within the Cretaceous and Jurassic sections. In particular, the Barrow Group sands generally have excellent reservoir potential, and the Mardie Greensand may have intervals with reservoir quality developed in some areas. The Jurassic Dingo Claystone is considered to be the major source of oil and gas so far discovered in the Barrow Sub-basin. Intra-Barrow Group shales and the Muderong Shale provide the most likely seals for the area. Overpressuring in shales below 3000 m has caused drilling difficulties in some wells in the region.

Major targets for exploration in the West Barrow Vacant Area are likely to be structural traps at the top Barrow Group (Flacourt Formation), and modern seismic surveying may define structural or stratigraphic traps within the lower Barrow Group (Malouet Formation). The Dupuy Formation may provide additional deeper objectives. Several structural prospects (West Barrow, Gillian and Rosily) have been mapped, along with a number of smaller leads.

1. INTRODUCTION

The West Barrow Vacant Area comprises 16 blocks in the offshore Carnarvon Basin, located about 45 km north of Onslow and 15 km west of Barrow Island. Water depths range from 75 m in the east to 150 m in the west. The Area lies in the central part of the Barrow Sub-basin, which is part of a northeast-trending rift basin containing more than 10 000 m of Palaeozoic to Cainozoic sediments. The tectonic elements bordering the rift are the Rankin Platform to the northwest and the Peedamullah Shelf on the southeast. The southeastern boundary of the rift is taken to be the Flinders Fault system which swings westwards to form the Long Island Fault system. The Barrow Sub-basin links with the Dampier Sub-basin to the northeast and the Exmouth Sub-basin to the southwest (Fig. 1).

A number of oil fields, including Harriet, Barrow Island, South Pepper, North Herald and Saladin, are located at distances of about 15 to 60 km from northeast to southeast of the West Barrow Vacant Area, and the recent Chinook, Griffin and Scindian discoveries lie approximately 25 km to the southwest of the Area. Oil in these fields is reservoired in the Jurassic Dupuy Sandstone Member, sealed by Jurassic shales, and the Cretaceous Barrow Group and Windalia Sandstone Member, sealed by the Muderong Shale and lower Gearle Siltstone.

Gas fields are also located in the vicinity of the West Barrow Vacant Area. Three deep wells drilled on Barrow Island encountered gas in the Middle Jurassic Biggada Formation, and Spar 1, about 17 km north of the Area discovered gas in the Barrow Group. Table 1 summarises the major hydrocarbon occurrences in the Barrow Sub-basin.

The Barrow Group sands in particular have generally excellent reservoir parameters, and the Mardie Greensand may have intervals with reservoir quality developed in some areas. The Jurassic Dingo Claystone is considered to be the major source of the oil and gas discovered in the Barrow Sub-basin.

The West Barrow Vacant Area was originally part of exploration permit WA-25-P granted to West Australian Petroleum Pty Ltd (WAPET) in 1968. Although early WAPET seismic data outlined a number of anticlinal features in and adjacent to what is now the West Barrow Vacant Area, it was included as part of WAPET's WA-25-P relinquishment package.

In March 1977, a consortium led by Offshore Oil NL took up the West Barrow Vacant Area as WA-64-P. During its first period of operatorship, Offshore Oil conducted two seismic surveys, Southwest Barrow Marine Survey of

386 km in 1979 and North Rosily Marine Survey of 529 km in 1980. In addition, Offshore Oil drilled West Barrow 1/1A in 1982. During the first renewal period of WA-64-P, BHP Petroleum (BHPP) took over as Operator and drilled West Barrow 2, and followed up with the B85A Marine Survey (545.8 km). In 1986, Petroz NL took over as operator, with BP Petroleum Development Ltd (BP) farming in and drilling Robot 1A in 1988. The operator surrendered the permit, effective from 6 June 1990.

The West Barrow Vacant Area has been surveyed with a broad reconnaissance grid of seismic surveying prior to 1979, as well as semi-detailed and detailed surveys in 1979, 1980 and 1985. The quality of data recorded to 1979 is generally poor to fair, whereas the quality of data recorded in 1980 and 1985 is fair to good. Line spacings up to 1980 vary from 1.5 km to 8.0 km. The grid spacings of the 1985 survey are as close as 1.0 km x 2.0 km. There has been no seismic surveying in the West Barrow Vacant Area since 1985.

Three wells have been drilled within the West Barrow Vacant Area. In 1982, West Barrow 1A was drilled to a total depth of 3520 m KB, and encountered significant hydrocarbon shows within the Barrow Group. A 110 m hydrocarbon column was interpreted from wireline logs, but mechanical problems prevented the well from being tested, and it was suspended. In 1985, West Barrow 2, located about 1.5 km east of West Barrow 1A, was drilled to a total depth of 3437 m KB. Although there were minor hydrocarbon shows in the Barrow Group, and wireline log interpretation indicates the possible presence of residual hydrocarbons, the well was not tested, and was plugged and abandoned. In 1988, Robot 1A was drilled to a total depth of 3459 m KB, to test a stratigraphic play of stacked foreset sands within the Barrow Group. No hydrocarbons were encountered in the well and it was plugged and abandoned as a dry hole.

Table 1. Significant hydrocarbon discoveries in the Barrow Sub-basin

Field/well	Oil/gas/cond	Main reservoirs	Estimated remaining reserves (proved/probable) Oil 10^6 Kl	Gas $10^9 \cdot m^3$	Cond 10^6 Kl
Barrow Island	Oil/gas/cond	Windalia, Muderong, Mardie, Malouet, Dupuy	5.175	1.614	0.016
Barrow Island	(deep gas)	Biggada		8.46 (in place)	
Harriet	Oil/gas	Flag	2.177	0.429	-
Campbell	Gas/cond	Flag	-	0.056	0.122
Rosette	Oil/gas/cond	Flag	0.030	0.604	0.081
Bambra	Oil/gas/cond	Flag	0.040	0.260	0.012
South Pepper	Oil/gas	Flacourt, Malouet	0.416	0.242	-
North Herald	Oil/gas	Flacourt	0.260	0.019	-
Chervil	Oil/gas	Flacourt	0.293	0.117	-
Saladin	Oil/gas	Flacourt	4.462	0.350	-
Cowle	Oil/gas	Flacourt	4.0 (est)	-	-
Roller	Oil/gas	Flacourt	0.6 (est)	-	-
Tubridgi	Gas	Birdrong	2.140	-	-
West Tryal Rocks	Gas	Mungaroo	-	108	-
Gorgon	Gas	Mungaroo	-	333	-
Spar	Gas/cond	Flacourt	-	11.74	-
Hilda-1A	Oil/gas (FIT)	Mardie	N/A	-	-
Chinook-1	Oil/gas	Barrow	8.0 (est)	-	-
Griffin-1	Oil/gas	Barrow	8.0 (est)	-	-
Scindian-1	Oil/gas	Barrow	N/A	-	-

(After McClure & others 1988; WA Department of Mines 1990)

2. REGIONAL GEOLOGY

2.1 Structure

2.1.1 General Tectonic Setting

The West Barrow Vacant Area is located is in the central part of the Barrow Sub-basin of the northern Carnarvon Basin (Fig. 1). The evolution of the northern Carnarvon Basin may be broadly divided into three phases: a relatively stable intra-cratonic phase up to the Mesozoic continental rifting of 'greater India' away from the Australian continental mass, events associated with the rifting, and post-breakup subsidence (Falvey & Mutter 1981).

During the Late Palaeozoic the region appears to have been relatively tectonically stable. In the Late Carboniferous there was tectonism associated with plate movements and the inception of the Westralian Super-basin on the Australian northwestern margin (Veevers 1988). A thick sheet of Triassic (and possibly) Permian sediments were deposited across the intra-cratonic downwarp of the northern Carnarvon Basin.

Primary rifting during the separation of 'greater India' from the North West Shelf began in the Early Jurassic. The rift ultimately accommodating continental separation occurred west of the Exmouth Plateau. The main northeast-trending rift of the Barrow, Dampier and Exmouth Sub-basins developed as a secondary, parallel, rift which became the focus of thick Jurassic sedimentation. The onset of sea floor spreading in the latest Jurassic to Early Cretaceous. resulted in movement and elevation along the line of the Cape Range Fracture Zone on the southwestern margin of the Exmouth Plateau and Barrow-Dampier rift, which sourced a northeasterly prograding deltaic unit (Barber 1982).

Erosion and further spreading probably removed the sediment source and by the Late Neocomian the northern Carnarvon Basin became a mature, continental margin sag open to marine sedimentation on which the primary control appears to have been sea level movements. Some minor, but significant, tectonism occurred in the Late Cretaceous, including wrench movements. A period of Middle Miocene tectonism is associated with the collision of the Australian and Eurasian plates.

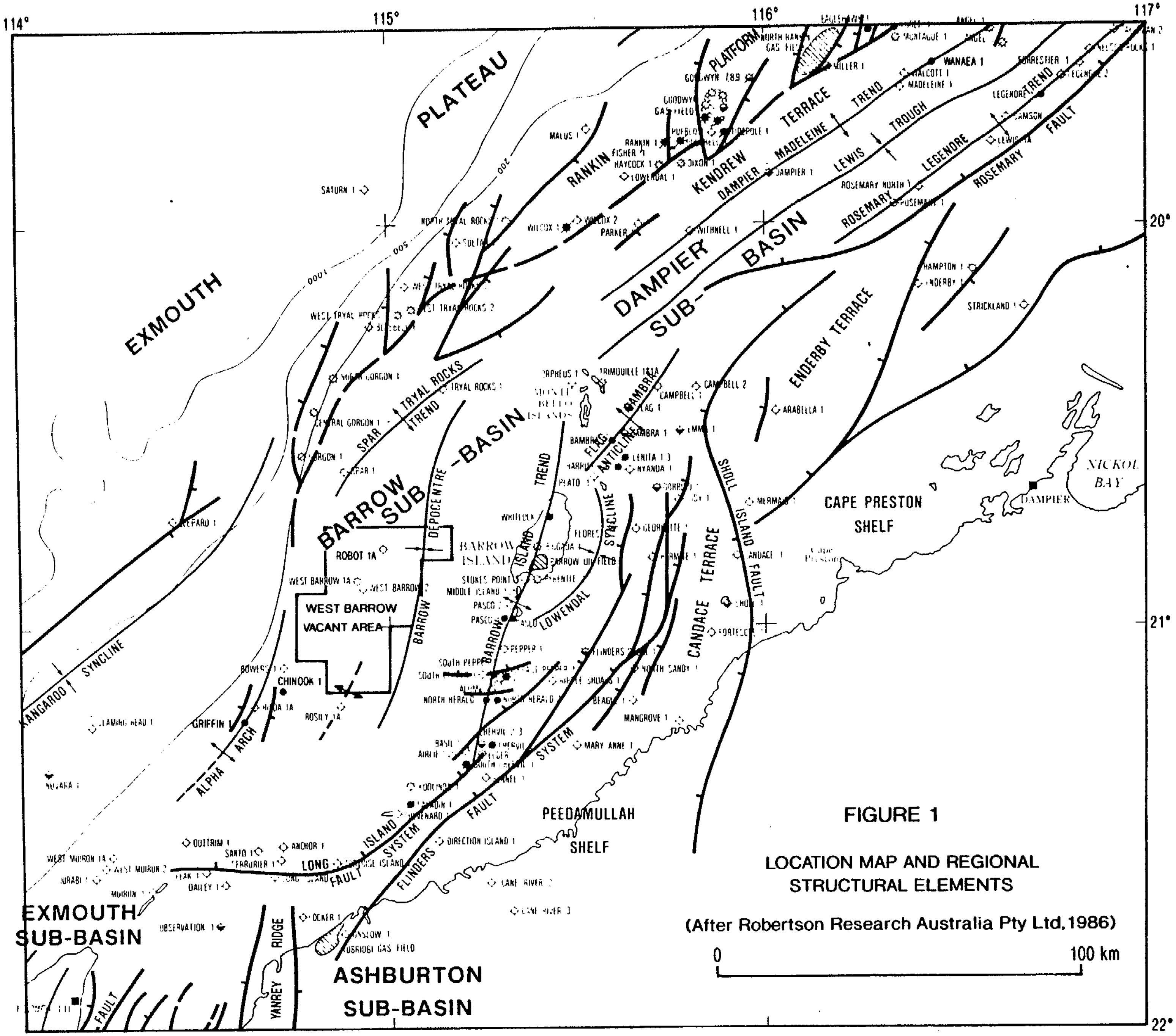


FIGURE 1

LOCATION MAP AND REGIONAL STRUCTURAL ELEMENTS

(After Robertson Research Australia Pty Ltd, 1986)

2.1.2 Barrow Sub-basin

The Barrow Sub-basin (Fig. 1; Plate 1) is a feature controlled by northeast-trending faults which developed during the Jurassic rifting phase, and in part by more northerly-trending faults of earlier tectonic phases. These structural trends are particularly evident on the platforms bounding the main Jurassic rift.

2.1.2.1. STRUCTURAL ELEMENTS

The Barrow Sub-basin has much in common with the co-eval Dampier Sub-basin to its northeast and some authors refer to the Barrow-Dampier Sub-basin, but Hocking & others (1987) consider that the sub-basins are structurally differentiated by the Cape Preston Arch, an extension of the Sholl Island Fault System (Plate 1). The southeastern flank of the sub-basin is formed by the Peedamullah Shelf and Candace Terrace - these are bounded to the east by the Sholl Island Fault System, and basinwards by the Flinders Fault System. The Flinders Fault System is a series of en-echelon arcuate faults, some of which are basement-controlled, others of which sole out listrically (Parry & Smith 1988). The Rankin Platform forms the northwestern flank of the sub-basin. It comprises a series of fault blocks tilted away from the rift system. The southwestern margin of the Barrow Sub-basin at its junction with the co-eval Exmouth Sub-basin is coincident with the line of the Long Island Fault System (Parry & Smith 1988). The two main anticlinal trends within the sub-basin are the Barrow Island Trend to the east and the Spar-Tryal Rocks Trend to the west (Kopsen & McGann 1985).

2.1.2.2 STRUCTURAL EVOLUTION

Formation of the Barrow Sub-basin occurred with the rifting that started in the Early Jurassic (Pliensbachian) and culminated in the Middle Jurassic (Callovian). Kopsen & McGann (1985) conclude that there was up to 2 000 m of relative uplift along the rift margins. Sedimentologically, these events are reflected by the regional 'Rift Onset' and 'Main' - or 'Breakup' - unconformities (Barber 1982).

Movement continued intermittently on rift-bounding faults long after the rift had aborted (Parry & Smith 1988). The northeast-trending rift margin faults and earlier more north-trending faults bound triangular horsts along the edge of the Rankin Platform, some of which host large gas-condensate accumulations. Southwest of, and possibly extending into the westernmost part of the West Barrow Vacant Area, the Alpha Arch is an extension of the Rankin Platform buried in the Late Jurassic to Early Cretaceous. Movement probably continued intermittently on some of the faults developed there during rifting, and together with drape may have contributed to the formation of traps over the Alpha Arch, such as at Bowers and Hilda. The recent discoveries at Chinook, Griffin and Scindian may also be in traps originating in this way. It is possible that other underlying horsts and grabens in similar orientation to the Alpha Arch and Rankin Platform may exert some subtle control on potential trap development across the Barrow Sub-basin.

An important set of faults in the Barrow Sub-basin trends east-west. These faults tend to die out rapidly in the strike direction and are sigmoidal in cross-section. They may have complex histories, and together with some similar northeast-trending faults are interpreted to be mainly the result of right-lateral wrenching; some of these movements may have occurred as reactivation along previous fractures. One or other of these sets of faults is associated with petroleum accumulations such as at Barrow Island, South Pepper, Harriet and Saladin, and could be a factor in most fields with fault-associated traps in the sub-basin. This period of faulting appears to have commenced in the Late Neocomian, with the strongest and final phase occurring in the Turonian. (Kopsen & McGann 1985; Williams & Poynton 1985; Osborne & Howell 1987; Parry & Smith 1988; Tait & others 1989).

The main anticlinal feature of the sub-basin, the Barrow Island anticline, is thought to have originated in the Neocomian and shows growth through the Late Cretaceous and Cainozoic (Thomas & Smith 1976; Kopsen & McGann 1985). Other anticlines may be associated with the various periods of earth movements in the sub-basin, and with drape of sediments over horst blocks, erosional features or mounded sediments such as are present in the Lower Cretaceous Malouet Formation.

Further wrench faulting during Miocene earth movements may have reactivated as well as initiated faults, and uplifted the Spar-Tryal Rocks and Barrow Island anticlinal trends (Kopsen & McGann 1985; Forrest & Horstman 1986).

Faults with small throws developed at the top of the Barrow Group in the West Barrow Vacant Area may be related to adjustments of the main sediment pile over deeper-seated Triassic to Lower Jurassic fault blocks.

2.2 Stratigraphy

Sediments of the northern Carnarvon Basin, and the Barrow Sub-basin in particular, are described in detail in Hocking & others (1987) and are also described in Thomas & Smith (1976), Kopsen & McGann (1985), Parry & Smith (1988), Hocking (1988) and Woodside Offshore Petroleum (1988). The following is a summary based largely on these descriptions; other sources are noted in the text. The stratigraphy of the Barrow Sub-basin is illustrated in Figure 2.

The oldest rocks penetrated in the northern Carnarvon Basin are of Devonian and Carboniferous age. In the Barrow Sub-basin the oldest sediments penetrated are on its southeastern flank. Bentley (1988) considers that limestones drilled on the Candace Terrace can be correlated with the Lower Carboniferous Moogooree Limestone of the southern Carnarvon Basin and that sediments assignable to the overlying Lower Carboniferous Quail Formation occur in wells on the Candace Terrace and Peedamullah Shelf.

On the Peedamullah Shelf, Carboniferous to Permian sandstones and shales are age-equivalents of the glacially-derived Lyons Group of the southern Carnarvon Basin (Delfos & Dedman 1988). The Permian Byro and Kennedy Groups comprise shales, siltstones and sandstones deposited in shoreface to marine shelf environments, which may have been affected by local tectonism. Some of the sandstones are of reservoir quality and shales may have source and seal potential.

The uppermost Permian Chinty Formation is known from the Peedamullah Shelf and Candace Terrace, and represents the earliest part of a marine transgression. It is predominantly a marine shelf sandstone unit with minor siltstone, shale and limestone, and has good reservoir characteristics. Where seen, its lower boundary is unconformable on older units and it underlies the Locker Shale conformably or disconformably.

The mainly Lower to Middle Triassic Locker Shale comprises predominantly dark grey siltstone and shale with minor sandstone interbeds and the carbonate Cunaloo Member near its base. It was deposited under marine conditions. The unit has only been penetrated along the eastern margin of the basin where it is up to 1000 m thick, but is interpreted from seismic to extend westwards under the Exmouth Plateau. It has hydrocarbon - including oil - source potential, and has sealing capacity for underlying units. The Locker Shale grades upwards into the Mungaroo Formation which is also a unit of regional extent and is at least 1247 m thick on the Rankin Platform. The Mungaroo Formation comprises a marginal marine to fluvial sequence of interbedded sandstones and shales which include the reservoirs of major hydrocarbon accumulations along the Rankin Platform. The coarse clastics were deposited in braided channel to fluvio-estuarine environments while finer grained units and coals are indicative of marginal marine and floodplain conditions. Reservoir characteristics in the sandstones are moderate to good, although generally better in the more westerly areas than along the Peedamullah Shelf where sandstones may be less mature being more proximal to their source areas. The shales may act as intraformational seals and some may have hydrocarbon source potential.

The Mungaroo Formation is the oldest unit drilled in the immediate vicinity of the West Barrow Vacant Area. It was penetrated in Bowers 1, 4 km southwest of the Area in a horst block on the eastern flank of the Alpha Arch, and may correspond to events interpreted on seismic line B85A-202 in the southwestern corner of the Area at depths greater than 3 km (Plate 7).

The Brigadier Formation was first described from the Dampier Sub-basin but is interpreted to be present on the eastern flank of the Barrow Sub-basin and in the Exmouth Sub-basin. It comprises thinly interbedded sandstones, shales and siltstones deposited in paralic to marginal marine environments of Late Triassic to Early Jurassic age. It is conformable with the Mungaroo Formation and resulted from the drowning of that formation. Some of the shales have been described as organically-rich and may be source rocks. The North Rankin Formation is a predominantly sandstone Lower Jurassic regressive unit conformably overlying the Brigadier Formation in the Dampier Sub-basin and which may extend into the Barrow Sub-basin.

Several of the stratigraphic units described above, particularly the Locker Shale and Mungaroo Formation were widely deposited across the northern Carnarvon Basin. The effects of continental rifting in the Early Jurassic resulted in the differentiation of the Exmouth, Barrow and Dampier Sub-basins and other structural provinces. Within the sub-basins the Early Jurassic rift-onset unconformity and Middle Jurassic 'breakup' or 'Main' unconformity are significant except towards the central parts/ depocentres where sediments may have been deposited conformably through these timespans (Hocking 1988; Barber 1982).

In the Barrow Sub-basin the name 'Dingo Claystone' was long used for a thick pile of fine grained sediments deposited through most of the Jurassic. This has now been subdivided formally by Cockbain & Hocking

(1989) and the name Dingo Claystone reserved for the youngest part of the sequence.

The 'Dingo Claystone' in the older, wider sense is a thick (up to 5500 m) unit of claystones and siltstones ranging from shallow marine to marine, moderately organic-rich in places, and grading laterally into other facies defined as separate rock units. It is significant in relation to the West Barrow Vacant Area for its hydrocarbon source potential. It is overpressured in parts of the Barrow Sub-basin.

The Murat Siltstone is the lowest part of the former 'Dingo Claystone'. It is a Lower Jurassic unit of argillaceous siltstones and shales with minor sandstones, and a basal limestone unit in some areas. It is a more basinal equivalent to the North Rankin Formation, also to the sandy Learmonth Formation of the Exmouth Sub-basin, underlying the rift-onset unconformity. The Athol Formation is the middle part of the greater 'Dingo Claystone'. It is late Early to Middle Jurassic in age, bounded by the rift-onset and 'breakup' unconformities except possibly in the deepest parts of the sub-basin, of similar lithologies to the Murat Siltstone. Lateral equivalents include the sandy Legendre Formation in the Dampier Sub-basin. The Upper Jurassic Dingo Claystone, as the name is now confined, was deposited over the Barrow Sub-basin excepting the marginal platforms. The unit comprises shelf to deeper marine claystones and siltstones deposited in the later stages of the Barrow-Dampier rift system. The Biggada Formation is a series of sandstones interbedded with shales that occurs at the base of the Dingo Claystone and is interpreted as submarine fan deposits derived from the Peedamullah Shelf. The Biggada Formation may extend westwards under the West Barrow Vacant Area, but may be at too great a depth to be an exploration objective. It is a gas reservoir under Barrow Island (McClure & others 1988). Other sandy units co-eval with the Dingo Claystone are the Dupuy Formation and, in the Dampier Sub-basin, the Angel Formation.

The Dupuy Formation was described in detail by Tait (1985). It conformably underlies the Barrow Group. It is a Late Jurassic unit comprising predominantly very fine to medium grained sandstones. The unit is marine and was deposited as series of turbidite and debris flows on a shallow slope. It was derived from the eastern flank of the Barrow Sub-basin and is interpreted to occupy much of the eastern part of the sub-basin, shaling out westwards possibly with equivalents derived from the western margins. The thickest section penetrated is 750 m. The Dupuy Formation is present under Barrow Island where it hosts petroleum accumulations, and may extend under at least the eastern part of the West Barrow Vacant Area.

In the Early Cretaceous the Barrow Group delta prograded northwards across much of the Barrow Sub-basin and part of the Exmouth Plateau. The unit is a major reservoir objective in the Barrow Sub-basin, and contains intraformational seals and underlies a regional seal. It is seen as the prime objective in the West Barrow Vacant Area, and was the primary objective for all three wells drilled to date in the Area.

The Barrow Group was sourced mainly from the south, but sediment input continued from along the eastern flank of the sub-basin. It is Late Tithonian to Valanginian in age. The unit has been the subject of considerable discussion and recent papers by Tait (1985), Williams & Poynton (1985), Tait & Smith (1987) and Eriyagama & others (1988) cover the history and current concepts of Barrow Group deposition. Over most of its extent the Barrow Group can be mapped as the Malouet Formation and the overlying Flacourt Formation. The Malouet Formation represents the bottomset or distal pro-delta units and the Flacourt Formation the topset and foreset or delta plain to proximal pro-delta sediments of the delta system. Each formation comprises an overall upwards coarsening sequence of sandstones, siltstones and shales. The Barrow Group is over 1000 m thick in the central part of the Barrow Sub-Basin.

The Malouet Formation is interpreted as submarine fan sediments deposited at or near the base of the prodelta slope and on the basinal plain, with the deep water claystones and turbidite sandstones of the lower part of the unit representing the more distal areas of the fans. The upper part of the Malouet Formation consists of coarser mass-flow sandstones and minor interbedded siltstones and shales of the more proximal parts of the fans. These lower and upper subdivisions correspond approximately to Units D and C of Williams & Poynton (1985).

In the Flacourt Formation the sand-rich topsets are fine to very coarse grained with minor shales and siltstones deposited in fluvial to shallow marine environments, while the lower part of the formation comprises shales, siltstones and poorly sorted sandstones of the delta foresets, and may also have preserved feeder channels for some of the Malouet Formation fan deposits. These lower and upper divisions correspond to Units B and A of Williams & Poynton (1985).

The Flacourt and Malouet Formations are generally represented seismically by broadly sigmoidal reflectors, the Malouet reflectors being mainly flat, subparallel, and with mounded and channelled features; the Flacourt is generally represented by subparallel topsets and sloping foresets. Tait (1985) interpreted that the rapidity of delta progradation resulted in a given thickness of delta top sediments being represented by a thicker interval of foresets, thus several seismic foresets may equal one seismic topset (Fige. 3.2-3.7).

The last foreset of the Barrow Group delta trends approximately west-northwest across the sub-basin under the northern part of Barrow Island and just north of the West Barrow Vacant Area (Tait, 1985).

The Flag Formation is a sequence of mainly medium grained, poorly to moderately sorted massive sandstones less than 300 m thick mainly developed to the north of Barrow Island. It is generally agreed that the unit comprises mainly sands deposited as fans in the prodelta of the Barrow Group delta (as is the Malouet Formation), although much of the sediment appears to have been sourced from the Peedamullah Shelf/Candace Terrace. Osborne & Howell (1987) considered the Flag 'Sandstone' overlies 'Lower Barrow Group' sandstones and shales and that together these are equivalent to the Malouet Formation. Cockbain & Hocking (1989) formalised the Flag as a formation and considered it is conformable on and interfingers with the Malouet Formation and interfingers with and overlies the Flacourt Formation. Parry & Smith (1988) assigned the Flag Formation at least in the Harriet field to the Malouet Formation. It appears that the unit is mainly an equivalent of the upper part of the Malouet Formation.

North beyond the limits of the Barrow Group delta, marine sediments - predominantly shales - deposited synchronously with the delta sediments are referred to as the Barrow Group (Vincent & Tilbury 1988), the Muderong Shale (Forrest & Horstman 1986) and, better, as 'Unnamed Shales' by Hocking & others (1987).

Barrow Group delta formation ceased in the Valanginian probably due to sediment starvation subsequent to continental breakup south of the Exmouth Plateau (Tait 1985).

A basinwide transgression occurred in the Late Neocomian, probably resulting from a combination of basin subsidence and eustatic sea level rise (Hocking & others 1988). The Muderong Shale was deposited over the Barrow Sub-basin as a regional seal, with sandy units at its base.

The Birdrong Sandstone comprises coastal coarse clastics formed along the eastern margins of the Exmouth, Barrow and Dampier Sub-basins in the early stages of the transgression. The Mardie Greensand is a more widespread unit. It comprises up to 60 m glauconitic silty sandstones and shales which are in part sublittoral to outer shelf partial equivalents and, in part, younger than the Birdrong Sandstone. Hocking & others (1988) discriminate two facies in the Mardie Greensand. Campbell & others (1984) also distinguished a fine grained sandstone Tunney Member at and near the base of the Muderong Shale on Barrow Island, with sandstones mineralogically intermediate between those of the Barrow Group and Mardie Greensand Member.

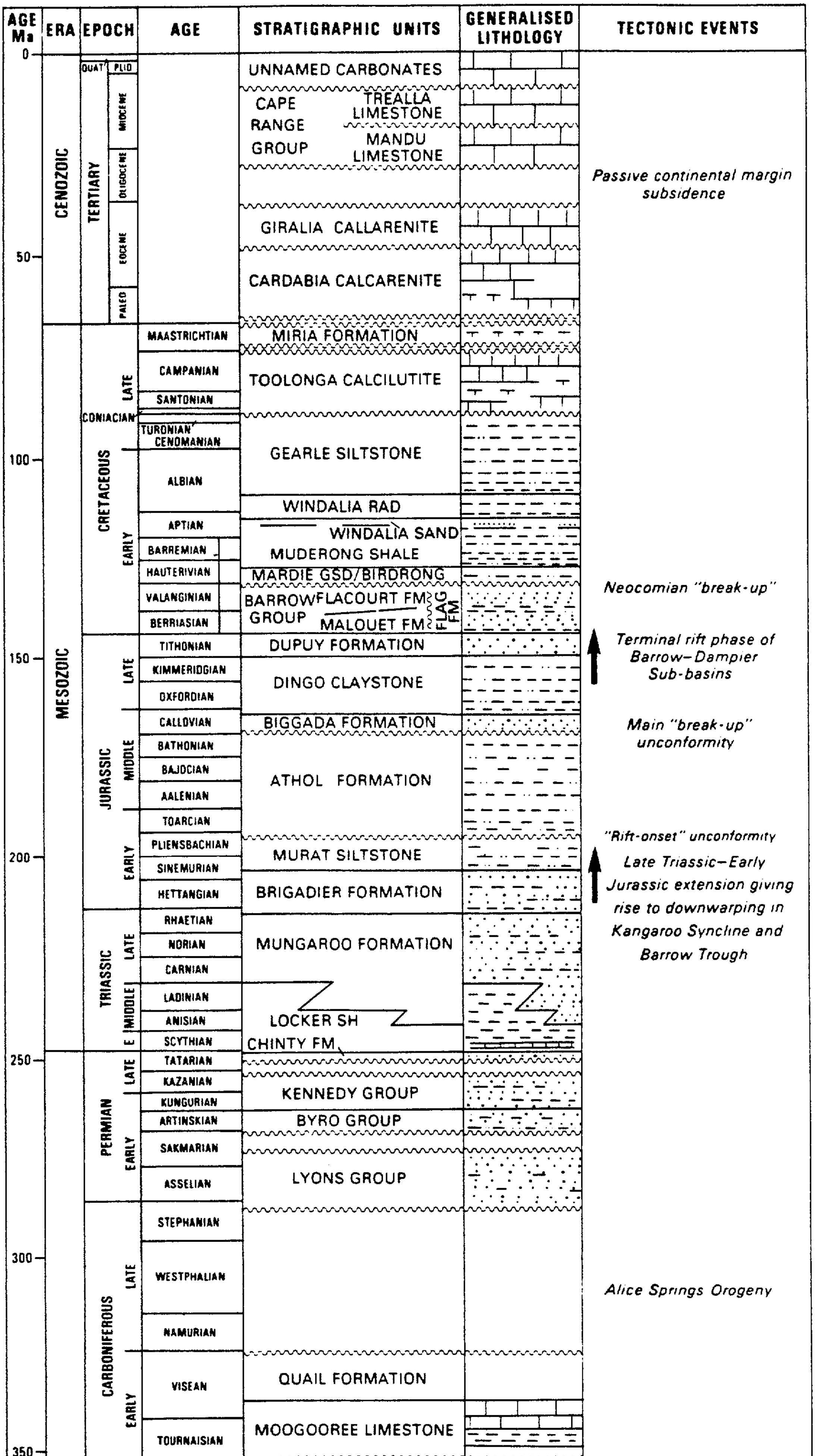
The most widespread lower unit of the transgression is the Muderong Shale. Its base is diachronous from Late Valanginian to Aptian (Wiseman 1979). The Muderong Shale consists of marine glauconitic argillaceous siltstones and shales, with thin carbonate beds. It thickens basinwards with a marked increase north of the last foreset of the Barrow Group where it reaches a thickness of over 900 m. The Windalia Sand Member occurs at the top of the Muderong Shale. It is an argillaceous, glauconitic, very fine to fine grained sandstone developed locally in the basin due to wave-winnowing of Muderong Shale sediments on topographically elevated submarine areas. It is best known from Barrow Island (where it is the major oil reservoir) and along the Peedamullah Shelf. It is up to 40 m thick on Barrow Island where it is divided by a 5 m thick shale bed (Campbell & others 1984). The Muderong Shale acts as a regional seal to underlying sediments and in parts is a potential source rock.

The Windalia Radiolarite is a basinwide siltstone and shale unit marked by the presence of significant numbers of radiolaria. It is up to 70 m thick, and was deposited in shallow to open marine environments. Bradshaw & others (1988) take the deposition of these pelagic sediments to represent the development of a mature ocean phase as the present day continental margin began to develop. The Windalia Radiolarite is an Upper Aptian to Albian unit, interpreted as conformable between the Muderong Shale and overlying Gearle Siltstone, although the lower boundary is unconformable to the north in the Dampier Sub-basin.

The Gearle Siltstone was deposited as marine shelf siltstones and shales with younger parts of the unit deposited in shelf edge to slope conditions. It comprises mainly argillaceous siltstones and shales, and with radiolarian and thin nodular carbonate layers. An upper sub-unit may be distinguished as more glauconitic and calcareous than the lower part. The Gearle Siltstone is of Albian to Turonian age, and is up to 350 m thick. The Haycock Marl is a more calcareous lateral equivalent in the Dampier Sub-basin (Hocking & others 1987; Parry & Smith 1988).

The Toolonga Calcilutite disconformably overlies the Gearle Siltstone. Its deposition marks the changeover from predominantly terrigenous to predominantly carbonate sedimentation in the basin. It is a calcareous pelagic deposit comprising glauconitic calcilutite, often characterised by Inoceramus fragments. Its age is Coniacian to Maastrichtian, and has a maximum thickness of over 600 m. The Withnell Formation is a glauconitic claystone partial equivalent of the Toolonga Calcilutite in the Dampier Sub-basin and the Korojon Calcarenite a shallow water equivalent in the Exmouth Sub-Basin. The Toolonga Calcilutite is disconformably overlain by the Miria Formation, a marl and argillaceous calcilutite up to 100 m thick of Maastrichtian age, deposited in a marine shelf environment.

The northern Carnarvon Basin continued as an open shelf through the Cainozoic, with several transgressions and regressions creating hiatuses in the deposition of a thick wedge of predominantly carbonate marine sediments. In the Barrow Sub-basin, the Palaeocene to Lower Eocene Cardabia Calcarenite is a calcilutite to calcarenite unit over 100 m thick. It is bounded by disconformities. It is overlain by the Giralia Calcarenite, of Middle to Late Eocene age, which comprises calcarenites and calcisiltites up to 400 m thick. This is overlain unconformably by the Cape Range Group, a wedge of carbonate sediments which reaches thicknesses of up to 1 km and was deposited in the Late Oligocene to Middle Miocene. It consists of two units, the lower of which is the Mandu Limestone. In the offshore Barrow Sub-basin the Mandu Limestone is made up of marls, chalks and calcarenites, and may be lithlogically difficult to distinguish from the upper unit, the Trealla Limestone. Carbonate deposition continued from the Late Miocene to Recent.



(after Kopsen and McGann, 1985 and Barber, 1988)

23 OA 572

Figure 2 Generalised stratigraphy of Barrow Sub-basin

3. SEISMIC INTERPRETATION

3.1 Seismic control

Prior to 1979, the West Barrow Vacant Area was surveyed with various vintages of regional seismic by WAPET. Quality of this seismic data is only fair, but gross anticlinal features were mapped in the Area as early as 1972. The three most recent seismic surveys, Southwest Barrow in 1979, North Rosily in 1980 (both by Offshore Oil NL) and B85A in 1985 by BHPP, provide fair to good data quality with a grid density ranging from 2 km x 5 km to 1 km x 2 km over most of the Area. There has been no seismic surveying over the Area since 1985. Plate 2 is a shotpoint location and water depth map for the West Barrow Vacant Area.

Seismic control from the three most recent surveys was used to compile a structure map (in two-way time) at near top Neocomian Barrow Group (Plate 3). This map shows essentially uniform regional dip to the west and northwest, with little or no faulting at Barrow Group level. Several prospects and a number of smaller, potential four-way dip closures were mapped. Modern detailed seismic surveying would be required to confidently prove up these leads. Fifteen key seismic lines over the mapped prospects and leads (Fig. 3.1; Plates 4-18), and six cross-sections illustrating the seismic stratigraphy of the West Barrow Vacant Area (Figs. 3.2-3.7) are included in this report. Four horizons were mapped and have been shown on the fifteen key seismic lines as follows:

3.1.1 Base Tertiary carbonates or top Cretaceous

This horizon corresponds to the base of a thick Recent to Tertiary carbonate sequence, and the top of a thick sequence of marine siltstones and shales belonging to the Upper Cretaceous Gearle Siltstone.

3.1.2 Top Windalia Radiolarite

A high amplitude continuous reflector corresponding to the Windalia Radiolarite which overlies the Cretaceous Muderong shale.

3.1.3 Near top Barrow Group

This horizon corresponds to the major change in acoustic impedance that occurs at or near the very top of the Neocomian Barrow Group sands.

3.1.4 Top Malouet Formation

This horizon corresponds to the sands at the top of the Malouet Formation at the location of Barrow 1A. From here, this reflecting horizon moves up the sequence to the southwest and finally pinches out against the topset sands of the top Barrow Group to the north of the Rosily structure.

3.2 Seismic stratigraphy

The main target for oil exploration in the West Barrow Vacant Area is the Neocomian Barrow Group sequence, which was deposited by a northeastwards prograding delta complex (Tait 1985). On seismic sections, the sequence can be divided into three major units:

Topsets - Seismic character is generally of low to moderate amplitude, parallel to divergent northwards. The sequence is predominantly sandstone with thin siltstone and shale interbeds, deposited in fluvial-deltaic and shallow marine environment.

Foresets - Seismic character is generally low amplitude sigmoidal or oblique, prograding northwards. The sequence is predominantly shale and sandy shale with sandy interbeds deposited on delta slopes.

Bottomsets - Seismic character generally of moderate amplitude and continuous, thinning basinwards to the north. The sequence predominantly stacked sandstone and shale units deposited largely by mass flows at the delta front.

Figure 3.2 shows an interpretation of line 80-12 through West Barrow 1A, clearly illustrating the relationship of the three major units of the Barrow Group. An interpretation of line B85A-201 through the Southwest Barrow Lead (Fig. 3.3) also shows the relationship of the three units, and in particular, the coalescing of the topsets and foresets as the Barrow Delta migrated northwards.

3.3 Top Barrow Group structures

Most of the known commercial and potentially commercial hydrocarbon accumulations in the Barrow Sub-basin are reservoired in the top Barrow Group (Flacourt Formation) sands (Table 1), with some of the remainder being reservoired in the bottomset sands of the lower Barrow Group (Malouet Formation).

Any hydrocarbon accumulations in the West Barrow Vacant Area are therefore likely to be similarly reservoired in the top Barrow Group sands, sealed by the overlying Muderong Shale. Glauconitic silts and sands of the Mardie Greensand could also occur at this level, and form a secondary target.

With the existing seismic control, it has been possible to remap several prospects, as well as identify a number of possible structural leads at the top Barrow Group level (Plate 3). However, more extensive and detailed seismic surveying may be needed to confidently define the leads, and to identify and map stratigraphic sand plays, particularly within the middle Barrow Group foresets and the lower Barrow Group bottomsets.

3.3.1 North Rosily Prospect

The North Rosily prospect was originally mapped by WAPET, and straddles the southern boundary of the West Barrow Vacant Area and the adjacent exploration permit WA-210-P operated by BHPP.
Rosily 1A, drilled by WAPET in 1982, tested a southern culmination of the structure, and recovered a small amount of gas from the bottomset sands. The North Rosily structure appears to be bounded by faults to the north, which probably extend into the lower Gearle Siltstone, and deeper Jurassic or Triassic faulting may control subtle structuring within the overlying Barrow Group (Fig. 3.4). The North Rosily prospect has an area of several square kilometres and has the potential for a commercial size accumulation in the top Barrow Group sands.

3.3.2 West Barrow Prospect

The West Barrow prospect is a large, closed structural trap at the top Barrow Group level, with an areal closure of at least 6 square kilometres. The structure was mapped in detail in 1979 and 1980 by Offshore Oil NL, who then drilled West Barrow 1/1A in 1982. A number of drilling problems associated with high formation pressures resulted in the well being suspended after six months of drilling. Although no tests were run, shows during drilling and subsequent wireline log analysis indicate there was potential for oil pay at the top Barrow Group, and additional pay in the lower foreset sands and bottomset sands (Plate 19). The bottomset sands of the lower Barrow Group (Malouet Formation) became the target of West Barrow 2 drilled in 1985 by BHPP. This well was located 1.5 kilometres southeast of West Barrow 1A, but did not have the intensity and number of oil and gas shows that were reported from West Barrow 1A, and was plugged and abandoned.

Remapping of the West Barrow structure with available seismic data indicates that West Barrow 2 may have been drilled downdip and slightly off structure. An interpretation of lines B85A-407 and B85A-409 through the structure (Figs. 3.5 and 3.6) indicates structural closure exists at both top and lower Barrow Group levels. Possible deeper faulting in the Jurassic or Triassic at the West Barrow location (Fig. 3.5) may be a lateral extension of the structure seen at North Rosily (Fig. 3.4), or related to uplift along the Alpha Arch to the west. It is probably also related, at least in part, to the structuring at West Barrow. The recent Chinook, Griffin and Scindian discoveries have been made in the Barrow Group overlying the Alpha Arch.

3.3.3 Gillian Prospect

The Gillian prospect is a large, closed structural trap at the top Barrow Group level, located in the northern, central part of the West Barrow Vacant Area. A normal fault extending into the lower Barrow Group bounds the northeast of the closure which has a relief of approximately ten milliseconds. The structure is likely to contain good reservoir sands at all levels of the Barrow Group sequence at this location, sealed by intraformational shales, and the Muderong Shale at the top Barrow Group (Fig. 3.7). The Gillian structure covers an area of 5 to 7 square kilometres, and could contain at least 20 metres of good quality Barrow Group reservoir sands, giving the potential for a small to middle-sized commercial oil field.

BP drilled Robot 1A approximately 3 kilometres northeast of the structure in 1988, to test a sequence of stacked sand bodies in the middle and lower Barrow Group. Presumably BP was hoping to find that these sands formed individual stratigraphically trapped reservoirs of a turbidite fan complex. Although the well lacked any good hydrocarbon shows, it did not provide a valid test of the Gillian structure.

3.3.4 Other leads

Several structural noses or subtle closures have been mapped from the available seismic, and the more obvious of these are shown in

Plate 3. Most of these leads are small and have been interpreted from single lines, and more modern and detailed seismic surveying would be required to properly define them.

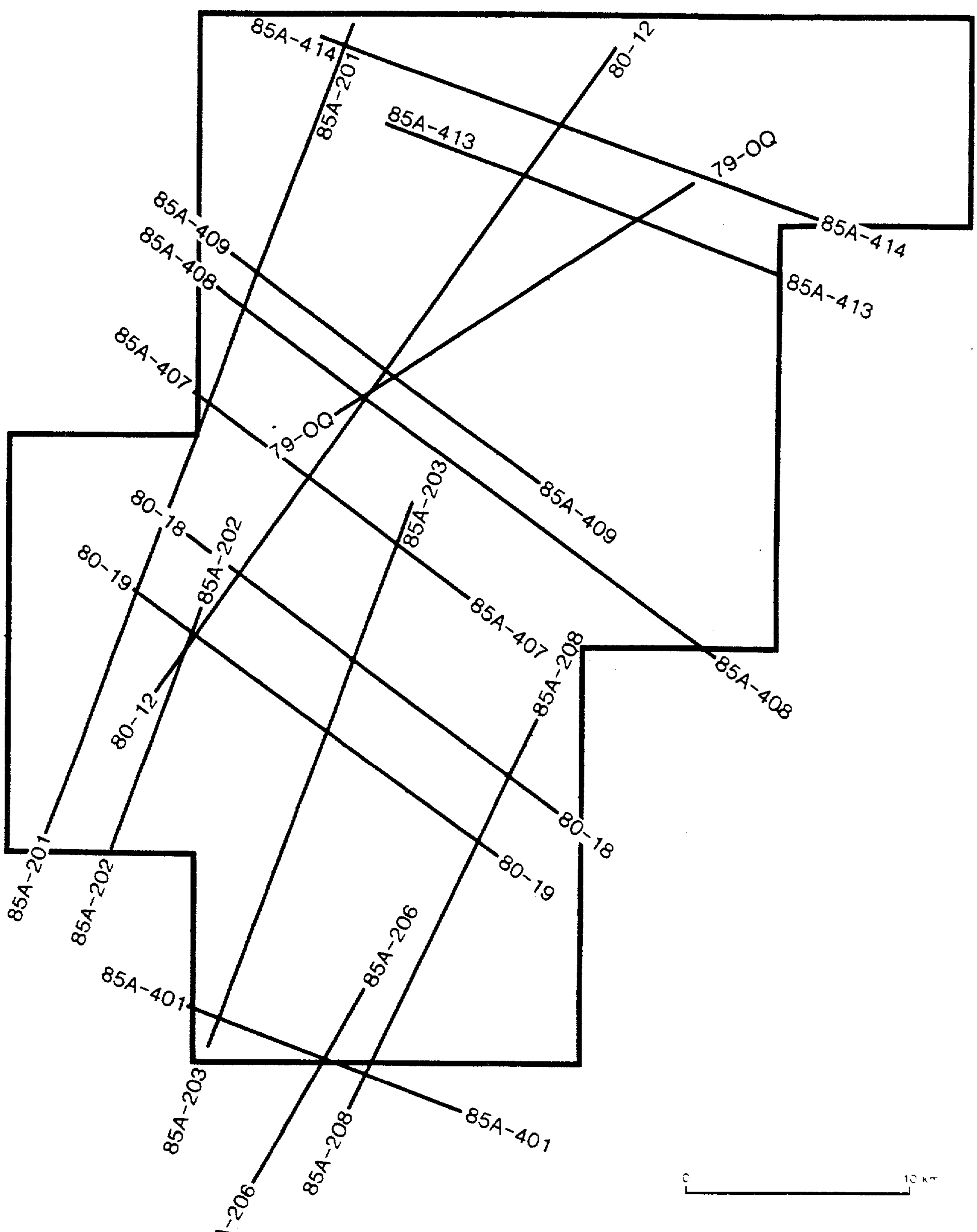


Figure 3.1 West Barrow Vacant Area,showing seismic control and interpreted lines included in this package

4. OPEN HOLE LOG INTERPRETATION

A Dual-Water (Dual-Mineral) wireline log interpretation model developed in-house at the Bureau of Mineral Resources (Morrison 1984) was used for this study. Data from four wells, West Barrow 1A and 2, Bowers 1 and Robot 1A were entered into the model by digitising open hole logs covering the interval of interest. In general, where available, the following logs were digitised: gamma ray, compensated neutron, density (FDC or LDL), MSFL, Laterolog-short, and Laterolog-deep.

For each interval the following cut off values were used by the model for determining net hydrocarbon thickness: a porosity greater than 5 percent, a volume of shale less than 50 percent, and a water saturation less than 60 percent. It is not known whether net intervals determined by this means are either highly permeable, or may be subjected to commercial, water-free production.

Generally the volume of shale was computed from the gamma ray log. However, where gamma-active sands were present, such as in the Mardie Greensand, other techniques were used. For example, volume of shale may be computed from the minimum of gamma ray and neutron-density log responses. Alternatively, just the neutron-density log response may be used.

Output from the Dual-Water model, in addition to average porosity and water saturation within the net hydrocarbon interval, is (as a function of depth): effective porosity, matrix density, water saturation, and volume of shale. On some plots, a 'gas flag' is indicated as '+' on the base of the matrix density log. This flag indicates a greater than 6 percent porosity separation between the neutron and density logs (limestone scale). Typically, a separation of more than 6 percent is due to a "light hydrocarbon effect". However, in some instances, it may also indicate borehole washout.

4.1 West Barrow 1A

Three major zones of open hole logs from West Barrow 1A were interpreted. These were (from top to bottom): the Mardie Greensand, the upper Flacourt Formation topsets, and the lowermost Flacourt Formation (foresets) and Malouet Formation.

The log interpretation for this well is complex, and is hampered by a lack of RFT and production test information. The determination of water resistivity, crucial for water saturation calculations, may be complicated by:

. the flushing of the upper Barrow Group (Flacourt Fm) sands, firstly by mud filtrate of high salinity (80 000 ppm), and later by a much lower salinity mud filtrate (27 000 to 29 000 ppm);

. a possibility that residual hydrocarbons, if present, will lower the log-derived water salinity because there were no reliable fluid recoveries from the reservoir zones;

. the setting of casing, preventing the logging of the uppermost six metres of the shale above the net sand; and

. by not knowing whether the Malouet Formation sands in this well are totally hydrocarbon bearing, contain residual hydrocarbons, or, from a water sample retrieved from the nearby West Barrow 1, contain water of a very low salinity (1570 ppm) (Offshore Oil 1982).

4.1.1 Interpretation results: Mardie Greensand

Fifty metres of open hole logs, between 2450 and 2500 m KB were digitised and interpreted. It was assumed that the water salinity of 29 000 ppm, calculated from the Flacourt Formation sands would be identical to the formation water within the Mardie Greensand.

On the basis of this assumption, the following results were computed from the Dual-Water model (volume of shale was computed from the minimum shale response from the gamma ray and neutron/ density logs):

- a net hydrocarbon thickness of 40.3 m
- an average effective porosity of 29.1 percent
- an average effective water saturation of 43.6 percent

The Mardie Greensand in West Barrow 1A is characterised by a high effective porosity. It is expected that net hydrocarbon thickness would be reduced proportionately with a reduction in the applied formation water salinity. It is not known whether the Mardie Greensand is oil or gas bearing. The results of this interpretation are shown graphically in Figure 4.1.

4.1.2 Interpretation results: top of upper Flacourt Formation (topsets)

Two hundred metres of open hole logs, between 2500 and 2700 m KB, were digitised and interpreted. Water resistivity calculations in the lowermost sandy intervals suggested that the formation water had a salinity of 29 000 ppm, which is essentially identical to that of the mud filtrate. This would explain the lack of separation, in general, between the MSFL, Laterolog-short and Laterolog-deep logging tool responses. Volume of shale was computed from the gamma ray log response.

The following results were computed from this model:

- a net hydrocarbon thickness of 27.5 m
- an average effective porosity of 17.4 percent
- an average effective water saturation of 39.1 percent

It is interesting to note that the net hydrocarbon zones are generally restricted to shalier intervals which may be of low permeability. The exception is a 2 m clean sand immediately below the shale at 2510 m KB, which may be oil bearing. The results of this interpretation are shown graphically in Figure 4.1.

4.1.3 Interpretation results: lower Flacourt Formation (foresets) and Malouet Formation

One hundred and fifty metres of open hole logs, between 3360 and 3510 m KB were digitised and interpreted. Two interpretations were made of this zone. The first interpretation assumed that this zone contained no clean, water-bearing intervals, and that the water salinity of the formation was equivalent to that used for the upper Flacourt Formation sands. The second interpretation assumed that the lowermost sand in this interval, between 3490 and 3506 m KB was totally water filled. A water salinity of 3600 ppm was computed and applied to the Dual-Water Model. Of interest is that this log-derived salinity is much closer to that determined from a water sample recovered from the same zone in West Barrow 2 (1570 ppm), when compared to the salinity of 29 000 ppm determined from the Flacourt Formation sands in West Barrow 1A. Volume of shale was computed from the gamma ray log response.

The results of the first interpretation are shown graphically in Figure 4.2:

- a net hydrocarbon thickness of 85.8 m
- an average effective porosity of 10.6 percent
- an average effective water saturation of 38.6 percent

The results of the second interpretation are shown graphically in Figure 4.3:

- a net hydrocarbon thickness of 4.5 m
- an average effective porosity of 12.5 percent
- an average effective water saturation of 49.1 percent

The differences in net hydrocarbon thickness between these two interpretations dramatically illustrate the problems with log interpretation in West Barrow 1A and, in particular, of determining accurate formation water salinities.

4.2 West Barrow 2

Four major zones of open hole logs were interpreted from West Barrow 2. These zones were (from top to bottom): the Mardie Greensand, the upper Flacourt Formation (topsets) and the lowermost Flacourt Formation (foresets) and Malouet Formation. Log interpretation complexities, similar to West Barrow 1A, were also encountered in this well.

4.2.1 Interpretation results: Mardie Greensand

Sixty-seven metres of open hole logs, between 2453 and 2520 m KB were digitised and interpreted. It was assumed that the water salinity of 55 000 ppm calculated from the Flacourt Formation sands would be identical to the formation water within the Mardie Greensand.

On the basis of this assumption, the following results were calculated using the Dual-Water model (volume of shale was computed from the minimum shale response from the gamma ray and neutron/density logs):

- a net hydrocarbon thickness of 35.8 m
- an average effective porosity of 28.4 percent
- an average water saturation of 23.3 percent

As for West Barrow 1A, the Mardie Greensand is characterised by a high effective porosity. It would be expected that the net hydrocarbon thickness would be reduced proportionately with a reduction in the applied formation water salinity. It is not known whether the Mardie Greensand is oil or gas bearing. The results of this interpretation are shown graphically in Figure 4.4.

4.2.2 Interpretation results: top of upper Flacourt Formation (topsets)

One hundred and fifty metres of open hole logs, between 2510 and 2660 m KB were digitised and interpreted. Water resistivity calculations in the lowermost, sandy intervals suggested that the formation water had a salinity of 55 000 ppm.

The following results were computed using the Dual-Water model (volume of shale was computed from the minimum shale response from the gamma ray and neutron/density logs):

- a net hydrocarbon thickness of 41 m
- an average effective porosity of 17.2 percent
- an average water saturation of 37.7 percent

Like West Barrow 1A, these net hydrocarbon zones were restricted to shalier intervals which may be of low permeability, the exception being some thin sands between 2510 and 2525 m KB which may be oil bearing. The results of this interpretation are shown graphically in Figure 4.4.

4.2.3 Interpretation results: lower Flacourt Formation (foresets) and Malouet Formation

One hundred and fifty metres of open hole logs, between 3270 and 3420 m KB were digitised and interpreted. Two interpretations were made for this zone. The first interpretation assumed that this zone contained no clean, water-bearing intervals, and that the water salinity of the formation was equivalent to that used for the Flacourt Formation. The second interpretation assumed that the lowermost sand in this interval, between 3370 and 3410 m KB was totally water filled. A water salinity of 9000 ppm was computed from this lowest sand and applied to the Dual-Water Model. This log-derived salinity is much closer to that determined from the water sample recovered from this zone (1570 ppm) than the water salinity applied for the first interpretation. The volume of shale was computed from the gamma ray log response.

The following results, shown graphically in Figure 4.5 were computed using the first interpretation:

- a net hydrocarbon thickness of 72.3 m
- an average effective porosity of 9.1 percent
- an average water saturation of 28 percent

The following results computed from the second interpretation are shown graphically in Figure 4.6:

- a net hydrocarbon thickness of 10.3 m
- an average effective porosity of 11.2 percent
- an average water saturation of 49 percent

The comment made for the interpretation of the same zone in West Barrow 1A also applies here. Until accurate formation water salinities can be determined, large uncertainties in the results of log interpretation will prevail.

4.3 Bowers 1

Only the lowermost Mardie Greensand and top Barrow Group were interpreted in this well, hole conditions being too washed out in the lower zones to interpret with any confidence. One hundred and fifty metres of open hole logs, between 2907 and 3057 m KB were digitised and interpreted. Water resistivity calculations in the lowermost, sandy interval suggested that the formation water had a salinity of 33 000 ppm, which is typical of sea water.

The following results were computed using the Dual-Water model (volume of shale was computed from the neutron-density log responses):

- a net hydrocarbon thickness of 43.8 m
- an average effective porosity of 21.6 percent
- an average water saturation of 47.6 percent

Of interest is the extent of the hydrocarbon column in this well which, although probably residual, shows the potential for the occurrence of hydrocarbons in this region. The results of this interpretation are shown graphically in Figure 4.7.

4.4 Robot 1A

Two zones were interpreted in Robot 1A, the upper Flacourt Formation (topset) sands and Malouet Formation.

4.4.1 Interpretation results: top of upper Flacourt Formation (topsets)

One hundred and fifty metres of open hole logs, between 2605 and 2755 m KB were digitised and interpreted. Water resistivity calculations in the lowermost, sandy intervals suggested that the formation water had a salinity of 25 000 ppm.

The following results were computed using the Dual-Water model (volume of shale was computed from the minimum shale response from the gamma ray and neutron/density logs):

- a net hydrocarbon thickness of 2.3 m
- an average effective porosity of 8.8 percent
- an average water saturation of 53.1 percent

This interval essentially contains only minor shows of residual hydrocarbons.

The results of this interpretation are shown graphically in Figure 4.8.

4.4.2 Interpretation results: Malouet Formation

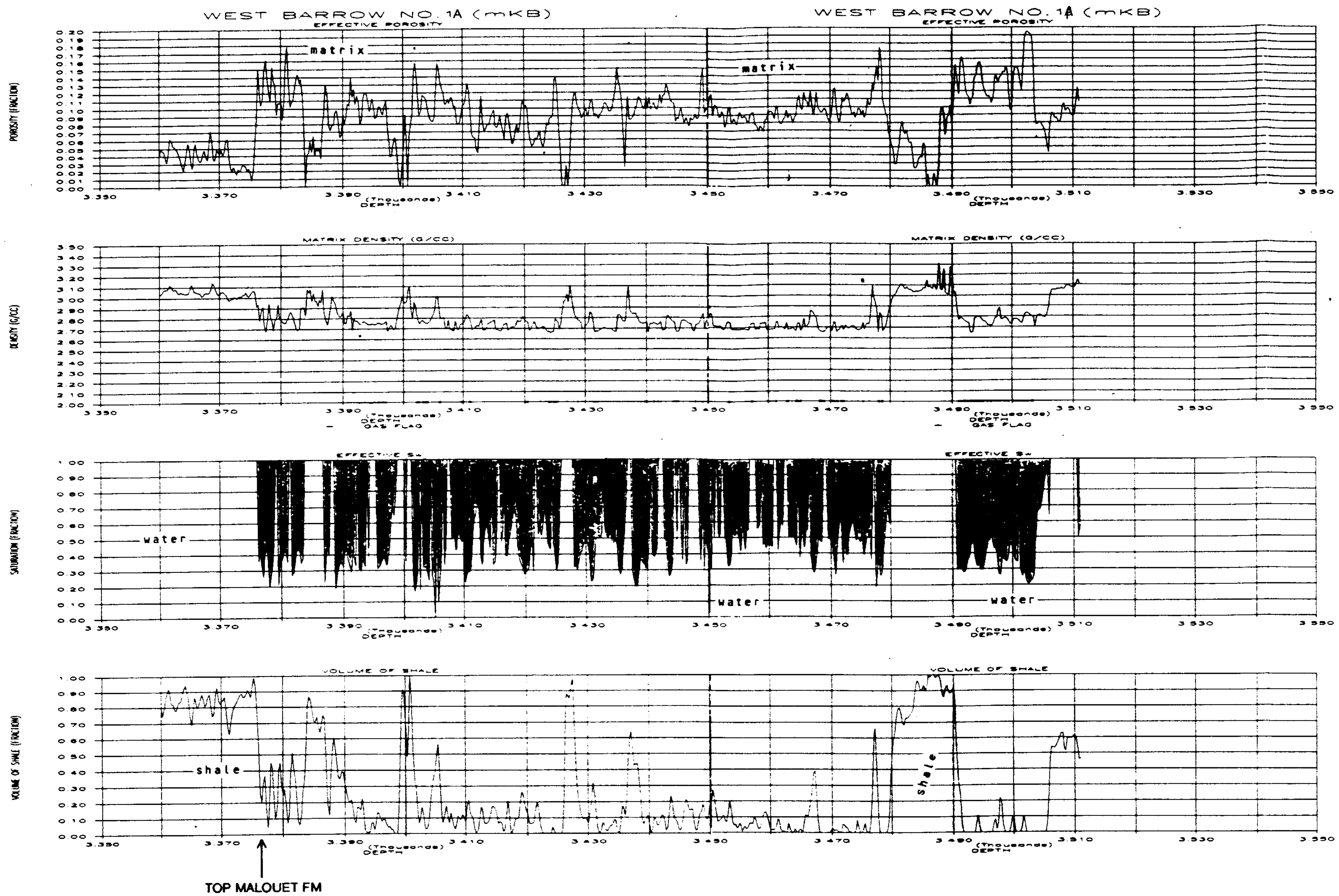
One hundred and fifty metres of open hole logs, between 3200 and 3450 m KB were digitised and interpreted. Water resistivity calculations in the lowermost, sandy intervals suggested that the formation water had a salinity of 4500 ppm. Salinities of this order of magnitude were also found in both West Barrow wells in this unit.

The following results were computed using the Dual-Water Model (volume of shale was computed from the response from the gamma ray log):

- a net hydrocarbon thickness of 17.8 m
- an average effective porosity of 18.3 percent
- an average effective water saturation of 43.7 percent

Like the upper Flacourt Formation in this well, this interval contained only residual hydrocarbons.

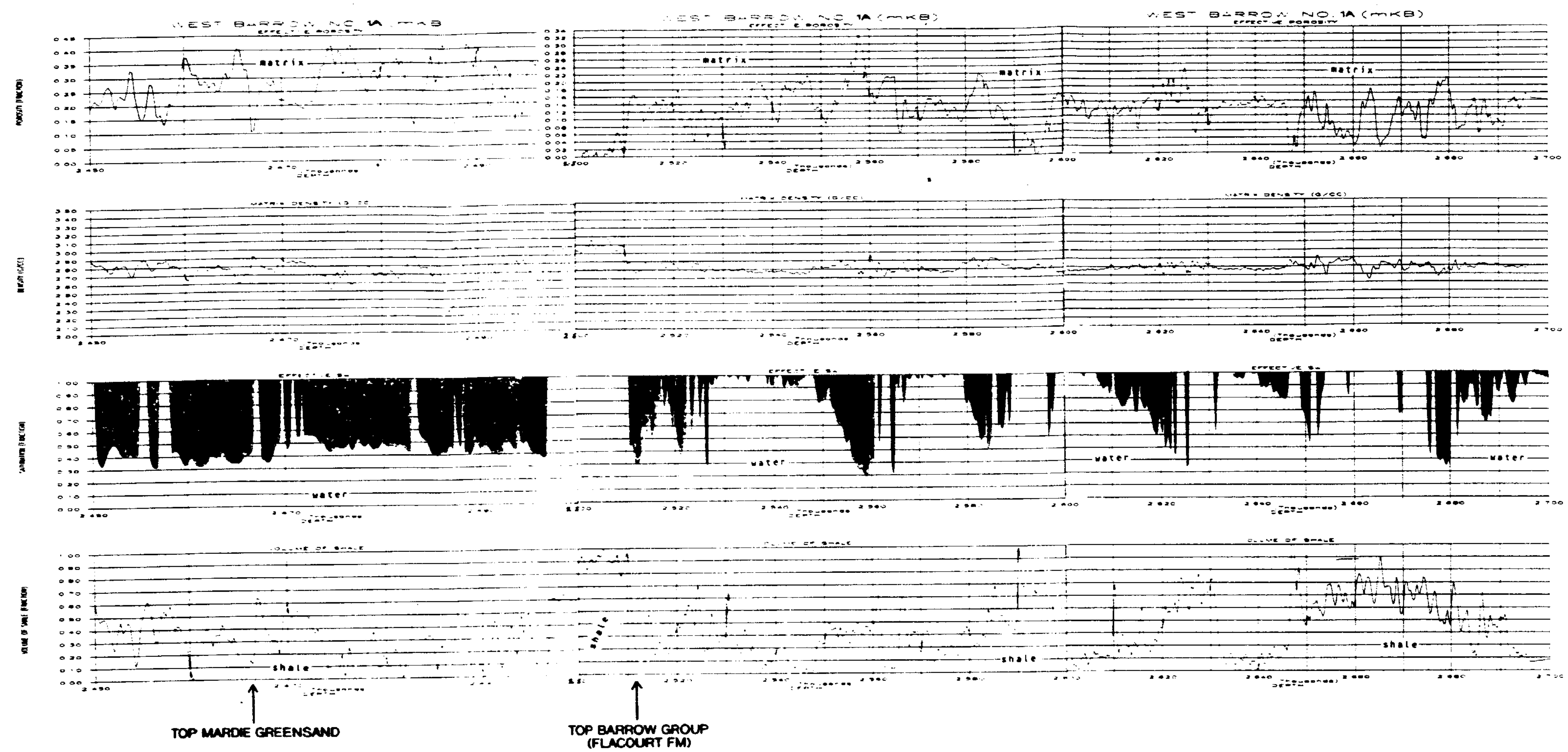
The results of this interpretation are shown graphically in Figure 4.9.



MALOUET FORMATION

NET HYDROCARBON THICKNESS = 85.8m
AVERAGE EFFECTIVE POROSITY = 0.106
AVERAGE EFFECTIVE WATER SATURATION = 0.386
Vsh (G.R.) SALINITY = 29 000ppm

Figure 4.2 Log interpretation of Malouet Formation - West Barrow 1A Well



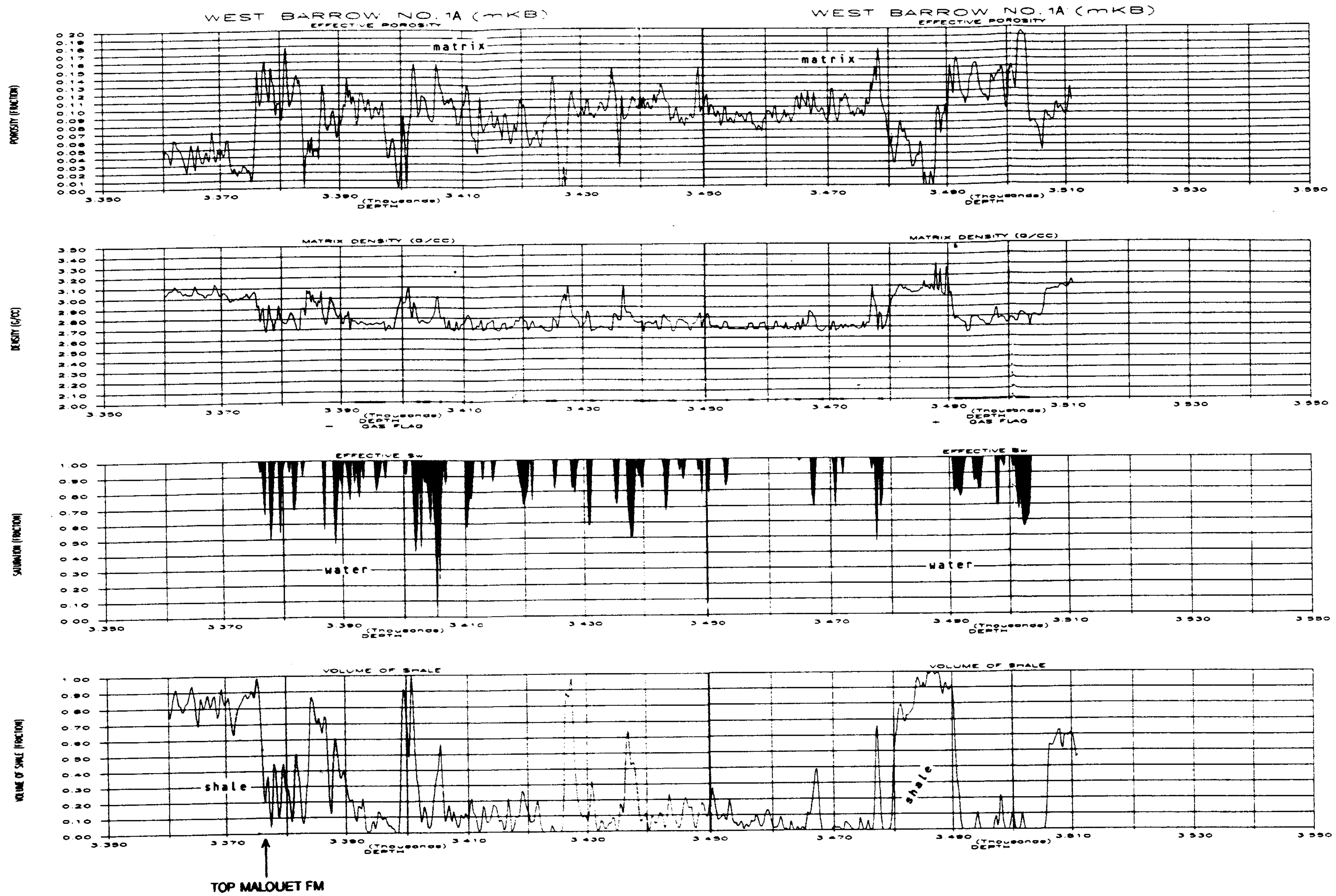
MARDIE GREENSAND

NET HYDROCARBON THICKNESS = 40.3m
AVERAGE EFFECTIVE POROSITY = 0.291
AVERAGE EFFECTIVE WATER SATURATION = 0.436
Vsh (GR) SALINITY = 29 000ppm

UPPER FLACOURT FORMATION

NET HYDROCARBON THICKNESS = 27.5m
AVERAGE EFFECTIVE POROSITY = 0.174
AVERAGE EFFECTIVE WATER SATURATION = 0.391
Vsh (GR) SALINITY = 29 000ppm

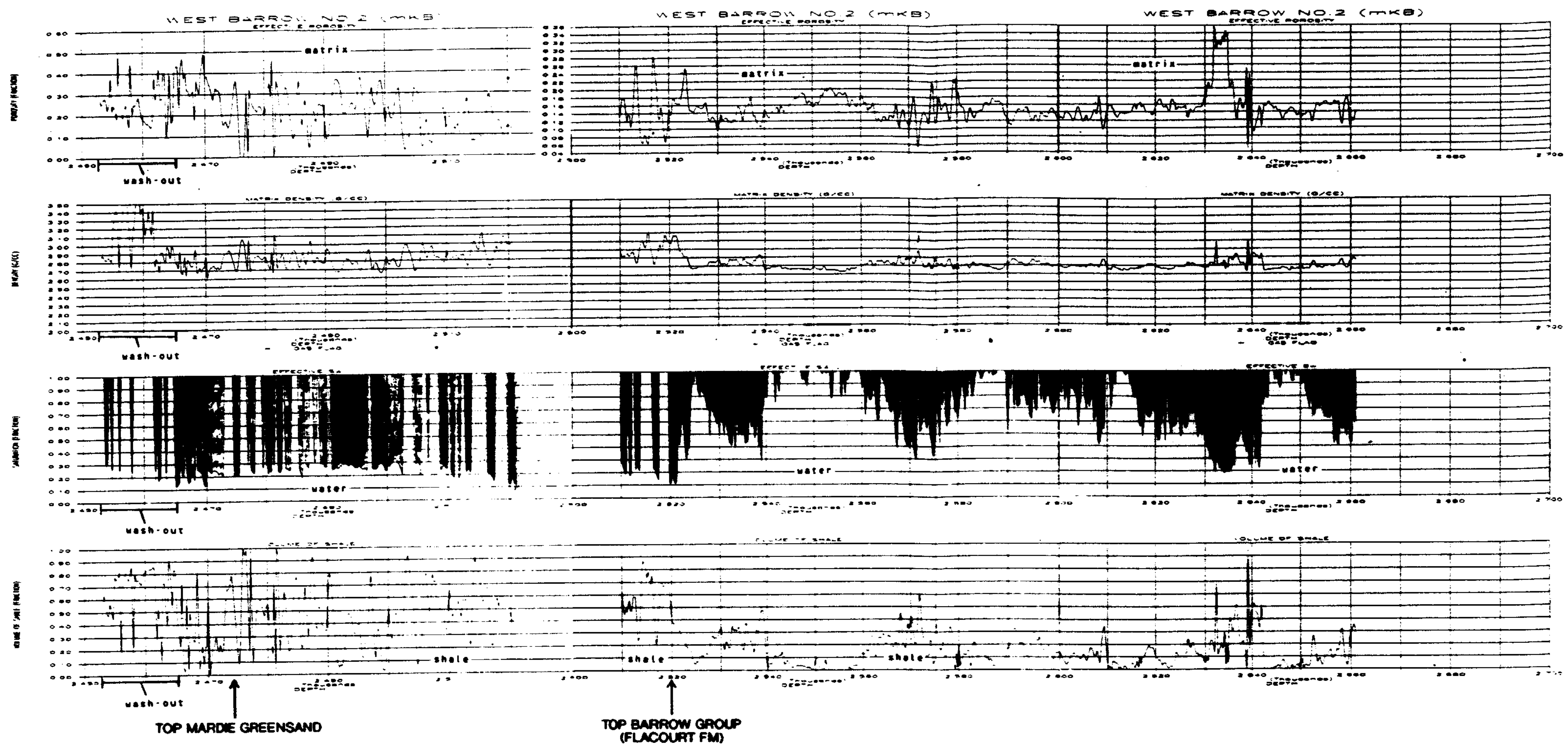
Figure 4.1 Log interpretation of Mardie Greensand and Upper Flacourt Formation – West Barrow 1A Well



MALOUET FORMATION

NET HYDROCARBON THICKNESS = 4.5m
AVERAGE EFFECTIVE POROSITY = 0.125
AVERAGE EFFECTIVE WATER SATURATION = 0.491
Vsh (GR) SALINITY = 3 600ppm

Figure 4.3 Alternative log interpretation of Malouet Formation - West Barrow 1A Well



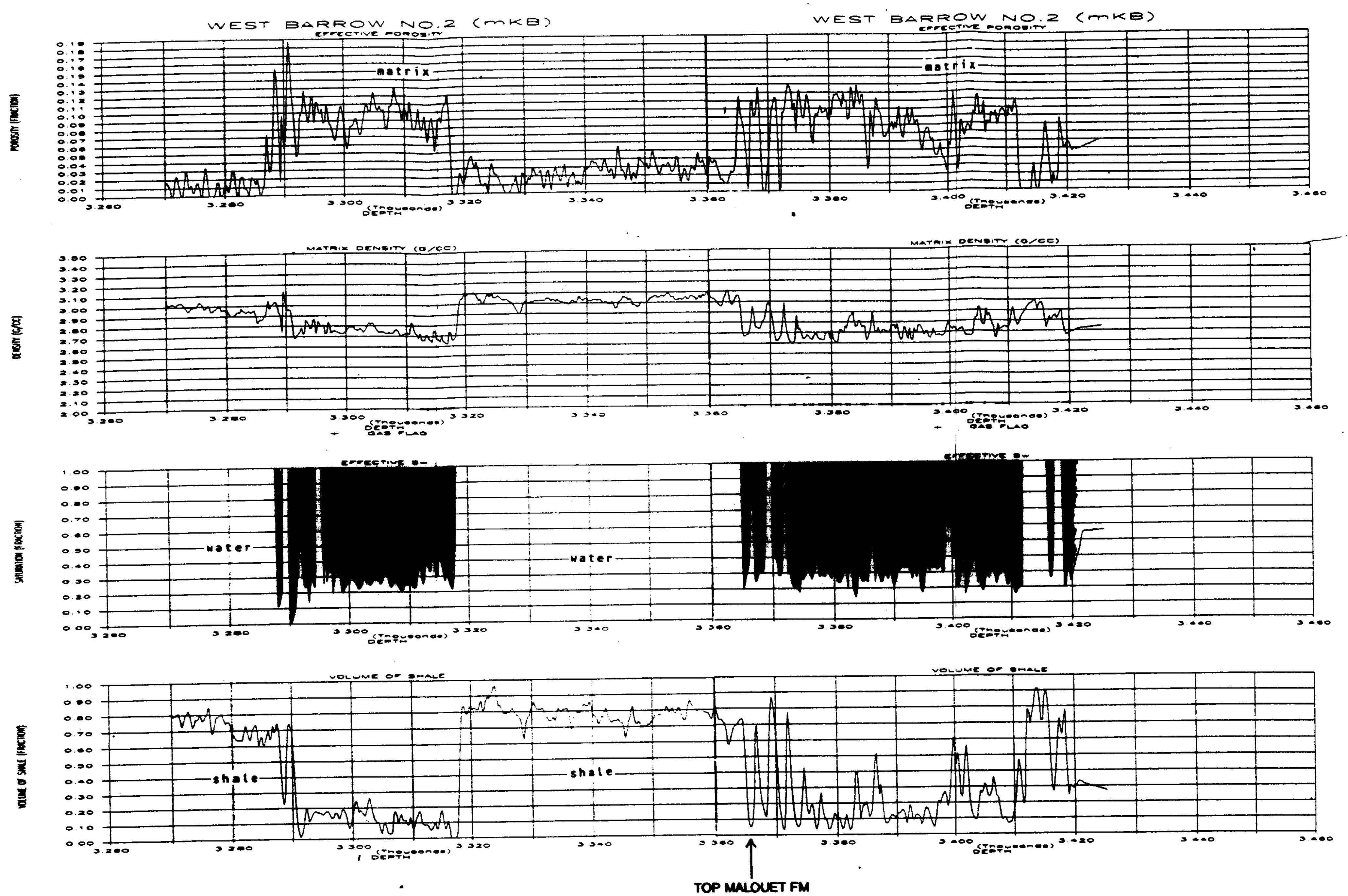
MARDIE GREENSAND

NET HYDROCARBON THICKNESS = 35.8m
AVERAGE EFFECTIVE POROSITY = 0.284
AVERAGE EFFECTIVE WATER SATURATION = 0.233
Vsh (MIN) SALINITY = 55 000ppm

UPPER FLACOURT FORMATION

NET HYDROCARBON THICKNESS = 41.0m
AVERAGE EFFECTIVE POROSITY = 0.172
AVERAGE EFFECTIVE WATER SATURATION = 0.377
Vsh (MIN) SALINITY = 55 000ppm

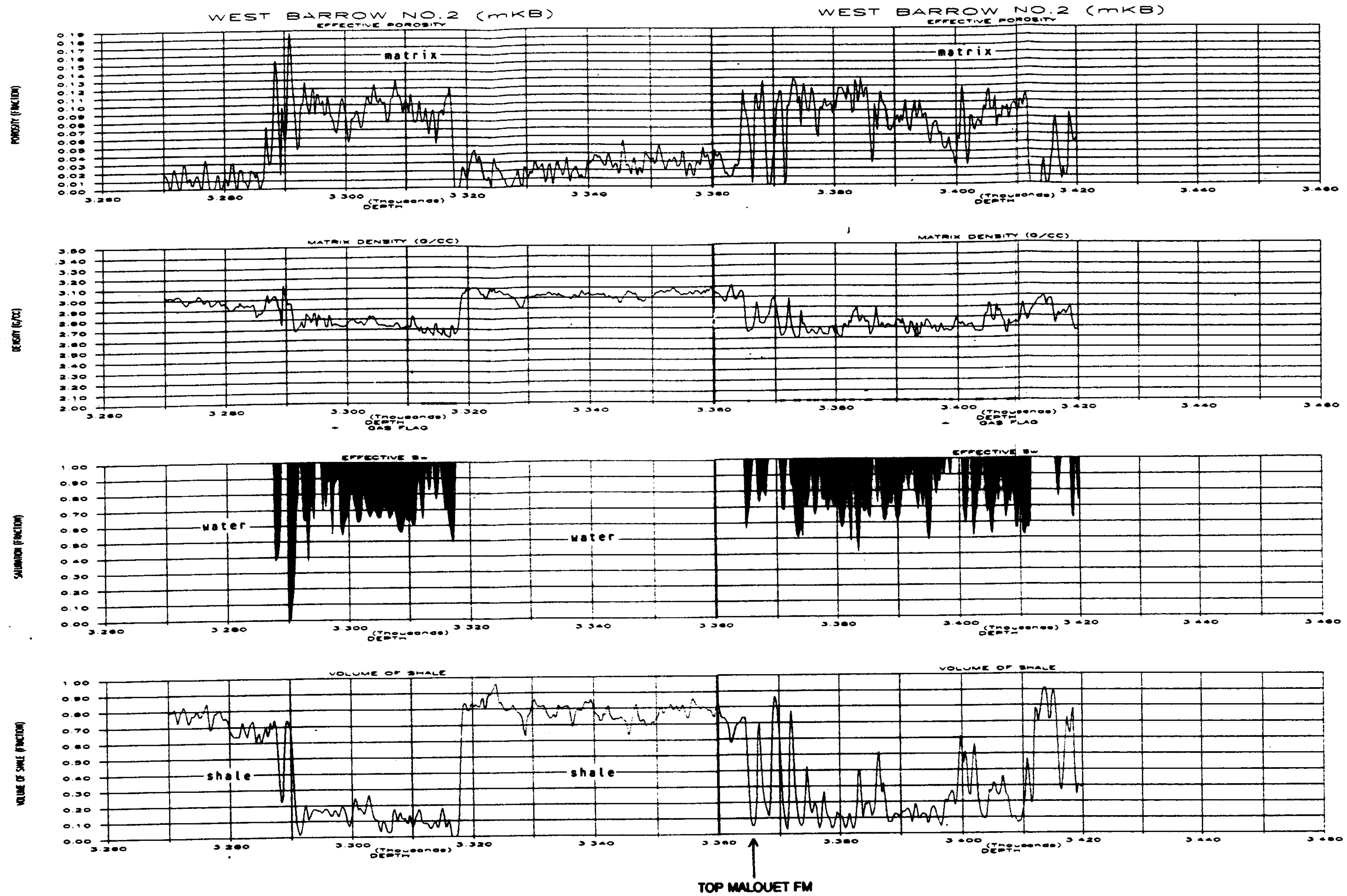
Figure 4.4 Log interpretation of Mardie Greensand and Upper Flacourt Formation – West Barrow 2 Well



LOWER FLACOURT FORMATION AND MALOUET FORMATION

NET HYDROCARBON THICKNESS = 72.3m
AVERAGE EFFECTIVE POROSITY = 0.091
AVERAGE EFFECTIVE WATER SATURATION = 0.280
Vsh (GR) SALINITY = 55 000ppm

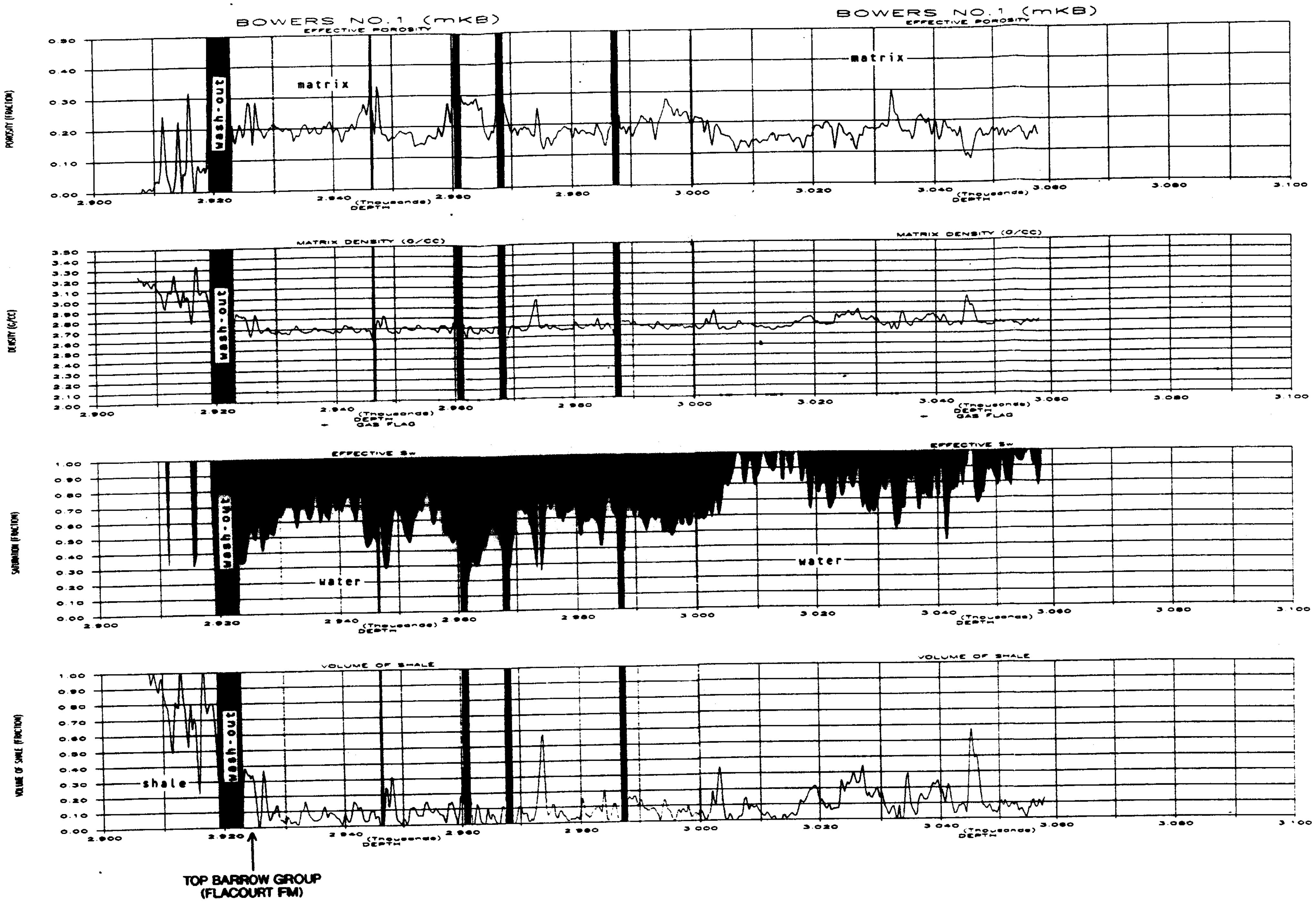
Figure 4.5 Log interpretation of lower Flacourt Formation and Malouet Formation - West Barrow 2 Well



LOWER FLACOURT FORMATION AND MALOUET FORMATION

NET HYDROCARBON THICKNESS = 10.3m
AVERAGE EFFECTIVE POROSITY = 0.112
AVERAGE EFFECTIVE WATER SATURATION = 0.490
Vsh (GR) SALINITY = 9 000ppm

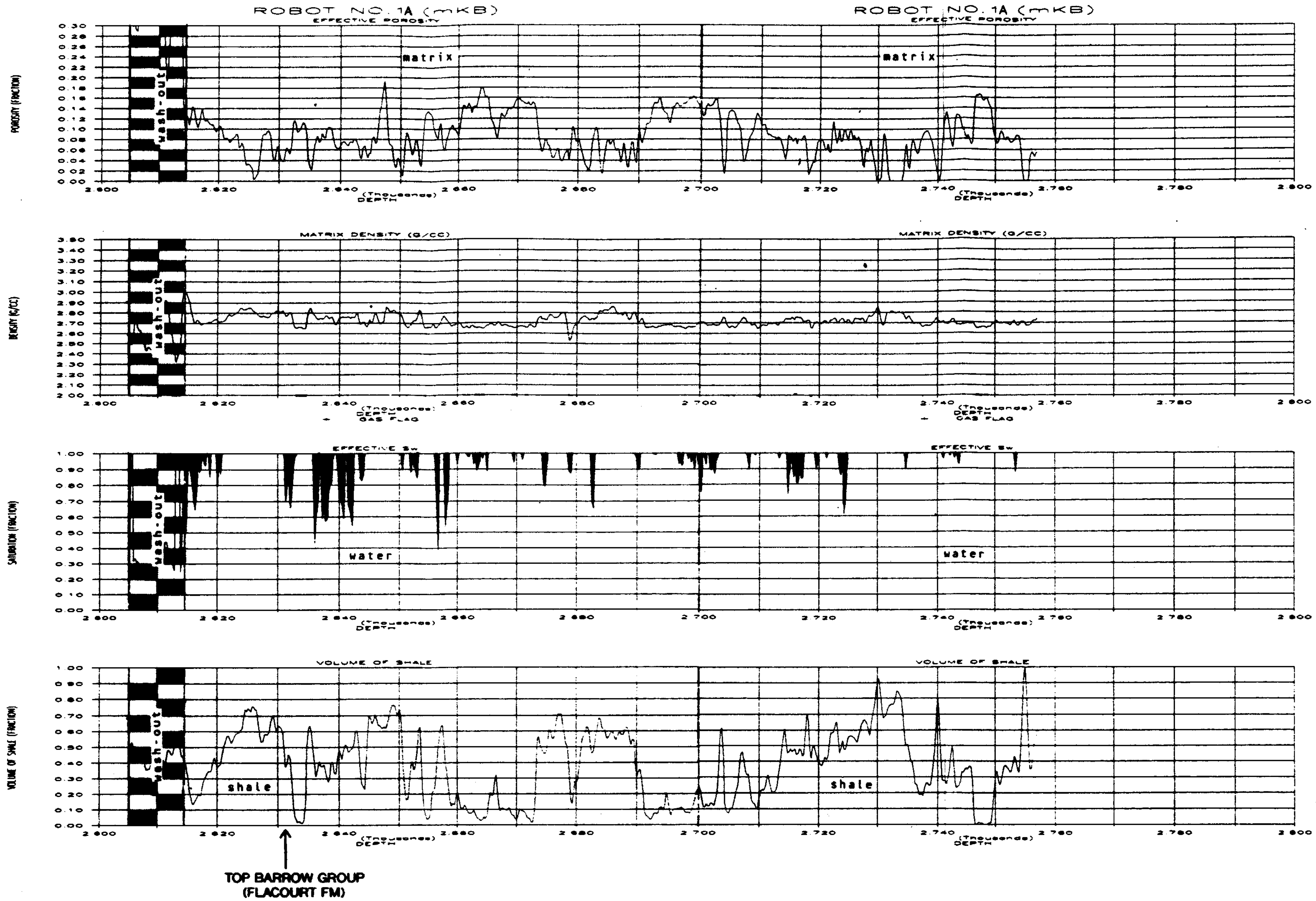
Figure 4.6 Alternative log interpretation of Lower Flacourt Formation and Malouet Formation – West Barrow 2 Well



FLACOURT FORMATION

NET HYDROCARBON THICKNESS = 43.8m
AVERAGE EFFECTIVE POROSITY = 0.216
AVERAGE EFFECTIVE WATER SATURATION = 0.476
Vsh (N/D) SALINITY = 33 000ppm

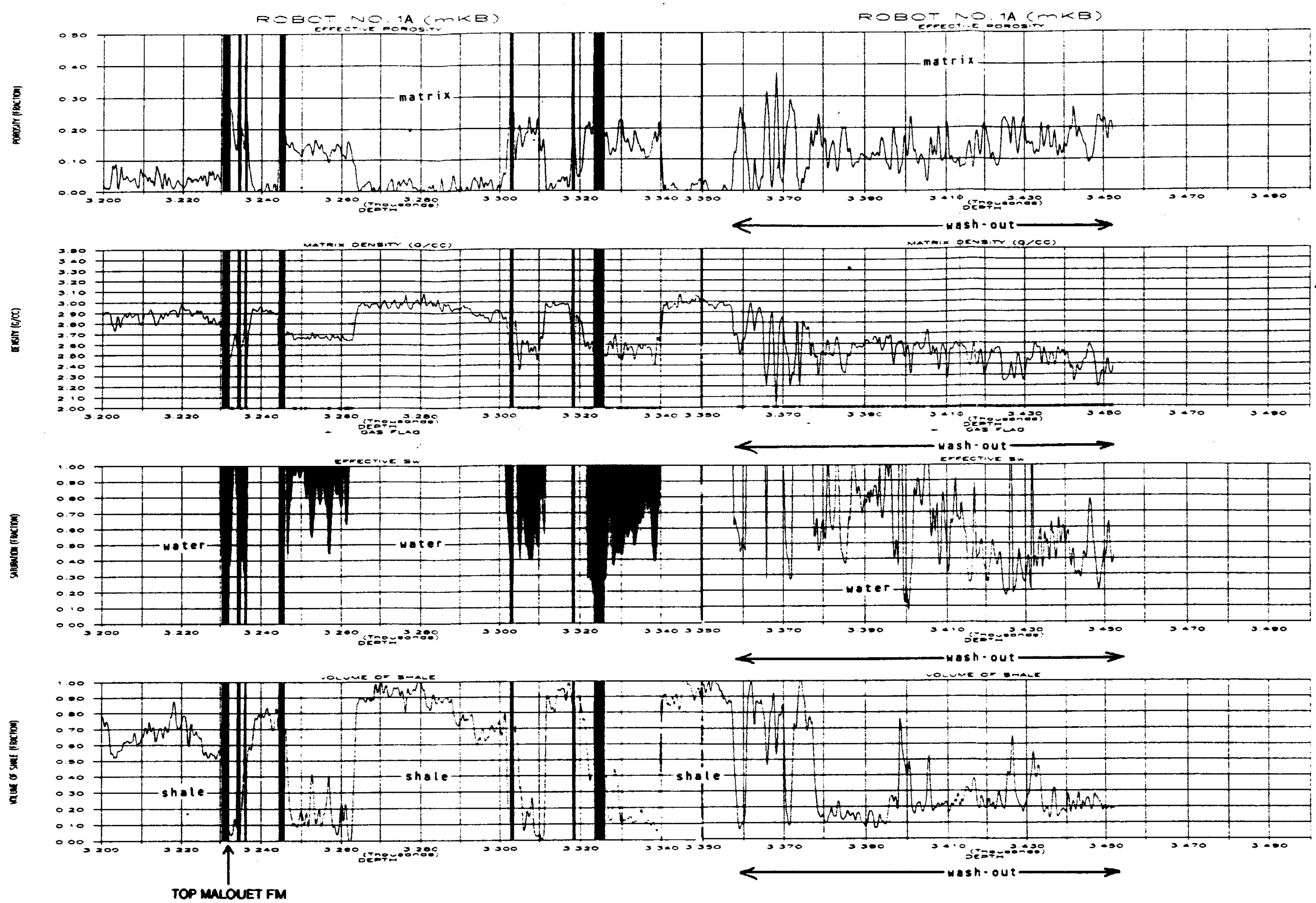
Figure 4.7 Log interpretation of Flacourt Formation - Bowers 1 Well



FLACOURT FORMATION

NET HYDROCARBON THICKNESS = 2.3m
AVERAGE EFFECTIVE POROSITY = 0.088
AVERAGE EFFECTIVE WATER SATURATION = 0.531
Vsh (GR) SALINITY = 25 000ppm

Figure 4.8 Log interpretation of Flacourt Formation - Robot 1A Well



MALOUET FORMATION - AVERAGE FOR INTERVAL 3200 TO 3350 MKB

NET HYDROCARBON THICKNESS = 17.8m   AVERAGE EFFECTIVE POROSITY = 0.183   AVERAGE EFFECTIVE WATER SATURATION = 0.437

Figure 4.9 Log interpretation of Malouet Formation - Robot 1A Well

5. IMPLICATION OF ABNORMAL PRESSURES ON DRILLING PRACTICES

In the Barrow Sub-basin, a major zone of overpressuring occurs in the upper part of the Dingo Claystone and lower part of the Barrow Group. Several wells have encountered drilling problems and resultant delays and increased costs after drilling into these overpressured zones.

5.1 Well data

The field data in an area are indispensable for accurate pore pressures and fracture gradients prediction, which are essential parameters for safe and economical well design. Data from seven wells drilled to date in, and adjacent to the West Barrow Vacant Area were used for this review. Pore pressures in each well were evaluated on the basis of various parameters measured during drilling and hole surveys such as "d" exponent, trip gas and connection gas readings, and shale densities. In the final analysis, direct measurement of formation pressures by DST and RFT testing were used. It should be noted that although the estimation of pore pressures using indirect methods is considered subjective, it should provide a definition of pressure regime sufficient to allow safe drilling in the area. The brief history and pore pressure evaluation of each well surveyed is summarized below.

5.1.1 Spar 1

General Data:	Operator - West Australian Petroleum Pty Ltd Location - 20°36'51.69"S, 114°53'6.13"E Elevation - Sea floor - 114.5 m, RT - 30 m Drilling commenced - 24/6/1976 Rig Released - 30/9/1976 Status - plugged and abandoned
Hole Sizes:	36" to 179 m, 26" to 528 m, 17 1/2" to 1511 m, 12 1/4" to 2610 m, 8 1/4" to 3450 m, 6 1/8" to 3721 m
Casing:	30" at 168 m, 20" at 518 m, 13 3/8" at 1502 m, 9 5/8" at 2600 m, 7" liner at 3450 m
Formation Integrity:	At 1502 m / 1.5 s.g., at 2603 m / 1.68 s.g., at 3450 m / 2.16 s.g.

<u>Drilling summary</u>

Spar 1 was drilled to 2226 m with no hole problems. At this depth the hole began to cave badly. The mud density was raised from 1.11 to 1.38 s.g. The well was drilled to 2610 m with the mud density gradually increasing to 1.45 s.g. to overcome the shale caving problem. After the 9 5/8" casing was set, the hole was drilled to 3000 m with 1.28 s.g. mud with no hole problems. The hole was deepened to 3450 m with 1.16 s.g. mud. In this section the mud density was occasionally raised to 1.56 s.g. when high gas readings were recorded. After the 7" liner was set, the hole was drilled to 3673 m with 1.62 s.g. mud. At this depth a drilling break was encountered and the well kicked. The well was killed with 1.84 s.g. mud. The well was drilled to total depth with the mud density raised to a maximum of 1.95 s.g. (Thomas & Scott 1977).

<u>Pore pressure evaluation</u>

0-2226 m:	Normal pressure gradients of between 1.0 to 1.1 s.g.
2226-2610 m:	The sloughing shale problems experienced in this section could have been due to the pore pressures being in excess of the hydrostatic pressure. However, there is no evidence of above-normal pressures on the "d" exponent or from increased penetration rates. The sloughing shale problems experienced in this section could have also been caused by erosion due to fluid circulation or hydration and swelling of shale.
2610-3000 m:	All indirect pressure evaluation parameters indicate a normal hydrostatic pressure gradient. Direct pressure measurement in water sand at 2700 m indicates pressure gradient of 1.026 s.g.
3000-3300 m:	Pore pressure increased from hydrostatic pressure gradient to pressure gradient of about 1.28 s.g.
3300-3340 m:	Pore pressure increased to 1.32 s.g.
3340-3500 m:	Pore pressures up to 1.5 s.g.
3500-3721 m:	Super overpressured zone. Pressure at total depth increased to 1.8 s.g.

5.1.2 West Barrow 1/1A

General Data:	Operator - Offshore Oil NL
	Location - 20°53'26.49"S, 114°54'52.8"E
	Elevation - Sea floor - 98.0 m, RT - 10.3 m
	Drilling Commenced - 18/2/1982
	Rig Released - 16/7/1982
	Status - Plugged and abandoned
Hole Sizes:	36" to 159 m, 26" to 511 m, 17 1/2" to 1402 m, 12 1/4" to 2519 m, 8 1/4" to 3520 m
Casing:	30" at 147 m, 20" at 417 m, 13 at 1384 m, 9 at 2508 m
Formation Integrity:	At 2508 m / 1.56 s.g., repeated at 3231 m drilling of depth / 2.03 s.g.

<u>Drilling summary</u>

West Barrow 1 was drilled with no returns to 494 m when a drill string tool joint failed and the string parted. Fishing attempts were unsuccessful and the hole was plugged and abandoned. The rig was repositioned and West Barrow 1A was spudded on 24 October 1982. Due to the difficulties with the 36" hole, the 30" casing was set shallow at 147 m. Difficult hole conditions continued in the 26" hole, which was drilled with sea water and with no returns. Because of poor hole conditions two cement plugs were set. The hole was swept with high viscosity mud on connections and each single had to be reamed. At 511 m, the drill string was stuck and had to be backed off due to the approach of a cyclone. The fish was engaged and pulled out of the hole and hole cleaned out to 431 m. At this point 20" casing was run. A 17 1/2" hole was drilled to 1000 m, but with much difficulty in maintaining circulation. It was only possible to maintain circulation with sea water, but sea water was not capable of maintaining a clean hole. Lost circulation additives were tried but the only remedy was setting and redrilling of multiple cement plugs. From 1000 to 2519 m, when the 13 3/8" casing was set, the hole was drilled with no problems. The 8 1/2" hole was drilled to 2987 m with 1.1 s.g. mud. At this depth a drilling break and pit gain was experienced and the mud weight had to be raised to 1.34 s.g. to control the well. On resuming drilling operations, the drill string was found to be stuck. A back-off was carried out and a fishing string run in an attempt to jar loose the stuck assembly, but the fishing string also became stuck. Both assemblies were released by bringing down the mud weight so that a controlled kick occurred. Drilling continued with 1.26 s.g. mud weight. West Barrow 1A was drilled to final depth of 3520 m with steady increases in mud weight to control background and connection gas final mud weight was 1.85 s.g. At this depth the intention was to run a 7" liner and drill ahead and a reverse circulating junk basket was run prior to running the liner. While pulling out of the hole, the string became differentially stuck with the basket at 2691 m. The string could not be recovered and the hole was plugged and abandoned. (Offshore Oil NL 1982).

Pore pressure evaluation

0-1520 m: Normal pressure gradients of about 1.04 s.g.

1520-1805 m: Formation pore pressure increased to between 1.8 and 1.9 s.g. Cuttings become larger, shale density decreased, flow line temperature increased gas levels rose and "d" exponent showed a negative trend.

1805-1970 m: Pore pressure rose to 1.12 s.g. as evidenced by negative "d" trend and splintery cuttings.

1970-2987 m: Pressures shifted back to the normal trend of 1.04 1.07 s.g. There is a possibility of minor pressure increase around 2400 m.

2987-3165 m: Abrupt increase in pore pressure from 1.06 to 1.28 s.g. Drill rate increased from 5 m/h to 75 m/h and a gas kick was taken. Shut in drill pipe pressure and RFT results confirmed a 1.28 s.g. pore pressure. The pressure gradient remained constant to 3165 m.

3165-3520 m: Formation pressure gradient increased abruptly to 1.74 s.g., and remained constant between 1.74 and 1.75 s.g.

5.1.3 West Barrow 2

General Data: Operator - BHP Petroleum Pty Ltd
Location - 20°53'56"S, 114°55'36"E
Elevation - Sea floor - 98.0 m, RT - 8 m

	Drilling Commenced - 21/3/1985
	Rig Released - 5/8/1985
	Status - Plugged and abandoned
Hole Sizes:	36" to 146 m, 26" pilot to 359 m, 30" under reamed to 359 m, 17 1/2" pilot to 1512 m, 26" under reamed to 1063 m, 17 1/2" pilot hole opened to 22" to 1498 m, 17 1/2" to 2462 m, 12 1/4" to 3204 m, 8 1/2" to 3437 m
Casing:	30" at 140 m, 24" at 354 m, 18 5/8" at 1062 m, 13 3/8" at 2452 m, 9 5/8" at 3192 m
Formation Integrity:	At 1062 m / 1.49 s.g. no leak off, at 2452 m / 1.93 s.g., at 3192 m / 2.3 s.g., no leak off

Drilling summary

After a 30" conductor was set, a 26" hole was drilled to 359 m and then under reamed to 30". Tight hole was experienced due to ledges and had to be reamed extensively prior to 24" casing being run. Because of tight hole conditions, difficulties were experienced in running the casing. Casing was re-run three times until it was successful. A 17 1/2" pilot hole was then drilled to 1512 m. Loss of circulation of up to 30 percent was experienced throughout this section, with total losses at 604 m. Ledges were experienced between 427 and 626 m and extensive reaming was necessary. Over pulls of up to 70 000 lb were experienced on connections and wiper trips. A 17 1/2" pilot hole was under reamed to 26" to a depth of 1063 m. The hole was opened to 22" with a conventional bit to a depth of 1498 m. The 18 5/8" casing was run and cemented at 1062 m. A 17 1/2" hole was drilled to 1555 m when the drill string become stuck at 1525 m. Attempts to free the string were unsuccessful and the hole was sidetracked from 1228 to 1281 m using a 12 1/4" bit. The sidetracked hole was opened to 17 1/2" and deepened to 2462 m when the 13 3/8" casing was set at 2452 m. Tight hole conditions were experienced between 1993 and 2187 m in this section. A 12 1/4" hole was drilled to 3204 m when a 9 5/8" casing was run and cemented at 3192 m. Mud weights in this section did not exceed 1.27 s.g. Tight hole was observed between 2735 and 2751 m. An 8 1/2" hole was drilled to 3232 m where a well flow required the mud weight to be raised to 1.45 s.g. The well was drilled to 3300 m with the mud gradually increasing to 1.56 s.g. At this point the well kicked and required 1.77 s.g. kill mud weight. Drilling continued to 3437 m with gradual increase in mud weight to 1.85 s.g. At this depth, the well kicked again and required a kill mud weight of 1.92 s.g. After logging, a decision was made to plug and abandon the well at this depth. (Thek & Gilchrist 1985).

<u>Pore pressure evaluation</u>

0-3100 m:	Normal pressure gradient of about 1.04 to 1.05 s.g.
3100-3437 :	A supernormally pressured interval was penetrated at approximately 3100 m. From this point, pressure gradually increased to 1.9 s.g. at 3437 m. This interpretation is confirmed by direct RFT pressure measurement.

5.1.4 Rosily 1 & 1A

General Data:	Operator - West Australian Petroleum Pty Ltd Location - 21°12'10.602"S, 114°51'59.926"E Elevation - Sea floor - 99.9 m, RT - 25 m Drilling Commenced - 29/1/1982 Rig Released - 7/5/1982 Status - Plugged and abandoned
Hole Sizes:	36" to 164 m, 26" to 321 m, 17 1/2" to 1121 m, 12 1/4" to 1990 m, 8 1/4" to 3066 m
Casing:	30" at 155 m, 20" at 237 m, 13 3/8" at 1092 m, 9 5/8" at 1968 m
Formation Integrity:	At 1092 m / 1.46 s.g.

<u>Drilling summary</u>

The 26" hole was drilled to 218 m when the drill string become stuck. The string could not be freed and the well was plugged and abandoned. The rig was relocated and the well respudded as Rosily 1A. After a 30" casing was cemented, the 26" hole was drilled to 321 m. Tight hole conditions were experienced from 180 to 300 m. The drill string was stuck on three occasions. Also, difficulties from a caving hole were experienced in running the 20" casing. The 17 1/2" hole was drilled to 1121 m with no returns. The 13 3/8" casing was run in tight hole conditions to 1092 m. The 12 1/4" hole was drilled to 1990 m when the 9 5/8" casing was run. The 9 5/8" casing shoe was drilled out in a 12 1/4" hole. Tight hole conditions were experienced which necessitated reaming, and as a result three cones were lost in the hole. Attempts to retrieve the cones with a reverse circulating junk basket were unsuccessful because of caving hole conditions. The junk was milled successfully until the well had to be secured due to the proximity of a cyclone. A balanced cement plug was set in the 9 5/8" casing, the drill string hung in the blowout preventers and the riser pulled off. After the operation was resumed, it was found that the string was left in the cement plug. Freeing the string by a wash over operation was unsuccessful and the hole was sidetracked. The window in the 9 5/8" casing was cut from 1809 to 1830 m. The 8 1/2" sidetracked hole was drilled to a total depth of 3066 m. The mud weight in this section was kept at about 1.39 s.g. in order to control hole caving. (Gilchrist & Rogers 1983).

<u>Pore pressure evaluation</u>:

0-2929 m:	Normal pressure gradients of between 1.0 and 1.1 s.g.
2929-3066 m:	Below the depth of 2929 m, all indicators point to a supernormal pressure regime. The plot of "d" exponent versus depth below 1950 m showed a slight shift to the left of the normal compaction trend. At 1920 m, a significant increase in background gas was detected. Sonic and resistivity logs also showed a supernormal pressure zone at this depth. The abnormal pressures are confirmed by direct RFT pressure measurements.

5.1.5 Robot 1/1A

General Data:	BP Petroleum Ltd Location - 20°48'13.50"S, 115°01'05.88"E Elevation - Sea Floor - 91.43 m, RT - 15 m Drilling Commenced - 14/6/1988 Rig Released - 24/9/1988 Status - Plugged and abandoned
Hole Sizes:	36" to 90 m, 17 1/2" pilot to 1103 m opened to 26" to 950 m, 17 1/2" pilot to 1500 m opened to 20" to 1484 m, 12 1/4" pilot to 2608 m opening to 17 1/2" unsuccessful 8 1/2" to 3450 m
Casing:	30" at 184 m, 20" at 930 m, 16" liner at 1472 m, 9 5/8" at 2600 m

Formation Integrity:	At 1107 m / 0.9 s.g., at 1473 m / 1.41 s.g., at 2609 m /1.67 s.g.

Drilling summary

Robot 1 was abandoned at 969 m after the 20" casing become stuck at 606 m and all attempts to remedy the situation were unsuccessful. The well was respudded as Robot 1A and a 36" hole was drilled to 190 m and the 30" casing was set at 184 m. The 26" open hole was then drilled to 1103 m, initially with the 17 1/2" bit followed by a 26" hole opener. Tight hole was experienced in this section caused by the hard-soft ledgy nature of the formations. The string became stuck several times, but was successfully freed each time and pulled out of the hole. The 20" casing was set with the shoe at 930 m. The 17 1/2" pilot hole was then drilled to 1500 m followed by a 20" under reamer. A 16" liner was run to 1472 m with the hanger at 830 m to isolate the lost circulation zones associated with the very loose limestone lithologies. The 12 1/4" pilot hole was then drilled to 1900 m. At this point the string became stuck. The fishing was unsuccessful and the side track hole had to be drilled to 2609 m with a 12 1/4" bit. Attempts to under ream this section to 17 1/2" were unsuccessful and the 9 5/8" casing had to be set with the shoe at 2600 m. The 8 1/2" hole was drilled to total depth with no significant problems. Several drilling breaks were encountered in this section but with no significant shows and without encountering the predicted overpressured formations. (BP Petroleum Development Ltd 1988).

Pore pressure evaluation

0-1900 m:	The "d" exponent shows two main zones of potential overpressures 1842 to 1870 m and 1930 to 1978 m. However, this is not supported by any other evidence such as increased trip and connection gas. Shale density was constant between 2.25 and 2.35 s.g. The cuttings were large but not splintery.
1900-2600 m:	This section was normally pressured. Pore pressure gradient is estimated at 1.04 s.g.
2600-2632 m:	There was some evidence of minor overpressure in this zone indicated by the "d" exponent. However, the cuttings evidence was inconclusive, the background gas was low, and no hole problems were

encountered by drilling with 1.36 mud weight. Pore pressure gradient was estimated to be 1.04 s.g.

3632-3100 m: This hole section was considered normally pressured.

3100-3450 m: There is some evidence from the "d" exponent that this section is in the transition zone. The pore pressure at total depth is evaluated to be close to 1.04 s.g. as evidence to the contrary was largely unsubstantiated.

5.1.6 Hilda 1/1A

General Data:	West Australian Petroleum Pty Ltd Location - 21°12'00.02"S, 114°38'12.09"E Elevation - Sea floor - 144.5 m, RT - 12 m Drilling Commenced - 5/3/1974 Rig Released - 28/9/1974 Status - Plugged and abandoned
Hole Sizes:	36" to 192 m, 26" to 400 m, 17 1/2 to 1552 m, 12 1/4" to 1663 m, 8 1/2 to 2686 m
Casing:	30" at 183 m, 20" at 394 m, 13 3/8" at 1532 m, 9 5/8" at 1644 m, 7" liner at 2692 m
Formation Integrity:	At 1644 m / 1.74 s.g., at 2692 m / 1.92 s.g.

Drilling summary

Because of mechanical difficulties, Hilda 1 was abandoned at a depth of 1546 m and respudded some 30 m from the original location as Hilda 1A. The well was drilled to the 20" casing depth with no difficulties. Drilling below the 20" casing shoe resumed with a 17 1/2" bit to 1556 m. Continued mud losses of between 60 and 150 bbl/h were experienced throughout this section. Five successive cement plugs were set using a total of 1100 sacks of cement in order to cure losses but without success. Cementing of the 13 3/8" casing was not successful and an additional 9 5/8" casing had to be run. The 9 5/8" casing shoe was drilled out with a 8 1/2" bit and the hole drilled to 2064 m with no problems. At this depth drilling was suspended for three days due to rig mechanical difficulties. Drilling resumed to 2669 m with a slow average rate of 6 m/hour. Tight hole and bridging was experienced in this section. The mud weight was raised to 1.56 s.g. At this depth, the 7" liner was run as a protective string and the drilling resumed to 3207 m with a 6" bit and no hole problems. The mud weight was reduced from 1.56 to 1.31 s.g. At this depth logs were run, after which the hole was deepened to a total depth of 3466 m. After running a series of RFT logs, the hole was plugged and abandoned (Meath & Wright 1974).

<u>Pore pressure evaluation</u>

0-3466 m:	All indirect pressure evaluation parameters indicate a normal hydrostatic pressure gradient of 1.0 to 1.03 s.g. RFT tests conducted between 2668 and 3086 m support this conclusion.

5.1.7 Bowers 1

General Data:	West Australian Petroleum Pty Ltd Location - 21°06'13.92"S, 114°42'54.01"E Elevation - Sea floor - 133.3 m, RT - 25 m Drilling Commenced - 12/5/1982 Rig Released - 26/8/1982 Status - Plugged and abandoned
Hole Sizes:	36" to 195 m, 26" to 518 m, 17 1/2" to 1768 m, 12 1/4" to 2919 m, 8 1/2" to 4300 m
Casing:	30" at 183 m, 20" at 508 m, 13 3/8" 1748 m, 9 5/8" at 2903
Formation Integrity:	At 2903 m / 1.65 s.g.

<u>Drilling summary</u>

36" and 26" holes were drilled and 30" and 20" casings run with no hole problems. The 17 1/2" hole was then drilled to 1768 m. In this section various degrees of mud losses were encountered. Between 750 and 1056 m, mud losses averaged some 20 bbl/h. At 1056 m, after a bit trip, the loss was 200 bbl/h but was later reduced to earlier levels by use of loss circulation material. The remaining section was drilled with an average loss of 30 bbl/h. Mud density was kept between 1.06 and 1.1 s.g. A 12 1/4" hole was drilled to 2919 m with no significant problems. Mud densities were raised to 1.38 s.g. to prevent formation sloughing. A 8 1/2" hole was drilled to 3688 m with mud densities ranging between 1.13 and

1.15 s.g. From this depth, mud weight was gradually increased to 1.45 s.g. to combat connection gas and gas-cutting of the mud. At a drilling depth of 3845 m, the drill string was differentially stuck against the Flacourt Formation while tripping out of the hole. The string was freed and the hole drilled to total depth without incident. (Spagnuolo & Wright 1983).

<u>Pore pressure evaluation</u>

0-3519 m: There is no indication of abnormal pressures in this section. One RFT measurement at 3372 m indicated pore pressure of 1.24 s.g. However, RFT measurement at 2953, 3074 and 3396 m gave a normal pressure gradient of about 1.0 s.g.

3519- 3731 m: At 3519 m, the Malouet Formation was intersected. In the section, increase of background and connection gas indicate a possible overpressured zone. Also, the "d" exponent exhibited a minor shift to the left. RFT measurements were not successful because of a badly washed-out hole and tight formation, so abnormal pressures could not be confirmed by direct measurements.

3731-4300 m: Normal hydrostatic pressure regime of about 1.07 s.g. This is confirmed by RFT measurements at 3936, 3952, 3970 and 4032 m.

5.2 Interpretation of normally pressured and overpressured intervals

Normal formation pressure at any depth is usually defined as the hydrostatic pressure exerted by the column of water from that depth to the surface. Normal pore pressure is a function of formation water density or salinity and can be only maintained if a sufficiently permeable pathway to surface exists. Normal pressure gradients generally vary between 0.433 psi/ft (fresh water) and 0.465 psi/ft (salt water). Pore pressures in excess of these values are considered abnormal and the formation is called overpressured. Sometimes formation pressures higher than hydrostatic are caused by differential effects. Thus low density gas on top of a normal pressured water column is called abnormal pressure. It is doubtful, however, that this classification is correct because the system is basically under a hydrostatic regime.

From the drilling point of view, formation pore pressure is important because it has a direct effect on the ability of the formation to resist hydraulic fracturing and subsequent lost circulation, it is of primary consideration in well control, and it has indirect effects on drilling rate and drilling costs.

In this study, pore pressures as evaluated by indirect means and direct measurement are plotted versus depth on Figures 5.1 and 5.2. Wells which showed abnormal pressure behaviour are plotted on Figure 5.1 while wells which showed normal pressure behaviour are plotted on Figure 5.2. The gross lithologies encountered by each well and evaluation of fracture propagation pressures in each well are also shown.

Fracture propagation pressures were calculated by the following equation:

$$P_f = \frac{\mu}{1-\mu}(S_v - P_p) + P_p \quad ; \text{ where}$$

P_f = Fracture propagation pressure (psi)

μ = Poisson's ratio (dimensionless; taken as 0.33)

S_v = Total vertical stress of overburden (psi; taken as 1.04 psi/ft)

P_p = Formation pore pressure (psi; taken as evaluated)

Because Poisson's ratio and vertical stress were taken uniformly across the trajectory of each well, changes in lithology and formation densities were disregarded and the fracture propagation pressures calculated by the above equation may vary considerably from the true values.

5.3 Causes of overpressured intervals

Over much of the Barrow Sub-basin, overpressures occur in the upper part of the Dingo Claystone (Kopsen & McGann 1985). The tops of the main overpressured zones, where present in the wells studied here, occur in the Barrow Group. None of the wells determined to have overpressured sections penetrated the upper part of the Dingo Claystone. Thus it could not be determined if overpressured zones extend down into the Dingo Claystone, or if separate overpressured zones occur in that unit in the West Barrow Vacant Area.

As shown above, three of the seven wells studied - Bowers 1, Hilda 1/1A, Robot 1/1A - were essentially normally pressured. Both Bowers 1 and Hilda 1A lie southwest of the West Barrow Vacant Area on the Alpha Arch. They both drilled through the 'Main' Unconformity below the Barrow Group section but did not encounter the Dingo Claystone. Robot 1/1A is in the northern part of the West Barrow Vacant Area. The other four wells studied encountered overpressured zones. In West Barrow 1A and 2 and Spar 1, the top of overpressuring occurs in the fine-grained lower part of the Flacourt Formation in the prodelta sediments. To the south, in Rosily 1A, the whole of the Flacourt Formation and the upper sandy part of the Malouet Formation are normally pressured and the top of overpressuring occurs in the lower shaley part of the Malouet Formation. However, the top of the overpressured zones occurs at similar depths in the four wells (Fig. 5.1). If the overpressuring is a continuous zone between the wells, there must be a transition from normal pressure to overpressure within the sandy upper Malouet Formation between Rosily 1A and West Barrow 1/1A and 2. The nature of such a boundary is uncertain, and could presumably follow a stepwise path through shales between discontinuous sandstones, or comprise a fault, or a combination of these and some form of cementation or other barrier within sandstones. Alternatively, the overpressured regime at Rosily 1A may be a separate system to the one, or ones, further north.

There are numerous possible causes of overpressures in geological formations. Horstman (1988) has recently summarized these causes with reference to the Australian North West Shelf. He concluded that the primary causes are hydrocarbon generation and non-equilibrium compaction which may be considered as 'active' and 'passive' processes respectively. Although these two processes are likely to be the main causes of overpressured intervals in the Barrow Sub-basin, as noted by Plumley (1980), overpressures may well occur as a combination of causes.

Non-equilibrium compaction may have been induced by the relatively rapid deposition of the Barrow Group sequences of thick sandstones and shales, preventing normal water loss from the underlying shale units as they compacted. At later burial stages, aquathermal pressuring may have contributed to, or reinforced, the overpressures.

The overpressures in the wells studied are at depths corresponding to Horstman's (1988) 'deeper' zone of overpressures which he attributes to hydrocarbon generation. Additionally, the overpressures are at a depth which corresponds approximately to the main zone of maturation (Robertson Research 1986). Although data are sparse, the absence of overpressures in the Barrow Group shales in some places may be due to the absence of hydrocarbon source potential, although the intervals may be organically mature. Thus the lower Flacourt Formation shales may be source rocks at West Barrow 2 and Spar 1, but lack source potential at Bowers 1 (Robertson Research 1986), and overpressures are developed at the former wells but not at Bowers 1. Hence, overpressuring in the Barrow Group may be dependent on the organic facies of shale units within the organically mature zone.

Another factor in the non-occurrence of overpressured zones where they might be expected in the region is release of pressures through faults and/or sediment conduits. Readjustments on faults through the Cretaceous and Tertiary are likely to have resulted in periods of relaxation of some faults, or sections of faults, which allowed relief of overpressured intervals.

On balance, it seems likely that the prime cause of overpressuring in the Barrow Group in the central part of the Barrow Sub-basin is phase pressure due to hydrocarbon generation. Non-equilibrium compaction and aquathermal pressuring may be additional factors. Although well data on overpressured zones combined with organic maturity mapping may prove to be a good guide to where overpressuring may occur in this area, the distribution of overpressed intervals is by no means entirely predictable.

5.4 Drilling problems

The problems associated with drilling into the overpressured formations in the region of the West Barrow Vacant Area are mainly due to inadequate casing design and, consequently, differential sticking. A number of strings have been left in the hole and projected total depth was not reached for that reason. It appears that a prudent practice should be to set additional casing string, prior to drilling, into these overpressured zones. In addition to overpressures, the area proved to be extremely difficult to drill in the surface hole to approximately 700 m. From the surface to approximately 300 m, the formations consists of unconsolidated sandstones with minor interbedded carbonates. From approximately 300 to 700 m, carbonates become progressively more abundant and, at approximately 700 m, the section comprises mainly massive carbonates. The problems associated with surface hole drilling are:

- hole cleaning, because unconsolidated sandstone tends to flow into the well bore when the circulation is stopped, and the sand settles around the bottomhole assembly causing the string to stick;

. straight hole drilling due to carbonate ledges; and

. loss of circulation in the massive carbonate section.

Furthermore, if drilling is not properly balanced, the thick shale section above the Barrow Group will cause shale sloughing and eventually hole collapsed in case of greatly underbalanced drilling, or shale ballooning in case of greatly overbalanced drilling.

Therefore drilling programs in the West Barrow Vacant Area should particularly take into account the likely occurrence of overpressured sediments within the Barrow Group, the possibility of lost circulation in Cainozoic carbonates, and the sloughing of Cretaceous shales above the main objective Barrow Group.

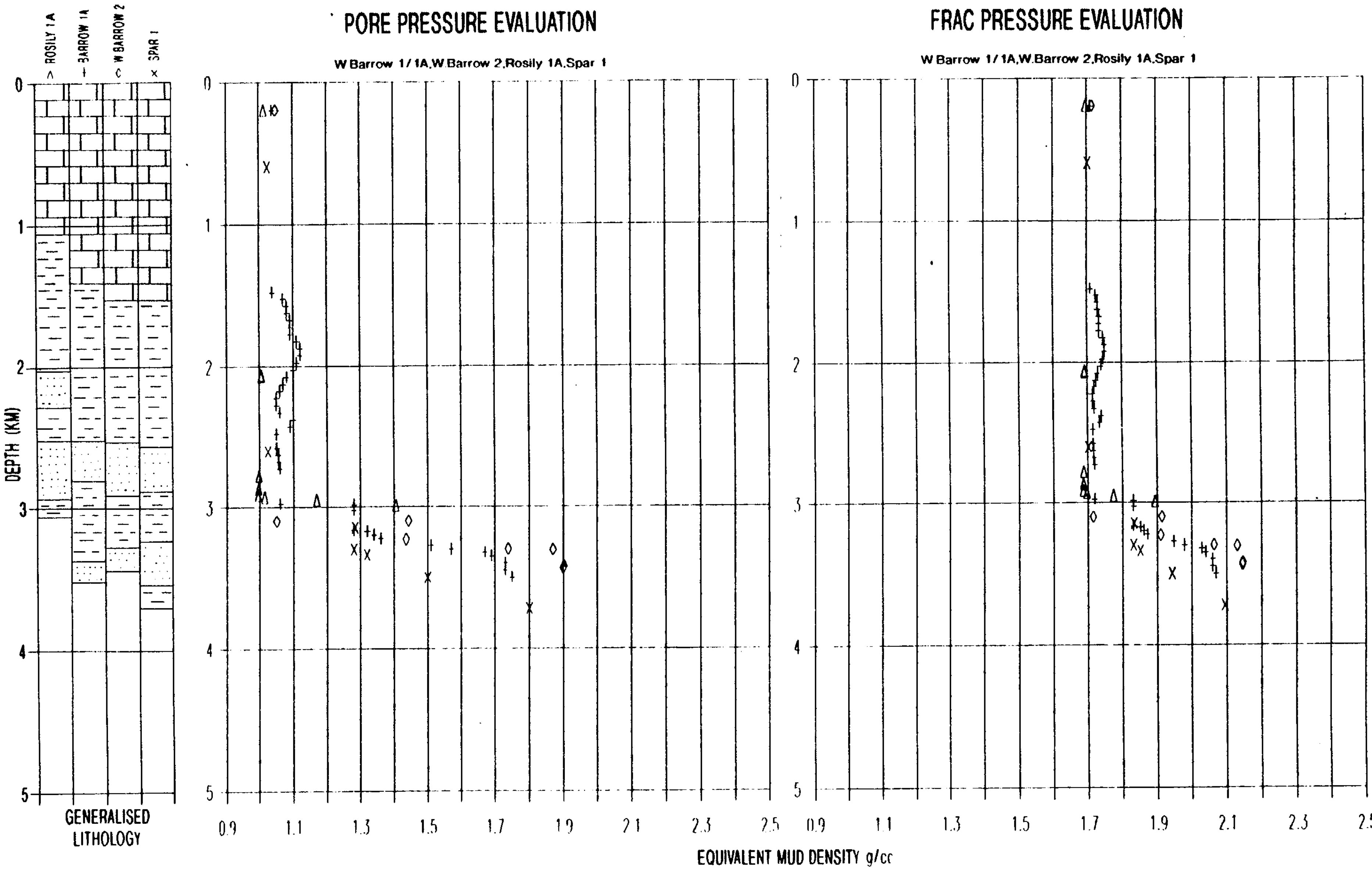


Figure 5.1 Pressure evaluation for West Barrow 1A/2,Rosily 1A and Spar 1 (over pressuring)

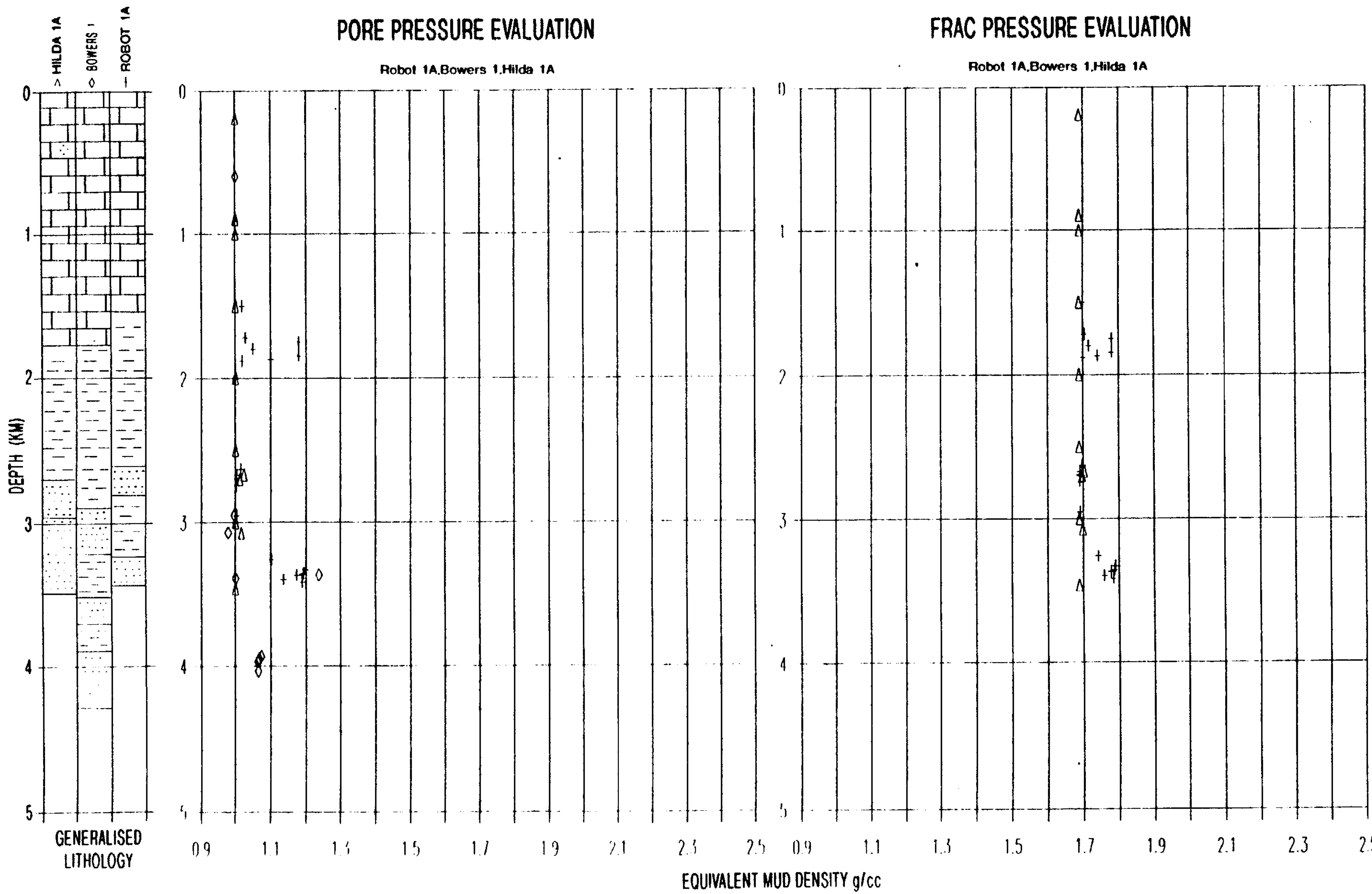


Figure 5.2 Pressure evaluation for Robot 1A, Bowers 1 and Hilda 1A (normal pressures)

6. PETROLEUM PROSPECTIVITY

6.1 Reservoir and seal potential

The prime reservoir and seal combination in the West Barrow Vacant Area is the Flacourt Formation at the top of the Barrow Group, overlain by the Muderong Shale and the Mardie Greensand. Potential targets are the Malouet Formation sealed by lower Flacourt Formation shales, and clean sandstones that may be developed within the Mardie Greensand. Deeper potential objectives are Dupuy Formation sandstones, and possibly the Biggada Sandstone Member or equivalent sandstones if they can be identified in upthrown blocks at drillable depths - the identification of upthrown fault blocks is also necessary to bring the Mungaroo Formation into consideration as an objective. The Windalia Sandstone Member may prove to be present in the area. Younger formations are unlikely to be considered as primary or secondary targets, but some could host hydrocarbons that have migrated through the underlying section.

6.1.1. <u>Main Potential Reservoirs</u>

6.1.1.1 BARROW GROUP - FLACOURT FORMATION

The Flacourt Formation contains good quality reservoir sandstones deposited in the upper part of a major delta system as it advanced northwards through the southern and central Barrow Sub-Basin. A series of stacked sands dominate the upper part of the Flacourt Formation (Plates 19 & 20). They are generally described as fine to very coarse grained and pebbly quartz sandstones, well to poorly sorted, variably cemented, slightly kaolinitic, with thin interbeds of siltstone and sandstone and minor coal.

Porosity in the reservoir sections of fields in the upper Flacourt Formation of the Barrow Sub-basin ranges from 18 to 26 percent and permeability from 200 md to several darcies (Parry & Smith 1988; Tait & others 1989).

Porosities interpreted from logs of selected wells within and adjacent to the West Barrow Vacant Area are shown in Figures 6.1-6.4. Porosity in sandstones with less than 20 percent interpreted shale is mainly fair to good. In Bowers 1 porosity in the upper Flacourt Formation is mainly between 10 and 33 percent, the average declining with depth from 20 to 15 percent. In West Barrow 1A and 2 and Robot 1A porosity is mainly in the range 10 to 22 percent, averaging approximately 14 percent overall and increasing to 17 percent in the shallower parts of the upper Flacourt Formation.

Sandstones which may be considered as potential reservoirs occur as minor components of the finer grained lower part of the Flacourt Formation. This section represents the prodelta sequence, and comprises predominantly siltsones and claystones with isolated fine to very coarse grained sandstones.

The Mardie Greensand, which overlies the Flacourt Formation in the West Barrow Vacant Area, has both reservoir and seal properties as discussed below, and may act as a thin 'thief zone'. The overlying Muderong Shale and, above that, the Gearle Siltstone are excellent regional seals, and Parry & Smith (1988) concluded that all oil fields discovered in the Barrow Sub-basin are sealed by these formations. From available information this conclusion appears to be valid.

Upper Flacourt Formation sandstones are considered to constitute the primary exploration target in the West Barrow Vacant Area.

6.1.1.2 BARROW GROUP - MALOUET FORMATION

The Malouet Formation also contains significant thicknesses of good quality reservoir sandstones (Plates 19 & 20), and is considered to be second only to the Flacourt Formation as an exploration objective in the West Barrow Vacant Area. As noted previously, the Malouet Formation generally comprises an upper sandy section and a lower silty section comprising distal prodelta and fan deposits. The three wells drilled in the West Barrow Vacant Area have only penetrated a sandy section of Malouet Formation, but have not drilled through the unit. However, the silty lower part of the Malouet Formation does occur in Rosily 1A, and probably extends north into the West Barrow Vacant Area. Overpressures have been encountered in the Malouet Formation in several wells (see Section 5 - Implication of abnormal pressures on drilling practices).

The upper Malouet Formation consists of fine to very coarse grained, moderately to poorly sorted sandstones, in part silty and argillaceous, with varying siliceous or calcareous cementation. These sandstones are interbedded with siltstones and claystones.

Porosity in the Malouet Formation, interpreted from logs from wells in the West Barrow Vacant Area, is shown in Figures 6.5-6.7.

Porosity ranges mainly between 5 and 15 percent in West Barrow 1A and 2, averaging from 8 to 10 percent. In Robot 1A porosity ranges from 7 to 28 percent with an average of 15 percent. Core analyses from Malouet Formation sandstones between 3520 and 3650 m subsea in Bowers 1 immediately south of the West Barrow Vacant Area range from 3 to 17 percent with an average of 10.6 percent; permeability ranges from 0.5 to 100 md with an average of 7.8 md (Spagnuolo & Wright 1983).

The Flag Formation is an approximate facies equivalent of the Malouet Formation to the north of, and possibly extending into, the West Barrow Vacant Area. Porosity averages 22 percent and permeability is 800 to 2000 md in the Harriet Field at approximately 1900 m subsea (De Boer & Collins 1988).

Malouet Formation reservoirs are likely to be sealed by predominantly siltstones and shales of the prodelta facies in the lower part of the Flacourt Formation, which range from at least 401 to 547 m thick in wells in the West Barrow Vacant Area. There are also intraformational shales which are potential seals.

6.1.2 <u>Subsidiary Potential Reservoirs</u>

6.1.2.1 MARDIE GREENSAND

The Mardie Greensand has some reservoir potential, although generally acts as a seal or a 'thief zone'. There are intervals of good porosity in sandstone units, but good permeability is rarely developed. The only producing pool in the unit is on Barrow Island where the reservoir has 28 percent porosity and averages 4 md porosity (Crank 1973; Campbell & others 1984). In the southwest Barrow Sub-basin, the Mardie Greensand in the South Pepper field has up to 30 percent porosity and permeability between 0.5 and 55 md; a gas flow of 25 000 m^3/day was recorded from a test of the unit (Williams & Poynton 1985). Core analyses in Mardie 1 and 1A on the Peedamullah Shelf show porosities of 23 to 46 percent and permeabilities of 0.5 to 263 md (Thomas 1978).

In the West Barrow Vacant Area, the Mardie Greensand is represented mainly by a glauconitic pebbly wacke facies, partly underlain by thin glauconitic conglomerate. The pebbly wackes are described as fining upwards cycles (up to 2 m thick) grading from pebbly to argillaceous glauconitic wackes, as shown by core material from Rosily 1A (Hocking & others 1988). In West Barrow 1A, the Mardie Greensand was described as medium grained quartzose sandstones with rare glauconite at the base, grading upwards to glauconitic fine grained sandstones with interbedded siltstones and claystones (Offshore Oil 1982). The best reservoir potential in the unit is likely to be developed in the more quartzose sandstones, probably largely derived by reworking of the Flacourt Formation, where acceptable permeabilities may occur.

Clean sandstones (<20 percent shale) in the Mardie Greensand in West Barrow 1A and 2 have been determined from neutron and density logs to account for the glauconite effect on the gamma ray log (see Section 4 - Open Hole Log Interpretation). Clean sandstones have log interpreted porosity ranging from 29 to 46 percent with an average of 33 percent.

In Hilda 1A, a 3 m oil column was identified near the top of the Mardie Greensand, as interpreted in this study (Plate 19); the sandstone has 16 percent porosity and a permeability range of 100 to 1000 md was calculated from FIT data (Meath & Wright 1974). In the Mardie Greensand in Rosily 1A, core porosity was measured as ranging from 14 to 20 percent with a mean of 17 percent and the permeability range was 0.01 to 3.8 md with a mean of 0.78 md (Gilchrist & Rogers 1983). Light oil was noted bleeding from the core.

Prediction of permeable sandstone occurences in the Mardie Greensand will continue to be extremely difficult or impossible, but the unit has potential for the development of thin reservoir-quality sandstones which may be adjuncts to accumulations discovered in the Flacourt Formation.

6.1.3 Other potential reservoirs

The Cretaceous Windalia Sand Member at the top of the Muderong Shale is the main reservoir for the Barrow Island oil field, but its sporadic development through the Barrow Sub-basin and relatively poor permeability in the Barrow Island field - average 2.5 md at approximately 600 m depth - make it a low priority target for offshore exploration. Where present, it is enclosed in the excellent seals of the Muderong Shale and overlying Gearle Siltstone.

The Jurassic Dupuy and Biggada Formations are petroleum reservoirs on Barrow Island, east of the West Barrow Vacant Area. The Dupuy Formation comprises slightly to moderately argillaceous, glauconitic and occasionally pyritic, poorly to well sorted, very fine to medium grained sandstones interbedded with siltsones and shales. Tait

(1985) divided the Dupuy Formation into three lithofacies: fine grained homogenous sandstones, bioturbated sediments, and matrix-supported conglomerates. On Barrow Island at depths of approximately 2000 m, porosity is of the order of 20 percent and permeability up to 200 md (Crank 1973). The Dupuy Formation reservoirs may be sealed by basal shales of the Malouet Formation and by intraformational seals.

Sandstones of the Biggada Formation are mainly clean, moderately sorted, medium to very coarse grained. On Barrow Island 20 percent porosity and 18 md were recorded for gas productive sandstones (McClure & others 1988). The thick overlying Dingo Claystone seals the Biggada Formation regionally, and intraformational seals are also developed.

Like the Dupuy and Biggada Formations, Triassic units are likely to be too deeply buried to be exploration targets in the West Barrow Vacant Area, unless preserved at sufficiently shallow depths in horst blocks. The Mungaroo Formation is a petroleum reservoir along the Rankin Platform and Alpha Arch. Just southwest of the West Barrow Vacant Area, porosity in the Mungaroo Formation in Bowers 1 was 5 to 14 percent below 3881 m subsea (Spagnuolo & Wright 1983) and in Hilda 1A average porosity in the formation declines from 20 to 12 percent between 2988 and 3454 m subsea with poor to fair permeability (Meath & Wright 1974). On the Rankin Platform northwest of the West Barrow Vacant Area, porosity in the Mungaroo Formation is 14 to 18 percent and, permeability 100 to 128 md in the Gorgon and West Tryal Rocks fields (Parry & Smith 1988).

6.2 Hydrocarbon source potential

The following is summarised from an extensive study of the petroleum geochemistry of the North West Shelf by Robertson Research (1986). The report is now available on open file from the Bureau of Mineral Resources.

The main effective oil source rocks for the Barrow Sub-basin in general, and the West Barrow Vacant Area in particular, occur in the Dingo Claystone of Late Jurassic age. The kerogens are detrital and were derived from the delta plain and the landmass to the east. Within the central part of the basin, exinites become abundant, grading to vitrinitic-rich and then to predominantly inertinite on the basin margins. Both the Murat Siltstone and Athol Formation contain good oil-prone source rocks but they are less extensive than the Dingo Claystone source rocks.

The Dingo Claystone in the basinal areas is within the oil window and may have reached late maturity in the deeper parts of the sub-basin.

The source potential of the Triassic sediments (Mungaroo Formation and Locker Shale) is more speculative because there are fewer data points. The Locker Shale may be a good source rock, particularly if its deep water facies is represented by black shale deposited under stagnant, anoxic conditions. Such source rocks would have become mature by the end of the Triassic and post-mature and gas-generating in the Late Jurassic. The Mungaroo Formation contains poor quality, but thick, gas source rocks but there is an area of good oil potential in the northwestern part of the Barrow Sub-basin. The Mungaroo Formation is in the late mature to post-mature phases of oil generation over most of the Barrow Sub-basin. Oil potential has been determined in parts of the prodelta shales of the lower part of the Flacourt Formation which are mature in the central part of the sub-basin.

Fair to good oil source rocks occur in the Cretaceous Muderong Shale within the sub-basin axis. However, this sequence is only in the oil window in the deepest parts of the sub-basin.

6.2.1 Interpretive methods

Source rocks in this study include shales, siltstones and coals. Their environments of deposition range from upper delta plain through lower delta plain and delta front to deep water shales interbedded with turbidites. Their potential is constrained by thickness and by quality so that thin, rich source rocks such as coals, as well as thick, poor quality shale sources, have been evaluated on a comparative basis.

The interpretation of pyrolysis data gives estimates of the amounts of algal sapropel (Type I), exinite or waxy sapropel (Type II), vitrinite (Type III) and inertinite (Type IV). Where a suite of analyses is available for a well section of interest, they are averaged. In order to compare well sections of a source rock which are at different levels of maturity, kerogen abundances are adjusted to a common base level.

The abundances of kerogen types always show the presence of inertinite and therefore discrimination between different kerogen types is made by recognising an inertinite facies, only if inertinite is 51 percent or greater of the kerogen. For lower values of inertinite content, the kerogen facies is allocated to the most abundant kerogen type other than inertinite. Mapping of kerogen facies demonstrates the relations between kerogen facies and lithofacies and the trends and controls on organic sedimentation.

6.2.2 Organic facies

6.2.2.1 PERMIAN

Shales in the Kennedy and Byro Groups have organic carbon contents of 1 to 2 percent, but with only a minor component of oil-generating kerogen. It is possible that thickness and frequency of shales and their richness in oil-generating kerogen increases away from the basin edge. However, in that direction, Permian source rocks will be over mature and would have entered the gas zone by the end of the Triassic.

6.2.2.2 LOCKER SHALE

The Locker Shale averages up to 2.3 percent total organic carbon (TOC) on and adjacent to the Peedamullah Shelf. Shales are vitrinitic in Sholl 1 and Observation 1. They contain a slight predominance of waxy kerogen in Hermite 1, thus making a good quality source rock. The trends suggest that the Locker Shale may be a good source rock in the northern Carnarvon Basin. Such source rocks developed under the central Barrow Sub-basin would have become mature by the end of the Triassic, and post-mature and gas-generating in the Late Jurassic.

6.2.2.3 MUNGAROO FORMATION

Organic carbon contents of the shales are most frequently between 0.5 and 1.5 percent, but the most carbonaceous shales approach 10 percent. Hydrogen indices are low and the kerogens are dominated by inertinite with subordinate vitrinite. Coals contain 80 to 100 percent vitrinite. In general, there is potential for large amounts of gas sourcing.

6.2.2.4 BRIGADIER BEDS

Occasionally, thin shales contain low quality oil source rocks.

6.2.2.5 MURAT SILTSTONE

TOC levels are between 1 and 4 percent. Over most of the Barrow Sub-basin shales are interpreted to be vitrinite rich.

6.2.2.6 ATHOL FORMATION

The marine shales of the Athol Formation contain kerogens dominated by vitrinite and inertinite. However, an enrichment in oil-generating kerogen may be present to the west and north of Koolinda 1, which contains 350 m of shale with an average organic content of 1.7 percent. The subordinate amount of exinite in this source rock unit make it a fair quality oil and gas source rock.

6.2.2.7 DINGO CLAYSTONE

The most productive source rocks of the Barrow and Dampier Sub-basins are present within this the Dingo Claystone. Deposition of marine shales took place within a deep water, restricted marine basin. The shales are rarely very carbonaceous, with organic carbon contents usually between 1 and 3 percent. The kerogens are detrital and were derived from the delta plain and landmass to the east. On the margins of the basin, the kerogens are dominated by inertinite, but they become increasingly vitrinite-rich towards the basin centre. Within the central part of the sub-basins, exinites become abundant, but rarely exceed 40 percent of the kerogen.

The area of most oil-prone source rocks extends southwards from the south side of the Rankin Platform and includes Flag 1 and Koolinda 1, but not Anchor 1 or West Muiron 2 (Fig. 6.8).

6.2.2.8 BARROW GROUP

Shales with organic carbon contents of 1 to 3 percent accumulated as both distal delta and prodelta deposits. Inertinite-rich sediments are confined to the thin shales within the marine shelfal sediments. Some enrichment in exinite occurs in deltaic shale in West Barrow 2. A trend to increasing exinite content is also apparent in distal prodelta shales, based on subordinate amounts appearing in shales in some wells. Although these shales are only poor to fair quality oil source rocks, their thicknesses are such that they could have generated fair amounts of oil (10-15 million bbl/km^2) where fully mature.

6.2.2.9 MUDERONG SHALE

Over much of the Barrow Sub-basin, shales of this unit are carbonaceous, with organic contents between 2 and 3 percent, and occasional richer horizons of 3 to 4 percent. The distribution of different types of kerogen is generally controlled by distance from shoreline. Inertinite-rich kerogens dominate near-shore sediments on the southeasterly margin of the basin. The kerogen facies of the southern part of the central Barrow Sub-basin is interpreted as vitrinitic, becoming waxy exinitic to the north and west (Fig. 6.9). Within the zone of exinite-enriched kerogens, there are fair to good quality source rocks which have reached middle maturity.

6.2.3 Organic maturity

Organic maturity is mapped in terms of spore colour index (SCI) which is measured on a scale of 1 to 10. Although oil generation begins at SCI 3.5, the generally low quality source rocks of the Carnarvon Basin are not likely to have generated enough oil for effective migration until SCI 5.0 is reached. The effective oil window is therefore taken to be from SCI 5.0 to SCI 8.5.

Over most of the Barrow Sub-basin, rocks older than mid-Triassic, including the Locker Shale, have passed through the oil window, although these units are only early to middle mature on the eastern margin of the sub-basin. The deepest sedimentary sections are even passing out of the gas zone into incipient regional metamorphic zones.

Over much of the Barrow Sub-basin, the Mungaroo Formation is post-mature, although in the southern part of the sub-basin it is late mature, and in part of the Alpha Arch the unit is still only in the middle mature zone (Fig. 6.10).

The top of the Upper Dingo Claystone or, if absent, strata at base Cretaceous level, are in the effective oil window across most of the Barrow Sub-basin including under the West Barrow Vacant Area, and in the northern Barrow Sub-basin reaches late maturity and possibly the gas zone (Fig. 6.11).

The Muderong Shale is early mature over most of the Barrow Sub-basin and mature for oil generation in the central part of the sub-basin, including part of the West Barrow Vacant Area (Fig. 6.12).

6.3 Timing of migration

Migration of oil generated in the main petroleum source rock in the Barrow Sub-basin, the Dingo Claystone, probably occurred from Late Cretaceous to Miocene, coincident with the significant phases of structuring.

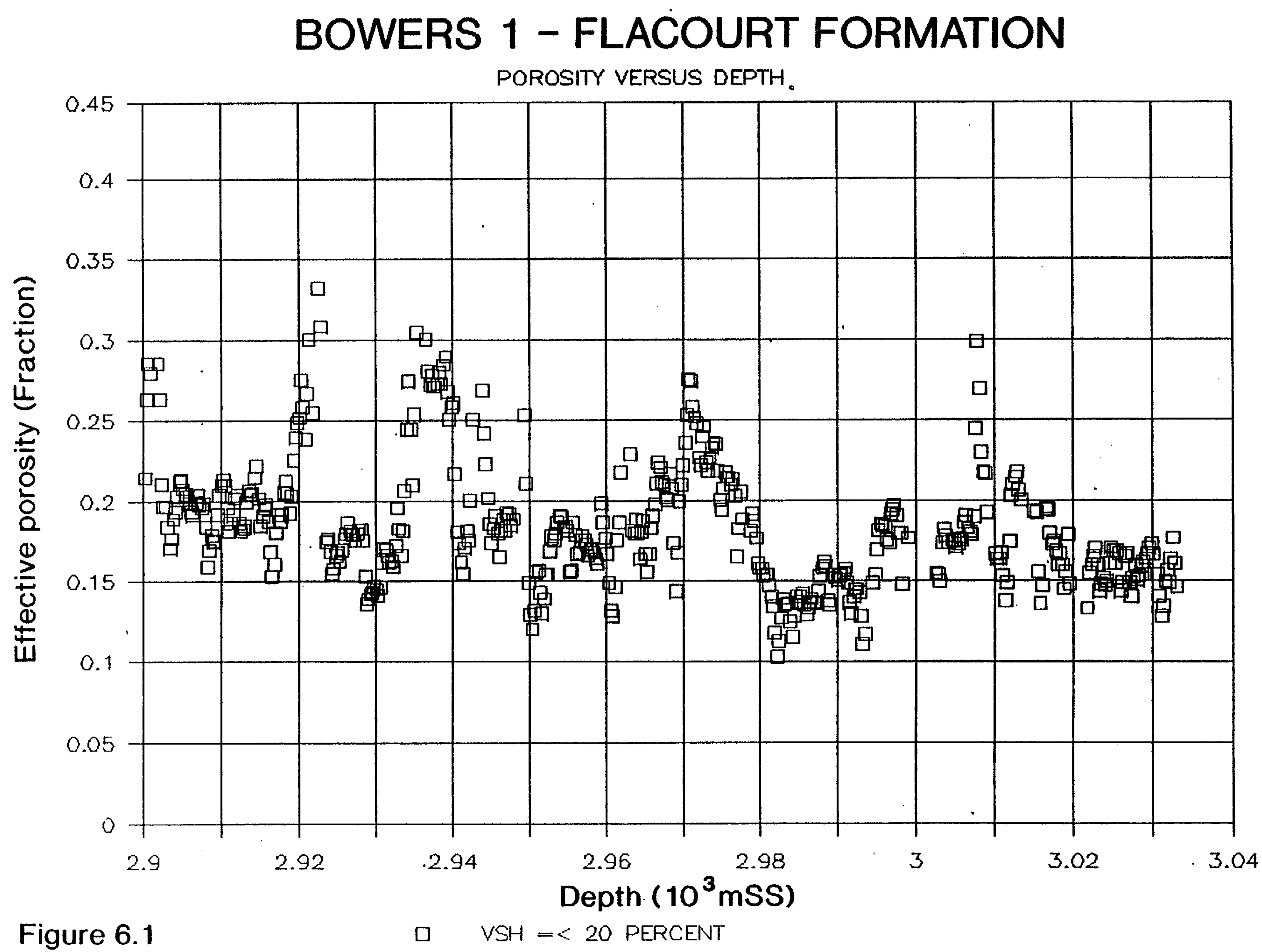

BOWERS 1 - FLACOURT FORMATION
POROSITY VERSUS DEPTH
Effective porosity (Fraction)
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
2.9
2.92
2.94
2.96
2.98
3
3.02
3.04
Depth (10^{3}mSS)
VSH =< 20 PERCENT

Figure 6.1

WEST BARROW 1A - FLACOURT FORMATION

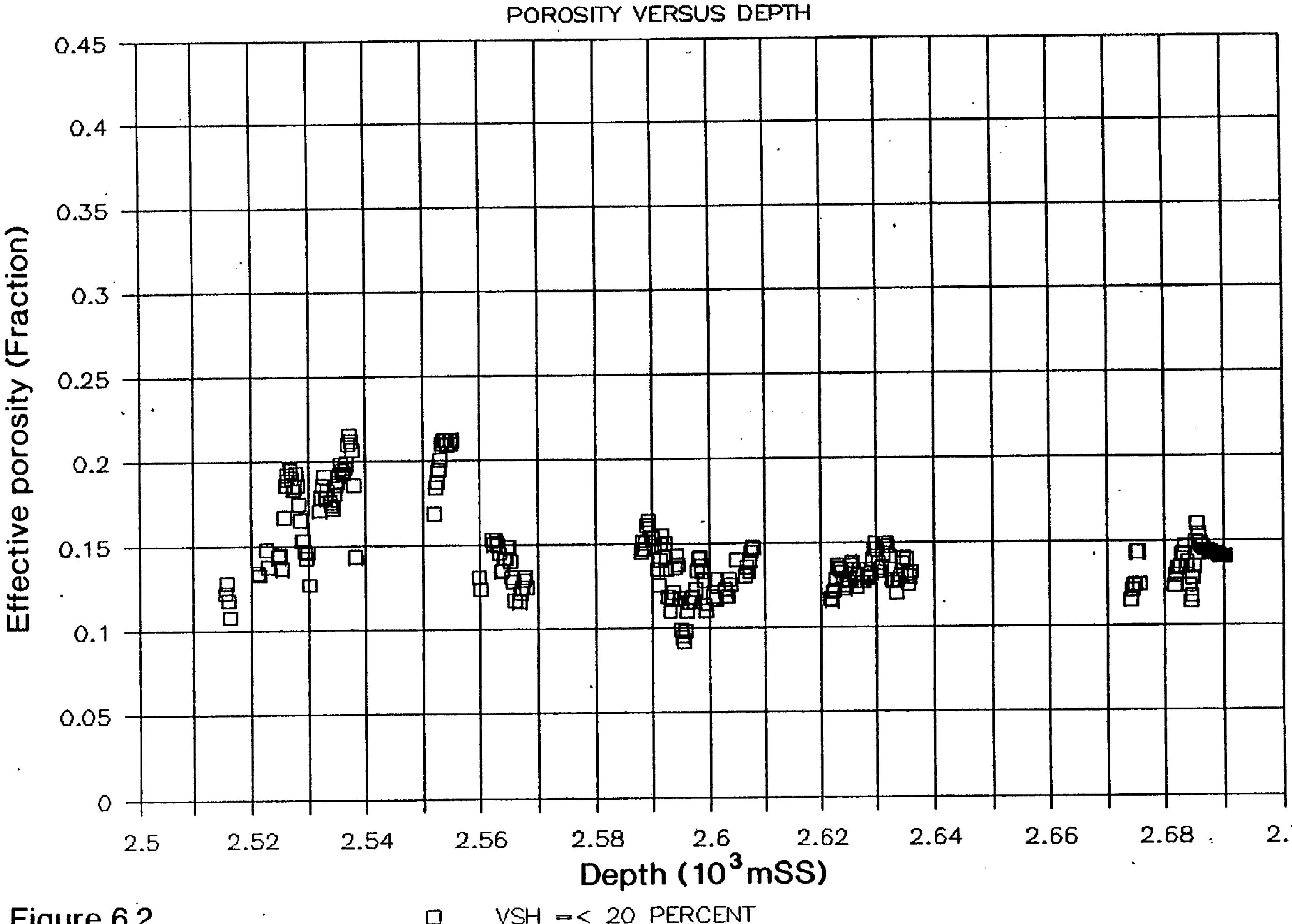


Figure 6.2

WEST BARROW 2 - FLACOURT FORMATION

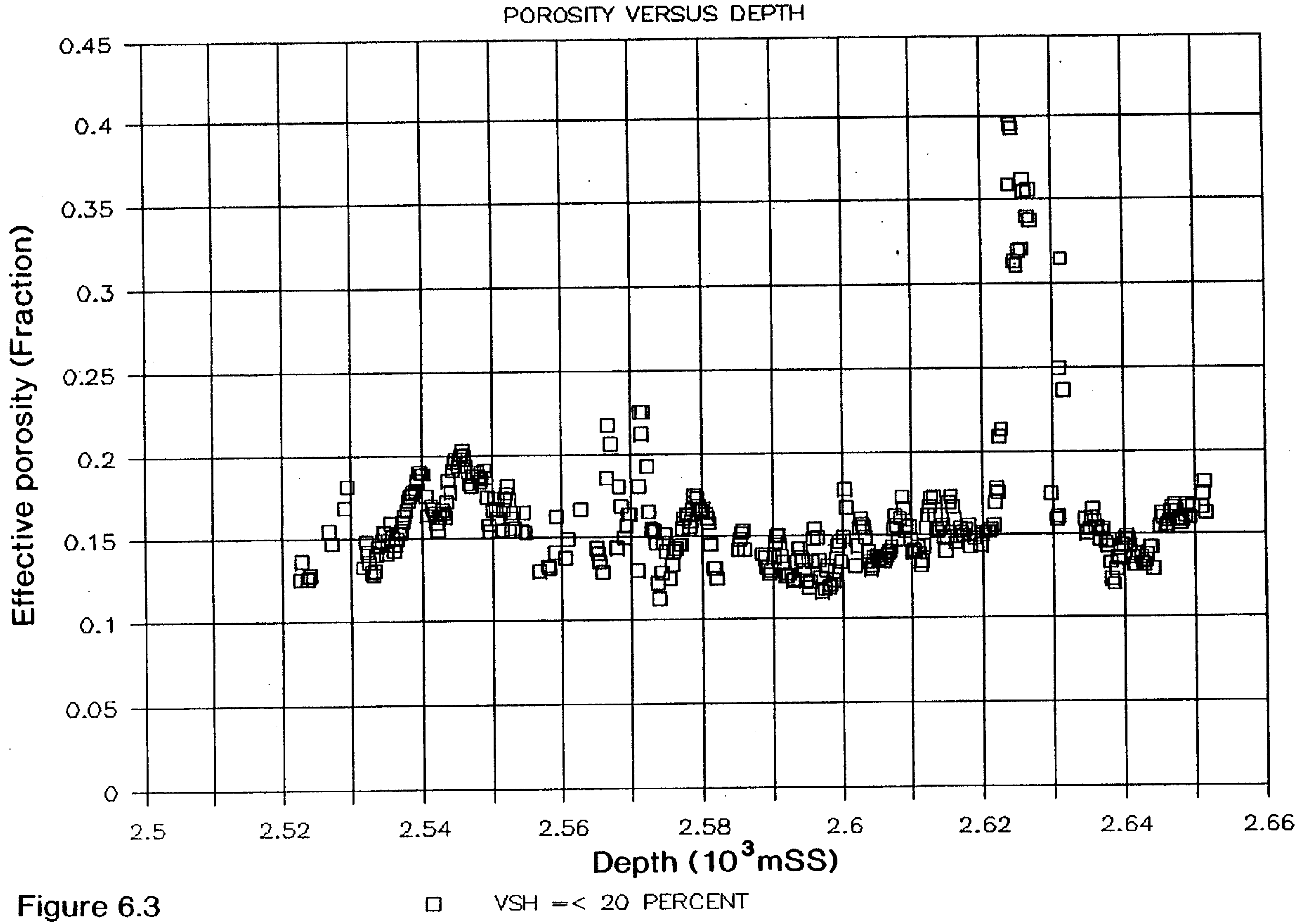
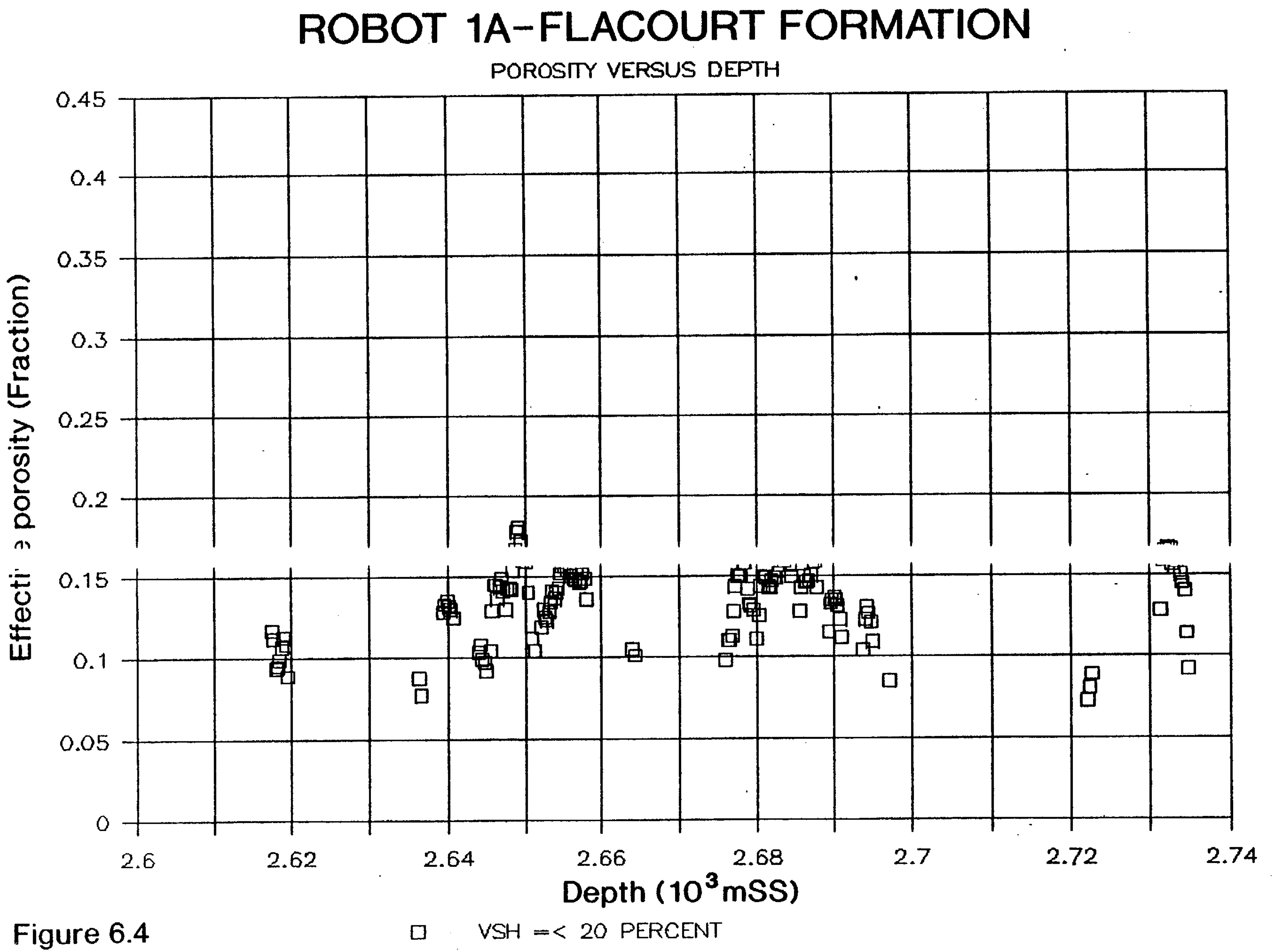


Figure 6.3



ROBOT 1A-FLACOURT FORMATION
POROSITY VERSUS DEPTH
Effective porosity (Fraction)
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
2.6
2.62
2.64
2.66
2.68
2.7
2.72
2.74
Depth (10³mSS)
VSH =< 20 PERCENT

Figure 6.4

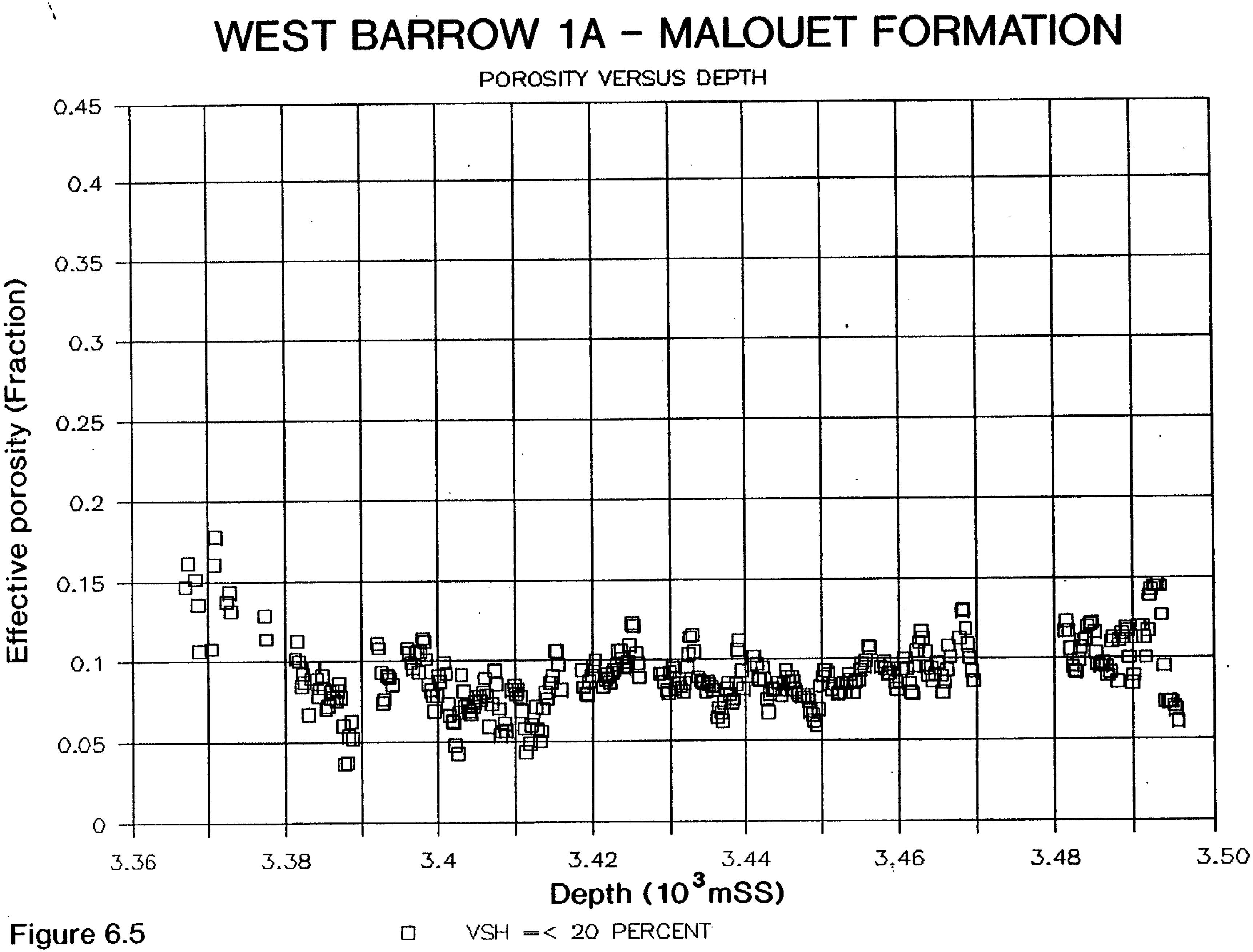

WEST BARROW 1A - MALOUET FORMATION
POROSITY VERSUS DEPTH
Effective porosity (Fraction)
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
3.36
3.38
3.4
3.42
3.44
3.46
3.48
3.50
Depth (10^3mSS)
VSH =< 20 PERCENT

Figure 6.5

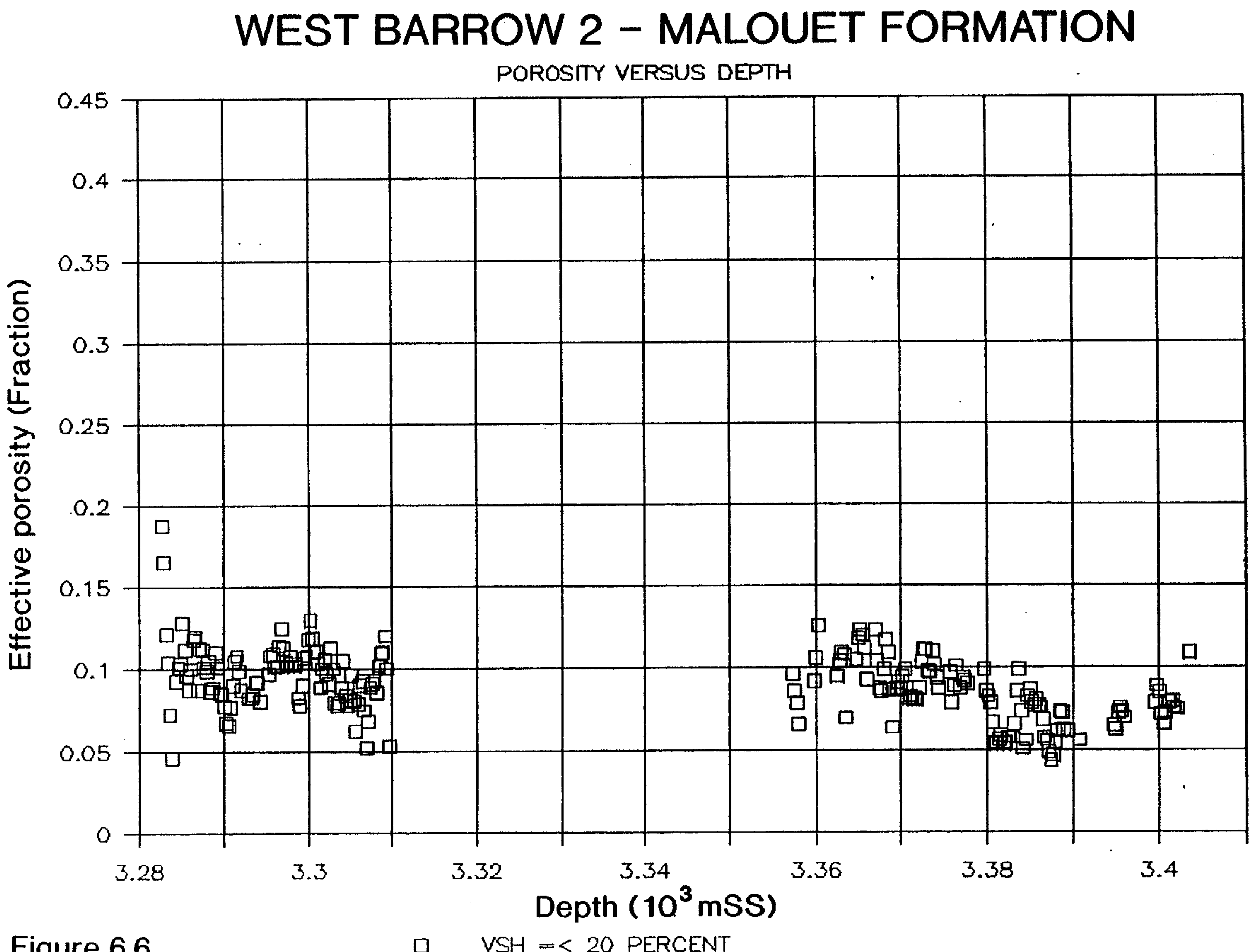

WEST BARROW 2 - MALOUET FORMATION
POROSITY VERSUS DEPTH
Effective porosity (Fraction)
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
3.28
3.3
3.32
3.34
3.36
3.38
3.4
Depth (10³ mSS)
VSH =< 20 PERCENT

Figure 6.6

ROBOT 1A-LOWER ZONE - MALOUET FORMATION

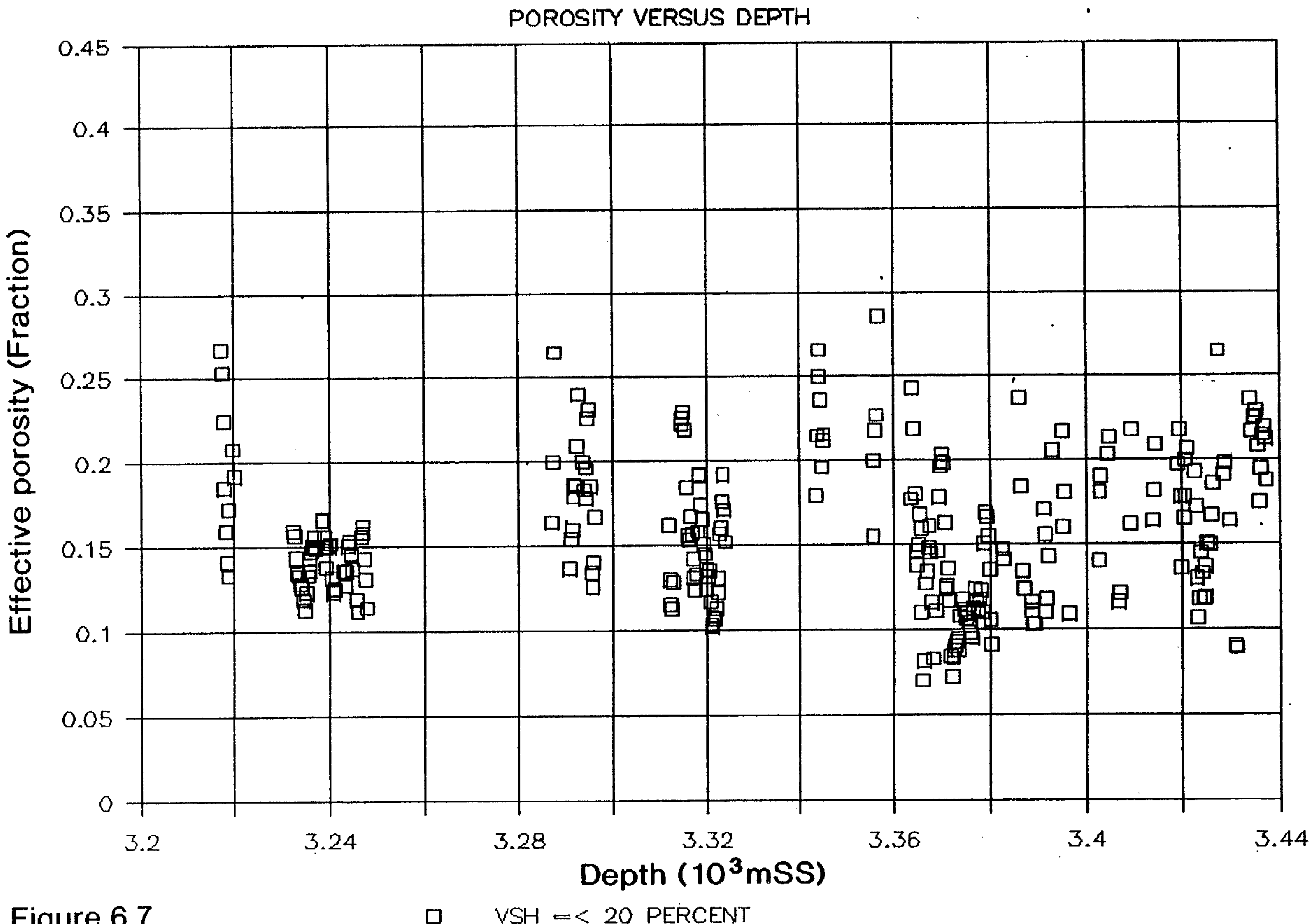


Figure 6.7

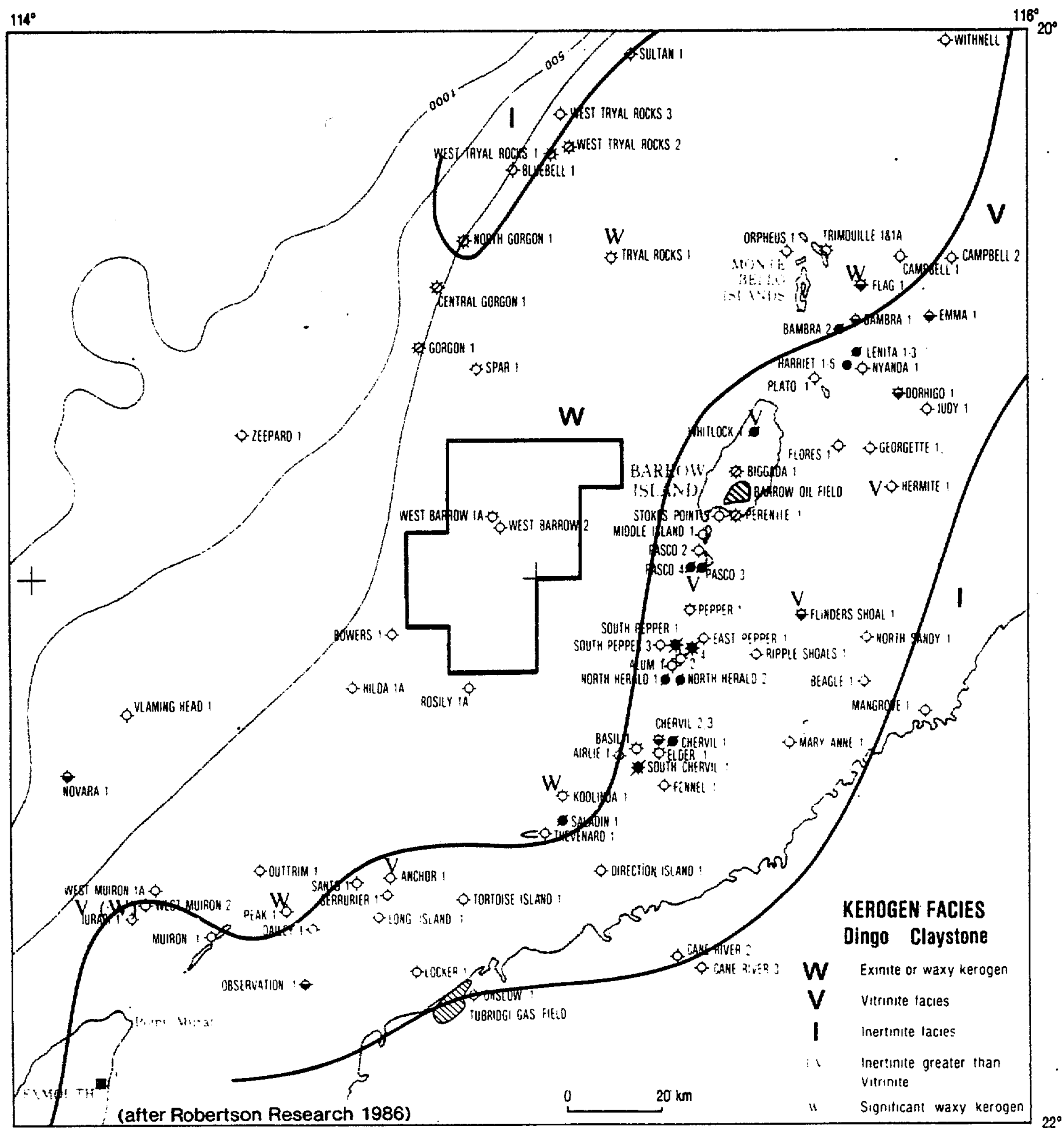


Figure 6.8 Upper Jurassic Dingo Claystone – organic facies

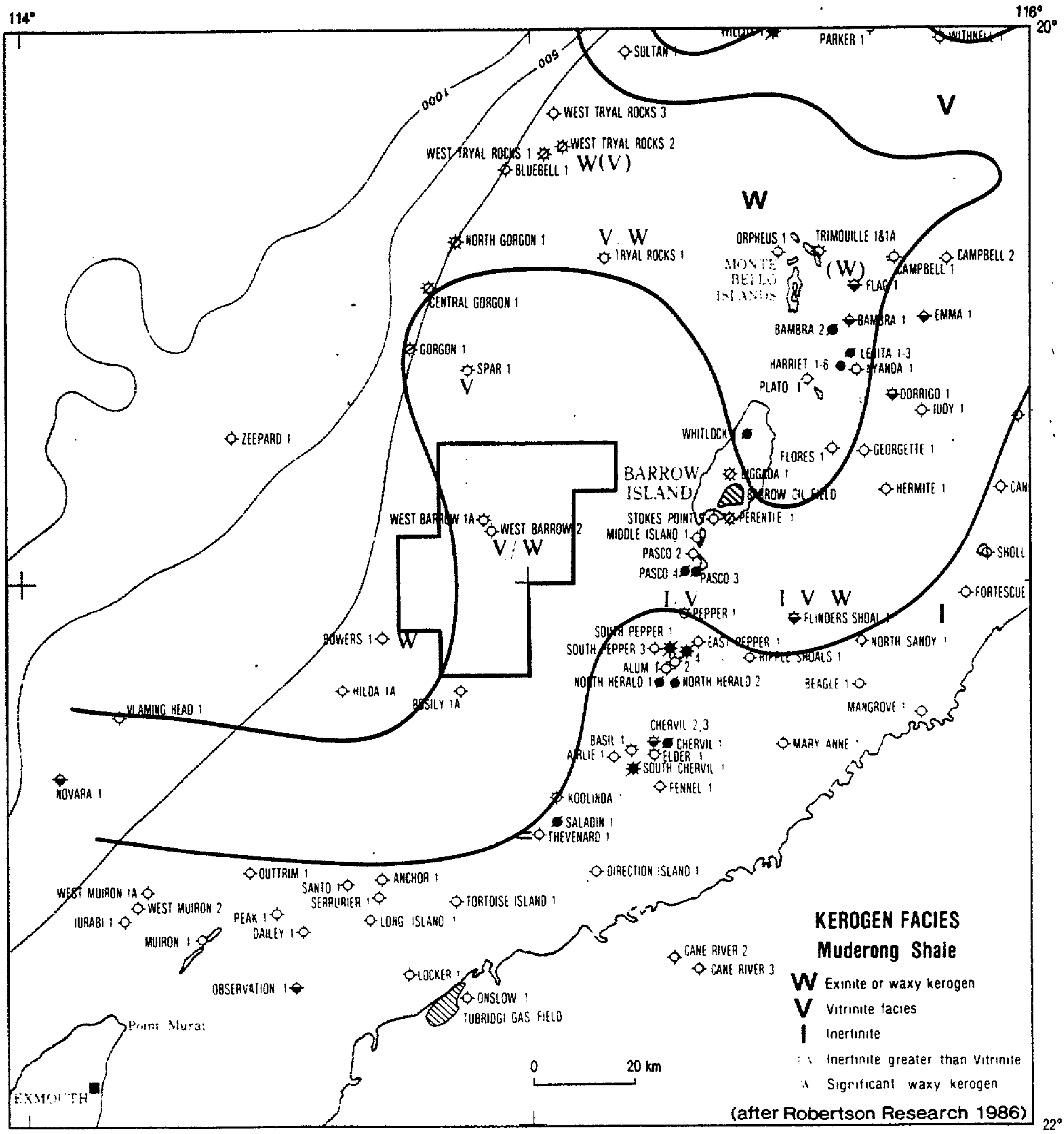
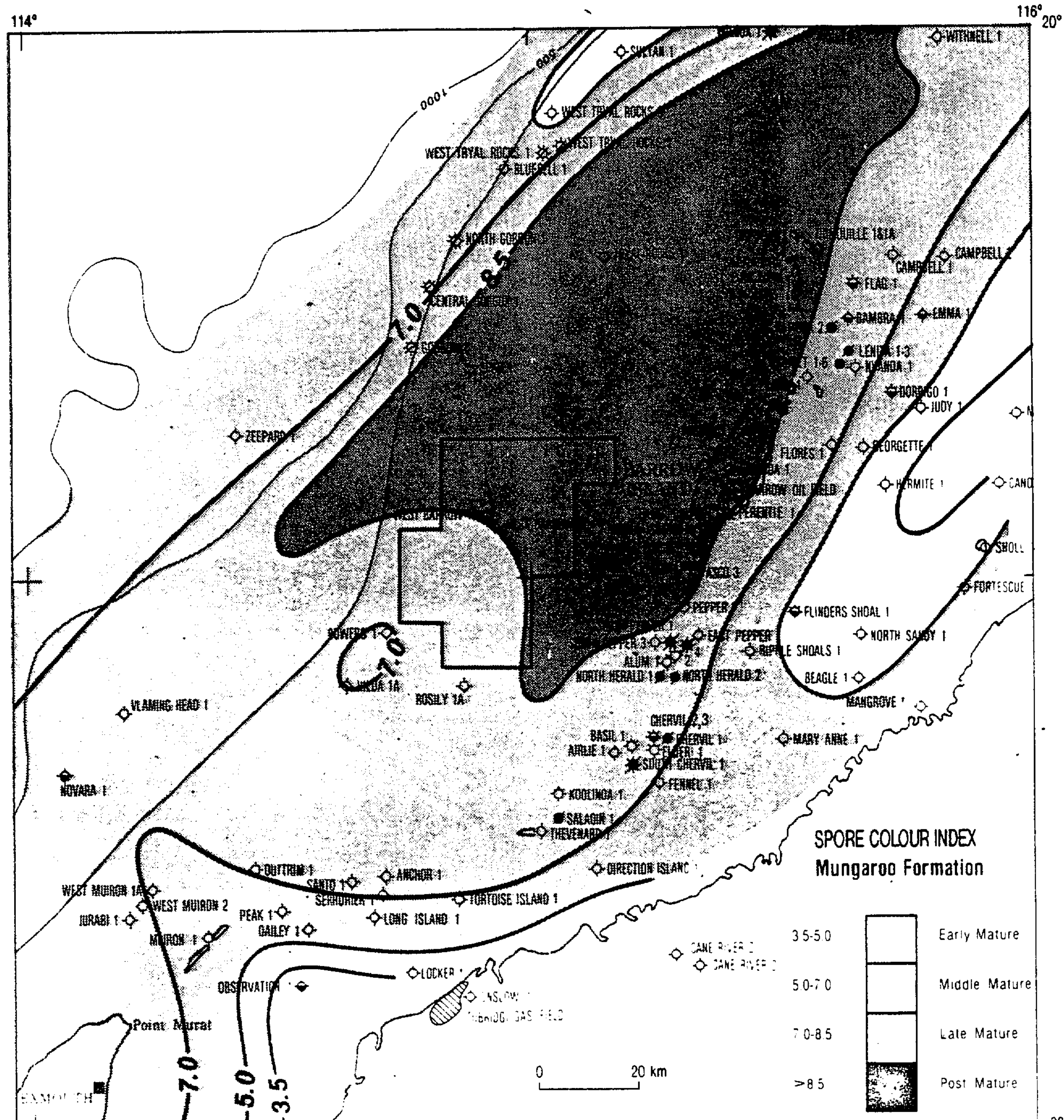


Figure 6.9 Lower Cretaceous Muderong Shale - organic facies



(after Robertson Research,1986)

Figure 6.10 Triassic Mungaroo Formation - organic maturity

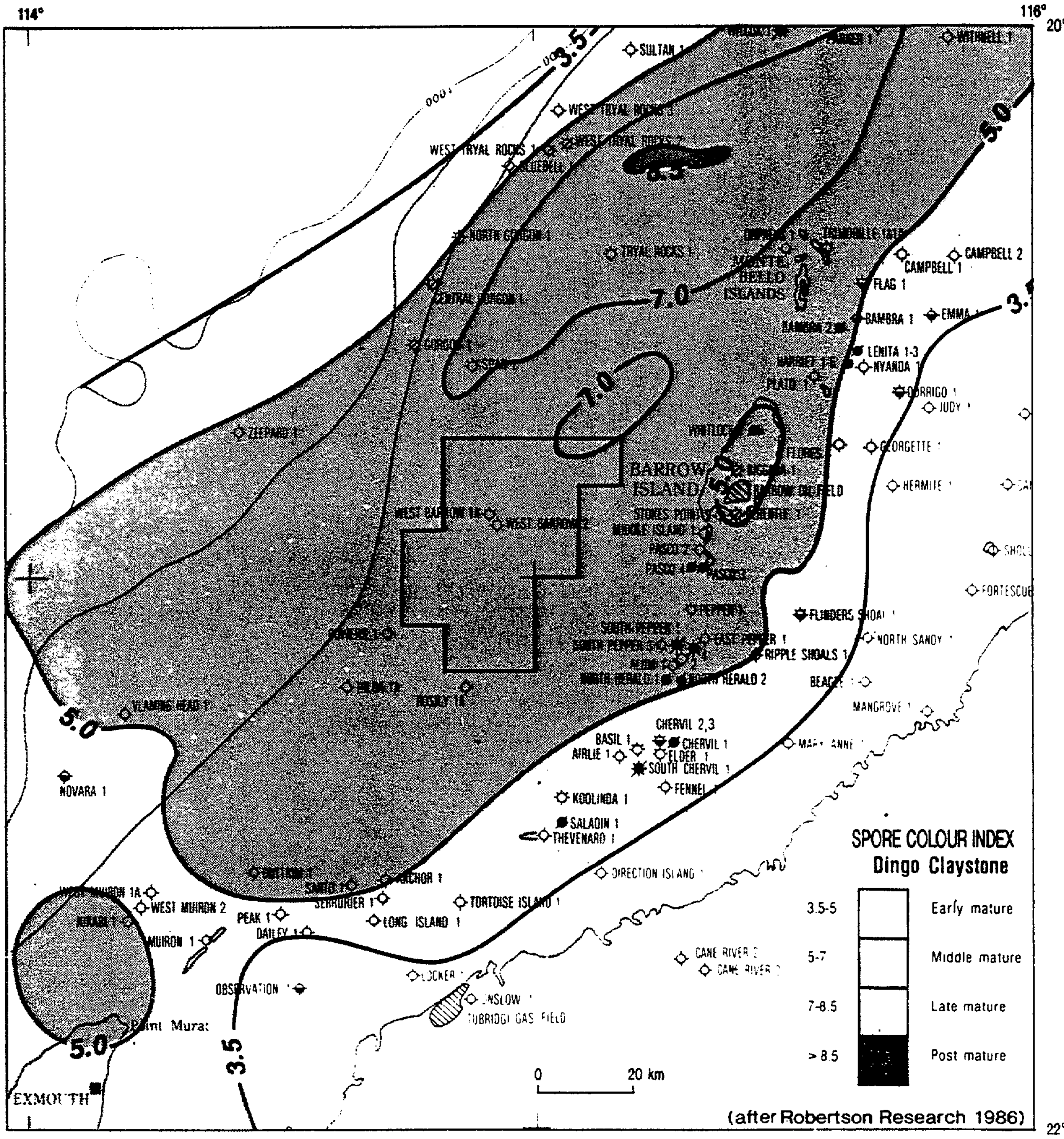


Figure 6.11 Upper Jurassic Dingo Claystone - organic maturity

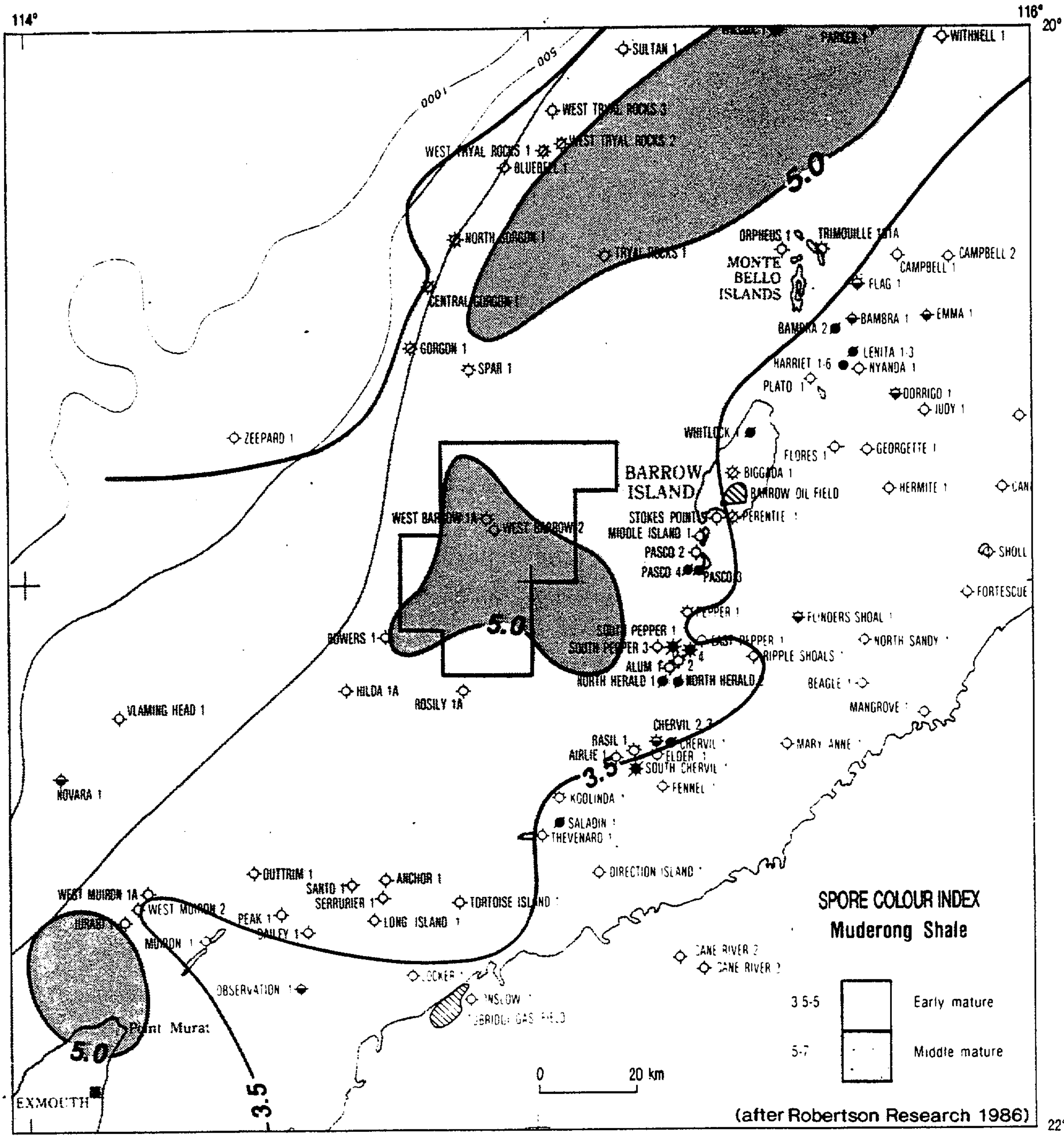


Figure 6.12 Lower Cretaceous Muderong Shale - organic maturity

7. PROSPECTIVITY

7.1 Source

The West Barrow Vacant Area is located within the centre of the Barrow Sub-basin which has been shown to have generated and reservoired liquid hydrocarbons by virtue of the discovery of commercial oil fields throughout its length. These include the newly discovered Griffin and Chinook fields located only 25 to 30 kilometres southwest of the Area, the Barrow Island field located 50 kilometres northeast of the Area, the Harriet-Bambra fields at the northern end of the Barrow Sub-basin and the South Pepper, North Herald, Chervil and Saladin fields located along its southeastern margin (Plate 1).

Figure 7.1 summarises the main factors affecting prospectivity of the West Barrow Vacant Area.

The West Barrow Vacant Area is underlain by a major petroleum kitchen which has generated significant quantities of oil as well as large amounts of gas. Source rock studies demonstrate that the Upper Jurassic Dingo Claystone is the main effective source rock, but that hydrocarbons have also been generated in the rest of the Jurassic to Lower Cretaceous sediment pile from the Murat Siltstone, Athol Formation, Barrow Group and Muderong Shale. Triassic formations, now mainly post-mature, also generated significant amounts of hydrocarbons early in the Barrow Sub-basin's history.

The occurrence of good oil shows from the Mardie Greensand, and from sands in the upper and middle Barrow Group (Flacourt Fm) and also from the lower Barrow Group (Malouet Fm) in West Barrow 1A, confirms the prediction of mature source rocks, that can be made from regional maturation and source rock studies.

Calculated timing of migration of petroleum from source rocks is Late Cretaceous through Cainozoic. This is favourable to the timing of trap formation as is evidenced by petroleum discoveries in the Barrow Sub-basin.

7.2 Reservoirs

Good reservoir sands occur throughout the Barrow Group. In addition, potential reservoir sands also occur in the overlying Mardie Greensand and underlying Dupuy Formation.

Both the Mardie Greensand and the Dupuy Formation form secondary targets. The Dupuy sands are a higher risk target because of the greater depth of burial. By contrast, good oil shows have been found in the Mardie Greensand in Hilda 1A adjacent to the West Barrow Vacant Area, but adequate permeability is rarely developed.

A regional synthesis of hydrocarbon shows the distribution of good porosity and permeability, and the flow rates from surrounding oil fields, clearly establish the top Barrow Group sands as the major reservoir throughout the Barrow Sub-basin. Data from West Barrow 1A, and 2, Robot 1A, Rosily 1A, Bowers 1A and Hilda 1A show that these sands are likely to have good porosity, permeability and areal distribution in the West Barrow Vacant Area.

The topmost Barrow Group sands were deposited as the topsets of a major "Barrow" delta system which prograded in a general northwards direction from Jurassic and Neocomian highlands which lay to the southeast and south of the Barrow Sub-basin. The direction of progradation can be clearly established by mapping the delta foresets as well as the distribution of the major delta surfaces as shown by the attitude of the main seismic reflectors within the "Barrow" delta complex as illustrated on Figures 3.2-3.3.

The three major sequences of the Barrow Delta System, the topset, foreset and bottomset sequences, are described as follows.

7.2.1 Topset sequence

In the West Barrow Vacant Area, the topset sequence is 300 to 400 metres thick and consists of a series of sands which have varying patterns on logs. Its log patterns, cuttings analysis descriptions, distribution as seen on seismic sections and other data, suggest that they have been deposited in a deltaic environment, probably as an inner and outer deltaic plain. Strandline or beach barrier sands may occur at the top of the sequence and upgrade its reservoir potential.

The relationship to the overlying Mardie Greensand is not well established. It appears to be a slightly unconformable contact which implies that the uppermost surface of the Barrow Delta was probably an abandoned coastal plain for some considerable time before it was covered during a rise in sea level, by sediments of the Mardie Greensand interval.

Evidence of cleaner sands occurring at the very top of the Barrow Sequence is seen in Bowers 1A and Rosily 1A. A close inspection of the distribution of vertical sequences in the upper Barrow "topset" mega-sequence indicates that it is made up of both fining-upwards and coarsening-upwards sequences. In general, the lowermost half of this topset sequence is made up of coarsening-upwards cycles which were probably deposited in an outer deltaic plain environment. In Bowers 1A, these corsening-upwards cycles are capped by a sequence of fining-upwards cycles, which is presumed to have been deposited in an inner deltaic plain or fluvial system. Similar inner deltaic plain sediments can also be found in Rosily 1A and West Barrow overlying a sequence of coarsening-upwards cycles.

In some wells, the inner deltaic plain sands are capped with outer deltaic plain (coarsening-upwards) cycles (Rosily 1A, West Barrow 1A, Robot 1A). These are often overlain by a sand which has a 'blocky' log character and which may represent a beach facies. The best reservoir porosities and permeabilities would be expected to occur in these sands.

7.2.2 Foreset sequence

The sediments of these sequences are dominantly shaley. Some thin sands occur, but they tend to be finer grained than those of the topset sequence and, hence, of poorer reservoir quality.

Canyon fill sands may occur within the foreset sequence, as a system of submarine channels is required to transport the sands of the bottomset facies down the front of the delta slope into deeper water. These sands, if extensive, could form excellent reservoirs.

7.2.3 Bottomset sequence

The foreset sequence merges downslope into more horizontal strata which form a sandy bottomset sequence called the Malouet Formation. Potentially good reservoirs occur throughout the Malouet Formation.

These sands are presumed to have formed in a submarine fan environment.

7.3 Play summary

Figures 7.2 to 7.6, together with Figure 7.1, encapsulate the main play interval in the West Barrow Vacant Area.

Figure 7.2 shows the extent and productivity of the main oil source unit, the Upper Jurassic Dingo claystone.

Figure 7.3 shows Late Jurassic palaeogeography, with the interplay of source, seal and reservoir rocks of the Dingo Claystone and Dupuy Formation.

Figure 7.4 shows the limit of progradation of the Lower Cretaceous Barrow Group, which contains the main reservoir intervals, the Barrow Group.

Figure 7.5 shows the extent and thickness of the Muderong Shale regional seal, together with its source potential in the West Barrow Vacant Area.

Figure 7.6 is a cross-section illustrating the favourable position of mature source beds of the Dingo Claystone particularly in relation to Barrow Group reservoirs.

The main targets for exploration are likely to be structural traps at the top of the Barrow Group (Flacourt Fm). Modern seismic surveying techniques are likely to allow the definition of structural and stratigraphic traps in the Malouet Formation. The Dupuy Formation may provide additional deeper objectives, and it is possible that the Mungaroo Formation may be an objective if the Alpha Arch is shown to extend into the area at shallow enough depths. There may be some reservoir potential developed in the Mardie Greensand.

Timing of hydrocarbon generation and formation of traps from Cretaceous through Tertiary is considered favourable for accumulation of petroleum pools in the West Barrow Vacant Area.

7.4 Traps and leads

Good sealing shales occur overlying most of the potential reservoir horizons. As there is little faulting that extends through these seals, it appears likely that structural traps that can be mapped on seismic are sealed and not leaky.

Three structural prospects have been identified and remapped in the West Barrow Vacant Area.

7.4.1 The North Rosily Prospect

Half the closure of this prospect is in the West Barrow Vacant Area. As this structure has considerable relief it should have the same and maybe better potential than the other two prospects. The most obvious target will be in Barrow Group sands. Faulting complicates the structure and 3-D seismic may be needed before drilling.

7.4.2 The West Barrow Prospect

The West Barrow Prospect has not been properly tested as West Barrow 1A drilled the edge of closure at the top Barrow (Flacourt Fm) and lower Barrow (Malouet Fm) levels, and West Barrow 2 drilled downdip at the top Barrow level. The definition of this prospect would benefit from remapping with 3-D seismic before further drilling.

7.4.3 The Gillian Prospect

The Gillian Prospect is yet to be drilled. It is by far the most prominent structural lead, but needs to be remapped as the seismic that was used to define it is of several different vintages and the present seismic grid is too broad for good definition of the prospect. Good potential reservoirs could exist within the Mardie Greensand, top Barrow and lower Barrow intervals.

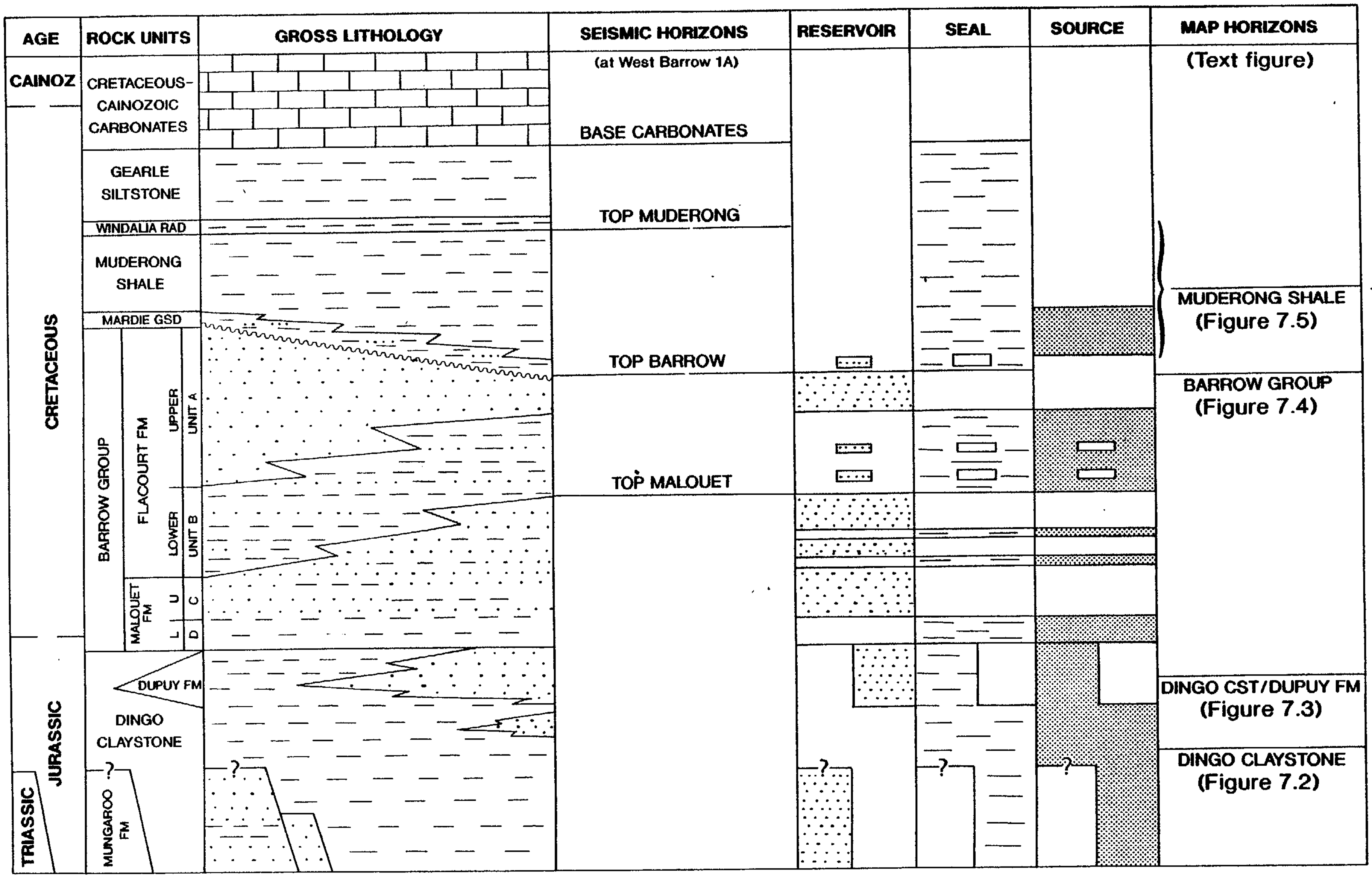


Figure 7.1 Summary chart - West Barrow Area Petroleum Prospectivity

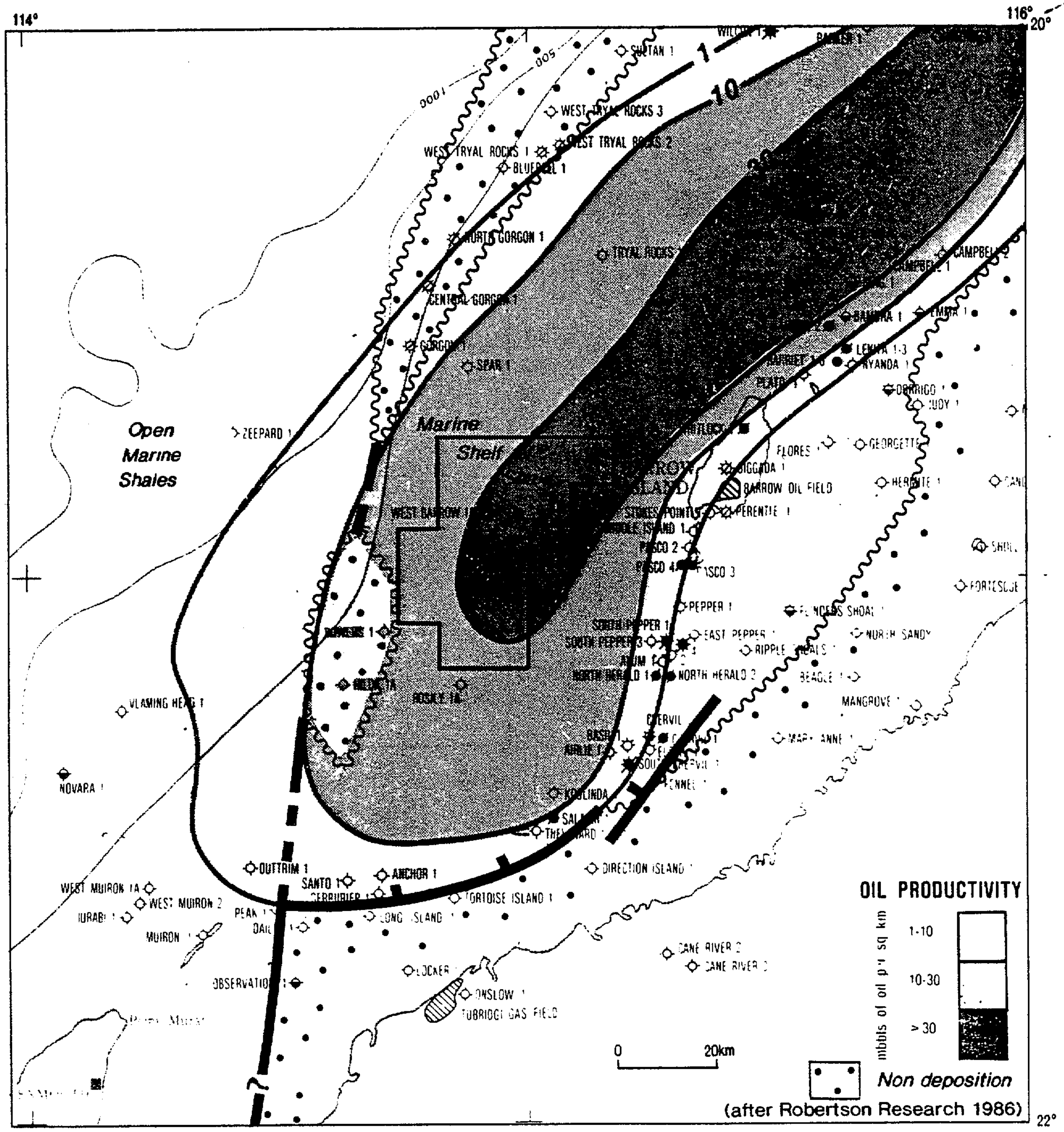


Figure 7.2 Upper Jurassic Dingo Claystone Source Rock

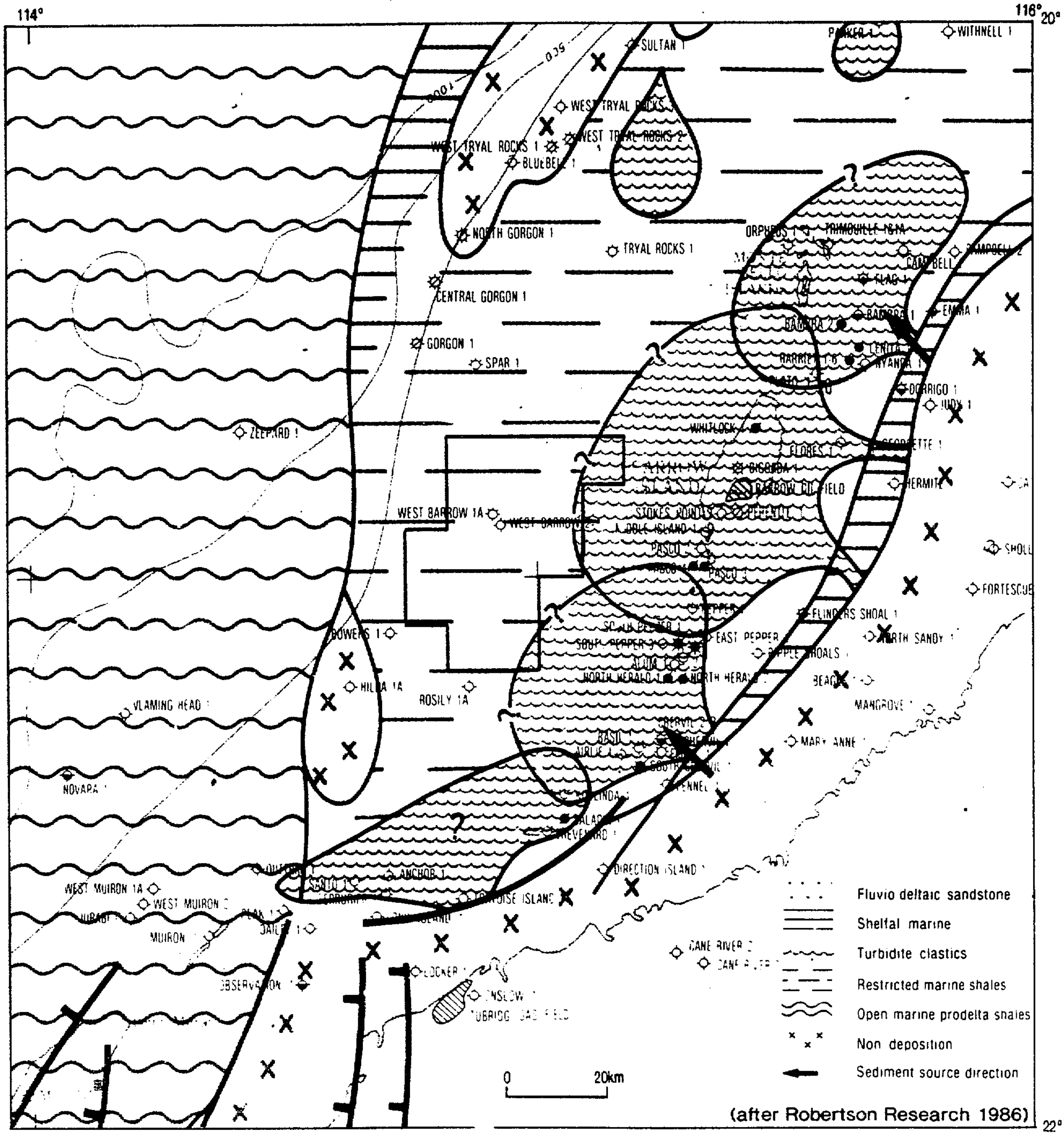


Figure 7.3 Upper Jurassic Dingo Claystone / Dupuy Formation Source / Reservoir / Seal Rocks

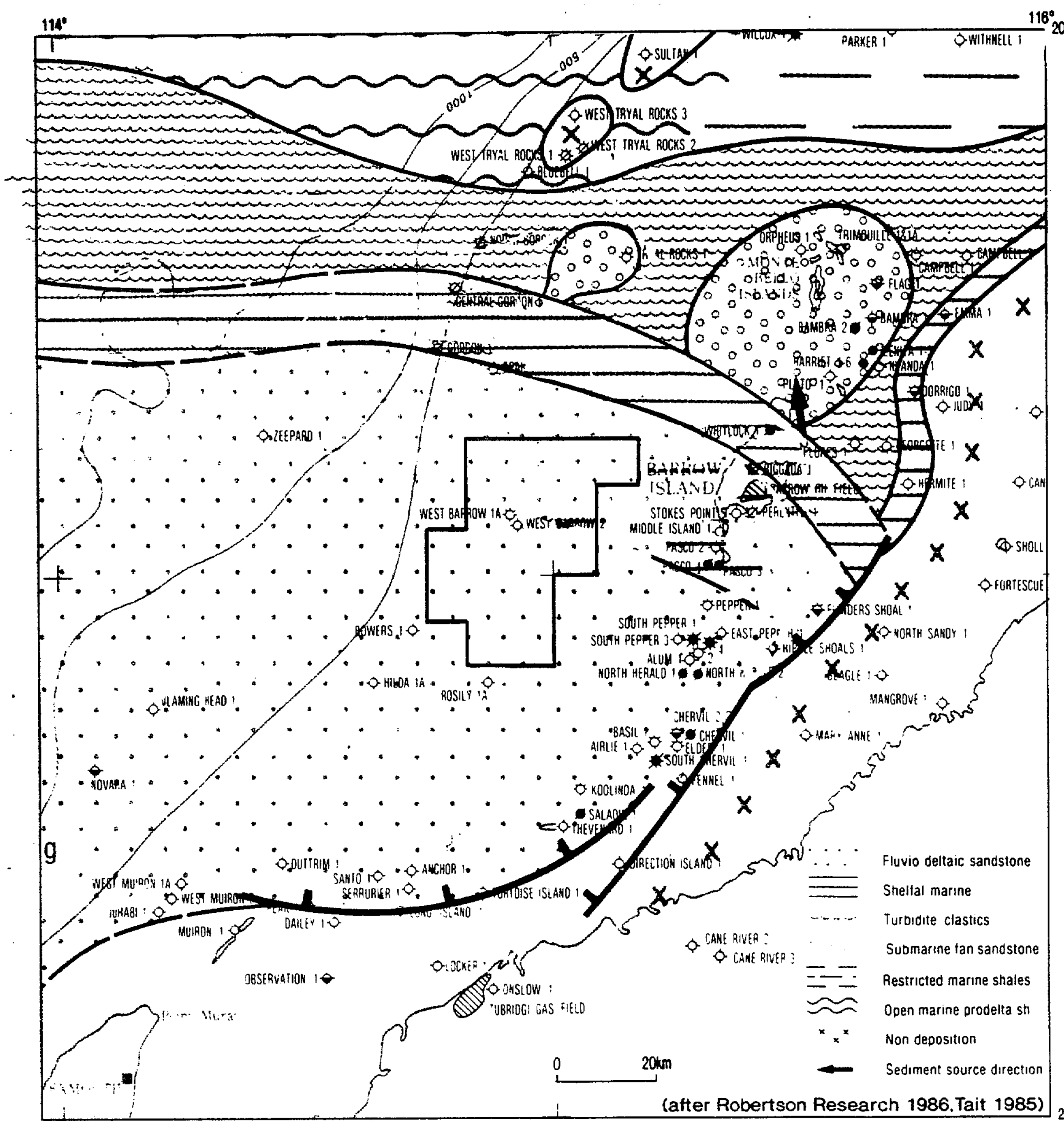


Figure 7.4 Lower Cretaceous Barrow Group Reservoir Rocks

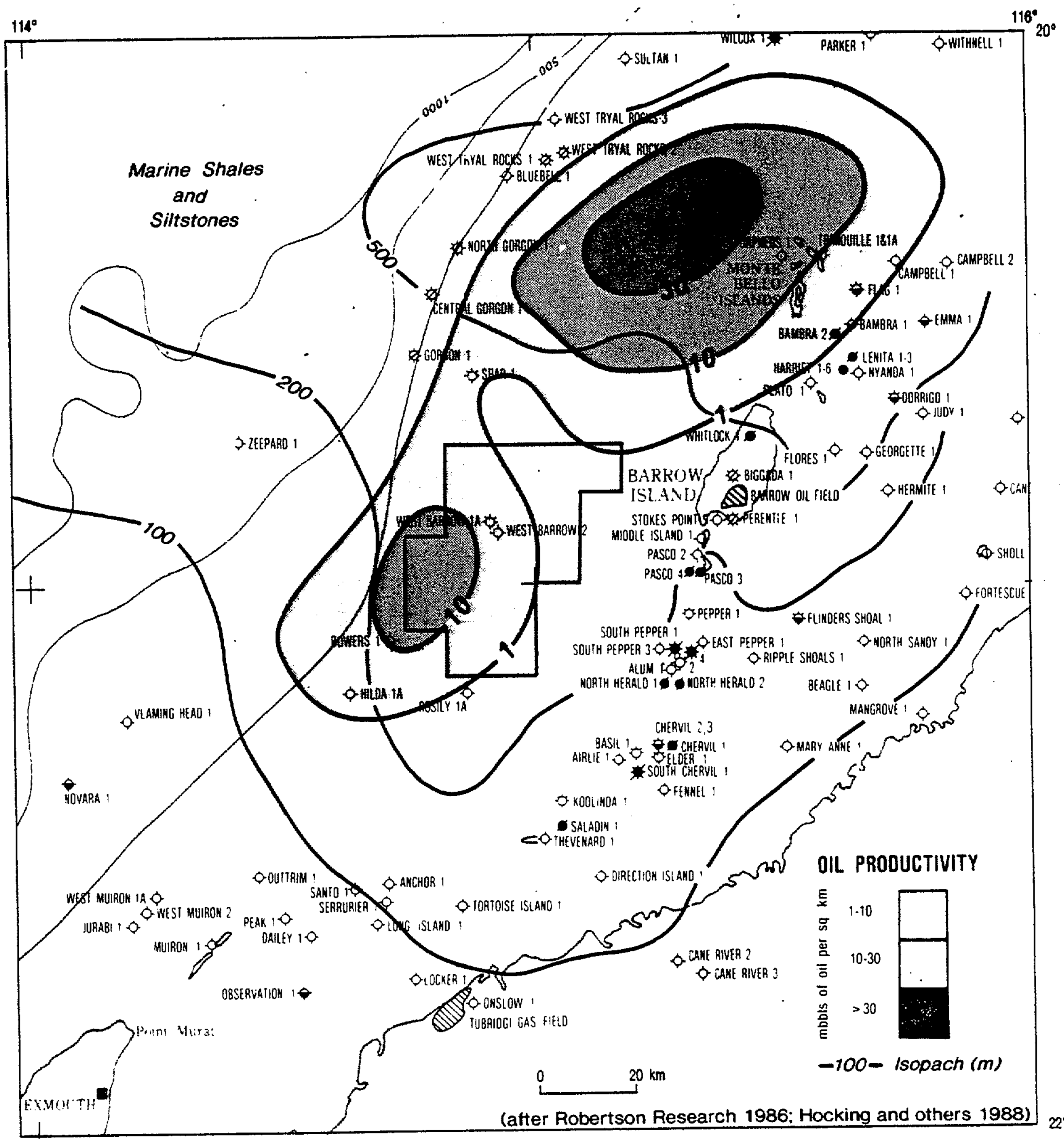


Figure 7.5 Lower Cretaceous Muderong Shale Seal / Source Rocks

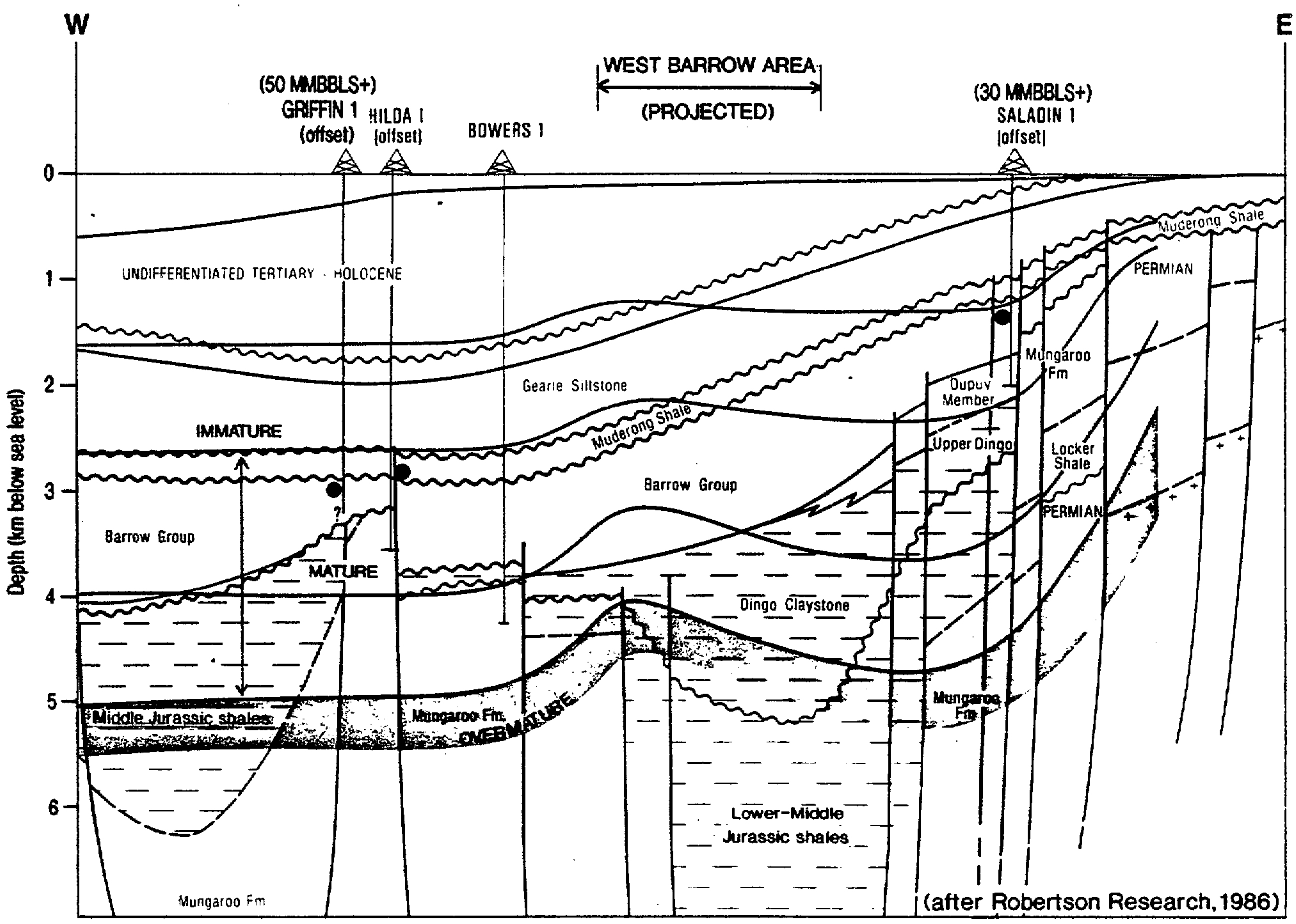


Figure 7.6 Section across Barrow Sub-basin, summarising maturity levels
(● denotes oil occurrence)

8. ACKNOWLEDGEMENTS

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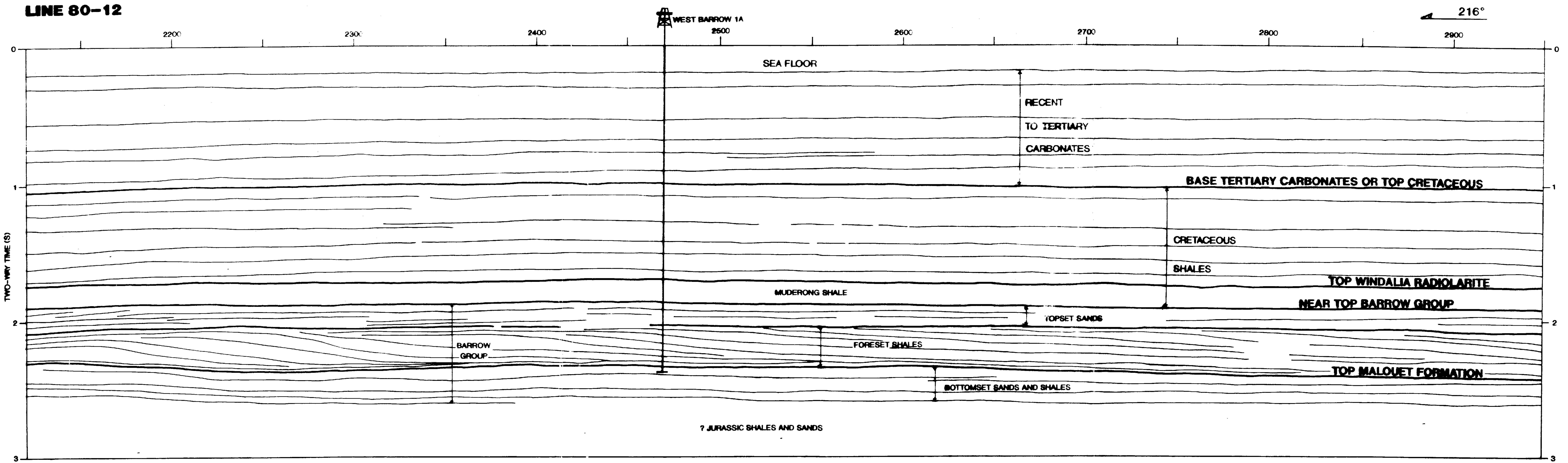

Figure 3.2 Interpretation of seismic line 80–12 through West Barrow 1A well

R9008004

Figure 3.3 Interpretation of seismic line B85A-201 showing Southwest Barrow Lead

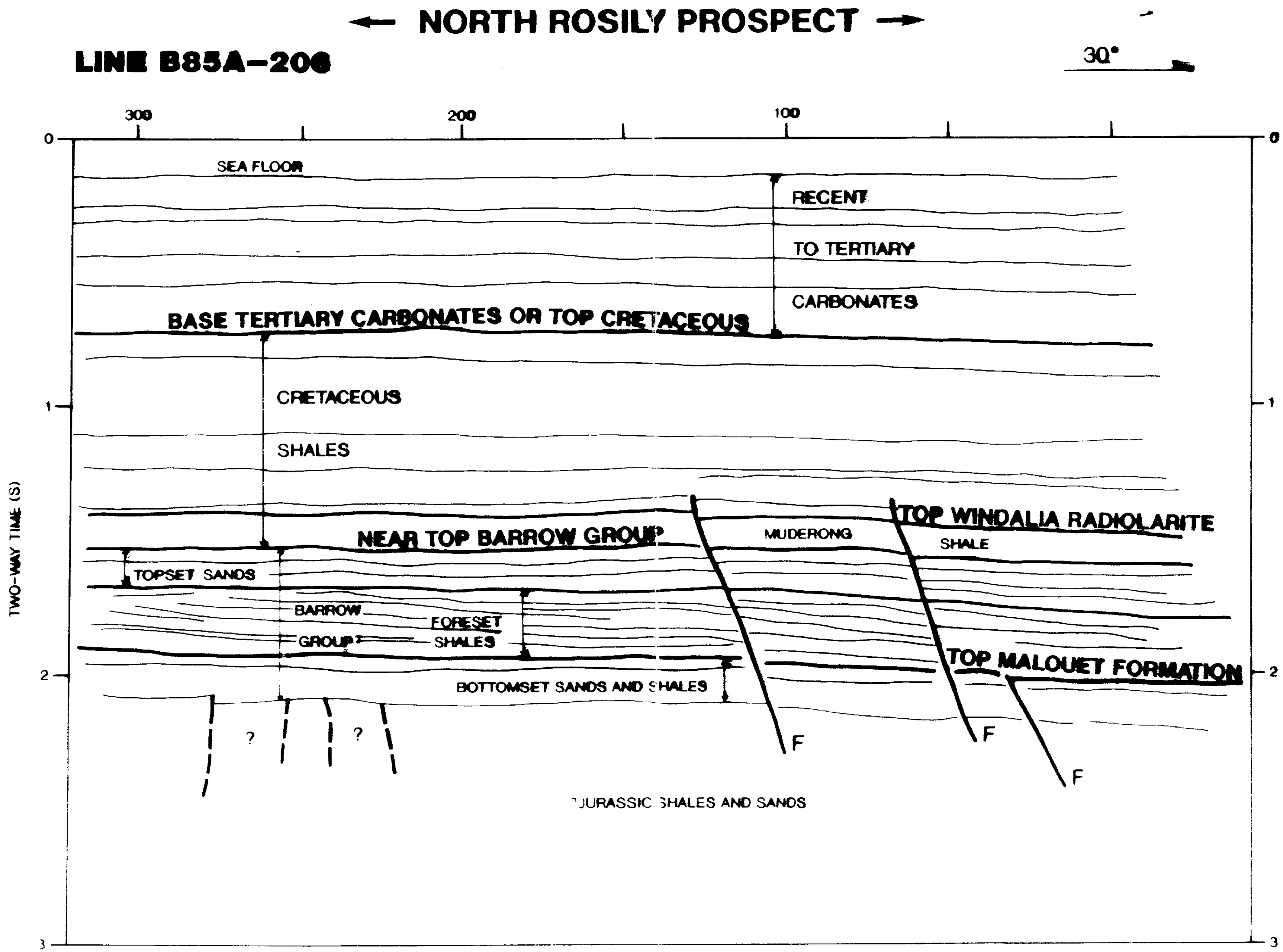

Figure 3.4 Interpretation of seismic line B85A-206 showing North Rosily Prospect

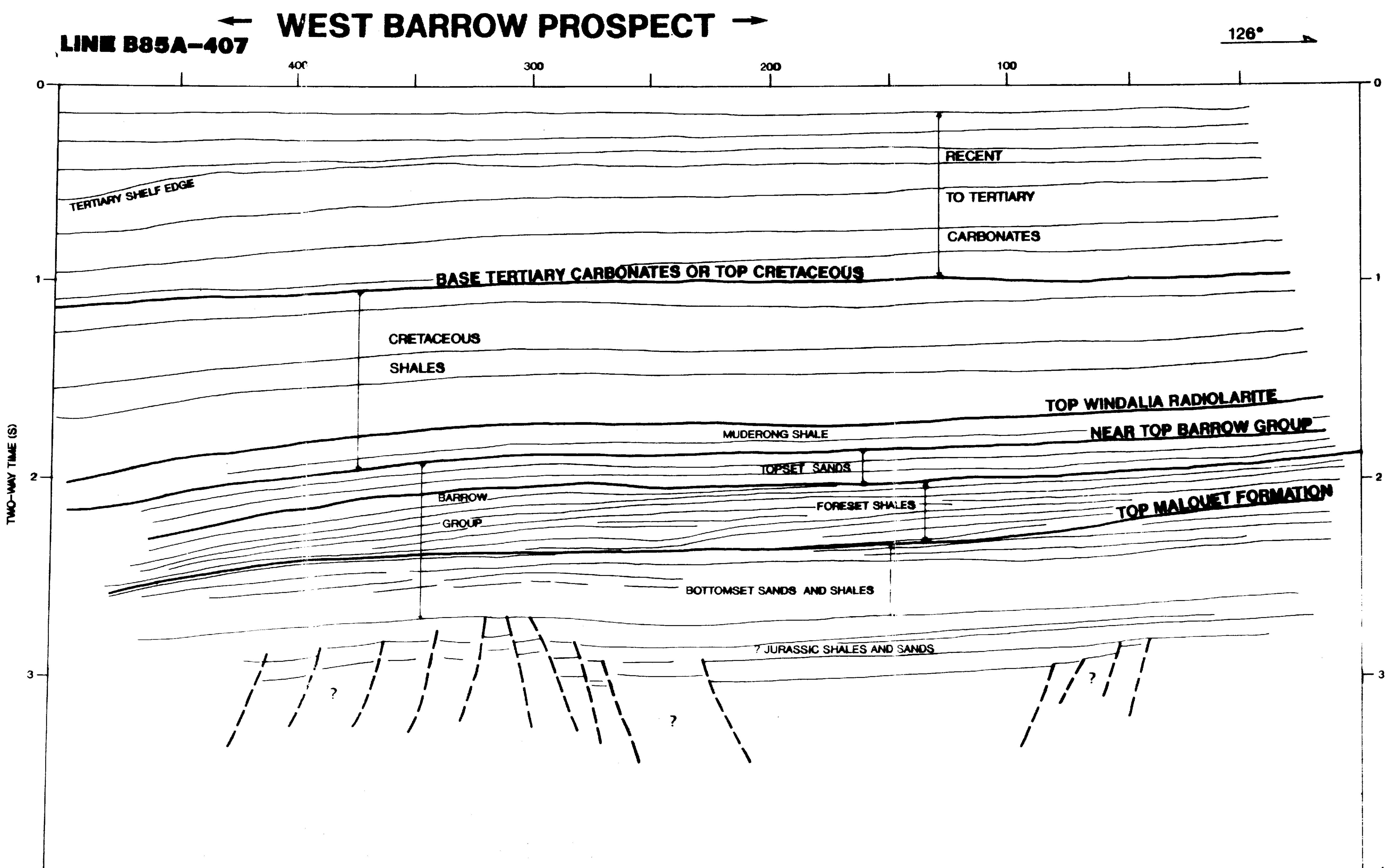

Figure 3.5 Interpretation of seismic line B85A-407 showing West Barrow Prospect

R9008006

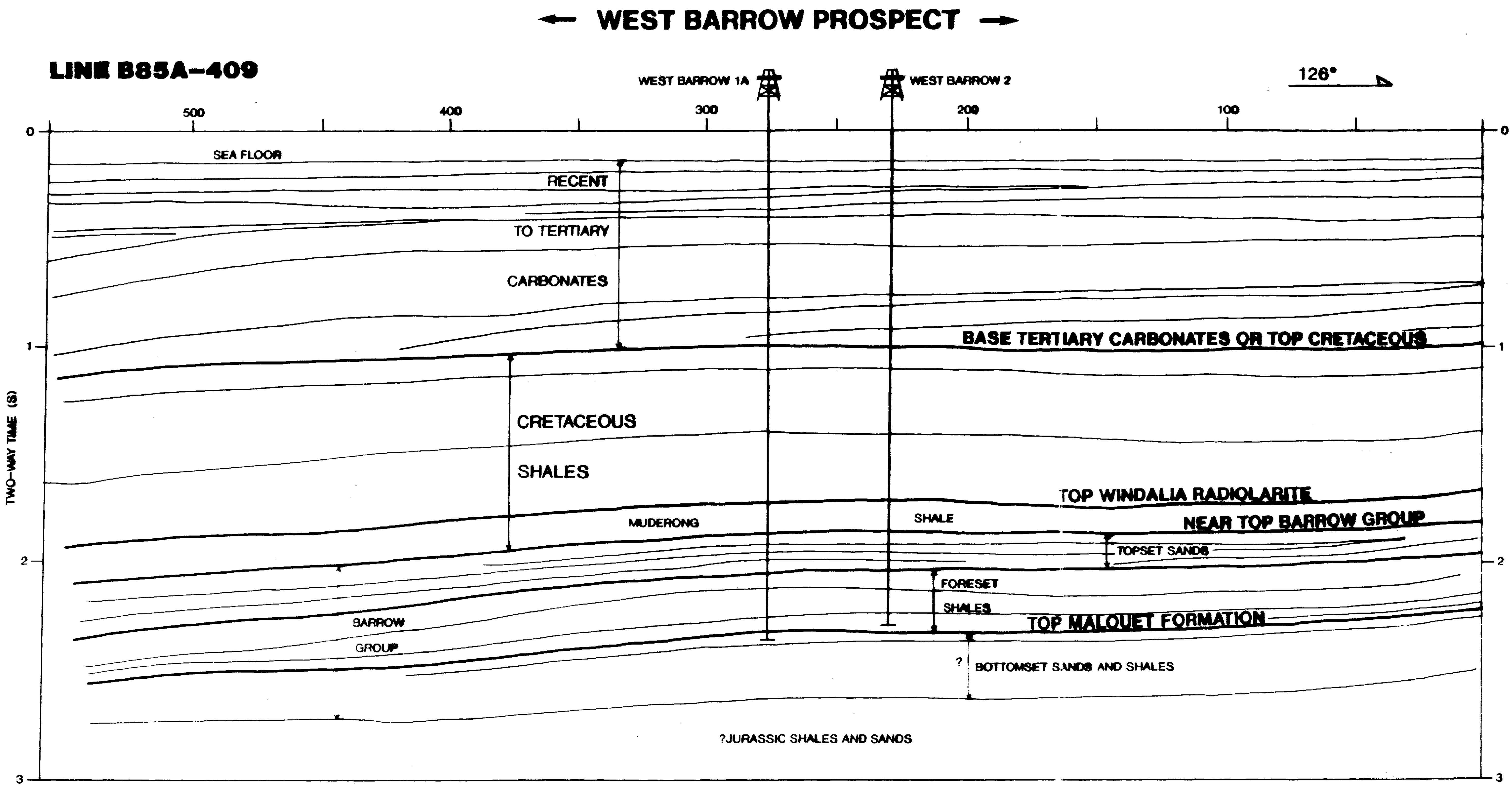

Figure 3.6 Interpretation of seismic line B85A-409 showing West Barrow Prospect

R9008007

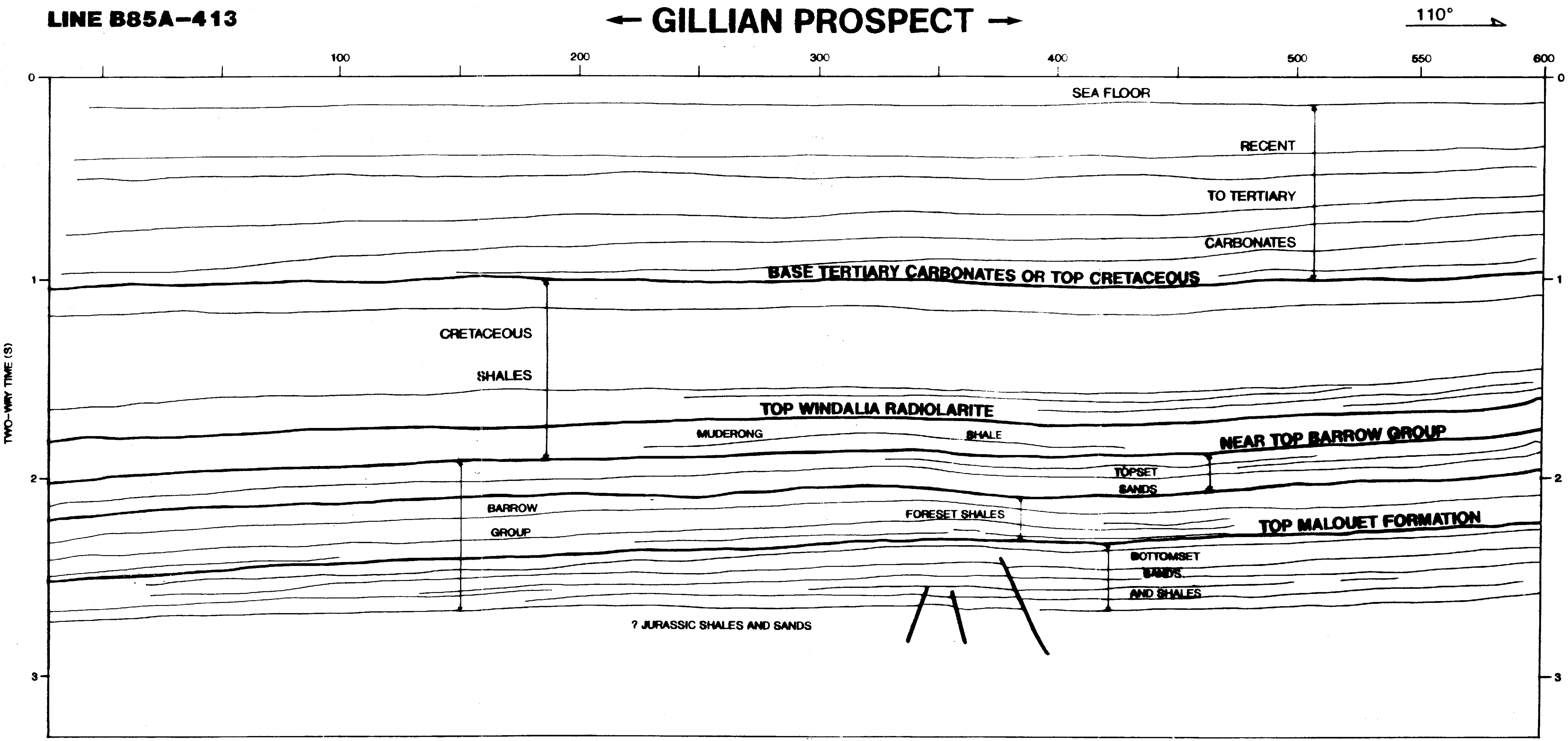

Figure 3.7 Interpretation of seismic line B85A-413 showing Gillian Prospect

R9008008