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Progress in Petroleum Prospecting on Australia's Continental Shelf

by

R.F. Thyer

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SUMMARY

This paper was prepared for presentation at the Ninth Commonwealth Mining and Metallurgical Congress which is to be held in London from 5th May to 24th May, 1969.

Over the past few years an increasing percentage of petroleum exploration has been directed to the Continental Shelf. A combination of geophysical techniques has indicated considerable thicknesses of sediments of which a substantial part are Mesozoic or younger.

Anticlinal structures are developed in some areas and drilling is in progress to test them. A major oil and gas field has been discovered in the off-shore Gippsland Basin and promising indications of hydrocarbons have been found in the Gulf of Papua.

A brief description is given of the off-shore wells already drilled or currently drilling at August, 1968.

INTRODUCTION

The history of petroleum prospecting on the Australian continental shelf is one of remarkable progress and achievement. In the brief space of a few years the existence of substantial thicknesses of Mesozoic and younger sediments over much of the shelf area has been indicated by geophysical methods. Numerous promising structures have been delineated and a major oil and gas province has been proved by drilling off Gippsland, Victoria.

Australia, including Papua and New Guinea covers 3.2 million square miles of which about 43% (1.36 million square miles) comprises sedimentary basins of varying degrees of prospectiveness.

The Australian continental shelf includes an area of about 600,000 square miles in which sediments ranging in age from Upper Proterozoic to Recent have been deposited. Although the average total thickness of sediments is approximately the same on land as off-shore, the average thickness of Mesozoic and younger sediments (exceeding 6,000 feet) is more than twice the average on land and marine facies are more abundant. Not only do sediments on the continental shelf appear to be more prospective than those on land but it has been found that in many areas excellent seismic results can be obtained offshore in contrast to very poor results on their onshore extensions.

Exploration for petroleum on offshore areas began in 1956 when an aeromagnetic survey was carried out in the Gippsland Basin by the Commonwealth Bureau of Mineral Resources. This survey clearly showed that the Tertiary sediments of the Lakes Entrance region, which were known to contain minor amounts of oil and gas, thickened very considerably offshore.

Towards the end of 1959 the interests of an Australian Company, the Broken Hill Pty. Co. were directed to offshore areas of south eastern Australia in general including the Bass Strait area between Tasmania and Victoria. Large areas were taken up in 1960 and 1961 by Hematite Petroleum Pty. Ltd., a subsidiary formed by BHP for that purpose.

Interest in Australian offshore areas built up rapidly during the early 1960's and by 1964 all the likely areas were held under some form of prospecting tenement. These tenements were granted by the bordering States on somewhat insecure grounds. The legal status of the continental shelf outside the three mile territorial limit was the subject of lively debate between the Commonwealth and the States and the need for a common legal framework to govern the exploration for and exploitation of petroleum resources was apparent to all.

OFFSHORE LEGISLATION

By a remarkable act of co-operation between the individual States and the Commonwealth, uniform legislation was enacted simultaneously by all parliaments in the latter part of 1967. Hand in hand with the legislation governing the exploration and exploitation of offshore petroleum the offshore boundaries between adjacent States were defined and each State made responsible for administering that part of the offshore area adjacent to its own shore line.

A two stage system of mineral titles was adopted. The Permit to explore for petroleum, which covers all stages of exploration including test drilling, and Licences covering production. A graticule system was adopted (5 minutes x 5 minutes per block) and the maximum size of a single Permit fixed at 400 blocks (approximately 10,000 square miles).

Provision is made for the compulsory relinquishment of 50% of the area after an initial period of 6 years and a further 50% of the remainder at the end of each succeeding 5 year period. There is no limit to the number of Permits that a single operator may be granted but specific working conditions will apply to each Permit area.

Following the discovery of a commercial petroleum deposit the permittee has the right to take out a Licence for production. He is required to nominate on block as a central discovery block and this and the surrounding 8 blocks become a discovery Location. The permittee then has the right to take up any 5 of the 9 blocks (roughly 125 square miles) and pay a standard royalty rate of 10% of well head value of production. As a second choice the permittee has the right to take up one or more of the remaining 4 blocks and to pay an additional override royalty not only on the additional blocks but on the original 5 as well. The amount of the additional override royalty will be negotiated and may range between 1% and 2½% i.e. the total royalty rate payable over the whole licence area may range from 11% to 12½%. Licences are for an initial period of 21 years plus an extension for a second period of 21 years with possible further extensions provided for.

EXPLORATION

The first offshore well was drilled by the ship drilling rig Glomar III in the Gippsland Basin in 1964. Since then offshore drilling has extended to a number of other areas on the Australian continental shelf and in mid-August, 1968 there were six marine drilling rigs in operation excluding production drilling from the Marlin and Barracouta platforms.

The total offshore expenditure for 1967, including money spent on development and production was more than half the Australian total and offshore expenditure can be expected to rise substantially in 1968.

The following table gives some idea of the rate of expansion in offshore prospecting for petroleum since 1959.

Australia - Papua and New Guinea

Expenditure on Petroleum Exploration, Development and Production
($A million)

Year	Government (including subsidy)	Private industry (excludes subsidy)	Total *	OFFSHORE Expenditure	OFFSHORE Percentage of Total
1959	2.9	11.8	14.7	Nil	Nil
1960	3.7	12.5	16.2	0.3	1.8%
1961	5.4	13.0	18.4	0.6	3.3
1962	9.3	21.1	34.4	0.9	2.6
1963	14.2	29.2	43.4	1.7	3.9
1964	13.9	36.1	50.0	5.1	10.2
1965	14.9	55.9	70.8	9.1	12.8
1966	14.5	58.8	73.3	14.3	19.5
1967	15.3	88.7	104.0	54.3	52.3

* The total includes expenditure on development drilling and production for which complete figures are not available; expenditure on development and production in 1966 was $7.2 million and in 1967, $29.7 million.

Figure 1 shows the sedimentary basins on land and their probable extensions seaward. The positions of exploratory wells are also shown.

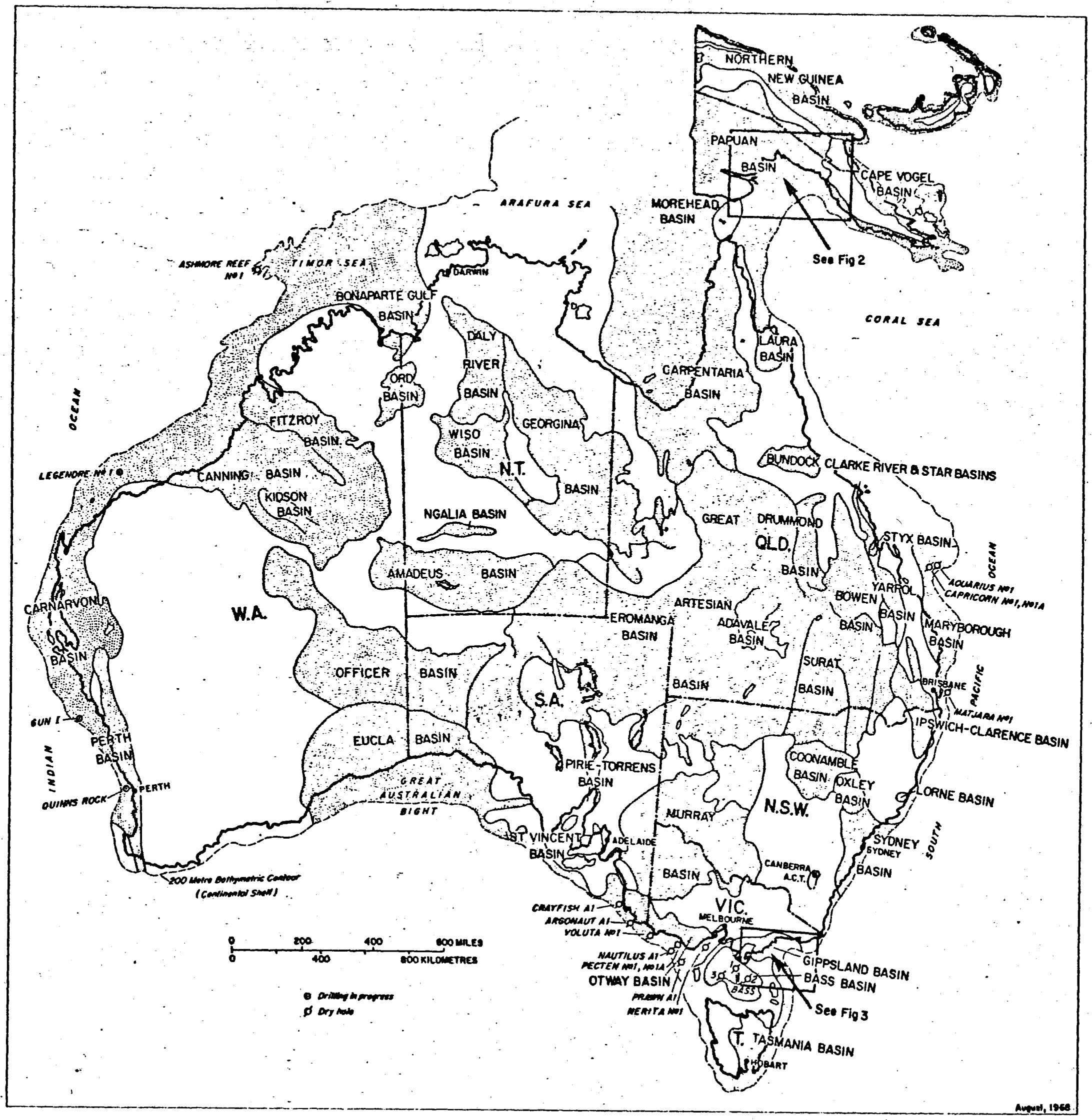

Fig. 1. Australia and New Guinea.
Sedimentary basins and offshore drilling to Aug. 1968.

Gulf of Papua

The Papuan Basin is an assymetrical Tertiary basin with gently folded strata on the south-western side where it hinges on the northwards extension of the Australian shield. The Basin has a deep central part, the Aure Trough, and very thick and steeply folded strata on the north-eastern side against the central ranges of New Guinea.

In the Aure Trough there are at least 15,000 feet of Miocene marine greywacks and mudstones. Natural oil and gas seeps occur at many localities in Aure Trough but absence of suitable reservoirs has discouraged exploration. The development of reef and shoal limestones on the south-western hinge-line has been regarded as more encouraging for the development of reservoirs and drilling has led to significant discoveries of gas and shows of oil at a number of places.

The offshore extension of the Papuan Basin beneath the Gulf of Papua appears to be an area in which more favourable reservoir conditions might be expected. Extensive marine seismic surveys were carried out by Phillips Australia Oil Co. as operator for a group of companies holding the prospecting rights over most of the shelf area and this work defined a large number of drilling targets which are probably anticlinal and/or reef structures of moderately large areal extent.

The drilling ship "Glomar Conception" arrived in the Gulf of Papua in October, 1967 to commence a programme of drilling for Phillips in the Gulf of Papua and by mid-August, 1968 it was drilling on its eighth location. The sites of the eight wells are shown on Fig. 2.

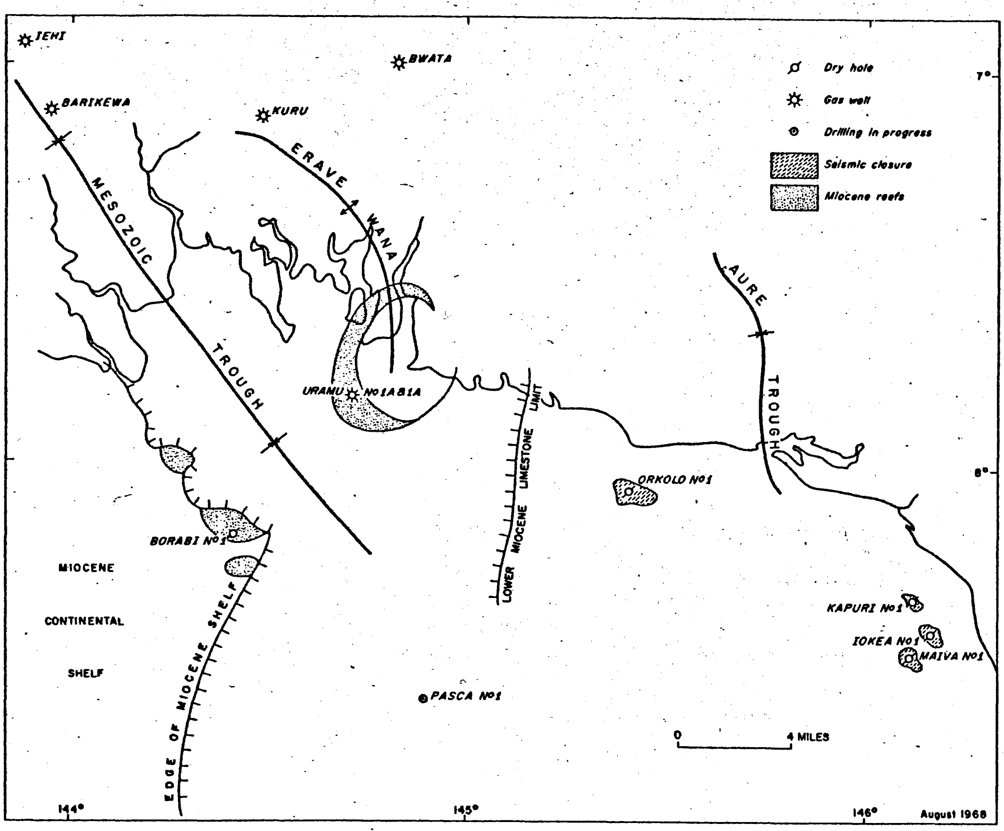

Fig. 2. PAPUAN BASIN, Territory of Papua and New Guinea.
Offshore drilling to Aug. 1968.

The first well drilled was Borabi No. 1 at a site 30 miles offshore and 210 miles north-west of Port Moresby. Drilling commenced on the 8th October, 1967 and the well terminated in Mesozoic shales at 9,442 feet. Circulation was completely lost at about 5,000 feet and was not restored.

Borabi No. 1 was selected to test the largest of several reef developments along the hinge line on the western flank of the Papuan Basin. Seismic data indicated a closed structure within Miocene reefs at depths of about 5,000 and 8,000 feet.

The well confirmed the presence of over 4,000 feet of Miocene reef and back-reef limestone having excellent reservoir characteristics and in a favourable environment as regards source rocks. However the structure was found to have no effective cap rock and no significant shows of hydrocarbons were detected. All potential reservoirs were found to be filled with fresh water.

The second offshore well in the Gulf of Papua, Uramu No. 1 was drilled 200 miles northwest of Port Moresby and 10 miles offshore to test a seismic anomaly of a Miocene reef structure similar to that at Borabi No. 1. Mechanical difficulties led to the abandonment of the hole at a depth of 6,433 feet and Uramu No. 1-A was then drilled nearby. The well penetrated Recent to Upper Miocene clastic sediments to a depth of 6132 feet where the Lower Miocene reefal sediments were intersected. Large amounts of wet gas were encountered in the Lower Miocene reef. From 9260 feet to 10,010 feet the well penetrated Upper Eocene argillaceous limestones and was terminated in Mesozoic shales at 10,106 feet. A formation test was taken in open hole near the top of the Lower Miocene reefal sediments and gas flows ranging up to 24.4 MMCF/D through ½" choke were measured. The well was cased prior to testing but owing to the onset of the south-easterly season and the shallowness of the water at the site it was considered too risky to attempt further testing at that time. The well was plugged and abandoned.

The next site tested was Orokolo No. 1 on the south western side of the Aure Trough. The well was drilled to 11,999 feet in sediments which were predominantly post-Miocene mudstones without significant reservoirs. Some high pressure gas shows were encountered in mudstones below 10,000 feet. A drill stem test in the interval 1,730 - 1,768 feet which included some unconsolidated sandstone recovered only salty water.

Maiva No. 1 was next drilled to test a seismic build up which had been interpreted as either reef structure in Miocene limestones or a volcanic hill on the narrow eastern shelf of the Aure Trough. The well was plugged and abandoned at a total depth of 9,807 feet after penetrating a section of principally mudstones. Volcanic rocks (tuffs and basalt), were penetrated from 7,960 feet to 9,430 feet and high pressure gas was encountered in mudstones below 5,210 feet. No suitable reservoirs were indicated in the logs.

Phillips Iokea No. 1 was next spudded about 7 miles north-east of Maiva No. 1 and was plugged and abandoned at 4,840 feet in basalt. The basalt was porous and a formation test flowed water to the surface.

Kapuri No. 1 was next drilled to test what appeared to be a reefal structure on the eastern side of the Aure Trough; it was plugged and abandoned at 5,572 feet in limestone. Indications of gas were found below 5,060 feet but two tests of porous limestone sections below 5,100 feet flowed salt water to the surface.

The well currently drilling (August, 1968) is Pasca No. 1 which is 55 miles offshore and is designed to test what appears to be a limestone reef. A test carried out from 7211 feet to 7245 feet yielded 6.85 mmcf/D of gas and in excess of 100 bb/mmcf condensate through a 26/64 inch choke.

In summary it may be said that the offshore wells on the western side of the Papuan Basin have demonstrated the presence of a Miocene reef limestone sequence which has excellent reservoir characteristics, but near the edge of the Miocene continental shelf the reservoirs may have been flushed.

Uramu No. 1A was a gas discovery well but its significance must await further testing. The eastern wells found that most of the seismic indications of "build-up" in that area were caused by volcanics, although one well (Kapuri No. 1) penetrated an isolated reef saturated with salt water.

Great Barrier Reef

The reef platform of the Great Barrier Reef covering an area of some 100,000 square miles attracted early attention in offshore exploration. The prospects revealed do not seem to be particularly attractive except at the extreme northern end, adjacent to Papua, where aeromagnetic and seismic surveys have indicated some 10,000 to 15,000 feet of sediments which appear to be Mesozoic and younger. These sediments appear to lie within the southward extension of the Papuan Basin in which a substantial development of Miocene reef limestones appears likely. It appears that the area is one in which gentle warping with some block faulting has occurred. Some closed structures have been delineated by seismic surveys but no drilling has yet been undertaken.

The Laura Basin appears to extend into Princess Charlotte Bay as far as the outer edge of the Great Barrier Reef. The sediments attain a maximum thickness of about 6,500 feet and are believed to be mainly Mesozoic with possibly some unaltered Permian sediments near their base. No obvious structural targets have been developed.

Maryborough Basin

The most promising development of sediments beneath the Great Barrier Reef platform appears to be in the Capricorn Embayment which adjoins the coast of Queensland at about the latitude of Rockhampton. These sediments lie within the northern extremity of the Maryborough Basin which on land contains a very considerable thickness of Mesozoic sediments. It was expected that offshore the Mesozoic sediments would be overlain by Tertiary sediments. The sediments in the Capricorn Embayment have been penetrated by two offshore wells Capricorn No. 1A and Aquarius No. 1 drilled by Australian Gulf Oil Co. (See Fig. 1).

Capricorn No. 1 was planned as a stratigraphic test on a closed anticlinal structure indicated by seismic methods. A strong reflection at a depth of a little over 4,000 feet was mapped as the "base" of the Tertiary. This reflection was believed to represent a strong unconformity as it coincided with a high speed refractor below which there is an almost complete absence of reflections.

The well spudded in November, 1967, but owing to mechanical difficulties it was necessary to start a "redrill" Capricorn No. 1A which terminated at a depth of 5,609 feet in January, 1968. The well was drilled in 347 feet of water and penetrated a series of mainly unconsolidated marls, clays, limestones, and sandstones to a depth of 4,030 feet. These are believed to range in age from Recent to Lower Tertiary. From 4,030 feet to 5,250 feet the well penetrated pebbley conglomerate which correlates with the Graham's Creek volcanics (Mesozoic). Below 5,250 feet to the total depth of 5,609 feet the well penetrated igneous rocks. No shows of hydrocarbons were encountered in Capricorn 1A. The Tertiary sediments are largely unconsolidated or poorly consolidated and have high porosity.

The second well, Aquarius No. 1, was drilled to test a seismic anomaly in the eastern portion of the Capricorn Embayment. Within this anomaly there was a pronounced change of character in the strong seismic reflection which throughout the Embayment has been interpreted as the "base" of the Tertiary. In places the reflection was missing and a series of confused reflections occurred. These observations led to the conclusion that Tertiary reefing may be the cause. There was also some seismic evidence that the Tertiary section might be significantly thicker than at Capricorn No. 1A.

Aquarius No. 1 was spudded in January 1968 and abandoned two months later. The well was drilled in 245 feet of water and unconsolidated marine marl, limestone and claystone, believed to be Lower Miocene, were encountered to 4805 feet; non-marine (Lower Tertiary) quartzose sandstone and claystone with some lignite and anhydrite were intersected to 5585 feet. An impure anhydrite layer 60 feet thick was encountered at 4770 feet and this may have important regional implications - it could be a suitable cap-rock for potential sandstone reservoirs below this level.

From 5585 feet to 8670 feet the well intersected red brown and black chert-pebble conglomerates and claystones which are believed to be Mesozoic sediments. The well was terminated at a total depth of 8695 feet after drilling 25 feet of slightly metamorphosed (Palaeozoic ?) shales and sandstone. No hydrocarbons were detected and nor were formation tests carried out.

Another offshore well Matjara No. 1 was drilled in mid-1968 at the southern end of the Maryborough basin to test an anticlinal structure indicated by a seismic survey. The well was abandoned in volcanic rocks at a depth of 2537 feet after penetrating about 1000 feet of volcanics. Unconsolidated sediments ranging in age from Recent to Tertiary overlie the volcanics.

Offshore New South Wales

On the eastern coast of Australia between the southern end of the Great Barrier Reef and Bass Strait the continental shelf is relatively narrow and although a considerable amount of geophysical work has been done on it especially in the Sydney Basin the results are inconclusive. The interpretation of aeromagnetic results has been rendered difficult because of the presence of magnetic sills and dykes and seismic results have been very poor.

Bass Strait

The most outstanding development in offshore prospecting for petroleum in Australia has been in Bass Strait, between Victoria and Tasmania, and in particular the Gippsland Basin.

Of the fourteen exploratory wells so far drilled offshore in the Gippsland Basin (August, 1968) no less than eleven have revealed commercial deposits of oil and/or gas. Gas reserves in the Marlin and Barracouta structures currently being developed to supply the Melbourne market have been estimated to exceed 5 million million cubic feet. Drilling is proceeding from one platform on each structure, and pipelines and shore installations are being constructed. It is expected that natural gas will be provided for the Melbourne market during 1969.

The prospects for oil were equally encouraging and the operating companies have advised the Victorian Government that their tentative estimate of reserves of recoverable oil in the structures so far tested is 1,220 million barrels and that by 1970 they will be producing oil at the rate of 240,000 barrels a day. This will be approximately 50% of Australian consumption at that time.

The Gippsland Basin is a relatively small sized Tertiary-Mesozoic basin within and near the southern extremity of the Palaeozoic Tasman Geosyncline (See Fig. 1). Its landward part occupies an area between Wilson's

Promontory and Lake Tyers in eastern Victoria. To date its chief claim to economic importance is related to the extensive brown coal deposits in the Latrobe Valley, which are used for electrical power generation and for the manufacture of briquettes.

During the Eocene times gentle regional down-warping occurred in the Gippsland area. Widespread swamp conditions with deposition of clays and coarse continental sands and great thicknesses of peat occurred leading ultimately to the development of great thicknesses of brown coal (Latrobe coal measures). In the western portion of the Gippsland Basin including the Latrobe Valley, over 2,000 feet of continental Latrobe Formations were deposited. A thinner and more brackish sequence was laid down to the east and south east.

The Gippsland Basin acquired its present shape and morphology with the sinking of the offshore land mass and the incursion of the sea. Marine sediments, mostly calcareous shales and littorial sand deposits interrupted progressive shale deposition. Through the Miocene and into the Lower Pliocene shallow and stable marine conditions continued with the deposition of marls and clayey limestones becoming sandier towards the end of this time. Regional uplift occurred towards the end of this period with gentle folding and small scale faulting.

The presence of hydrocarbons in the form of minor oil shows have been known since 1924, when a small show of oil and gas was discovered in a water well near Lakes Entrance. About 100 wells were drilled during the period 1924 to about 1950, but at most a few gallons of crude oil per day were produced.

The first attempt to investigate the seaward extension of the Gippsland Basin was by means of an aeromagnetic survey conducted by the Bureau of Mineral Resources in 1956. This survey showed quite clearly that the magnetic basement rocks underlying the Tertiary sediments at Lakes Entrance increased substantially in depth seaward. A maximum thickness of over 16,000 feet of non-magnetic sediments was indicated immediately south of Lakes Entrance.

Towards the end of 1959 Australian Iron & Steel Ltd., a subsidiary of the Broken Hill Pty. Co. engaged Lewis G. Weeks an eminent American Oil Geologist to review the work that the Company had done in petroleum exploration in the southern part of the Sydney Basin. Mr. Weeks recommended that the Company transfer its interests in petroleum investigations to offshore areas of south eastern Australia including the Bass Strait area between Tasmania and Victoria. Large areas were taken up by Hematite Petroleum Pty. Ltd., a subsidiary formed by BHP for that purpose in 1960 and 1961. These areas included the offshore extension of the Gippsland Basin which had been indicated initially by the work of the Bureau of Mineral Resources.

In mid-December 1960 Hematite carried out an aeromagnetic reconnaissance of the whole of the Bass Strait area which not only confirmed the seaward extension of the Gippsland Basin but also indicate the presence of a deep sedimentary basin lying off the north coast of Tasmania between King and Flinders Islands; this was subsequently named the Bass Basin.

These early results were later confirmed by more detailed aeromagnetic surveys carried out between September and December 1961 which indicated a thickness of over 20,000 feet of sediments in the Gippsland Basin.

Seismic surveys were conducted by Hematite between November 1962 and May, 1963 giving further confirmation of thick sedimentary sections and pointed up a large number of structural targets for drilling.

In May 1964 Hematite arranged a farmout with Esso Exploration and Production Australia Inc. (Esso). Under the terms of this farmout Esso agreed to carry out detailed seismic surveys to define more clearly the drilling targets and to drill 5 wells.

The first offshore well drilled in Australia was Esso Gippsland Shelf No. 1 (subsequently renamed Barracouta A-1) which was spudded by the drilling vessel Glomar III, on December 24th, 1964. It was drilled to a depth of 8701 feet and completed as a suspended gas well on June 5th, 1965. Since then a further 13 exploratory wells have been drilled in the offshore part of the Gippsland Basin. Three wells have also been drilled in the Bass Basin and others offshore in the Otway Basin. The position of these and the outline of some of the structures they tested are shown on Fig. 3.

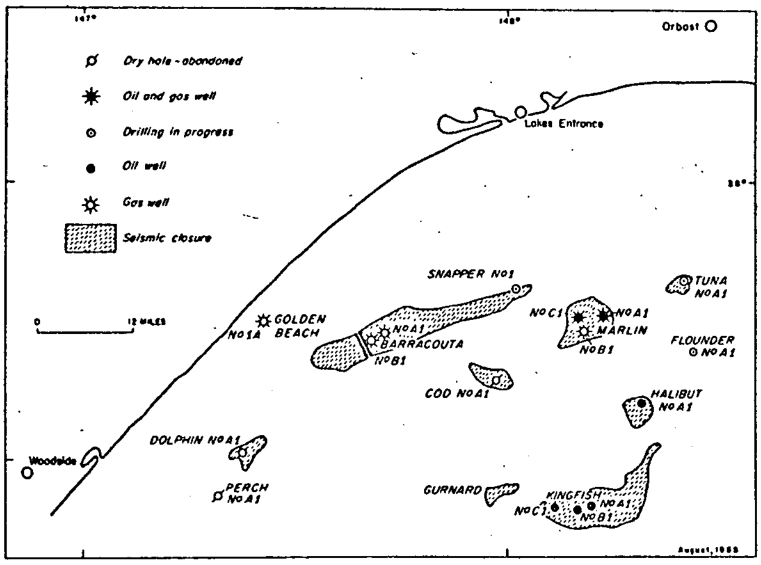

Fig. 3. Gippsland Basin, Victoria.
Offshore drilling to Aug. 1968.

Gippsland Basin

<u>Esso Gippsland Shelf No. 1</u> was remarkable in a number of respects. It was the first well drilled in Australian waters and it also provided the first offshore discovery. It was drilled near the crest of a closed anticlinal structure indicated by seismic data, to ascertain the stratigraphy and to test for prospective reservoirs in both Tertiary and underlying Upper Cretaceous sediments. The well intersected Tertiary strata to 5378 feet and Upper Cretaceous strata from 5378 to 8701 feet, the total depth. While cutting a core at about 5350 feet the well came in blowing gas. The hole was recovered and later deepened to a total depth of 8701 feet.

Evidence was obtained of a gross gas column approximately 353 feet thick in the top of the Eocene Latrobe Valley coal measures (3458 feet - 3811 feet). Subsequent tests within this interval established the gas water contact and gave maximum gas flow rates in two zones of 5.36 and 6.85 mmcf/D respectively plus between 70 and 80 bb/d of condensate. Gas shows were logged in Upper Cretaceous sands from 5707 feet to 6030 feet and below 7800 feet. Minor shows of oil and some fluorescence were detected in the interval 7834-7846 feet and 8687-8693 feet that were deemed non-commercial.

A second well was drilled on the Barracouta structure (Esso Gippsland Shelf No. 2 or Barracouta B-1) and completed as a shut-in gas producer. Drill-stem tests in the intervals 3731-3738.5 feet and 3488-3507 feet, gave 9.6 mmcf/D and 0.4 mmcf/D respectively, on a $\frac{7}{8}$" choke. The third well drilled Cod A-1, was abandoned as a dry hole.

The next three wells (Marlin A-1, B-1 and C-1) were drilled on a large closed structure centred about 30 miles east of the original discovery on the Barracouta structure. This is known as the Marlin structure which is currently being developed as a gas and oil producer.

Marlin A-1 (Gippsland Shelf No. 4) was drilled on the highest part of a domal structure delineated by seismic surveys. The structure covers an area of 42 square miles with a maximum closure of 900 feet.

The primary objective was to evaluate not only the Eocene Latrobe Valley coal measures but also the top of the underlying Upper Cretaceous section. Tertiary rocks were encountered to 6490 feet and Upper Cretaceous from 6490 to 8485 feet.

A gross gas column of 588 feet was logged in the top part of the Eocene Latrobe Valley coal measures from 4522 to 5110 feet. This was underlain by a gross thickness of 54 feet of oil sand and a formation test through perforations at 5122-5137 feet produced at a maximum flow rate through a 29/32" choke of 1182 bb/d of 51° - 53° gravity oil.

Production tests from within the Tertiary gas zone yielded up to 10.2 mmcf/D plus 44.6 bb/d condensate through a 1 inch choke. Within the Upper Cretaceous section a gross gas column of 591 feet (7049-7640 feet) was intersected and production tests gave up to 10.9 mmcf/D of gas plus 39 bb/d condensate 11/16" choke.

The well represents the first significant discovery of oil in the Latrobe Valley coal measures, and also the first major gas show in the Upper Cretaceous section.

Two assessment wells, Marlin B-1 and Marlin C-1, were next drilled on the Marlin structure. Tests carried out on Marlin B-1 yielded 6.0 mmcf/D of gas from the interval 5096-5117 feet through a $\frac{1}{2}$" choke, plus 41.9 bb/mmcf of condensate. The well was completed as a shut-in gas well. Production tests were also carried out in Marlin C-1 but no flow details were released by the Company, except that between 5108 and 5150 feet the well flowed oil, gas and water.

The next well drilled by Esso in the Gippsland Basin was Kingfish A-1 which was drilled on a closed structure indicated by seismic work and covering an area somewhat larger than the Marlin structure.

An oil discovery of major importance was made in this well which was drilled to a total depth of 8451 feet. Shows of oil were encountered in cores taken below 7500 feet and a production test over the interval 7584 feet to 7592 feet yielded 1500 bb/d of 49 gravity oil on a $\frac{5}{8}$" choke. The well was temporarily plugged and capped pending further evaluation of the structure.

Two additional step-out wells were subsequently drilled on the Kingfish structure; Kingfish B-1 approximately 2 miles east of A-1 and Kingfish C-1 about 6 miles west of A-1/ The results of coring, logging and wire line testing on these wells confirmed previous indications of reservoir characteristics shown in Kingfish A-1.

Following the discovery of oil in the Kingfish structure, another well, Halibut A-1 was drilled on a closed structure indicated by seismic work about 15 miles north east of Kingfish A-1, and approximately 50 miles offshore. It was drilled to a total depth of 10,011 feet and temporarily plugged and capped pending further evaluation. Continuous cores were taken from 7550 feet to 7900 feet in an alternating sand and shale section and oil shows were present in the sand sections throughout. A formation test was made over the interval 7800 feet to 7804 feet which yielded a maximum flow of 3230 bb/d of 44 gravity oil on a $\frac{1}{2}$" choke.

Following the drilling of Kingfish B-1 and C-1, additional seismic work was carried out on both the Kingfish and Halibut structures and the assessment of these results together with further detailed engineering studies led to a tentative estimate that the Halibut and Kingfish structures contain 1200 million barrels of recoverable oil. The company announced plans to erect three production platforms on the Kingfish structure and one on the Halibut structure. It was estimated that by the end of 1970 production from these two structures, together with that from Marlin, would be approximately 240,000 barrels a day. This was a discovery of major importance for Australia as the planned production would meet about 50% of Australia's liquid petroleum requirements at that time.

Two further wells have been completed by Esso in the Gippsland Basin on separate closed structures. These are Dolphin A-1, Perch A-1, in which shows of hydrocarbons were encountered and tested. In neither well was the occurrence regarded as commercial at this time.

At present (August 1968) three further wells are being drilled by Esso in the Gippsland Basin; Tuna A-1 in which promising shows of gas and oil have been encountered; Snapper A-1 in which several shows of hydrocarbons have been encountered in tight sands below 4000 feet, and Flounder A-1 in which a wire line test below 8200 feet resulted in the recovery of a small amount of oil which will need further evaluation.

The Esso-Hematite Group is not the only one holding prospecting permits in offshore Gippsland Basin, although they hold by far the greatest and most prospective area. An offshore well Golden Beach 1A was drilled by a group of companies to test the Golden Beach anticline about $2\frac{1}{2}$ miles offshore near Sale. Gas was found in the Latrobe Valley coal measures and a production test of the interval 2142 feet - 2147 feet yielded 4.5 mmcf/D on a 1" choke. The well was plugged and temporarily suspended pending an assessment of its commercial significance.

Bass Basin

The Bass Basin (see Fig. 1) was discovered by aeromagnetic and seismic methods, and was geologically unknown. It lies in Bass Strait between Flinders and King Islands and covers an area of some 25,000 square miles; a maximum of 12,000 feet of sediment was indicated at its centre. Three wells have been drilled to test structural targets indicated by seismic work. The first, Esso Bass-1 was spudded on the 26th July, 1965, and was designed essentially as a stratigraphic test. The objective was a seismic "build-up", which was thought might be due to a Tertiary carbonate reef complex. No such reef complex was found, but drilling proved a volcanic section of pyroclastics which apparently is the cause of the seismic anomaly. No hydrocarbons of commercial significance were detected.

The well was drilled to 7717 feet, plugged and abandoned. To 6380 feet the sediments are principally Tertiary marine shales, sandstones and siltstones which included both possible source and reservoir rocks. Upper Cretaceous sands and shales were intersected from 6380 feet to 7717 feet. The well passed through tuffite of Miocene age from about 2640 feet to 3140 feet. Other volcanics were intersected between 4100 feet and 4300 feet and thin sections of volcanics were also intersected at about 5400 feet in Eocene sediments.

Volcanic rocks were also intersected in Esso-Bass-2 about 30 miles south-east of Bass-1. Bass-2 was drilled on the crest of an anticlinal structure indicated by seismic work. The well encountered a total of 5244 feet of Tertiary sediments including a basal Paleocene-Eocene section 1673 feet thick, a deltaic complex of interbedded sandstone, siltstone, shale and coal. Beneath the Tertiary sediments the well intersected 256 feet of altered volcanic rock (possibly Mesozoic), and about 140 feet of altered tuffaceous mudstone of unknown age which formed the basement. No hydrocarbons of economic significance were detected in the well.

Bass-3 was spudded in February 1967 on the crest of a well defined northwest-southeast closed anticlinal feature mapped by seismic work. The section intersected was essentially as predicted; marine Tertiary sediments to 5304 feet, principally limestone, calcareous mudstone, shale and minor sandstone. The Paleocene-Eocene delta complex was intersected from 5304 to 7830 feet, and is principally sandstone with interbedded shale, siltstone and rare coal seams. The basement was intersected from 7830 feet to total depth 7978 feet and consisted of metamorphics of undetermined age. Hydrocarbons shows were logged in Bass-3 from 6739 feet to 6744 feet and it was the first valid show in the basin. Formation tests were carried out at four intervals between 5409 feet and 6740 feet and a small amount of gas was recovered. The well was plugged and abandoned as a dry hole.

Otway Basin

The Otway Basin occupies an area of about 33,000 square miles along the southern coast of Victoria and South Australia from Port Phillip in the east, to the vicinity of Robe in the west. It contains Mesozoic and Tertiary marine and fresh-water sediments, which in places exceed 12,000 feet in thickness. Small amounts of gas and oil have been discovered in wells near Port Campbell, Victoria, in Cretaceous sediments.

The sedimentary section appears to increase in thickness offshore, and seismic surveys have indicated a number of closed anticlinal structures. To date (August 1968) seven offshore wells have been completed in the Otway Basin. From east to west these are Nerita-1, Prawn A-1C, Pecten-1A and Nautilus A-1, Voluta No. 1, Argonaut A-1 and Crayfish A-1. The position of these is shown in Fig. 1.

Nerita-1 was drilled to test a closed structure indicated by seismic data about 12 miles offshore from Lorne, Victoria. The well drilled through a sequence of marine carbonate and marl of Miocene to Upper Eocene age to 1180 feet; mainly Eocene silt and clays to 2091 feet and a section of continental sands, silt, claystone and coal, also of Upper Eocene age to 2555 feet. Below this a sequence of fresh water sands, siltstone and claystone and coal of Paleocene to Upper Cretaceous age were penetrated to 4798 feet, and sandstone, siltstone and shale of Lower Cretaceous age to the total depth of 6700 feet. Wireline tests were made in the Lower Tertiary and Upper Cretaceous sections, which were found to be saturated with fresh to brackish water. Only minor methane shows were encountered.

Prawn A-1C was drilled after two earlier wells had been abandoned due to mechanical difficulties on the crest of a large closed anticlinal structure indicated by seismic data.

Soft marls and sandy limestones of Miocene to Upper Eocene age were intersected to 3024 feet; sediments of Pre-Upper Eocene and Paleocene age comprising mainly quartz sandstone were penetrated from 3024 feet to 4150 feet. Upper Cretaceous sediments were encountered from 4150 - 9660 feet being predominantly quartz sandstone with a few thin beds of silty carbonaceous shale. The Otway Group of Lower Cretaceous age were penetrated from 9660 feet to a total depth of 10,477 feet. No evidence of hydrocarbons was detected. The basal Tertiary sands and massive sandstone of Upper Cretaceous age were porous and found to be water saturated.

Pecten 1A was drilled, after mechanical difficulties lead to the abandonment of Pecten No. 1, to test an anticlinal structure indicated by seismic work 9 miles offshore from Port Campbell. The well was abandoned at a total depth of 9352 feet with only minor amounts of hydrocarbons being encountered.

Nautilus A-1 was drilled at a site 65 miles south east of Portland, Victoria, and 30 miles offshore to test a well defined wedge of sediments indicated from seismic data and thought to be of Oligocene age. The well reached a total depth of 6597 feet without encountering any significant shows of hydrocarbons and it was plugged and abandoned as a dry hole.

Voluta A-1 which reached a total depth of 13,037 feet, is the deepest of the offshore wells drilled so far in the Otway Basin. It was drilled to test a closed anticlinal structure indicated by seismic data about 5 miles offshore in the vicinity of Cape Bridgewater, Victoria. The well penetrated carbonates and sands of Upper Eocene age to 2754 feet and pebbly sand, silt and claystone of Paleocene age to 4385 feet, before entering Upper Cretaceous sediments. The Upper Cretaceous sediments were penetrated to the total depth of 13,037 feet, and comprised fine sands with minor shales, clays and siltstones and a few coal seams in the upper part of the section, and principally mudstones and sandstone towards the base. No significant hydrocarbon indications were noted, the porous formations being completely water saturated.

Argonaut A-1 was drilled to test a closed fault structure indicated by seismic data at the base of the Tertiary section. The area of the fault closure is about 11 square miles. The site is 7 miles offshore and approximately 26 miles south-south-east of the town of Millicent in South Australia. The well was abandoned at a total depth of 12,163 feet as a dry well. No significant indications of hydrocarbons were recorded and porous sands near the bottom of the well was shown by logs to be completely water saturated.

Esso Crayfish A-1 was drilled to test a small closed anticlinal structure indicated by seismic data near the base of Lower Cretaceous sediments at an approximate depth of 5,000 feet. The well is near the western side of the Otway Basin, and about 10 miles offshore near Robe in S.A. The well was drilled to a total depth of 10,497 feet, plugged and abandoned as a dry hole.

Marine Tertiary sediments were penetrated to 1,200 feet and Upper Cretaceous sediments from 1,200 to 1,561 feet comprising pyritic quartz sandstone with a few coal seams. Lower Cretaceous sediments were encountered at 1,561 feet to the bottom of the well. Minor dry gas shows were encountered below 5240 feet, but formation tests produced only formation water with minor dissolved gas.

Eucla Basin

Although the Eucla Basin which straddles the border between Western and South Australia covers a very large area, the sediments which might be favourable to the occurrence of petroleum rarely exceeds a total thickness of 2,000 feet. A limited amount of geophysical work conducted over the very extensive continental shelf, which averages more than 100 miles wide in the Great Australian Bight, have not in general indicated a much more favourable section. There are no immediate plans to undertake offshore drilling in this area.

Perth Basin

The shelf area adjacent to the Perth Basin is much more promising. In the vicinity of Perth extensive aeromagnetic and seismic surveys conducted offshore have indicated an increasing thickness of sediments extending to the edge of the continental shelf. It is probable that the sediments which range in age from Recent to Upper Proterozoic, exceed 40,000 feet in total thickness.

Extensive block faulting is present in the Pre-Cretaceous sediments and this has lead to the development of closed anticlinal structures in the Cretaceous and Tertiary sediments; these have been mapped by seismic methods

The jack-up drilling barge "Jubilee" has recently arrived in the Perth area to undertake a programme directed at testing closed structures within the Cretaceous and Tertiary sediments, as well as Pre-Cretaceous fault structures. The first well to be drilled is Quinn's Rock No. 1, 12½ miles off the coast near Rottnest Island. At the far northern end of the Perth Basin drilling is taking place on Gun Island in the Abrolhos Group of islands about 40 miles offshore from Geraldton to test a reef structure indicated by seismic data.

Carnarvon Basin - Northwestern Shelf

Considerable interest is at present centred around the Legendre No. 1 well, which is the first offshore test on the North Western Shelf. The well is approximately 120 miles northeast of Barrow Island on which there is a producing oilfield. (See Fig. 1).

At Barrow Island oil is being produced from the Windalia Sand of Lower Cretaceous age, but potential reservoirs exisit within the underlying Lower Cretaceous and Upper Jurassic sediments. Important showings of oil and gas have been proved at various horizons within the Jurassic sediments.

Extensive marine seismic surveys on the shelf area at the northern end of the Carnarvon Basin have mapped a number of regional disconformities within a thick sedimentary section, and defined a number of closed anticlinal structures at two or more horizons. At places the seismic data suggest the presence of reef structures.

The primary objectives of Legendre No. 1, which it is planned to drill to 12,000 feet, is to test a closed anticlinal structure which has been mapped by seismic work at two levels and to test the prospectiveness of the Windalia and various Jurassic sands which are believed to underlie the site.

At the present time (August 1968) Legendre No. 1 has reached a depth of 6500 feet and minor shows of hydrocarbons have been reported. The Cretaceous section has proved considerably thicker than at Barrow Island.

Reconnaissance geophysical work has indicated that over large sections of the Continental Shelf between North west Cape and the Timor Sea, the sediments are either relatively thin or devoid of favourable structures. Interest seems to have been centred mainly at the southern end immediately north east and southwest of Barrow Island and the extreme north eastern end near Cartier and Ashmore Islands. No immediate plans have been announced to undertake offshore drilling in the Canning Basin.

Bonaparte Gulf Basin - Sahul Shelf

The shelf area within Joseph Bonaparte Gulf and the Timor Sea has been extensively examined by geophysical surveys and several closed anticlinal structures have been indicated by seismic work.

On shore the Bonaparte Gulf Basin contains more than 18,000 feet of Palaeozoic sediments which in places are covered by a relatively thin layer of Mesozoic and Tertiary rocks. Offshore the Mesozoic and Tertiary sediments thicken considerably and on the Sahul Shelf attain a thickness exceeding 10,000 feet.

On the outer edge of the shelf there is a large number of coral reefs and there is a possibility that similar reefs may have existed in past geological periods during which sediments were deposited.

Only one well has been drilled in this area, namely Ashmore Reef No. 1 (see Fig. 1). It is situated on the extreme northwestern margin of the Sahul Shelf in the Timor Sea and about 200 miles from the nearest part of the Australian coast.

On the very broad Sahul Shelf the mapping of magnetic basement thought to be the top of the Precambrian, reveals a morphology that coincides with the offshore extensions of the Bonaparte Gulf Basin and the Kimberley Precambrian block. An important feature is the magnetic basement swell along the outer margin of the shelf. In general the Sahul Shelf appears to represent a marginal part of the Australian Precambrian craton which has been partly fragmented by faulting. Seismic data suggests a number of major breaks which have been interpreted as representing thick Upper Palaeozoic, Mesozoic and Tertiary sediments which are expected to be dominantly marine and highly prospective. The seismic data also indicates the presence of thick sedimentary sequences and moderate folding along the margin of the Sahul Shelf and including Ashmore Reef.

The site of the Ashmore Reef No. 1 was selected for a two-fold purpose. Firstly it was selected to test a closed anticlinal structure with a closure of not less than 150 square miles, and secondly to study a stratigraphic section in an area remote from any known subsurface geological data. Closure had been mapped in two prominent reflectors at depths of about 2,000 feet and 6,000 feet respectively below sea level. There was evidence of a marked unconformity at about 1,000 feet below the lower of these two and of another unconformity about 12,000 to 13,000 feet below sea level.

Ashmore Reef No. 1 was spudded in October 1967, and was drilled to a total depth of 12,843 feet. The well penetrated 893 feet of Quaternary carbonate before entering a sequence of 6903 feet of predominantly carbonate beds ranging in age from Middle Miocene to Upper Cretaceous; seismic evidence suggests that this sequence is interrupted by two unconformities.

Beneath the Upper Cretaceous beds there was a thin (146 feet) section of Uppermost Jurassic sediments resting conformably on 1041 feet of Upper Jurassic volcanics; altered amygdaloidal basalt and interbedded claystones overlying a thick sequence of olivine basalt lavas with interbedded tuffs. The volcanic rocks rested unconformably on Upper Triassic sediments, predominantly clastic, which were penetrated for 3700 feet to total depth. Only very minor amounts of gas were detected and no tests were carried out.

Good potential reservoir conditions were encountered, particularly in calcarenites of Eocene age and within the Upper Triassic clastics. Marls and shales within the Tertiary and Upper Triassic are possible source rocks. The uplift which formed the Ashmore reef structure was post-early Middle Miocene in age and is young relative to sediment deposition. This possibly accounts for the lack of hydrocarbon shows in an environment which otherwise seems favourable.

Arafura Sea and Gulf of Carpentaria

The very extensive shelf area in the Arafura Sea and the Gulf of Carpentaria has been investigated with aeromagnetic and seismic methods. Although a thick (up to 12,000 feet) section of sediments believed to be Mesozoic and younger has been indicated in the north western part of the area, the sediments elsewhere are generally thin.

So far few, if any structures favourable to the accumulation of petroleum have been discovered and there are no immediate plans to undertake offshore drilling in these areas.

CONCLUSION

The exploration of the Australian continental shelf has reached a very interesting stage. Important discoveries of natural gas have been made in the Gulf of Papua and a major oil and gas field discovered in the Gippsland Basin. Evidence is accumulating that deposits of very substantial thicknesses of Mesozoic and Tertiary sediments are widespread. These sediments might be expected to contain both favourable source rocks and reservoirs and in many places, they have been folded into closed anticlinal structures.

It is not too optimistic to hope that when the potential of the Australian shelf area has been fully tested, Australia will have sufficient petroleum for its own needs.

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