UNITED STATES DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY

Undiscovered Petroleum Resources of Indonesia

by

John Kingston

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ASSESSMENT OF RECOVERABLE ENERGY RESOURCES

The World Energy Resources Program of the U.S. Geological Survey (USGS) intends to develop reliable and credible estimates of undiscovered recoverable petroleum resources throughout the world. Initial program efforts have focused on the major producing areas of the world to gain a broad geological understanding of the characteristics of petroleum occurrence for purposes of resource assessment, as well as for analysis of production potential. Investigations of production potential are carried out in cooperation with other U.S. Government agencies; specifically, the studies of the main free world exporting nations, of which this study is a part, are carried out in cooperation with the Foreign Energy Supply Assessment Program of the Department of Energy. The estimates represent the views of a U.S. Geological Survey study team and should not be regarded as an official position of the U.S. Government.

The program seeks to investigate resource potential at the basin level, primarily through analogy with other petroleum regions, and does not necessarily require, therefore, current exploration information that is commonly held proprietary. In conducting the geological investigations, we intend to build a support base of publicly available data and regional geologic synthesis against which to measure the progress of exploration and thereby validate the assessment. Most of these investigations will lead directly to quantitative resource assessments; resource assessment, like exploration, to be effective, must be an ongoing process taking advantage of changing ideas and data availability--the results produced being progress reports reflecting on a state of knowledge at a point in time. Because this program is coordinated with the USGS domestic assessment program and both utilize similar techniques for assessment, the user can be assured of a thread of consistency permitting comparisons between the various petroleum basins of the world, including the United States, that have been assessed in the overall USGS program.

In addition to resource estimates, the program provides a regional base of understanding for in-country exploration analysis and for analysis of media reports regarding the exploratory success or failure of ventures in studied areas.

Other U.S. Geological Survey publications relating to the assessment of undiscovered conventionally recoverable petroleum resources are available from the Open File Services Section, Branch of Distribution, USGS, Box 25425, Federal Center, Denver, CO 80225.

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ABSTRACT

Thirteen of the 44 sedimentary basins along the 2,900-mile east-west extent of Indonesia are believed to contain nearly all of Indonesia's petroleum resources. Western Indonesia, underlain by the Asian (Sunda) continental block, comprises the Sumatra-Java archipelago, the island of Kalimantan, and the intervening Sunda Shelf. This area contains more than 95 percent of present Indonesian petroleum reserves, and exploration has reached the stage of early to middle maturity. Reserves are concentrated in the five larger back-arc basins of the archipelago and in three rifted basins of the Kalimantan-Sunda Shelf area.

Eastern Indonesia, essentially Irian Jaya (western New Guinea) and the adjoining shelf, was formed by tectonic activity along the north edge of the Australian-New Guinea continental block, whwere locally derived coarsely clastic, non-marine in nature (fig. 7), followed by dark, carbonaceous, brackish water shales. By early Miocene time, continued subsidence west of an early Miocene hinge line resulted in coalescing of the subbasins in a quiet, marine environment. West of the hinge line, deposition was largely shale with carbonate facies over horst-block highs, while calcarenite and sandstones or reefal carbonates were deposited on the platform east of the hinge line. Continued slower subsidey eight USGS geologists with 48 play analyses in 17 basins as a guide, and the results are shown as probability curves.

Aggregation of the mean estimates for the four main groups of basins: Sumatra-Java, Kalimantan, Natuna, and Irian Jaya, indicates that undiscovered recoverable petroleum resources of Indonesia are 10 billion barrels of oil (BBO) and condensate, and 95 trillion cubic feet (Tcf) of gas (not including 60 Tcf of discovered, but undeveloped gas).

INTRODUCTION

Indonesia is a country of great lateral extent, measuring about 2,900 miles from east to west with 44 onshore and offshore sedimentary basins covering an area of approximately 550,000 mi^2 (fig. 1). The resource assessment study concentrates on 13 of these basins which have an overall area of about 420,000 mi^2, and for reasons discussed below are estimated to have at least 90 percent of the Nation's discovered and undiscovered petroleum.

Discovered or producing fields of Indonesia have original reserves of some 20 billion barrels of oil (BBO) (and condensate) and over 100 trillion cubic feet (Tcf) of gas (including about 60 Tcf of gas which are believed to be discovered but not on production). Petroleum production is confined to 10 basins, plus significant discoveries or shows indicating potential production in two additional basins (fig. 2).

Proved reserve estimates are beyond the scope of this study but are presented as a scaling tool for the resource estimate of each basin. Various published estimates or indications of reserves differ considerably, but not so much as to affect such an application. Used in this study were the latest available oil and condensate estimates, as of 1983, published by the Energy Information Administration (EIA) (Dietzman, 1984). The only available gas reserve numbers (1979) are those derived from the combined data of Hariadi (1980) and Patmosukismo (1980) of Pertamina.

The level of petroleum exploration in Indonesian basins varies. Some basins, such as South Sumatra, are explored rather thoroughly and have been declining in production for years; others, such as those of Irian Jaya (Indonesian New Guinea) and eastern Indonesia, are very sparsely explored. Details of exploration and production history are discussed under the individual basins.

The purpose of this study is to provide a basis for a quantitative assessment of undiscovered petroleum resources of Indonesia. To this end, every appropriate estimate of a geological or historical factor is quantified, even though it may be only a guess, and the derivation of, or rationale behind, each estimate is given. New information may cause a revision of a particular number; the revision can then be plugged back individually into the system effecting a corresponding change in the overall resource estimate.

Data sources of the study are essentially limited to available published information, though some unpublished maps and other data have been referred to.

Although background geology is covered briefly, the focus of this study is on the significant geologic factors bearing directly upon petroleum occurrence. The study is structured to support a play analysis approach. Estimates of the significant geologic factors for 48 plays in 17 basins are summarized in play analysis form.

The play analysis method used here is a modified volumetric yield method with each of the appropriate geologic factors considered separately (Roadifer, 1979). In this play analysis, estimates are made of seven principal factors; 1) acres of untested trap, 2) percent of untested trap area which is productive, 3) percent of oil versus gas, 4) feet of average effective pay, 5) oil recovery in barrels per acre-foot (a function of reservoir quality), 6) gas recovery in thousands of cubic feet per acre-foot, and 7) natural gas liquids (NGL) in barrels per million cubic feet of gas. The estimates are given as ranges to indicate varying degrees of certainty. For brevity, only the most likely value (or mode) is used in the text discussion of the

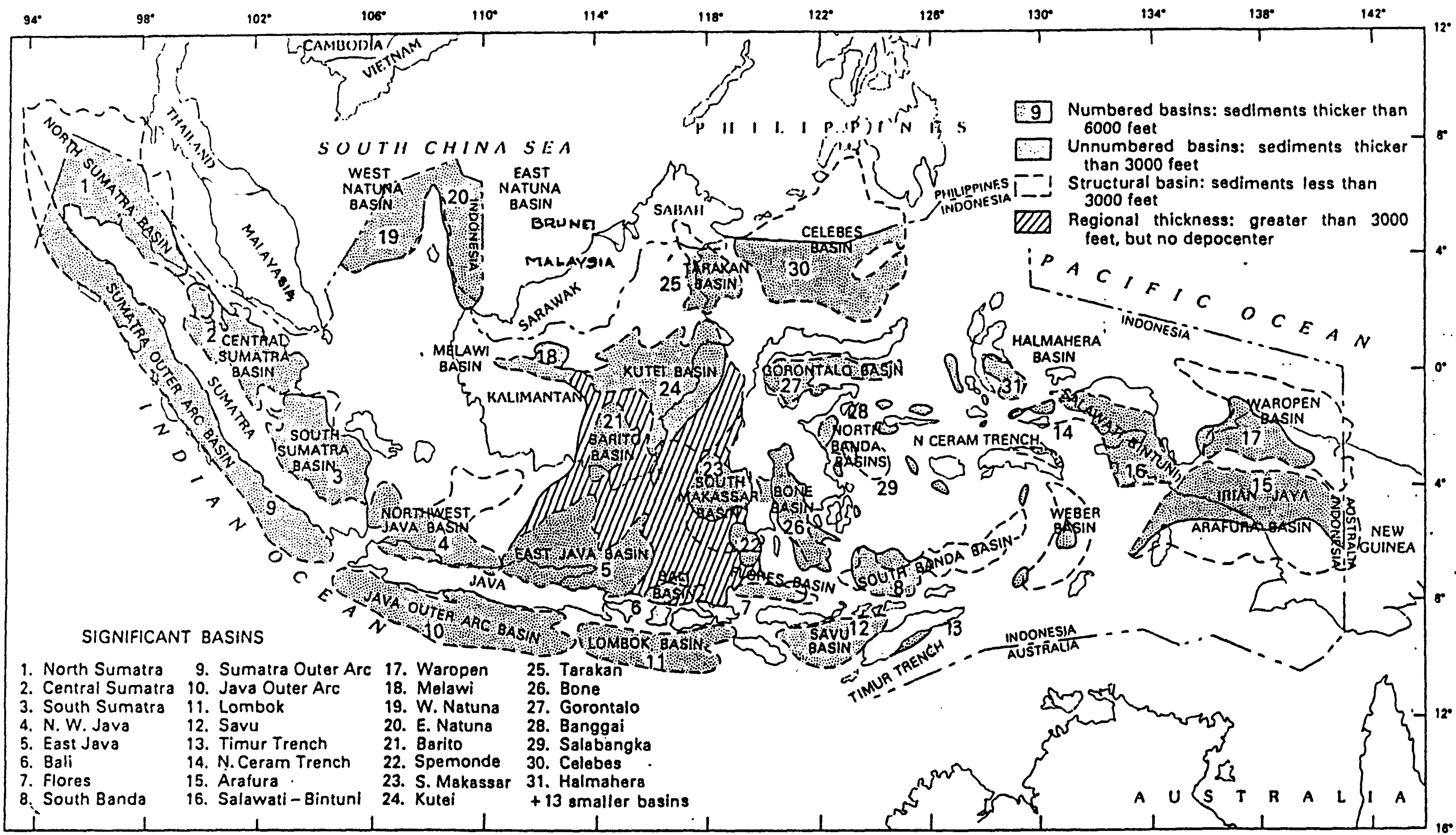


Figure 1.--Map showing significant Tertiary basins of Indonesia.

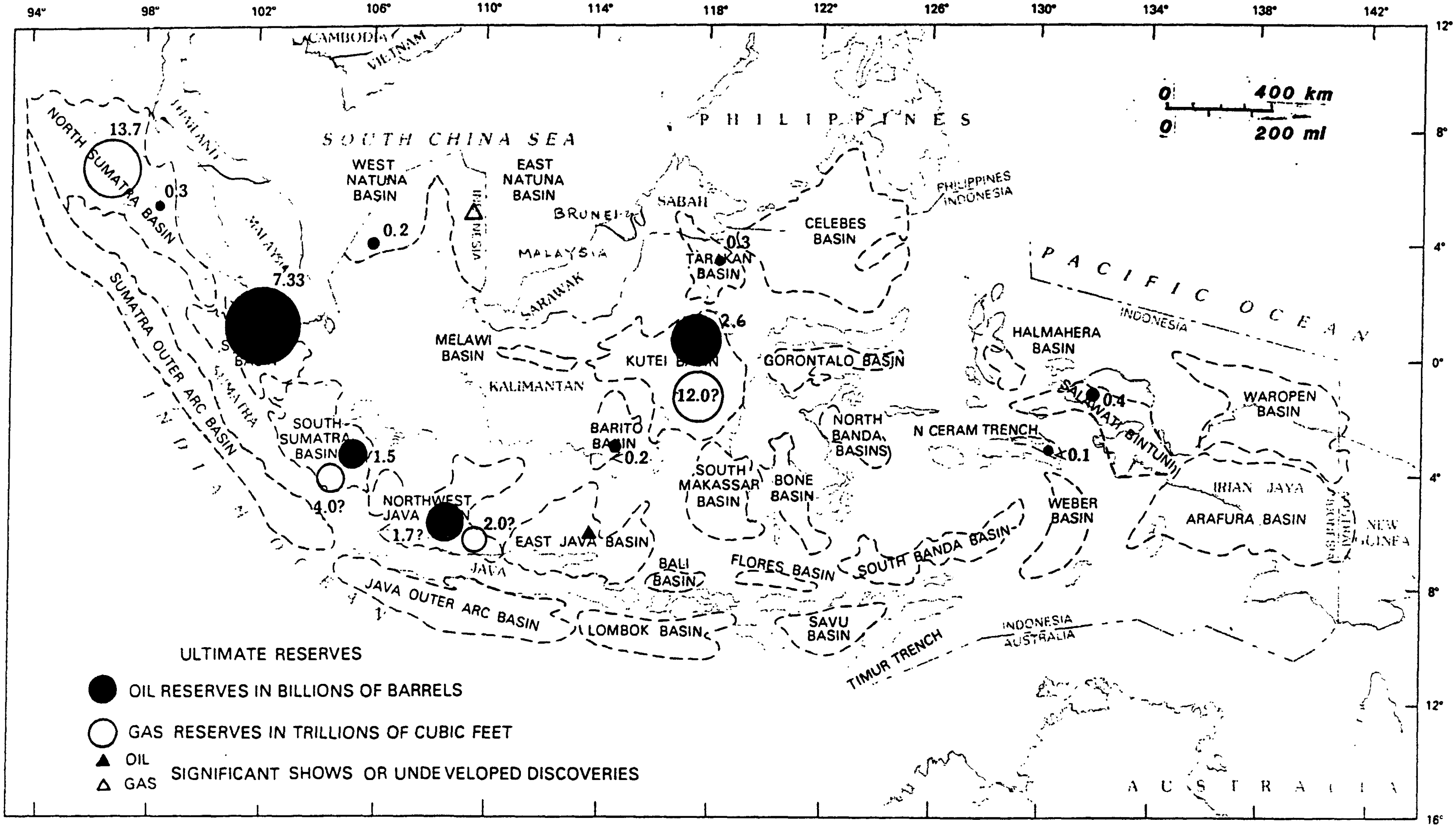


Figure 2.--Map showing petroleum occurrences in Indonesia.

rationale behind each estimate. As an additional assessment guide, the limiting factor or factors affecting the play are emphasized.

The petroleum geology outlined in this report, along with the play analyses, was presented to a board of eight U.S. Geological Survey (USGS) geologists who, after discussion and deliberation from the perspective of their individual experiences, arrived at a subjective consensus as to the amount of undiscovered recoverable petroleum resources in each basin or group of basins (a modified Delphi method described by Dolton and others in USGS Circular 860). Because the unknown cannot be predicted with precision, probability curves better convey the true nature of the estimate rather than a single, or point value. On the condition that recoverable resources are indeed present, initial assessments were made for each of the provinces as follows:

1) A low resource estimate corresponding to a 95-percent probability that the resource quantity exceeds that amount,
2) A high resource estimate corresponding to a 5-percent probability that the resource quantity exceeds that amount,
3) A modal (most likely) estimate of the quantity of resource.

Final estimates of the group are averaged, and those numbers are computer processed by using probabilistic methodology (Crovelli, 1981). The resulting curves show graphically the resource values associated with a full range of probabilities and determine the mean, as well as other statistical parameters. The resultant curves for each province are shown. Estimates drawn from these curves form the conclusion of this report.

REGIONAL GEOLOGY

Role of Tectonics

Tectonics assume a special importance in Indonesia in regard to petroleum accumulation. Maturation of source rock, preservation of source material, development of reservoirs, and the formation of traps are all directly affected by the movements and interaction of lithospheric plates. The principal plates involved are the Asian Plate (including the accreted Sunda continental fragment), the Pacific Plate, and the once separate Indian and Australian Plates.

There are five principal Tertiary tectonic events or interactions, in order of importance affecting basin formation and the accumulation of petroleum:

1. Subduction of the Indian Plate beneath the Asian Plate
2. Rifting of eastern Sulawesi (the Celebes) from Kalimantan (Borneo)
3. Relative westward and southward thrust of the Pacific Plate into the region, causing disruption of previous terrains, sinistral wrenching, and oblique collision and subduction under the Australian continental block, which includes southern New Guinea
4. Rifting and opening of the South China Sea
5. Opening of the Thai-Malay Graben

Plate interactions are considered in more detail in the discussions of the individual basins.

Tectonic Basin Classification

It is difficult to define sedimentary areas as to what should be basins or subbasins in this complex region. For the sake of conformity, the definitions of previous authors, i.e., Hamilton, 1974, 1978; Fletcher and Soeparjadi, 1975, 1977; Kartaadiputra and others, 1982, were used. A significant basin is defined as one containing sediments with thicknesses greater than about 3,000 ft (about 1 km, or 1 second of seismic reflection time). On that basis, I have shown 44 basins comprising an area of 550,000 mi^2 (fig. 1). In the exceptional case of the eastern Java Sea, where the whole shelfal region has a sedimentary thickness of over 3,000 ft, individual depocenters of somewhat thicker sedimentary fill (i.e. approximately 5,000 ft) are designated as basins. More than half of the basin area (300,000 m^2) is over oceanic or attenuated continental crust regions in deep water; this basinal area would be much larger if it were not limited, by my definition, to basins having over 3,000 ft of sediment. In fact, some of the structural basins of the oceanic crust areas indicated as major basins (e.g. Weber, North Banda) by some authors, have been shown by Kartaadiputra and others, 1982, to have minimal sediment thicknesses.

Basins may be categorized tectonically by their positions on the interacting plates or continents of the region. Figure 3 shows the predominant tectonic characteristic of each of the principal basins; not indicated is that wrenching is a dominant trait of many of the basins, particularly those of Sumatra, West Natuna, and Irian Jaya. The areal extent of these basins varies from 1,000 sq mi^2 to 75,000 mi^2 (Sumatra Outer Arc), and sedimentary thicknesses range up to over 30,000 ft (Kutei basin).

The effect of the position of the basin, in relation to the interacting plates, on the thermal gradients is of paramount significance for petroleum generation. In general, the inner- or back-arc basins are the warmest, the rifted continental margin basins are next warmest, and the outer arc basins are the coolest.

Effects of Underlying Crust

Indonesia is divided, geologically, into three regions on the basis of the underlying crust, 1) Asian continental crust, 2) Australian continental crust, and 3) oceanic and island-arc crust (fig. 3). Continental crust regions, being more buoyant, approximate topographically higher areas where water depth is less than 600 ft. The continental crust is made up mostly of old, granite-intruded terrain (craton). Fourteen of the 44 basins are underlain by continental crust (fig. 3). The other less buoyant crustal areas, those underlain by oceanic crust or attenuated continental crust, are generally covered by more than 600 ft of water.

The distribution of continental versus oceanic crust also affects the thermal gradient of the basins; gradients over continental crust areas are significantly higher. For example, the foreland basins of Sumatra, underlain by craton, have a high gradient but gradually become cooler in the East Java basin, underlain by accreted continental crust, and even cooler in the Bali and Flores basins, which are underlain by oceanic crust.

Basins off the continental crust area are generally of poorer source, being of low thermal gradient and further from the source of terrestrial organic matter, the prime source material of the generally high paraffinic petroleum of Indonesia. These basins also generally lack adequate reservoir rocks because they are further from quartz-rich provenances and lack a high-energy neritic depositional environment. Basins underlain by oceanic or attenuated continental crust are, therefore, less prospective and contain a negligible amount of undiscovered petroleum. They, therefore, are not discussed further. However, because three of these deep-water basins, the Sumatra

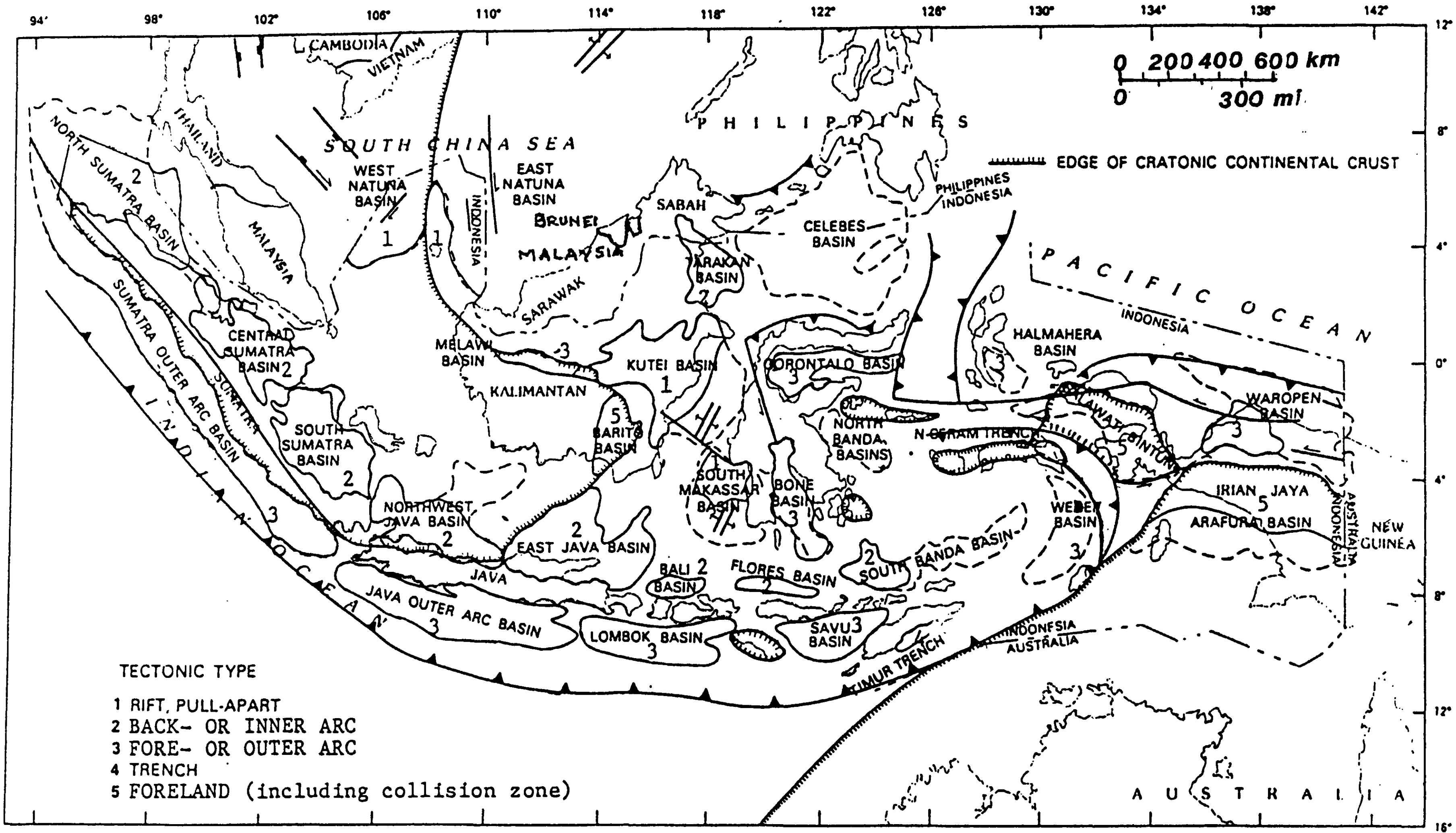


Figure 3.--Map showing tectonic basin classification of Indonesia.

Outer Arc, the Java Outer Arc, and the South Makassar basins, have such a great volume of sediment a play analysis of each is included in this report.

Structural Trap Types

Individual trap-forming structures are discussed under each basin, but in general, there are four major types of relevant structures:

1. Early horst and graben block-faulting, usually lower Miocene or older, forms fault traps in older (Cretaceous to lower Miocene) sediments, drape closures in younger (Neogene) sediments, and growth sites for Miocene reefs.
2. Drag-fold structures are prevalent in Sumatra, West Natuna, and in Irian Jaya where wrench faulting is dominant.
3. Anticlinal folds of probable compressional origin are extensive along the east coast of Kalimantan (Borneo) and in central Irian Jaya.
4. Diapiric folds or folds with considerable shale flowage are common in the North Sumatra, East Java, eastern Kalimantan, and Waropen basins.

Regional Stratigraphy

Because the stratigraphy of Indonesia is highly variable, it is best described if the rocks of the Asian continental block are considered separately from those in the Australian continental block.

Asian Continental Block

The Asian block (Sundaland) is ringed by a line of Tertiary basins (fig. 3). Although these basins vary in detail, their sedimentary record has a parallel, one-cycle history, broken down into three phases, 1) transgression, 2) still stand, and, 3) a regression:

1. Eocene to early Miocene - initial filling of isolated terrestrial basins, largely grabens, followed by marine transgression and delta development at the end of the period
2. Early to middle Miocene - regional quiescence characterized by shale and carbonate deposition
3. Middle Miocene to Pliocene - regression with coarser clastics and deltaic deposition.

Australian Continental Block

The southern half of the island of New Guinea had been a north-facing continental shelf from Middle Jurassic to mid-Tertiary. Shelf sedimentation of mainly Australia-derived sandstones and shales (Kembelangan Group) persisted through the Jurassic, Cretaceous, and early Tertiary. During early Tertiary through late Miocene, clastic inflow diminished, and sedimentation was mainly carbonate and shale (New Guinea Limestone Group). Near the end of the Miocene, more coarse clastic sediments (Klasaman, Steenkool, and Buru Formations) filled the shelf area basins of southern and western Irian Jaya. These sandstones and shales, in contrast to the older, Australia-derived sediments from the south, were derived from the medial, east-west trending mountains of Irian Jaya to the north, which were formed by the Miocene collision of the Australian continent with an island arc of the Pacific Plate. At about the same time, Miocene and Pliocene sediments, which were derived from the collision zone and from the higher parts of the finally accreted island arc forming the north coast of Irian Jaya, filled the Waropen Basin of north Irian Jaya.

Probable Source Rocks

Figure 2 shows petroleum production and reserves, and substantial occurrences (i.e. indications of potential production), or discoveries. It also shows that production is limited to ten basins, and production plus significant occurrence to 12 basins.

Figure 4 shows the thermally mature rock distribution of Indonesia. This map was constructed by projecting the approximate top of thermally mature sediments in each basin laterally to the intersection with the basin flank. Determinations of the top of thermally mature sediments were derived from published maturity indices, or by estimation (method of Hood, 1975) from published thermal gradients and age-depth data. In analogous areas, estimates of thermal maturity were made by comparison of thermal gradients.

Figure 4 shows that only 18 of the 44 basins analyzed are underlain by significant amounts of thermally mature source sediments. In 14 of these 18 basins, thermally mature sediments appear to be of appreciable organic richness. Thermally mature sediments of 4 (the Sumatra and Java outer-arc basins and the Timor and N. Ceram Trenches) of the 18 basins, however, appear to be in a melange open-sea facies so that any organic richness might have been diluted or destroyed, and therefore have a much lower generating potential.

However, melange-type sediments do have some limited petroleum generating capacity, as indicated by oil and gas seeps along the edges of the Sumatra and Java outer arc basins, in addition to seeps on the island of Timor, and a small oil field (Bula) on the island of Ceram. An oil seep on the north side of the Waropen basin may emanate from melange or island-arc material.

A comparison of petroleum production and discoveries (fig. 2) with thermally mature source rock occurrence (fig. 4) shows that only three basins have an appreciable volume of thermally mature rock (non-melange), but no oil or gas discoveries (Waropen, Arafura, and South Makassar). Perhaps lack of discoveries may be related to the relatively minor exploration effort in these basins.

A comparison of the overall basin distribution (figs. 1 and 3) and mature source rock occurrences (fig. 4) indicates that the source rocks are confined to the continental crusted areas, but more importantly, only 14 of 44 Indonesian basins have an appreciable potential for generating petroleum.

Reservoirs

There are six groups of reservoirs, three associated with the Asian Continental Block and three with the Australian Continental Block.

Asian Continental Block Reservoirs

Reservoirs of western Indonesia are related to the previously described three phases of sedimentation of the Asian Continental Block.

a. Paleogene and lower Miocene Transgressive and Deltaic Sandstones

During early Tertiary, the western part of the Asian Continental Block was emergent and terrestrial sediments filled in and levelled intermontane

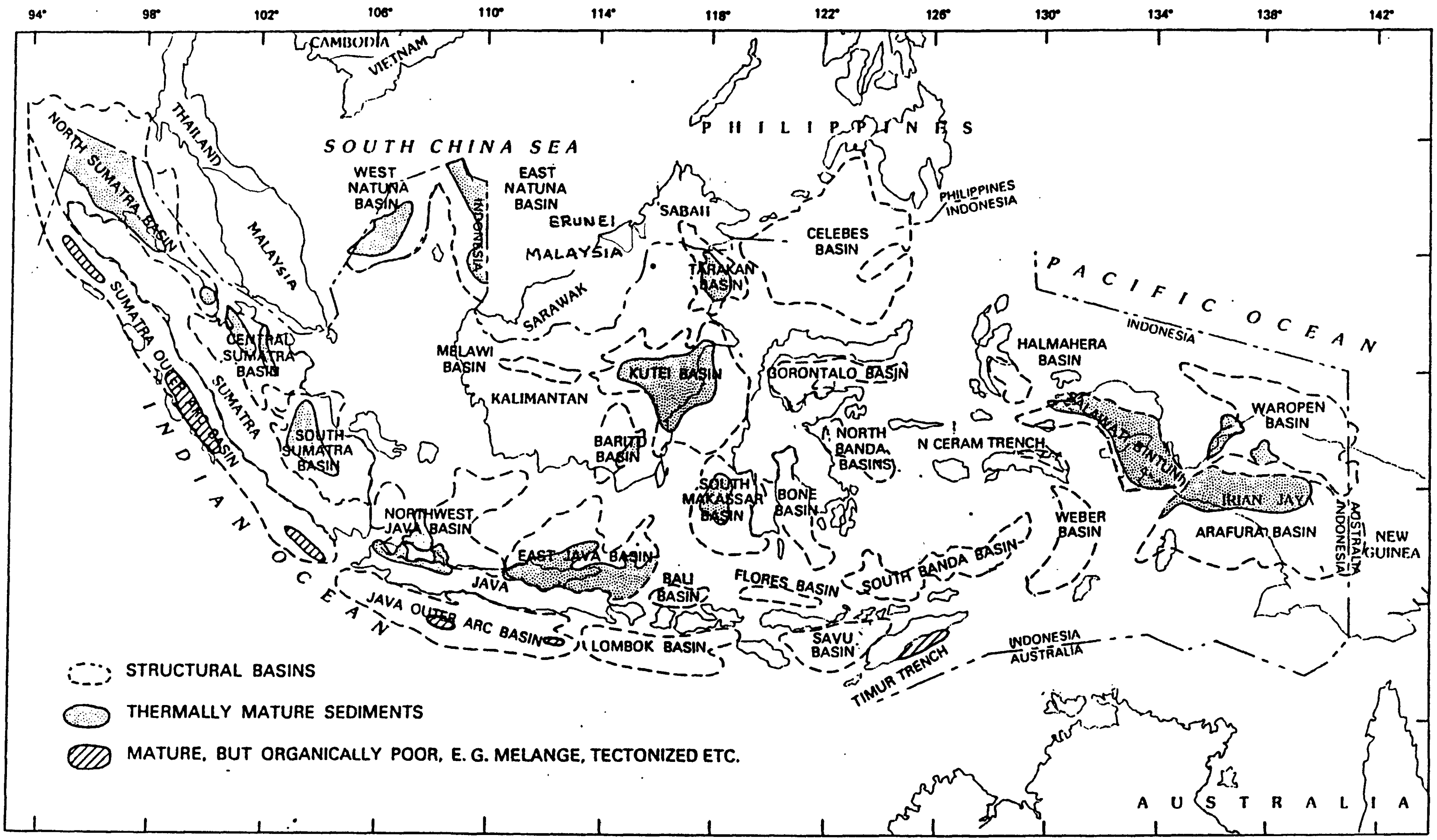


Figure 4.--Map showing distribution of thermally mature sediments of Indonesia.

lows. In the east, Eocene to Oligocene seas transgressed westward over the continent and carbonate rocks are abundant in the East Java Sea area. The terrestrial rocks contain only poor to fair reservoirs, although reserves of 217 MMBO have been found in fractured Eocene volcanics/tuffs in west Java, near Jatibarang. The marine transgressive Eocene sandstones of east Kalimantan (Borneo) have better reservoir properties; in the Barito basin they have 20 to 25 percent porosity.

In late Oligocene to early Miocene, there was even more widespread transgression, and these transgressive basal sandstones are productive of oil in North Sumatra and Central Sumatra and possibly in South Sumatra and West Natuna. Though as yet unproductive, these sandstones are of high potential in East Kalimantan. During the end of this geologic time range, rising highlands of Malaysia were the source of the Sihapas and Talang Akar deltas in the Central Sumatra, South Sumatra, and West Java basins. These deltaic sandstones, along with basal transgressive sandstones, have yielded most of the Indonesian petroleum produced in recent years. Central Sumatra deltaic sands alone provide about half of Indonesia's production of 1.4 MMBOPD.

b. Miocene Reefs

A single, lower Miocene, deeply buried, porous reef of central North Sumatra basin, the Arun Field, produces almost two-thirds of the reef production of Indonesia (73 MMBOE gas and 22 MMBOE condensate in 1980). Other deeply buried reefs are indicated, and upper Miocene reefs yield oil and gas on the shallow foreland of the North Sumatra basin. In the South Sumatra and Northwest Java basins, the lower Miocene is represented in part by carbonate rocks in the form of isolated reefs (Batu Raja Formation), but eastwards, in the East Java Sea and Barito basins, equivalent age carbonates were deposited as a thick platform sequence.

In the middle Miocene, an extensive, 1,000 to 3,000-ft thick carbonate platform with large (up to 25,000 acres) reefs (Terumbu Limestone) occupied the East Natuna Basin Shelf (the Terumbu Limestone). In one structure, the "L" structure, the porous zone (extending down into the platform carbonate) is 5,261 ft thick. Hydrocarbon gas (i.e., excluding 72 percent carbon dioxide) reserves of this single unproduced structure are estimated to be more than 60 Tcf.

c. Neogene Regressive and Deltaic Sandstones

Starting in about the middle Miocene, seas began to regress from the Asian Continental Block as a result of widespread deltaic deposition around the perimeter of the block. The deltaic sandstones, although not as abundant as Paleogene and lower Miocene deltaic sandstones, produce one-third of the oil and gas in Indonesia. These sandstones are of secondary importance in Sumatra, but they are the primary producers in the West and East Java and Kutei basins. Upper Miocene sandstones are also the main producers (over 100,000 BOPD and unknown amounts of gas) in the adjoining, down-dip Malaysian portion of the Indonesian West Natuna basin.

Australian Continental Block Reservoirs

There are three groups of reservoirs corresponding to the main sedimentary groups of the province on the Australian Continental Block.

a. Cretaceous Sandstones

Sandstones and shales, ranging in age from Jurassic to Paleogene, but mainly of Cretaceous age, are present in most of southern New Guinea. They exceed 1,500 ft in thickness, and, although details of reservoir quality are unavailable, appear to be prospective as reservoirs in the Salawati-Bintuni and Arafura basins.

b. Miocene Reefs

Middle to upper Miocene reefs produce oil in the Salawati subbasin and are the objectives in drilling of the Bintuni subbasin and the Arafura basin. Many reefs are dry and are believed to have been especially prone to leaking and flushing because of insufficient penecontemporaneous shale cover which is an important requirement for petroleum accumulation in these basins.

c. Pliocene Sandstones

There are two different geographic groups of Neogene, Pliocene, sandstones in Irian Jaya. One group is made up of the Steenkool, Klasaman, and Buru Formations, and extends east-west along the southern side of Irian Jaya Central Ranges. This group is shale and sandstone, with many, extensive sandstones at least in the Bintuni subbasin.

The second group, The Mamberamo Formation and its equivalent, is as much as 15,000 ft in thickness in the Waropen basin. It is derived from the Central Ranges to the south and from accreted island arc to the north. Gross descriptions report an abundance of graywackes and subgraywackes in the section, indicating less favorable reservoir quality. However, reported graded bedding indicates that turbidites exists in the deep Waropen basin and that there is some chance that adequate reservoirs are present.

Summary

1. Fourteen of 44 Indonesian basins are considered to have adequate thermally mature, organic-rich source rocks. There may be undiscovered petroleum resources outside of these 14 basins, but the amounts are not significant in this assessment, and are not considered further in the text of the report.

2. Four additional basins may have sufficient thermally mature source sediments but the organic richness of the sediments is in doubt. Three of these basins, though not included in the text discussion, are included in the play analyses.

3. Reservoirs of varying but adequate quantity and quality are present in the 14 basins with presumed favorable source rock, with the possible exception of South Makassar basin, leaving 13 basins with both adequate source and reservoir rock, which form the text of the report (South Makassar, however, is included in the play analysis).

4. Half of the oil and gas (58 percent of the oil) produced in Indonesia comes from Eocene - lower Miocene transgressive and delta front sandstones, which are largely confined to three basins, Central Sumatra, South Sumatra, and Northwest Java basins.

5. One-third of the oil and gas (31 percent of the oil) is produced mainly from regressive Miocene-Pliocene sandstones in the Kutei basin (94 percent), with the remaining 6 percent from the North Sumatra and Java basins.

6. Seventeen percent of Indonesian oil and gas (10 percent of the oil) is produced from Miocene reef reservoirs. When the "L" Structure Gas Field (East Natuna) is developed, most of Indonesian petroleum, mainly gas, will be from Miocene reef reservoirs.

7. Most of the Irian Jaya basins, i. e., the Arafura basin, the Waropen basin, and the Bintuni subbasin, apparently have adequate source and reservoir rocks where exploration has been minimal and no discoveries have been made.

INDIVIDUAL BASIN ASSESSMENTS

North Sumatra Basin

Location and Size

The North Sumatra basin is the westernmost of the Indonesian basins (fig. 1). As in the case of the other Sumatran basins, it is on the western edge of the Sunda continental block. It occupies the northwestern part of the island of Sumatra and has an area some 33,000 mi^2 with a sediment volume of approximately 97,000 mi^3 (fig. 5).

Exploration and Production History

Oil production began in 1885 from the Telaga Said Field, the first production in Indonesia and the birth of Shell Oil Company. By World War II, exploration resulted in a modest potential production of some 20,000 BOD. After a long interruption by World War II and subsequent political unrest, oil production slowly rose to about 25,000 BOD. Initial exploration targets were relatively shallow Miocene-Pliocene sandstones; the traps were largely found by surface geologic investigation. Later geophysical work led to the discovery of relatively deep (10,000-foot) gas in lower Miocene carbonate rocks at Arun in 1971, which was estimated to contain about 14.25 Tcf of gas plus approximately 755 MMB of condensate. Gas and oil were later discovered in sandstones and in small offshore reefs on the North Sumatra Shelf.

Six plays have been developed in North Sumatra (figs. 6 and 7) (1) deep basin reefs, 2) Neogene sandstones, 3) shallow shelf reefs, 4) early Miocene shelf sandstones, 5) Paleogene basal drapes, and 6) offshore slope, which will be discussed in some detail. Only one of these plays (deep basin reefs) has major production, one play (Neogene sandstones) has minor production, two plays (shallow shelf reefs and early Miocene shelf sandstones) have indicated discoveries but are yet to be put on production and two plays (Paleogene basal drapes and offshore slope) have yet to provide a discovery.

The estimated future discovery rate for the deep basin reefs is 20 percent; the Neogene sandstones, 14 percent; the shallow-shelf reefs, 22 percent; the early Miocene shelf sandstones, 20 percent; the Paleogene basal

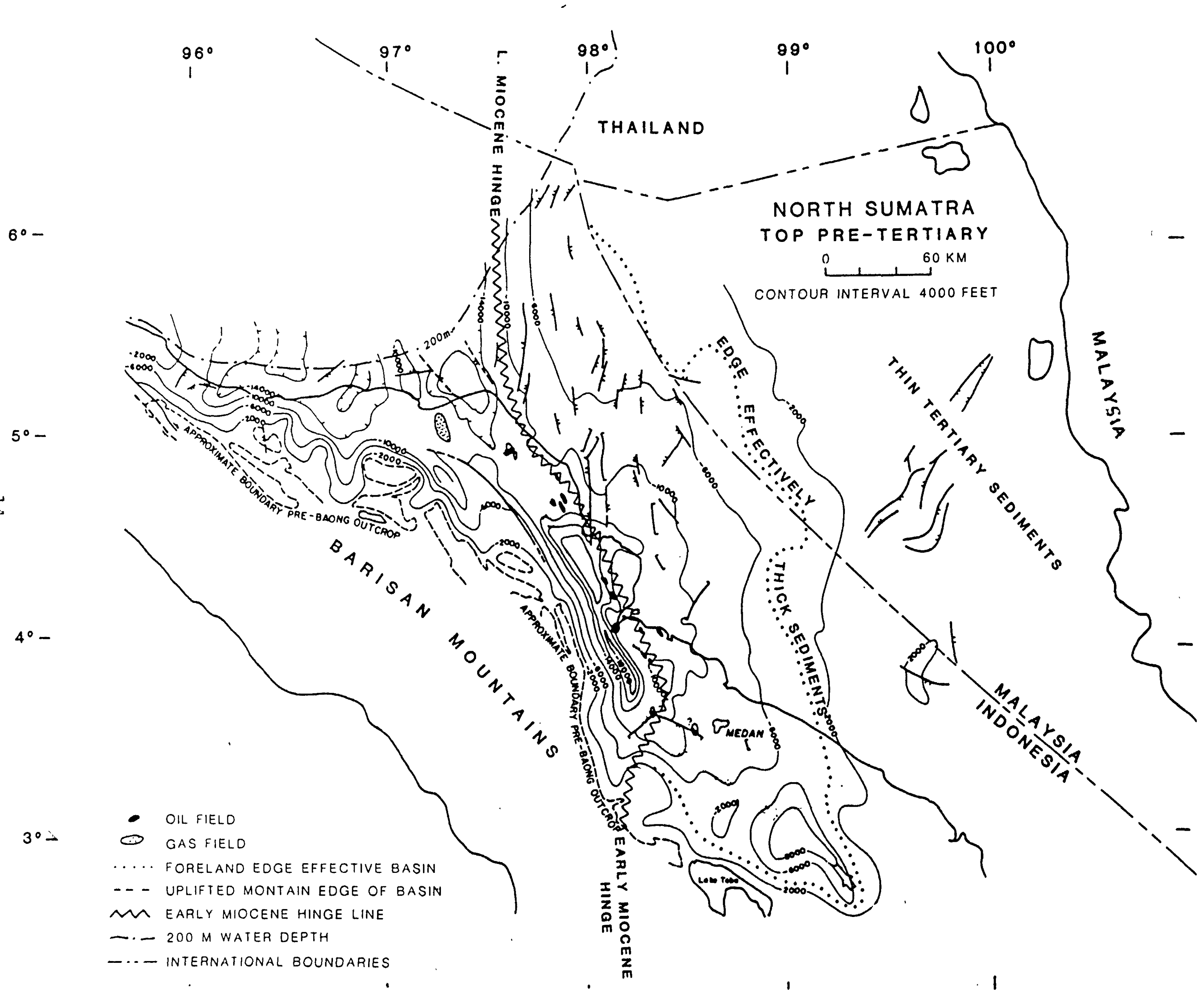


Figure 5.--Structure contour map North Sumatra basin showing depth to basement. After Kingston (1978).

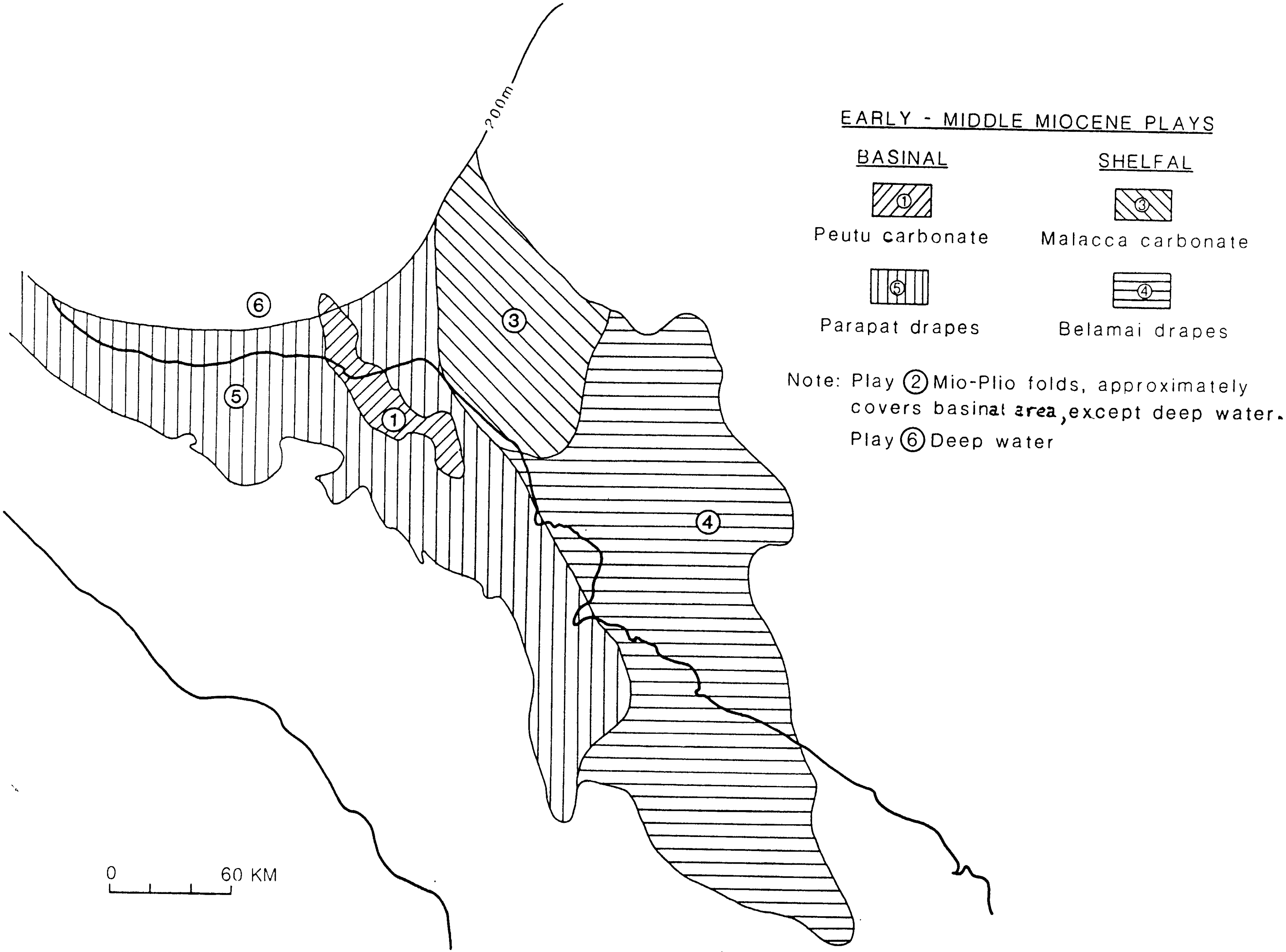


Figure 6.--Map of North Sumatra basin showing distribution of plays.

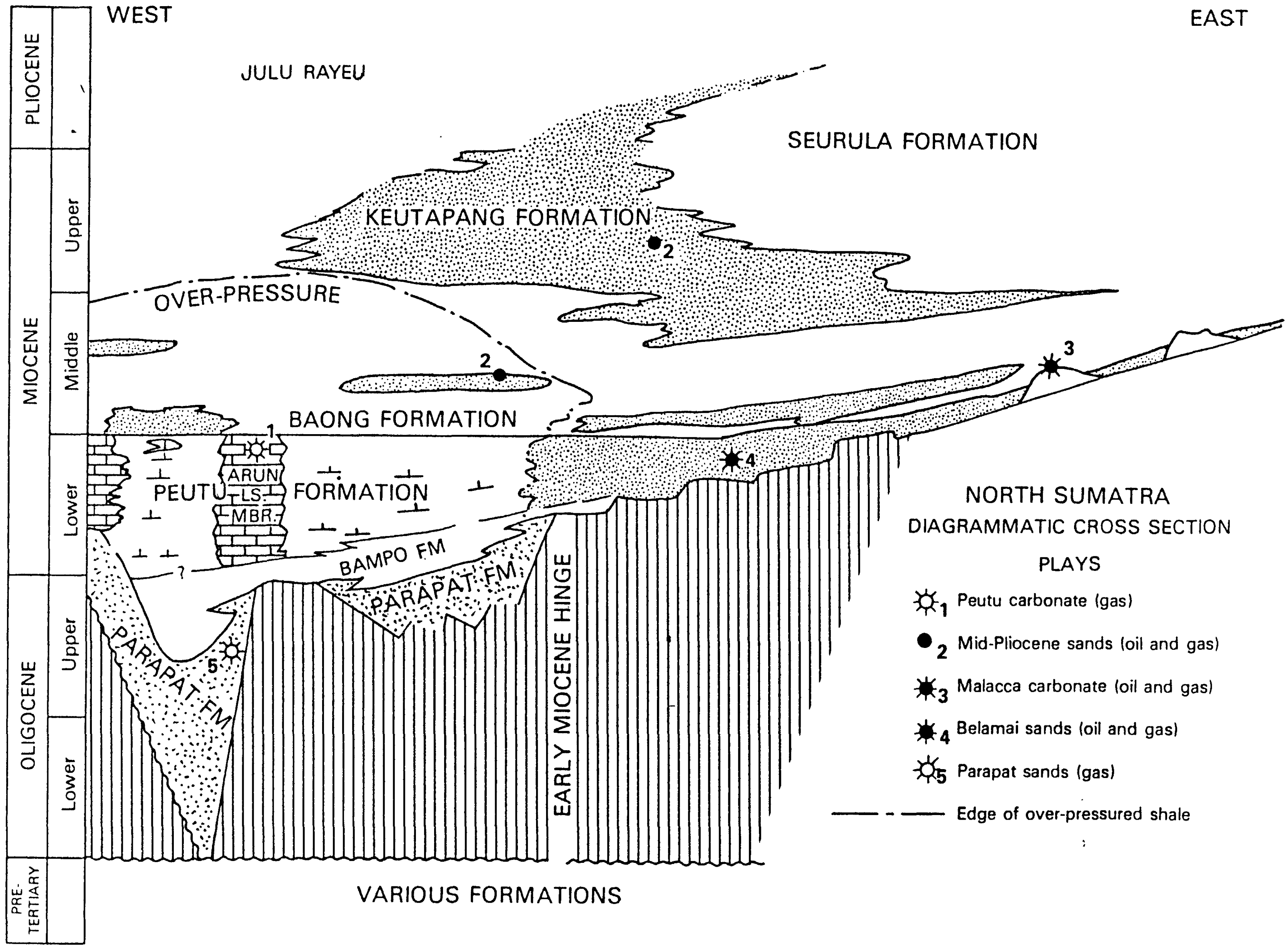


Figure 7.--Diagrammatic cross section of North Sumatra showing play distribution.

drapes have an assumed average of about 7 percent and the offshore slope even less, about 5 percent.

Exploration is still in an early mature stage; for the deep basin reefs, about 50 percent exploration is estimated; for the Neogene sandstones, 75 percent; for the shallow shelf reefs and early Miocene shelf sandstones, an average of about 30 percent; and for the Paleogene basal drapes, 10 percent. The offshore slope is yet to be explored.

Original primary reserves appear to be about 2.1 billion barrels of oil and condensate (2.377 according to EIA, 1984) and 16.25 Tcf of gas, including 14.25 Tcf of Arun proven gas reserves and an estimated 2 Tcf of undeveloped gas discovered in the shelf reefs.

Structure

General Tectonics

The North Sumatra basin is one of three inner-arc (back-arc) basins along the east side of Sumatra (figs. 1 and 5). The trace of the subduction zone, where the Indian Plate subducts obliquely beneath the Sunda Continental Block, is about 160 mi offshore, west of and parallel to the west coast of Sumatra; the related volcanic arc forms the Barisan Mountains along the west side of Sumatra. The North Sumatra basin lies between the Barisan Mountains on the west and the Malaysia craton area on the east and is underlain by continental crust of the Sunda Continental Block.

The formation of the North Sumatra basin began with the development of isolated subbasins in a north-trending Paleogene, or older, down-faulted trough with horst-graben structures. Initial sediments were locally derived coarsely clastic, non-marine in nature (fig. 7), followed by dark, carbonaceous, brackish water shales. By early Miocene time, continued subsidence west of an early Miocene hinge line resulted in coalescing of the subbasins in a quiet, marine environment. West of the hinge line, deposition was largely shale with carbonate facies over horst-block highs, while calcarenite and sandstones or reefal carbonates were deposited on the platform east of the hinge line. Continued slower subsidence resulted in deposition of shale interbedded with sandstones of probable turbidite origin coincident with the rise of the Barisan Mountains on the west side of the basin. From middle Miocene and later, the principal source of the sediments was from the Barisan Mountains. Prior to this, the Malaysia craton on the east was the source area.

Structural Traps

The most petroliferous traps in the basin are stratigraphic and are discussed under reservoirs (deep basin reefs and shallow shelf reefs).

The oldest structural traps are those associated with Paleogene north-trending horsts and grabens, which are largely confined to the deeper, basinal area west of the hinge line (fig. 5), and cover an area approximately 5.6 million acres (MMA), the Paleogene basal drape play area (fig. 6, area 5). The total area of all traps, including largely drape structures and some fault closures is estimated to be 5.5 percent of the play area or 308,000 acres. Reefal buildups associated with the horst and graben features, discussed under reservoirs, are important petroleum reservoirs, but are restricted in area (fig. 6, area 1).

East of the early Miocene hinge line (fig. 5) is the shallow Malacca Shelf, which has an irregular pre-Tertiary erosion surface of low relief, faulted knobs, following an approximate north trend. The knobs are the loci of draped sandstones and carbonate buildups of Tertiary age. In general, the knobs are mainly, but not exclusively, associated with reefal buildup in the northern one-fourth of the shelf (figs. 6 and 10), an area some 2.7 MMA compared to 10.7 MMA for the entire shelf area. Drape structures are present over the entire shelf. On the onshore part of the shelf, isolated highs, i.e. drape trap areas, make up 2 percent of the shelf area.

Apart from these older, basement-controlled structures are younger northwest-trending anticlines involving Miocene and Pliocene sandstones. These folds appear to be partly of compressional, and of diapiric origin, and are present over the entire basinal area west of the hinge line (fig. 6), an area of 5.6 MMA. Based on Mulnadiono's (1976) map of part of the area (fig. 8) approximately 8.3 percent of the Neogene sandstone (fig. 6) play area lies within closed anticlines, comprising 470,000 acres.

Sumatra was affected by dextral strike-slip (wrench) faulting, from at least the middle Miocene, as the Indian Plate slipped northward past the Sunda Continental Block. This event produced drag folds in Central Sumatra, but the drag origin of any of the folding has not been recognized in the North Sumatra basins, possibly due to the masking effect of shale diapirism.

Stratigraphy

General Stratigraphy

General stratigraphy of North Sumatra is summarized in figure 7. Basal, non-marine, coarse clastics (Parapat Formation) were deposited initially as basal sandstones in isolated graben-type basins in Paleogene time, followed by the deposition of brackish water, carbonaceous shales (Bampo Formation).

Subsidence continued in early Miocene time, and isolated subbasins coalesced with the deposition of the marine Peutu Formation more seaward (westward) of the early Miocene hinge line (fig. 5), and deposition of the Belumai Formation on the shelf to the east. The Peutu Formation is a calcareous shale-carbonate unit with the carbonate facies in the form of reefs (principal gas reservoir) on topographic highs. The Belumai Formation is a calcarenite, or sandstone, and shale unit with an equivalent carbonate facies; the carbonate facies (Malacca Limestone Member) forms carbonate buildups over basement highs. Maximum marine encroachment occurred in the middle Miocene, when the thick shale of the Baong Formation was deposited. Interbedded with the shale are isolated sandstone bodies, which have produced minor amounts of hydrocarbons to date.

Accelerated uplift of the Barisan Mountains in Miocene and Pliocene led to deposition of sandstone and shales of the Keutapang, Seurula, and Julu Rayeu Formations. In the west and south, adjacent to the Barisan Mountains, these formations are mainly sandstone but become more shaly to the east and north. These sandstones are the principal oil reservoirs in the North Sumatra basin.

Reservoirs

The five principal reservoirs of the North Sumatra basin Tertiary section are, in chronologic order: 1) Paleogene basal sandstones (Parapat Formation), 2) deep basin reefs (Peutu Formation), 3) lower Miocene shelf sandstones

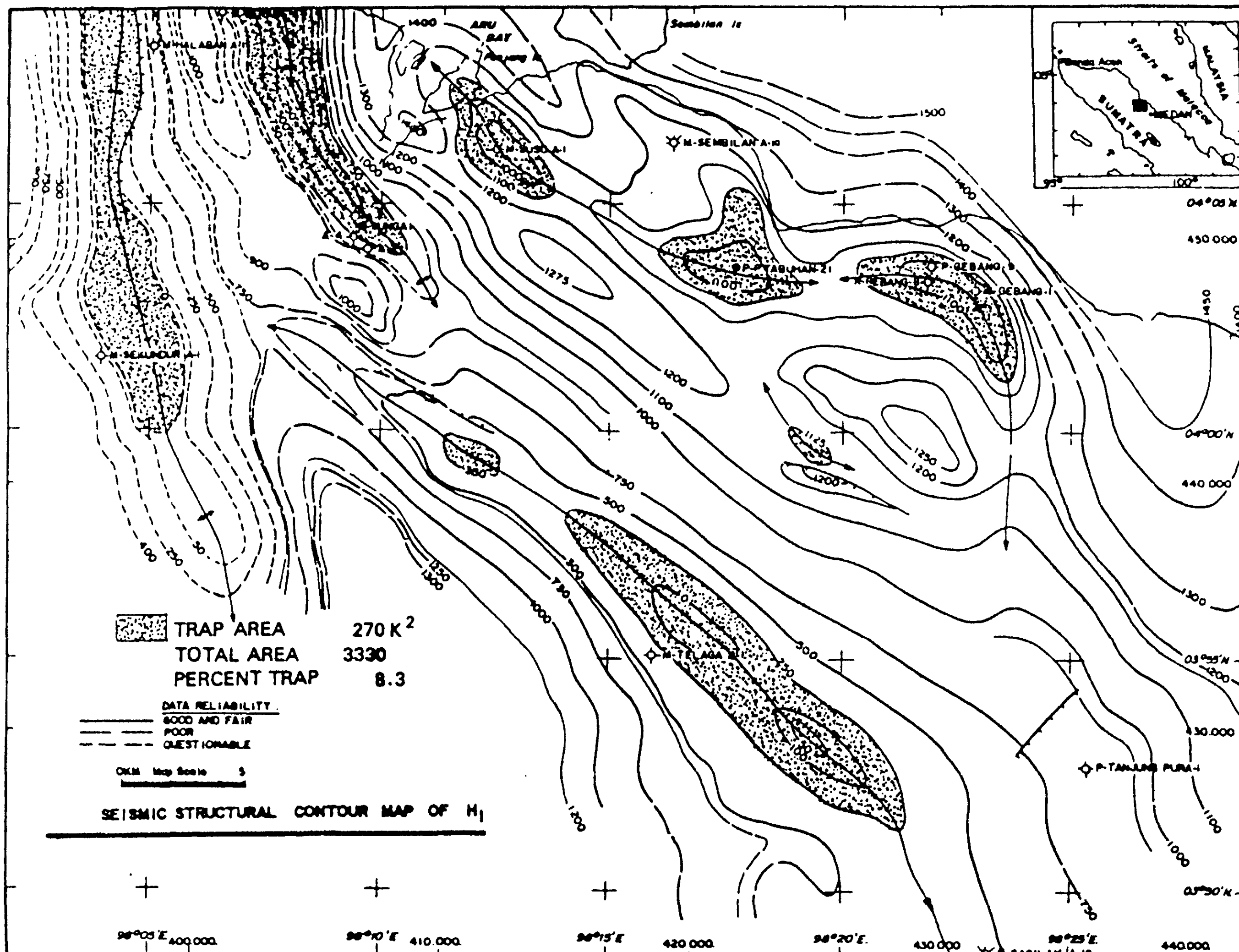


Figure 8.--Structure contour map of part of North Sumatra basin showing depth to a Miocene seismic horizon. After Mulhadiano (1976).

(Belamai Formation), 4) shallow shelf reefs (Malacca limestone Member, Belamai Formation), and 5) Neogene sandstones (Baong, Keutapang and Seurula Formations). These reservoirs are each of a unique geologic setting, and in four of six settings, the reservoir characteristics designate the play. The greatest hydrocarbon (gas) producer is the deep basin reefs. Neogene sandstones have produced all the oil to date from the basin, and gas and oil production is planned from the shallow shelf reefs. The lower Miocene shelf sandstones have yielded gas and oil, but at rates that are only marginally economic and the Paleogene basal sandstones have had only minor shows.

1. Paleogene sandstones (Parapat Formation)

Quartzose sandstones are present locally around the horst paleotopography that formed in the deeper part of the basin in late Mesozoic-early Paleogene. No data are available concerning effective pay thickness; in any case, this would not be a limiting parameter, and one hundred feet is assumed as an average effective pay. The porosity of these basal sandstones is poor, averaging about 12 percent where measurable.

2. Deep basin reefs (Peutu Reefs)

Gas accumulations occur in carbonate reefs and banks of the lower Miocene Peutu Formation. The play is limited to carbonate platforms over Paleogene horst blocks in the deep, central part of the North Sumatra basin (fig. 6). The area of the play is about 860 mi^2 or .55 million acres (MMA).

Reefs appear to have grown on the higher parts of an irregular carbonate platform. At Arun Field, reef growth, starting perhaps from a number of paleotopographic highs in this case, may have coalesced to form one large (42,000-acre) reef complex (fig. 9). Extrapolation in a part of the play indicates that about 13 percent, or about 71,000 acres, of the play area may be untested carbonate buildup.

Information concerning the reef objectives of this play is limited to the Arun Limestone (a member of the Peutu Formation from which gas of the Arun Field is produced). The reservoir in the Arun Field has an average net pay of 503 ft, and an average porosity of 16.2 percent with a water saturation of 17 percent. The Arun reef is probably one of the thickest reefs of the Peutu Formation; a realistic average pay thickness for the play is about 350 ft. The reservoir parameters of the Arun Field, mentioned above, are assumed to be average for the play. The volume of recoverable gas in these deep basin reefs is enhanced by the effects of over-pressure; reservoir pressure is reported to be about 7,000 pounds per square inch at the Arun Field at a depth of about 10,000 ft.

3. Lower Miocene Shelf Sandstones (Belumai Formation)

The Belumai Formation, made up of quartzose sandstones, calcarenites, and shales, overlies the shelf area of the basin (areas 3 and 4 of fig. 6). The quartzose sandstones are plentiful in the south, but carbonate-cemented sandstone and carbonates predominate to the north; therefore, the limited prospective reservoir, confined to area 4 (fig. 6), is about 8 million acres (MMA).

Effective thickness of pay is very irregular owing to unpredictable and rather pervasive effects of calcium carbonate cementation. Available data indicates that the average effective pay may be about 150 ft. Hydrocarbon recovery generally is low owing to the effects of both this carbonate cementation and to flushing. Fifteen percent porosity, 25 percent water saturation are good averages for the Belumai Formation reservoirs.

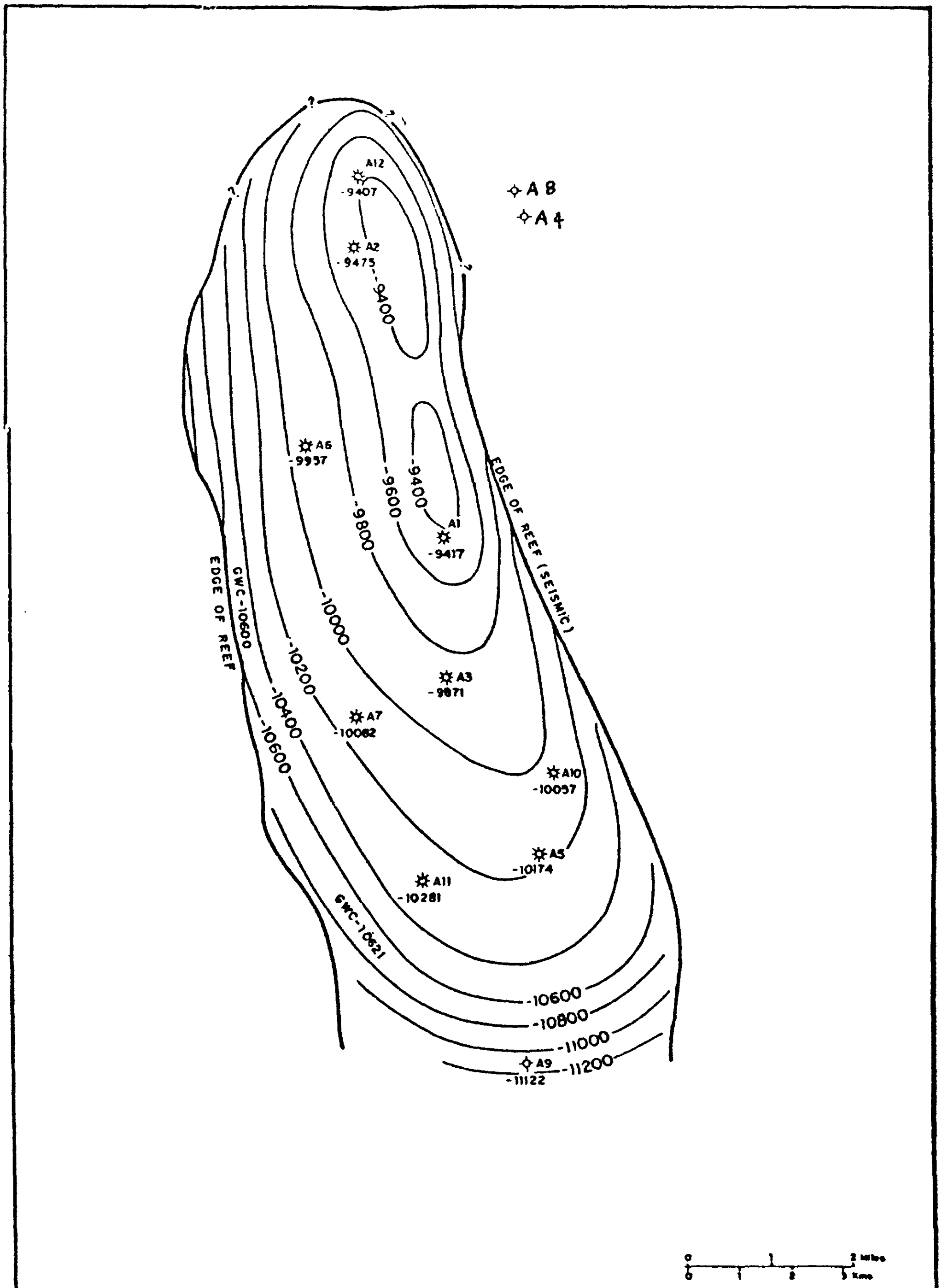


Figure 9.--Structure contour map of Arun gas field, contours on top to Peutu carbonate. After Alford et al. (1975).

4. Shallow Shelf Reefs (Malacca Linestone Member, Belumai Formation)

Reefs are situated on the irregular surface of the shallow Malacca Shelf east of the hinge line (figs. 5, 6, 7, and 10). They appear to be confined to the northern third of the Malacca Shelf, an area of about 2.7 million acres. Distribution of the reefs follows a northerly trend along pre-Tertiary and Paleogene paleotopography similar to early Miocene drape features (see Structural Traps) (fig. 10). Some 70 carbonate buildups were mapped by 1982, which had areal closures ranging from 125 to 10,000 acres and vertical relief of up to 1,100 ft (McArthur and Helm, 1982). The trap area of the reefs is estimated at 3.5 percent of the play area, and only about one-half of this area has been tested.

Reported hydrocarbon columns in the reefs range up to 680 ft, and average effective pay in the play is 200 ft. Average porosity value of reef limestone is around 24 percent, and the reef dolomite is about 20 percent, for an overall average of 22 percent. Permeability is variable and, as indicated by drill-stem test data, is appreciably affected by fracturing.

5. Neogene Sandstones

These shaly sandstone reservoirs largely derived from the rising Barisan Mountains to the west, are most prevalent in the western, more basinal part of North Sumatra basin. These sands are involved in structural folds in area 5 (fig. 6). Reservoir sandstones occur in three formations, Baong, Keutapang, and Seurula (fig. 7). The Baong Formation is largely a shale unit with interspersed isolated sandstones; the Keutapang contains many sandstones and the main potentially productive reservoirs; the Seurula has relatively little sandstone. The maximum gross sandstone thickness in the Keutapang Formation is 468 ft with in 14 zones; sandstones average 10 to 20 ft in thickness. Average sandstones thickness over the play area is estimated to be 150 ft. The sandstone reservoirs are shaly and porosity ranges from 15 to 20 percent.

Seals

The seals consist of shales of varying effectiveness. Of some concern are the blanket sandstones of the shelf part of the basin (Belumai Formation), which extend to the outcrop area, and where there has been extensive flushing of reservoirs on a regional scale.

Seal for the deeper basinal gas plays, that is, the deep basin reefs and probably most of the Paleogene basal sandstones, is massive, thick overpressured shale. The younger, oil and gas-bearing Miocene-Pliocene clastic section has a high shale content. The sandstones also have a high clay content and generally low permeability, and so the clay is believed to be a fairly effective seal. The shallow shelf reefs of the eastern shelf generally have a thin shale cover. Because of this, leakage may have occurred from these reefs.

Source Section

The main source rock is confined to the lower Baong Formation and the older part of the section below approximately 8,000 feet (see below).

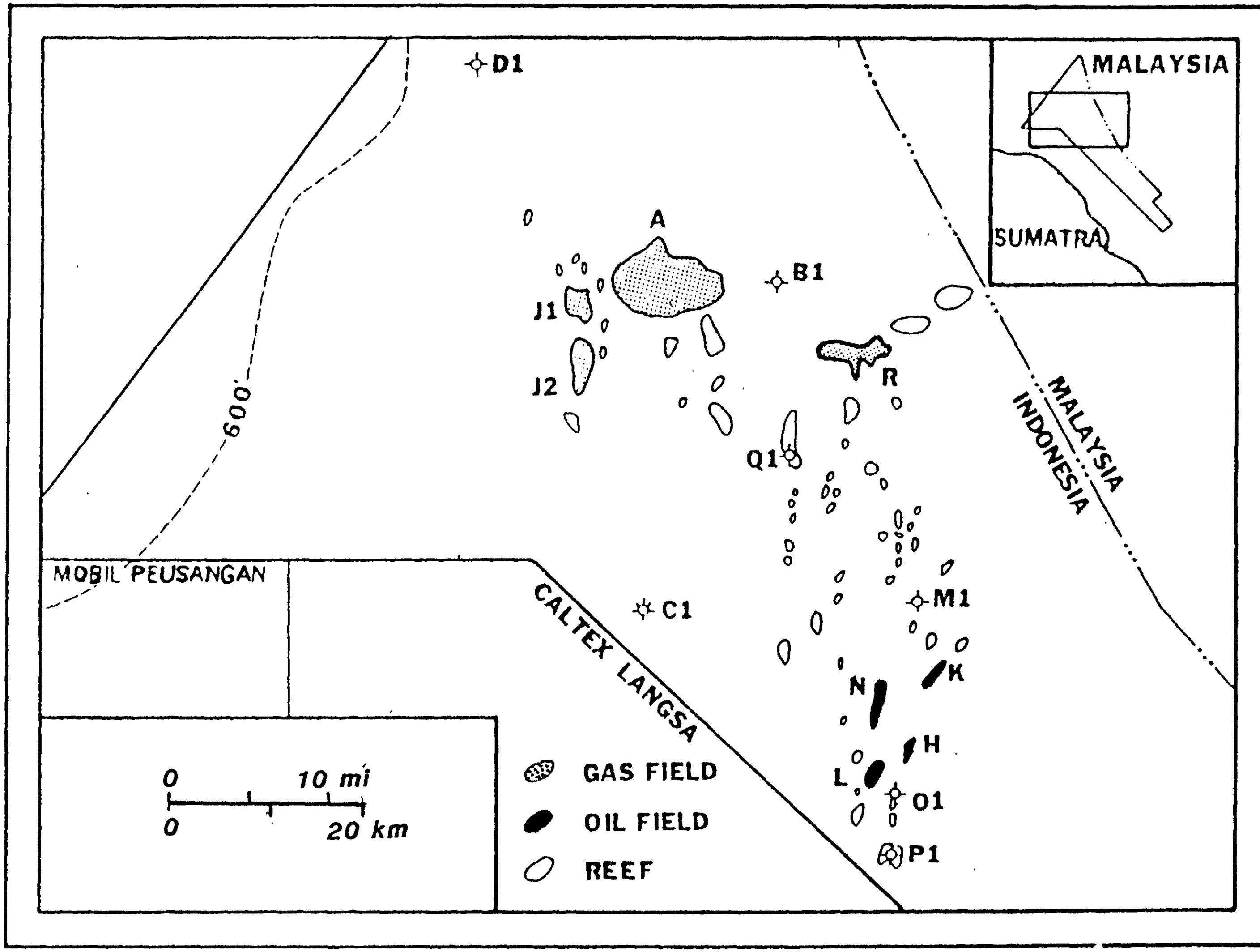


Figure 10.--Map of shelfal area of offshore North Sumatra basin showing reefs and reefal oil and gas fields. After McArthur and Helm (1982).

Petroleum Generation and Migration

Richness of Source

Measurements of the total organic carbon in the thermally mature sediments averages about 1 percent, which indicates an adequate, but not rich, source rock (Kingston, 1978). Organic matter appears to be a mixture of gas-prone and oil-prone kerogen. Adequacy of source, as well as seals, is confirmed by the 60 percent fill of the Arun reef reservoir, 40 percent oil and gas fill for the Miocene-Pliocene folds, 30 percent fill for the shelf sandstones, and a high 80 percent fill for the shelf reefs.

Depth and Volume of Source Rock

Depth to the top of the mature sediments is confirmed by vitrinite reflectance and carbon preference index measurements from a number of wells (Kingston, 1978). However, the depth varies throughout the basin because of local variable thermal gradients and subsidence rates, but averages about 8,000 ft, indicating that there is a volume of mature or over-mature sediments of about 25.6M mi^3.

Oil versus Gas

The major gas zone is limited to the deep, predominantly shale basin within overpressured depths, while the oil is limited to the shallow edges and shelf of the basin. It is believed that most undiscovered petroleum would be in the deeper, less explored parts of the basin, and would be only 7.5 to 15 percent oil versus gas while the shallower platform areas would be 25 to 75 percent oil.

Migration Timing versus Trap Formation

Assuming a uniform subsidence and thermal gradient through the Tertiary, petroleum generation and migration from source rocks would have commenced in about early Miocene time, when subsidence of the deeper parts of the basin reached 8,000 ft, and continued to the present. Source rocks affected range in age from Oligocene to late Miocene. Since the principal reservoirs are lower Miocene reefs and Pliocene structural folds involving upper Miocene sandstones, it appears that the beginning of migration followed the formation of carbonate traps, but generally antedates the structural traps that contain sandstone. Migration was considerably impeded by a thick, massive section of overpressured shale of Oligocene to middle Miocene age. It is believed that the overpressured shale allowed only the migration of the smaller hydrocarbon molecules (i.e., gas) by molecular diffusion. The larger molecules (i.e., oil) remaining locked in the shale until continued subsidence and heat eventually cracked the molecules to gas. Under these conditions, the deeper, central basin shale-enveloped reefs, e.g., the Arun reef, accumulated only gas. In contrast, the shallower basin edge sandstones accumulated oil, derived from shallower shales interbedded with the sandstones which bled off the overpressure that impeded migration of the larger oil molecules. The amount of oil that migrated and accumulated is limited, however, inasmuch as only a relatively small part of the total volume of thermally mature strata is in the relatively shallow shale and sandstone section above the overpressured shale. Some, or all, of this shallow oil (67 percent gasoline) may be retrograde condensate derived from gas/condensate which migrated along faults from the deep, geopressured section.

Plays

North Sumatra basin is divided into six principal plays, which are discussed in detail in the play analysis sheets and listed in order of their estimated potential, as follows:

1. Deep basin reef play. Gas accumulations in deep basin carbonate reefs and banks in the lower Miocene Peutu Formation (figs. 6 and 7).

2. Neogene sandstone play. Oil and gas accumulations in middle Miocene to lower Pliocene sandstones of the Baong, Keutapang, and Seurula Formations trapped in Neogene anticlines (figs. 6 and 7).

3. Shallow shelf reef play. Oil and gas accumulations in Miocene carbonate buildups (Malacca Member, Belumai Formation) on the relatively shallow foreland shelf (figs. 6 and 7).

4. Lower Miocene shelf sandstone play. Oil and gas accumulations in lower Miocene clastic reservoirs of the Belumai Formation, draped over north-trending, low relief basement highs on the foreland shelf (figs. 6 and 7).

5. Paleogene basal drapes play. Oil and gas accumulations in Paleogene basal sandstones of the Parapat Formation draped over horst blocks in the deeper part of the basin (figs. 6 and 7).

6. Offshore slope play. Oil or gas accumulations in folded or faulted rocks of the deep-water slope off the north coast of Sumatra.

Central Sumatra Basin

Location and Size

The Central Sumatra basin is in the central part of eastern Sumatra (fig. 1), near the west edge of the Asian Continental Block. It has an area some 27,000 mi^2, or 17.2 million acres, and is a relatively shallow basin with a volume of approximately 29,000 mi^3 (figs. 11 and 12).

Exploration and Production History

Petroleum exploration, begun in 1938, included outcrop surveys, shallow stratigraphic dug-pits and holes, followed by seismic surveys. A shallow gas field, Sebanga, was discovered in 1940. The discovery well of the Minas oil field was located just prior to World War II and actually was drilled by Japanese occupation troops in 1945. Subsequent exploration of the Central Sumatra basin resulted in the discovery of about 125 oil fields, with original reserves (as of 1978) of approximately 8.746 BBO (EIA, 1984) (fig. 11).

It is estimated that exploration of the basin is in a mature stage, about 75 percent complete. Greater than ninety percent of the petroleum comes from one play, the Sihapas sandstones (lower Miocene deltaic sandstones). The discovery rate is about 22 percent, but is probably declining. It is

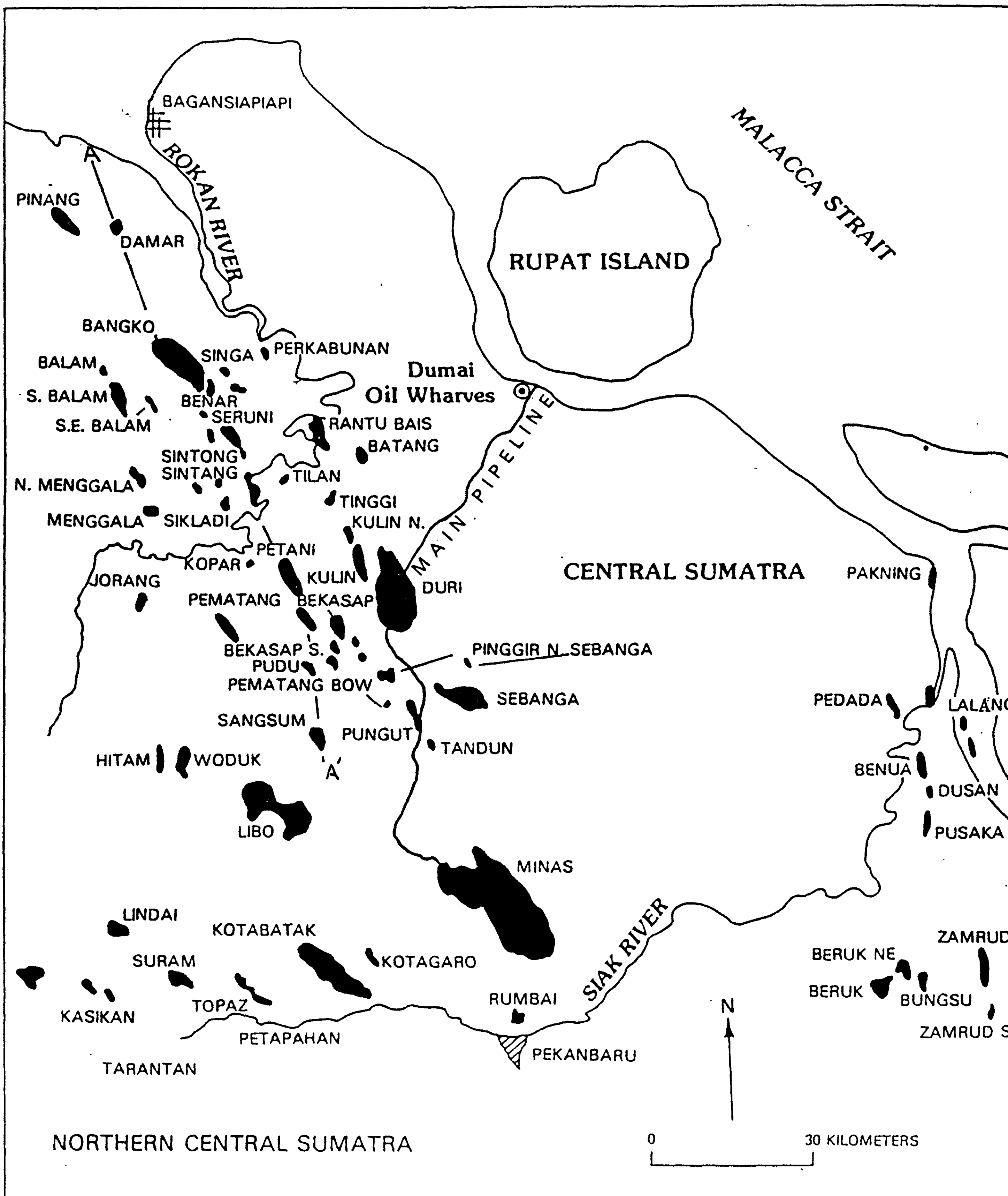


Figure 11.--Sketch map, principal oil fields, Central Sumatra.

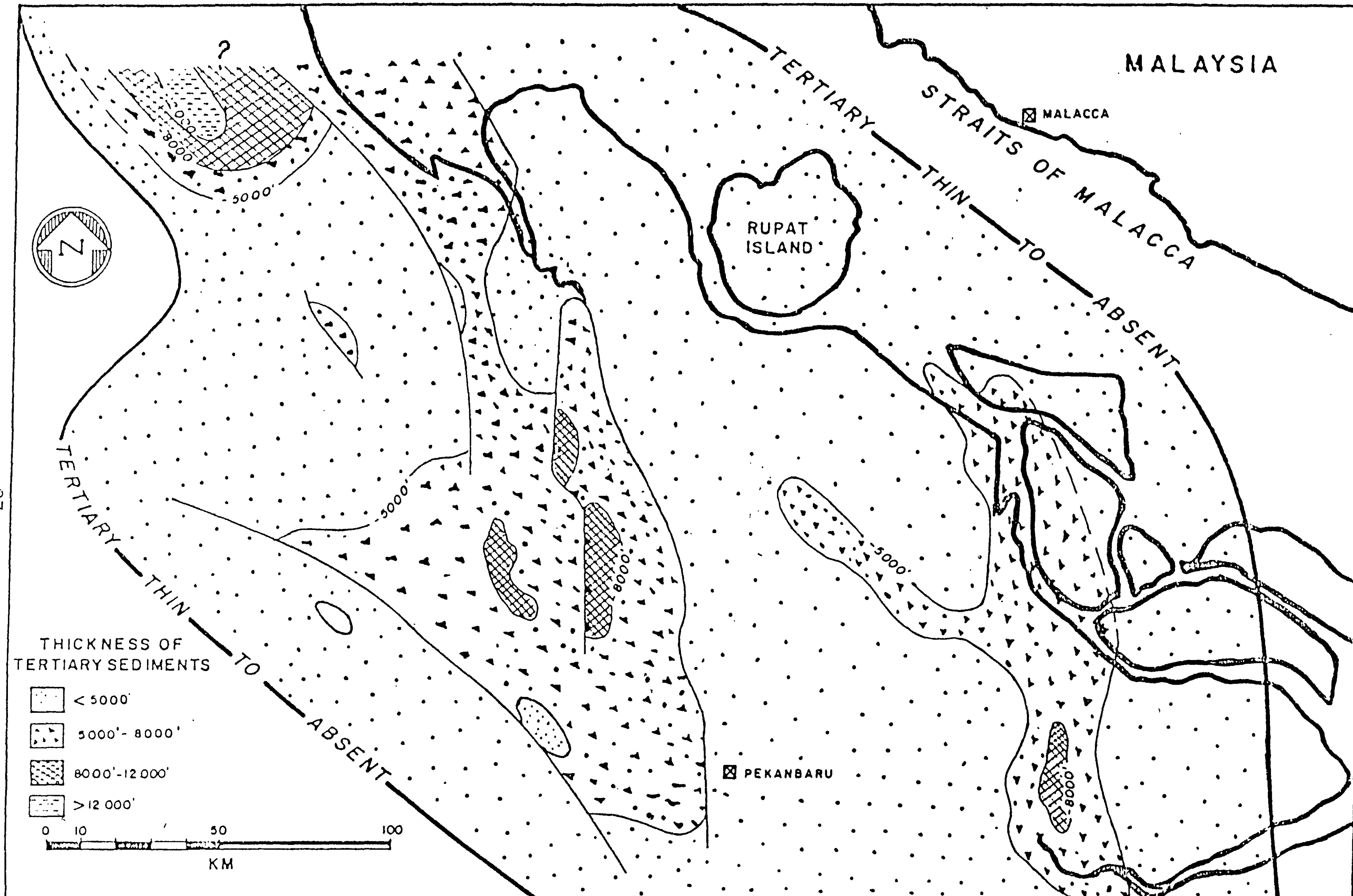


Figure 12.--Structure contour map of Central Sumatra showing depth to basement. After Wongsosantiko (1976) and Eubank and Makki (1981).

estimated that perhaps 15 percent of the untested, available trap-area may contain petroleum.

Structure

General Tectonics

The Central Sumatra basin is one of a series of back-arc (inner-arc) basins between the Barisan Mountain volcanic arc range and the Sunda Shelf (craton) to the northeast. In general, the basin is a shallow shelf generally less than 5,000 ft deep with generally north-trending graben-deeps or trenches, reaching 8,000 ft deep. While the southern part of the basin is shallow, the northwestern one-eighth, the so-called Baraman subbasin, is about 12,000 ft deep (fig. 12).

There appears to have been two structural events: 1) A Pre-Tertiary to Paleogene extension, which resulted in a series of approximately north-trending horsts and grabens, or troughs, which were filled with Paleogene (?), largely non- marine sediments, and 2) extensive, generally northwest-trending, dextral wrench faulting and accompanying drag folding, which probably prevailed through most of the Tertiary, reaching a climax in the Pliocene-Pleistocene.

Structural Traps

The petroleum-bearing structures of the basin in part resulted from sedimentary drape over older fault blocks, e.g., Minas and Duri Fields, and in part, from drag folds associated with wrenching, which includes most of the smaller accumulations. Extrapolation from field maps indicates that an estimated 5.5 percent of the basin is trap area. An estimated 75 percent of the individual traps have been tested, leaving some 236,000 acres to be tested.

Stratigraphy

General stratigraphy is summarized in Figure 14. In essence, the extensional horst and graben structure of the early Tertiary and pre-Tertiary was leveled by erosion of highs and infilling of the deep grabens in the Paleogene by the Pematang non-marine, largely lacustrine strata. In lower Miocene, the Sihapas Group, a wedge of deltaic-marginal marine sandstones, derived from the Sunda Shelf encroached southwestward into the basin. The Telisa Formation of open-marine shales is largely the basinward equivalent of the Sihapas Group but also is in part younger, and its younger part extends northeastward over the top of the Sihapas delta beds. Following middle Miocene uplift and erosion, the basin was filled by coarser clastics derived largely from the Barisan Mountains on the southwest.

Reservoirs

Reservoirs of the Sihapas Group contain over 90 percent of the oil of the Central Sumatra basin. The three principal reservoir units within the group are the Duri, Bekasap, and Menggala Formations (figs. 13 and 14). The closures often have stacked reservoirs so that the net effective pay may be as much as 800 ft, often 200 to 400 ft. It is estimated, however, that new finds will be in somewhat less favorable parts of the basin and will average a

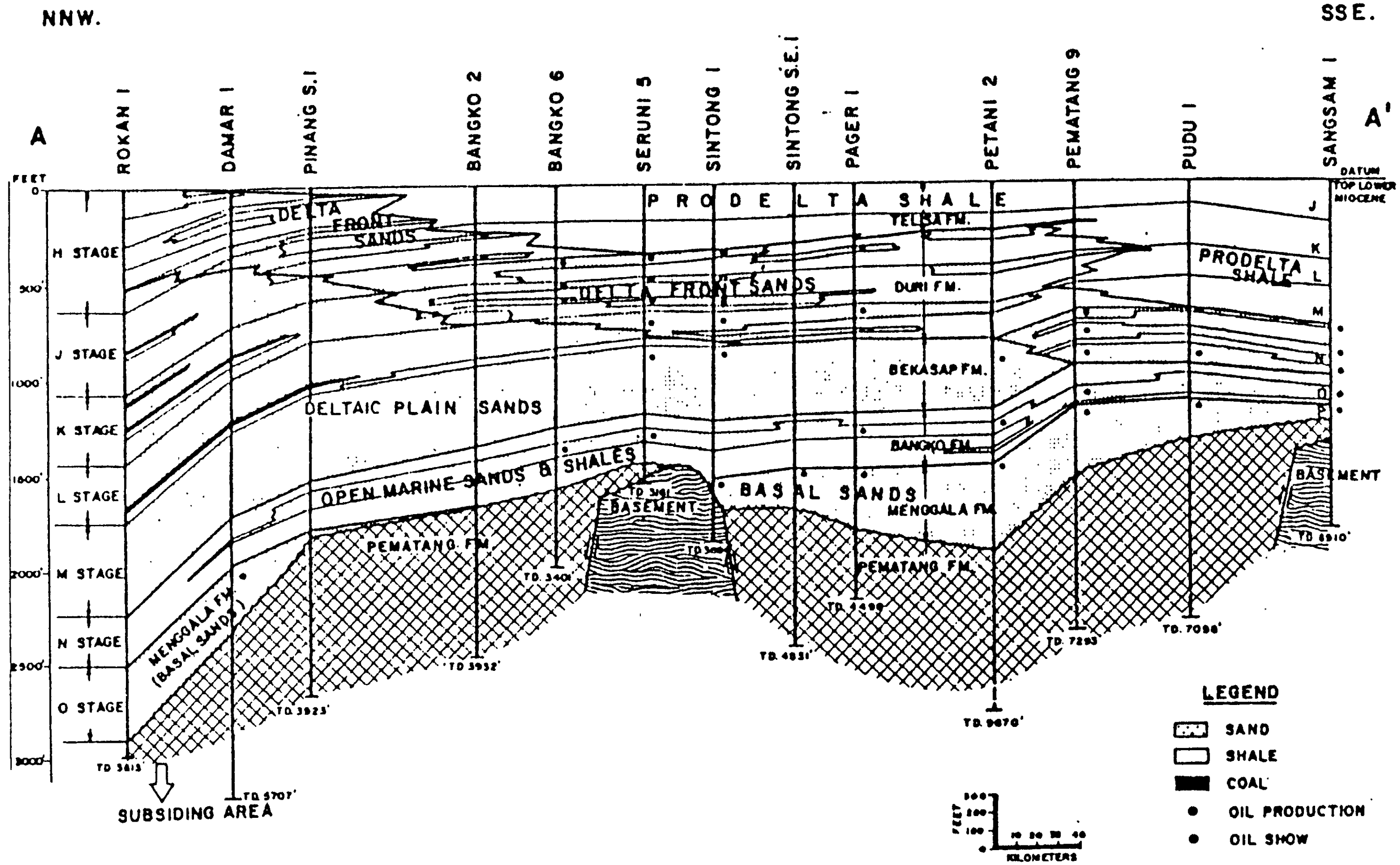


Figure 13.--NNW-SSE stratigraphic cross section, A-A[1], Central Sumatra basin. After Wongsosantiko (1976). See Figure 11.

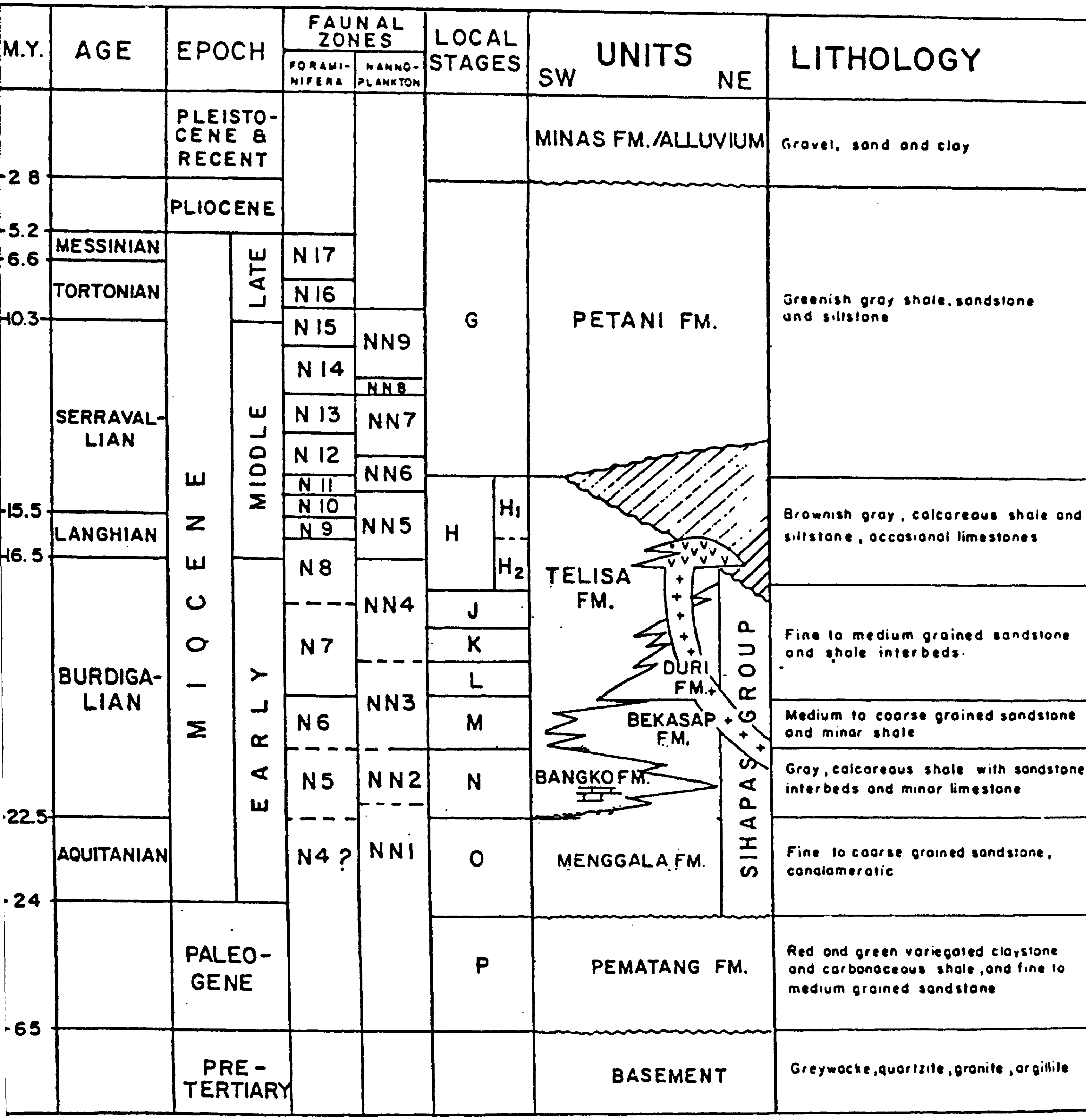


Figure 14.--Stratigraphic chart of Central Sumatra basin. From Eubank and Makki (1981).

little less pay, probably around 200 ft. Porosity ranges from 10 to 40 percent, averaging 27 percent in the Minas Field; this is taken to be the average of the basin. The primary oil recovery factor varies from a low of 7.3 percent at Duri to 25 percent. It is estimated that the average recovery is 350 barrels of oil per acre-foot.

Minor production has developed from the fluvial-lacustrine sands underlying the Sihapas Group (Pematang Formation) and from lower Telisa marginal marine sandstones, but these possibly additional prospects would not appreciably add to the estimates of undiscovered petroleum for the basin.

Seals

The regional seal for the Sihapas sandstones are the shales of the Telisa Formation, which appear to be quite effective. Intra-Sihapas shales, particularly of the Banko Formation, are good seals of the individual stacked reservoir sandstones.

Source Section

The source section appears to be largely in the Paleogene (Pematang Formation), but in the more deeply depressed parts of the basin, may be the intra-Sihapas shales or, to a slight extent, the Telisa Formation (see section on Petroleum Generation and Migration).

Petroleum Generation and Migration

Richness of Source

No organic richness data are available, but it appears that the largely non-marine, appreciably lacustrine, Pematang Formation must be the principal source, since 1) it is the only major unit of which a considerable volume is sufficiently deep to be mature, and 2) Central Sumatra basin crude has the character of non-marine oil source, being of a high wax content and high pour point.

The organic richness of the Pematang must be extremely high, as may be deduced by the great volume of oil in relation to the apparent small volume of source rock, confined as it is to the deeper grabens below 5,000 ft.

The amount of petroleum fill in available traps may be an indicator of the richness of the oil sources. The amount of fill varies from field to field; some are filled to the spill point while others are only 22 percent filled. The average fill is about 40 percent.

Depth and Volume of Source Rock

The average thermal gradient of the Central Sumatra basin is about 3.7°F/100 ft. This, together with its present average subsidence rate, places the top of the thermally mature zone for petroleum production at about 5,000 ft. Most of the basin is shallower than this depth so that the generating area is limited to the relatively narrow, deeper troughs, which are largely filled by the Pematang Formation (see fig. 12). It is estimated that the source volume is 9,200 mi^3.

Oil versus Gas

The gas-oil ratio is unusually low over most of the basin, 35 SCF/STB at Minas. It is estimated that undiscovered petroleum will be 95 percent oil. Minor gas occurrence in the western part of the basin has been related to coal versus lacustrine facies in the underlying Pematang source rock.

Migration Timing versus Trap Formation

Assuming generally uniform subsidence and thermal gradient through the Tertiary, petroleum generation and migration in appreciable quantities would have started when sufficient source rock reached a depth of 5,000 ft in the early Miocene. Trapping would not have commenced until shale cover developed in the early Miocene in the central part of the basin and middle Miocene along the northeast basin rim, so perhaps some oil escaped, but in general the timing was early and favorable, perhaps preserving the Sihapas sandstones from deterioration.

The Sihapas sandstones are good reservoir and conduits, and secondary lateral migration after the oil reached these sandstones was probably extensive. It is believed that a considerable portion of the present drag-fold closures were filled by secondary migration, i.e., oil already within the reservoir flowing laterally into the structure as it was raised.

Plays

Although the Central Sumatra basin is the most prolific of the Indonesian basins, it is geologically the simplest and is essentially one play; the Sihapas sandstones accumulations trapped in either sedimentary drapes or drag folds.

South Sumatra Basin

Location and Size

The South Sumatra basin is on the southern end of Sumatra near the west edge of the Asian Continental Block (fig. 1). It partially is separated from the Central Sumatra basin to the north at about 1° south latitude by a large basement outcrop, the Tigapuluh Mountains, and from the northwest Java basin by the shallow Lampung Platform (fig. 15). The basin has an approximate area of 18,300 mi^2 and a sedimentary volume of some 40,000 mi^3.

Exploration and Production History

Oil production was established in South Sumatra in the late nineteenth century from the regressive middle-upper Miocene sandstones (Air Benekat Formation). In 1922 oil production was obtained from the Talang Akar deltaic sands (Talang Akar Field, fig. 16), which have subsequently proved to be the primary producing formation of the basin from which, as of 1981, 1.3 BBO have been produced (Hutapea, 1981). Between 1938 and 1941, gas was discovered in three small fields from carbonate reservoirs of the Baturaja Formation, which has developed into the secondary petroleum and largely gas producer of South Sumatra. However, recent discoveries of substantial oil have been made in the Baturaja Formation in the Ramba and nearby fields.

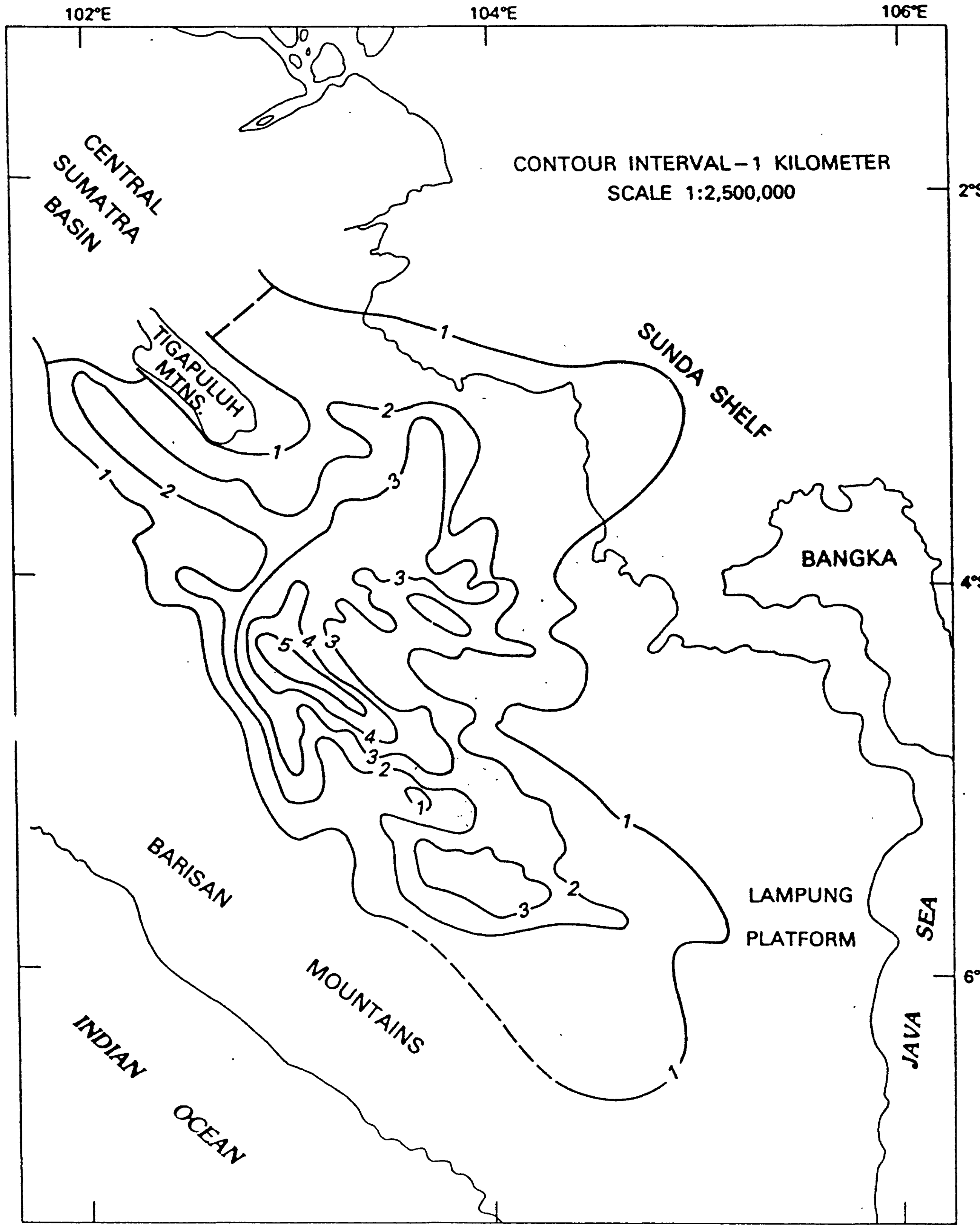


Figure 15.--Structure contour map of South Sumatra basin showing depth to basement. From Hamilton (1979).

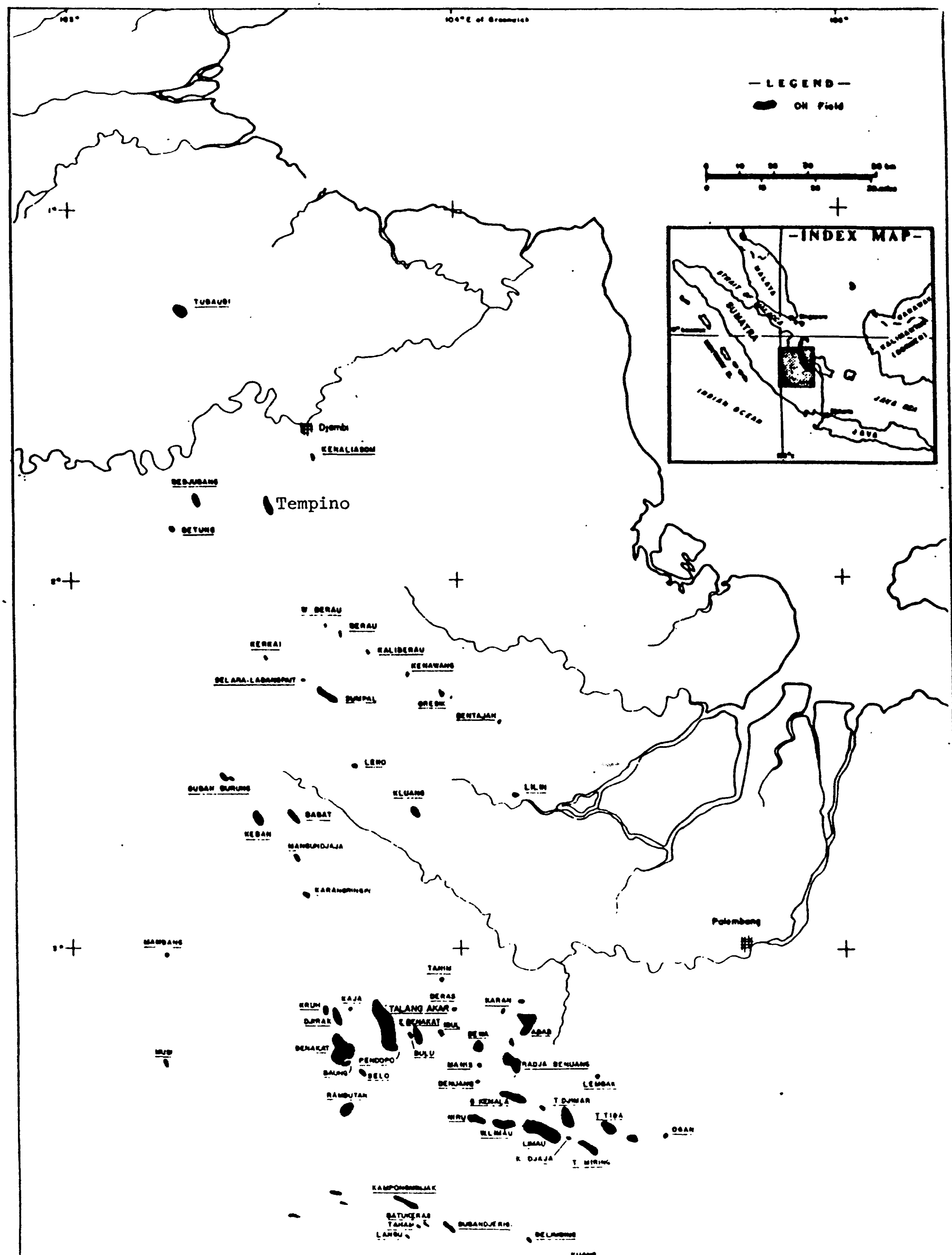


Figure 16.--Sketch map of principal oil fields of South Sumatra. From Petroconsultants (1980).

Most of the larger fields, i.e., reserves of more than 50 million barrels, were discovered prior to World War II. The size of discoveries after World War II has been declining, and, except for some notable exceptions, e.g., Ramba, the curve appears to be generally asymptotic to fields of about 10 million barrels of reserves. The anticlinal discovery rate is declining and appears to be averaging 10 percent and, at the present activity level, approaching an average of three successful wildcats per year. The Baturaja reef discovery rate is somewhat higher, about 13 percent. The basin is estimated to be about 80 percent explored.

Results of exploration to date have been to establish original oil reserves of 1.7 billion, of which about 1.5 billion had been produced (EIA, 1984). Gas reserves appear to be 4 Tcf, of which 1.7 have been produced as of 1980 (Hariadi, 1980; Patmosukismo, 1980).

Structure

General Tectonics

The South Sumatra basin is one of a string of back arc (inner-arc) basins between the Barisan Mountain volcanic arc to the southwest and the Sunda Shelf (craton) to the northeast. A late Cretaceous to Paleogene tensional (and wrenching) regime resulted in a number of north-northwest-trending, tilted horst blocks and grabens, half-grabens, or troughs. The Miocene-Pliocene wrenching, which is prominent in the Central Sumatra basin, is not so evident but surely present (although probably to a lesser degree).

There are little data concerning the amount of structural traps. It appears that the structures are dominantly sedimentary drapes and stratigraphic traps associated with the tilted fault blocks of the late-Cretaceous-Paleogene tensional (and wrenching) period. An unknown number of the productive traps may be drag folds, e.g., the Talang Akar Field.

Structural Traps

Individual structural closures are distributed over the basin. There are not sufficient data at hand to separate the drapes over tilted horst blocks from the drag folds associated with wrench faults, but a structure map of part of the basin where oil fields appear concentrated indicates that folds, of either origin, make up 11.5 percent of the area. The percentage probably would be lower, perhaps 7 percent for the whole basin. These structures involve both of the principal sandstone horizons, the lower Miocene (Talang Akar) sandstones and the middle Miocene-Pliocene sandstones. The lower Miocene (Baturaja) reefs are localized on some of these structures (see Reservoirs).

Stratigraphy

The Paleogene sedimentation was largely non-marine and volcanic (figs. 17 and 18), filling the lower part of the local grabens and troughs caused by the tensional (and wrenching), block-faulting tectonics of the late Cretaceous-early Tertiary so that by early Miocene many separate basins had coalesced into the South Sumatra basin (figs. 15 and 18). In the early Miocene, the extensive Talang Akar delta system of light-colored sandstones and dark shales prograded from the Sunda Shelf westward and southward into the basin. The sandstones developed over topographic highs and the shales filled the lows.

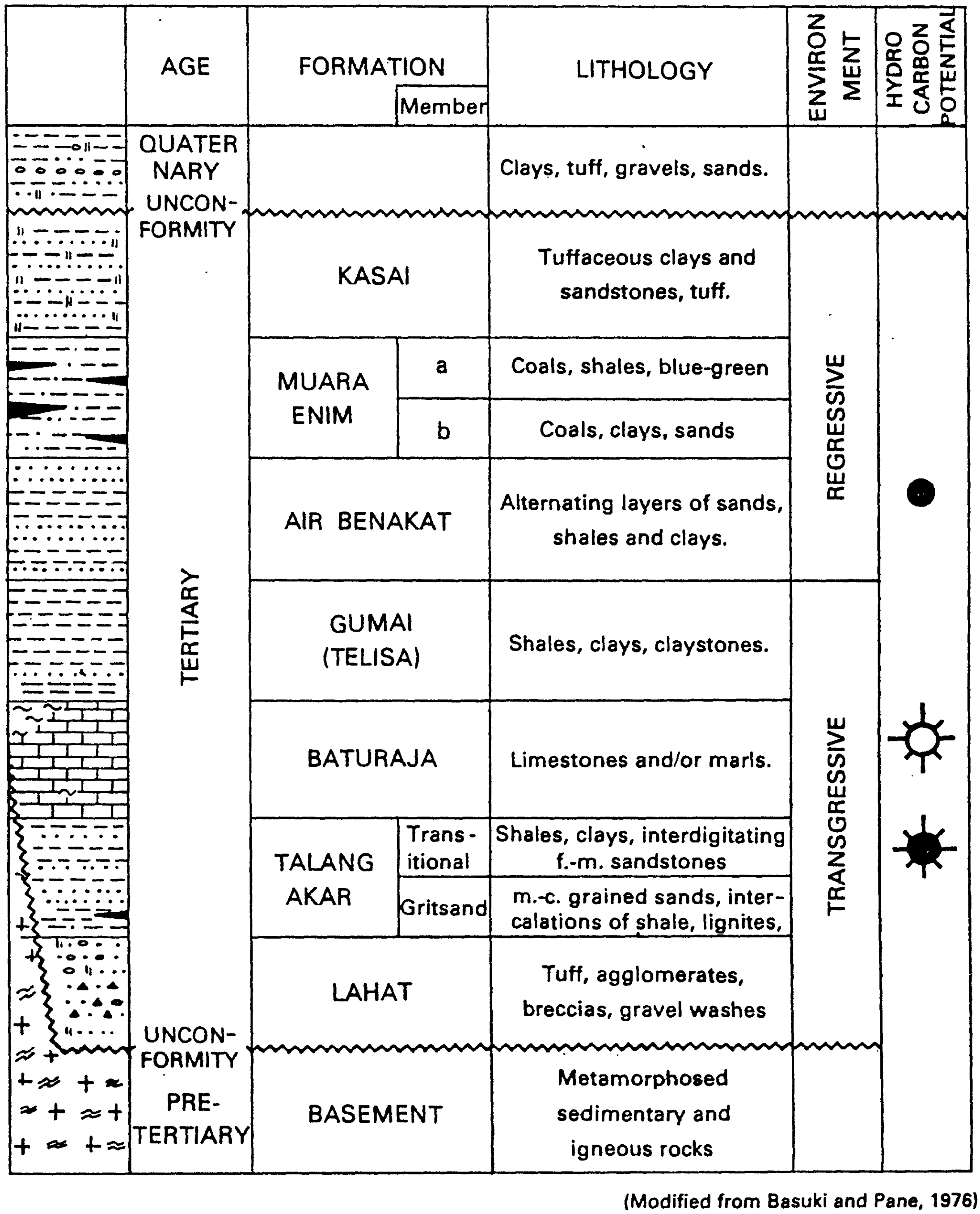


Figure 17.--Stratigraphic section, South Sumatra basin.

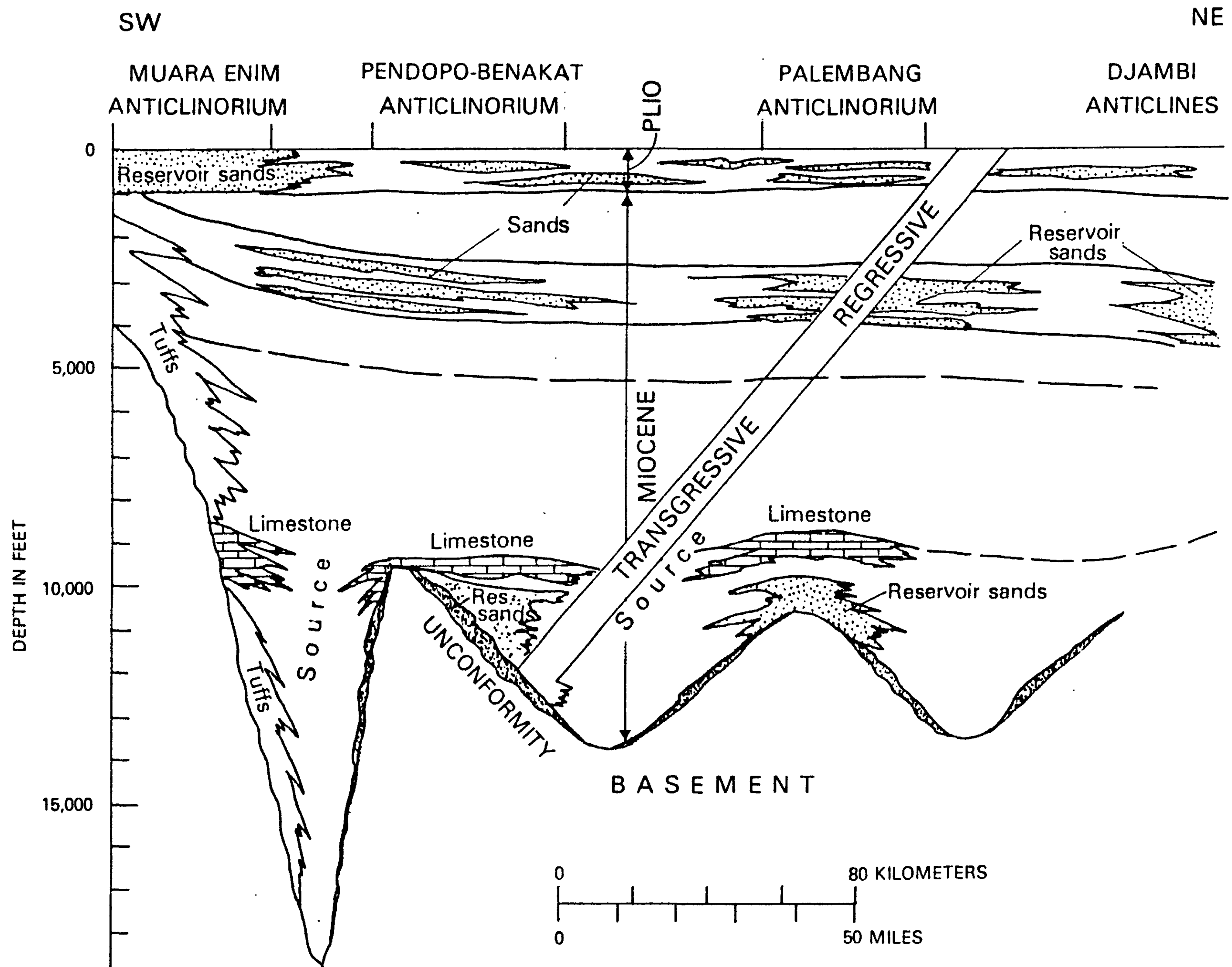


Figure 18.--Stratigraphic SW-NE cross section transverse South Sumatra basin.

About middle Miocene, there was a quiescent period allowing carbonate deposition on highs (Baturaja Formation), followed by a widespread transgression of the sea (Telisa Formation). A regressive period of deltaic and coarse clastic sedimentation began in late Miocene and has continued to the present.

Reservoirs

The principal reservoirs are the lower Miocene deltaic (Talang Akar) sandstones, lower Miocene (Baturaja) reefs, and middle-upper Miocene (Air Benekat-Maura Enem) sandstones. Each of these reservoirs constitutes a play and is discussed more fully in the play analyses. The lower Miocene sandstones contain some 90 percent of the petroleum reserves.

1. Lower Miocene Talang Akar Sandstones

The Talang Akar Formation contains many discontinuous sandy zones, as might be expected in a deltaic environment. In the Raja field, there are 16 production sandstones. In an illustration of a rather thin Raja field section, which contains only 11 production zones (Hutapea, 1981), there appears to be about 165 ft of net sandstone development. Elsewhere Basuni (1978) reported 517 ft of "hydrocarbon bearing sandstones" in the same field. It is estimated that the average net thickness over the Raja field may be 200 ft and that this thickness would be a reasonable net average for the South Sumatra basin reservoirs.

The porosity of the Talang Akar sandstones ranges from 15 to 23, averaging perhaps 19 percent at the Raja field, which is taken to be the average for the basin.

2. Lower Miocene (Baturaja) Reefs

The Baturaja Formation is a carbonate unit that extends discontinuously over the South Sumatra basin, the carbonate buildups being concentrated over Paleogene highs. Extrapolation of a reef distribution map (fig. 19; after Basuki and Pane, 1976,) indicates that 1 percent of the play area contains carbonate buildup, but it is suspected that double this amount will be discovered as the demand for gas is increased and as further and more advanced seismic techniques are applied.

In the Raja field, the Baturaja limestone "ranges from thin shaly limestone sections to intervals of 170 ft of extremely porous limestone" (Basuni, 1978); perhaps this 170 ft is a good average net pay thickness for the carbonate buildups of the basin.

The average porosity of the Baturaja carbonate in the Raja field is 20 percent (Basuni, 1978), and this is taken as the average for the basin. Water saturation is 20 percent in the Raja field, and this is likewise assumed to be the average for the basin.

3. Middle Miocene-Pliocene Sandstones

In the absence of available data and considering the small amount of production, the net pay of the middle Miocene-Pliocene sandstones is probably relatively thin, perhaps averaging 75 ft.

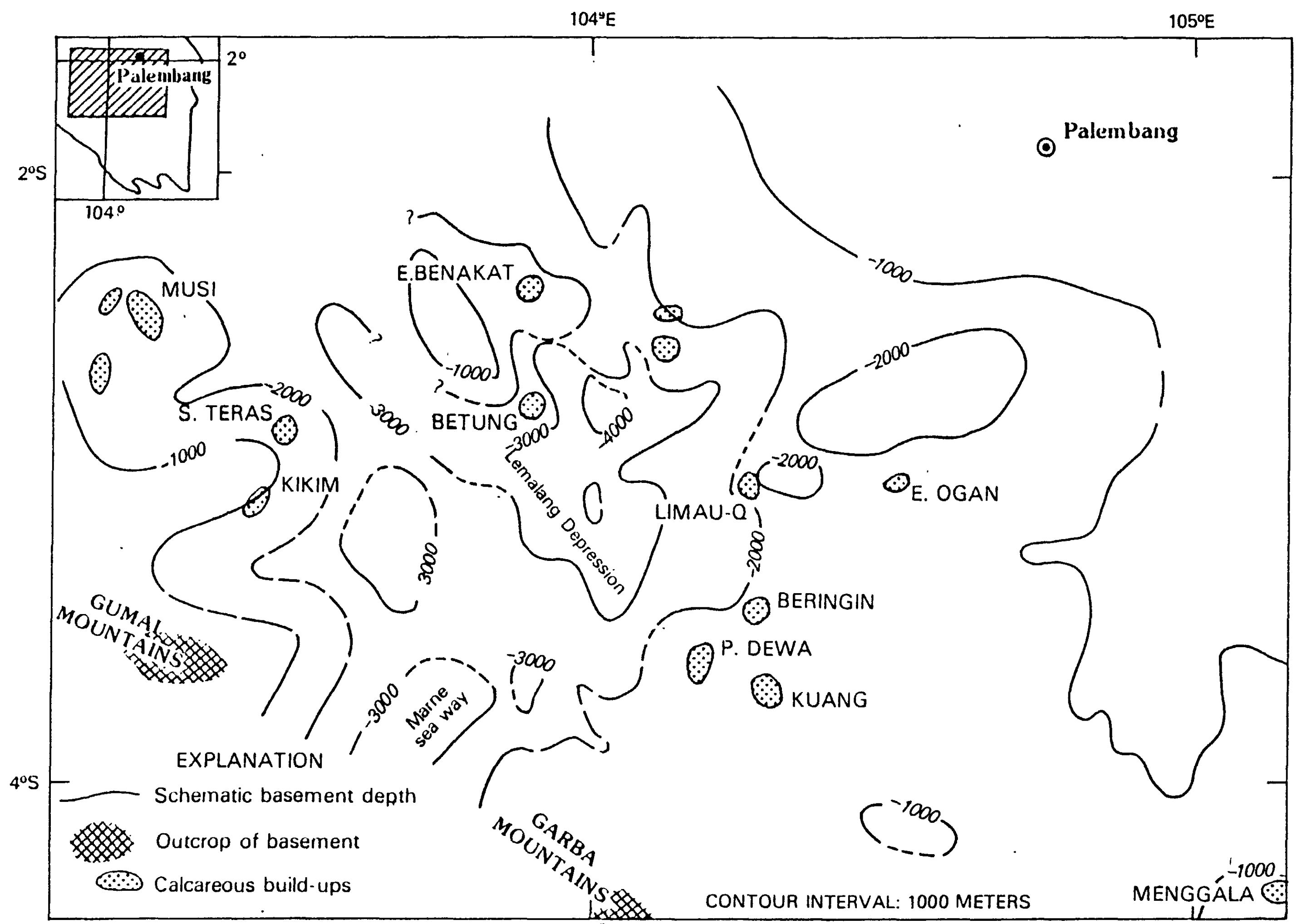


Figure 19.--Map showing distribution of calcareous buildups of the Baturaja Formation, South Sumatra. After Basuki and Pane (1976).

Seals

The principal reservoirs, i.e., the early Miocene sandstones, are effectively sealed by the middle Miocene marine (Telisa or Gumai) shales. The shallower much less prolific sandstones are not sealed so well.

Source Section

The source section is principally the lower Miocene deltaic dark shale of the Talang Akar Formation. It is discussed in the following section.

Petroleum Generation and Migration

Richness of Source

There are no data concerning the richness of source. However, it appears that at least the dark deltaic coal-bearing shales associated with main petroleum reservoirs, the Talang Akar sandstones, are sufficiently organically rich to be a source rock on the basis of the following:

1. The dark, organic appearance of the shales.

2. Oil is produced from sandstone lenses completely enclosed by the shale.

3. The oil is waxy and of a high pour-point, which is usually ascribed to a terrigenous, i.e., lacustrine, source.

4. Total organic carbon readings in the lithologically similar, coal-bearing Talang Akar shales in the basin to the east (Northwest Java basin) are high, indicating a rich source.

5. The overlying open-marine Telisa or Gumai shale appears to be a poor environment for organic preservation and probably is not an appreciable source.

6. A general indicator of the richness (and volume) of source (as well as seal) is the amount of petroleum fill. It is estimated from oil-field maps that average petroleum fill is about 40 percent of the closure area.

Depth and Volume of Source Rock

The average thermal gradient is about 2.15°F/100 ft and the subsidence rate about 420 ft per million years; this places the average top of the thermally mature sediments at approximately 6,500 ft and the top of the over-mature at 12,000 ft. These depths indicate 1) that the apparently richly organic lower Miocene (Talang Akar) shales are thermally mature because they are generally bracketed by these depths (fig. 18); 2) that the gas of the lower Miocene (Baturaja) reefs is probably generated biogenetically from immature sediments, or less likely, in the mature petroleum window rather than from the thermally over-mature section; 3) that oil accumulations in the upper Miocene-Pliocene sandstones require at least 1,000 ft of vertical migration, and 4) that the observed "source beds" of earlier investigators fit nicely within these thermal limits (fig. 18). It is doubtful, however, that much of the strata within this mature zone, the open-marine Telisa Formation, is organically rich enough to produce oil. The volume of source sediment is estimated to be 22,500 mi^3.

Oil versus Gas

About 1.7 Tcf of gas have been produced in South Sumatra (Hariadi, 1980); much additional gas has been vented and much used for reservoir repressuring. Original gas reserves amount to 4 Tcf according to Hariadi, 1980. Oil reserves are estimated at 1.7 billion barrels. It appears that the Talang Akar sandstones contain about equal amounts of oil and gas; the Baturaja reefs contain mostly gas, perhaps about 30 percent oil; and the minor remaining untested middle Miocene-Pliocene sandstones with less effective sealing are perhaps 70 percent oil. The gas of the Baturaja and younger formation is generally shallow (<3000 ft) occurring on platforms around the perimeter of the basin, and although no analyses are available, this gas may be mostly biogenic in origin.

Migration Timing versus Trap Formation

Assuming a uniform thermal gradient and rate of subsidence through the Tertiary, generation and migration would commence when the subsiding, organically-rich early Miocene Talang Akar shales reached a depth of 6,500 ft, which would be about in the middle Miocene. At that time, the principal reservoirs, the Talang Akar, and in most places, the Baturaja Formations, were in-place, but much of the Miocene-Pliocene sandstones were yet to be deposited. Drape closures were available for trapping but the reservoirs of the later Miocene-Pliocene drag folds depended on considerable vertical migration of relatively late-generated oil. The migration timing appears especially favorable for the Talang Akar Formation, although there was a period in the early Miocene when the reservoirs may have deteriorated prior to the occupancy of petroleum.

Plays

The South Sumatra basin appears to have three principal plays; all extend over the entire basin. They are considered in detail in the play analyses.

1. Lower Miocene (Talang Akar) Sandstones
    Oil and gas accumulations in lower Miocene deltaic sandstones trapped in anticlines of drape or drag-fold origin.

2. Lower Miocene (Baturaja) Reefs
    Petroleum, mainly gas, accumulation in lower Miocene (Baturaja) carbonate reefs and banks.

3. Middle Miocene-Pliocene Sandstones
    Petroleum accumulations in middle Miocene to Pliocene sandstones in anticlines formed mainly by drag folding or drapes.

Northwest Java Basin

Location and Size

The Northwest Java basin occupies the western Java sea and the adjoining onshore area of northwestern Java (fig. 1). It is separated from the South Sumatra basin by the Lampung high. It has some shallow continuity with East Java basin to the east, the boundary between the basins being drawn at a saddle near longitude 110°30' E. The basin has a number of significantly deeper early Miocene and older subbasins, the Sunda, Arjuna, Jatibarang, Ciputat, and Pasir Putih (fig. 20). Of these, the Sunda and Arjuna subbasins are the largest and principal petroleum producers and are often regarded as separate basins. The basin, as has existed since late middle Miocene, has an appreciable thickness (>3,000 ft) of Tertiary-age rocks (fig. 21) over an area of some 20,600 mi^2 with a volume of 25,600 mi^3.

Exploration and Production History

Although exploration of the onshore portion of the basin began in 1900, little was discovered until modern techniques were applied when post-World War II exploration began in 1967; the first onshore wildcat discovered the Jatibarang field in 1969. Offshore drilling commenced in 1968; in 1969 was the first offshore oil discovery PSI-E1 (EF field) followed shortly by the discovery of the B field, the largest in the basin. Until the beginning of 1983, 318 offshore wildcats had been drilled; 98 of these were designated discoveries, giving a success rate of 31 percent. The latest major discovery (in 1983) was Bima on the east edge of Sunda subbasin (fig. 20) which went on production in 1986 with recoverable reserves of some 150 MMBO. Drilling activity and the success rate have risen in late years, but it is probable that the new field sizes are diminishing. It is apparently economical to install a small offshore platform or tripod to exploit reserves of as little as 1 million barrels of oil (Hardjadiwinangan, 1982), although 3 million barrels may be taken as an average. This type of development would explain the high success ratio obtained in the last few years. Reportedly, seismic data are excellent and, by this date, of fairly dense coverage. Accordingly, the assumption is made that around 70 percent of the offshore traps have been drilled, presumably the larger, closer to facilities, and otherwise more economical.

Onshore, largely the Jatibarang subbasin, the seismic data are not as good, and only 60 percent of the potential onshore traps are assumed to have been tested. Estimates on reserves are hampered by lack of data and by the evident number of yet unappraised or developed fields.

It is estimated that the original oil reserves, as of the end of 1983, amount to around 2.75 BBO (EIA, 1984). Indicated original gas reserves as of 1979 are about 2.1 Tcf (Hariadi, 1980; Patmosukismo, 1980).

Structure

General Tectonics

The Northwest Java basin is one of a number of back-arc (or inner-arc) basins formed between the volcanic arc of Indonesia (i.e., the volcanic Barisan Mountains of Sumatra and the Southern Java Mountains of Java) to the

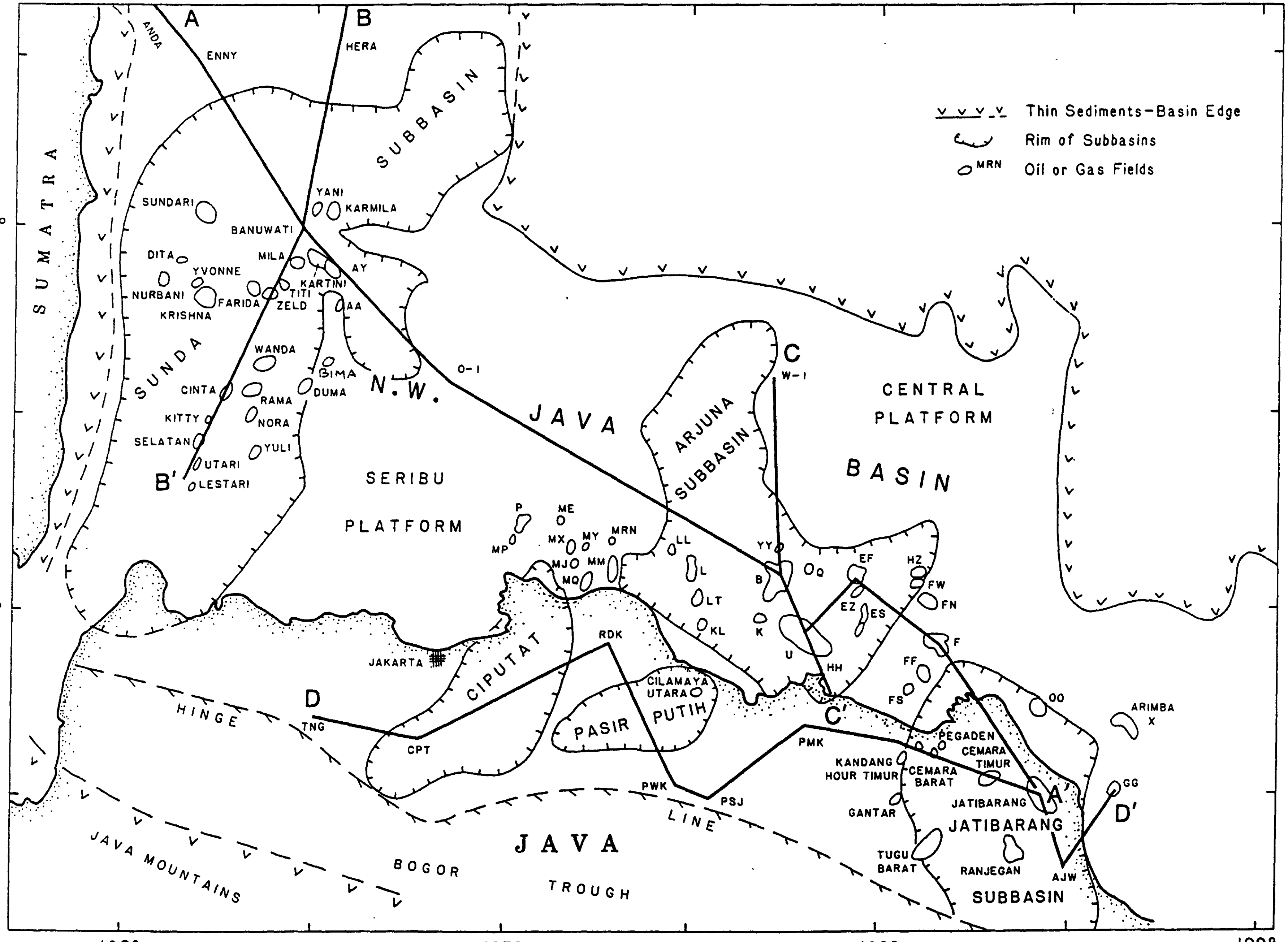


Figure 20.--Index map of Northwest Java basin showing distribution of subbasins, principal oil and gas fields, and location of geologic cross sections.

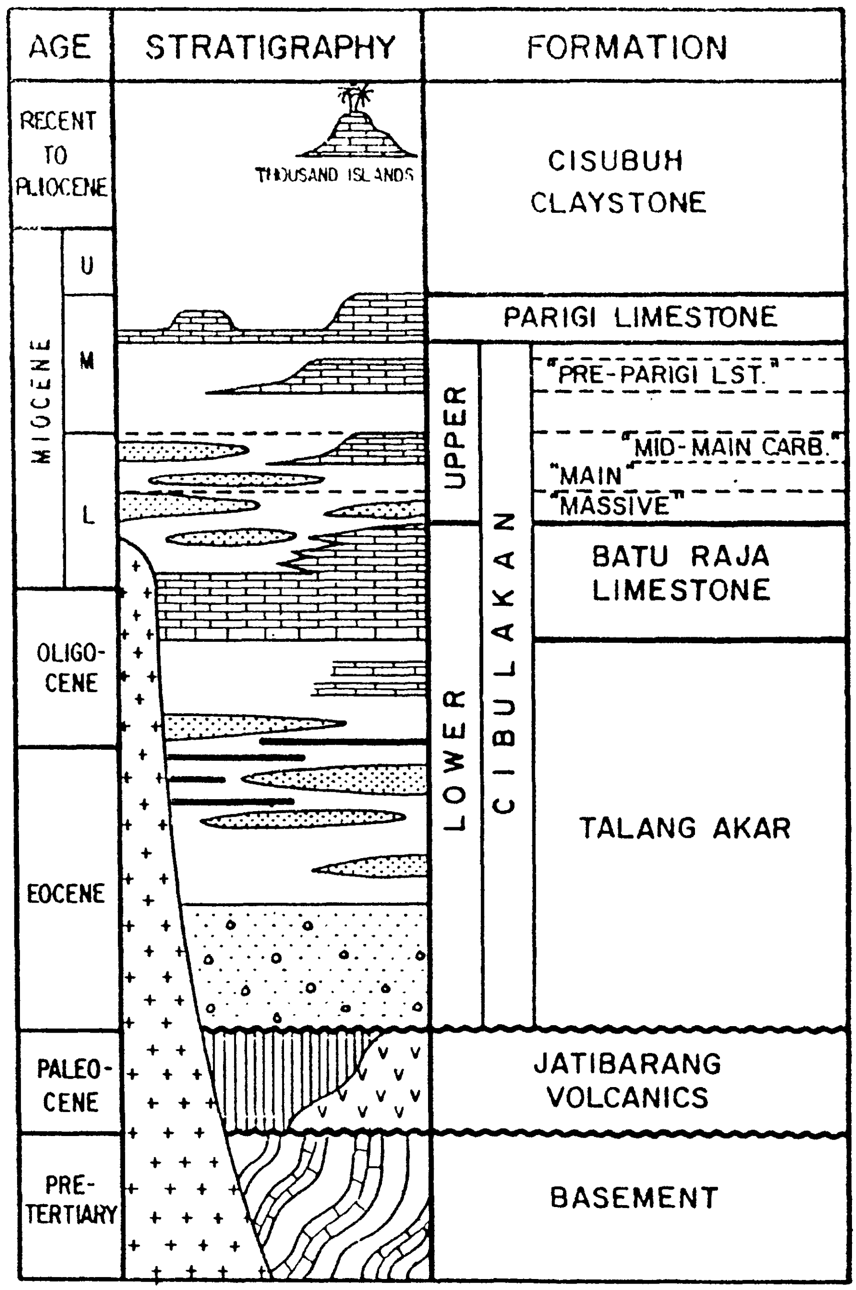


Figure 21.--Stratigraphic chart, Northwest Java basin.
From Burbury (1977).

south and west, and the craton area of Malaysia to the north and east (fig. 3).

Most of the basin is a shelf, sloping from the craton towards the south. A hinge line parallel and just south of the north coast of Java separates the shelf facies from a deeper basinal area (Bogor trough, fig. 20) of rapidly deposited shales and volcanic sediments to the south.

This generally east-trending basin is transected by a number of north-trending half-grabens (faulted on the east side) and grabens: the Sunda, Arjuna, Jatibarang, Ciputat, and Pasir Putih subbasins (figs. 20, 22, and 23). These in turn, are broken into smaller, closure-producing horsts and grabens. It is these subbasins which preserved organic material and, because of their depth and therefore heat, are the kitchens of petroleum generation.

Structural Traps

Sedimentary deposition largely filled the subbasins by the end of the Paleogene, reducing the relief of the Paleogene fault-block and drape features. Compaction, however, extended the effects of these features into early Miocene sedimentary drapes, but by late middle Miocene these effects were largely subdued. The effectiveness of Paleogene structural traps is therefore largely restricted to the Paleogene subbasins or half-grabens. These subbasins, shown in figures 20, 22, 23, and 24, have an area 7,000 mi^2 (5.46 MMA) or about one-third the total basin area (Sunda - 2.8 MMA, Arjuna - 1.2 MMA, Jatibarang - .74 MMA, and smaller onshore basins - .72 MMA).

No precise information is available concerning the amount of subbasinal area affected by the Paleogene fault-block and drape closures. In the vicinity of the Krishna oil field, the closures are judged to make up about 9 percent of the background area (i.e., after subtracting out the Krishna structure itself). In the adjoining South Sumatra basin where the geology is similar, the closures affecting Oligocene-lower Miocene sandstones are deemed to make up 5.5 percent of the play area. In the East Java Sea basin, adjoining to the east, Tertiary drapes are estimated to occupy 7 percent of the play area. On the basis of these analogies, it is estimated that 6 percent of the Paleogene play area, i.e., the subbasinal areas (5.5 MMA), is under structural closure, an area of some 330,000 acres.

The younger Neogene shallower drape closures are not confined to the deep subbasins. As effective petroleum traps, however, they are limited by sufficient reservoir sandstones in the northeastern part of the Northwest Java basin, i.e., the area approximately north of the Java shoreline and east of the Sunda subbasin, an area of some 1.6 MMA (the Arjuna basin, 1.2 MMA and its periphery, 0.4 MMA). No information is available concerning the Neogene trap area. By analogy to the traps of the Oligocene-lower Miocene (Talang Akar) sandstones, which are also drapes over essentially the same features and are presumably of parallel structures; these Neogene drapes are deemed to make up 6 percent of the play area or 100,000 acres.

Besides the structural traps, there are two plays involving carbonate traps, lower Miocene (Baturaja) carbonates and middle Miocene carbonates, whose areas and distribution will be discussed under Reservoirs.

Stratigraphy

The sediments of the Northwest Java basin are of Tertiary age and are summarized in the stratigraphic column of figure 21 and cross sections of figures 22 through 25. The stratigraphy, as displayed, is generalized for the

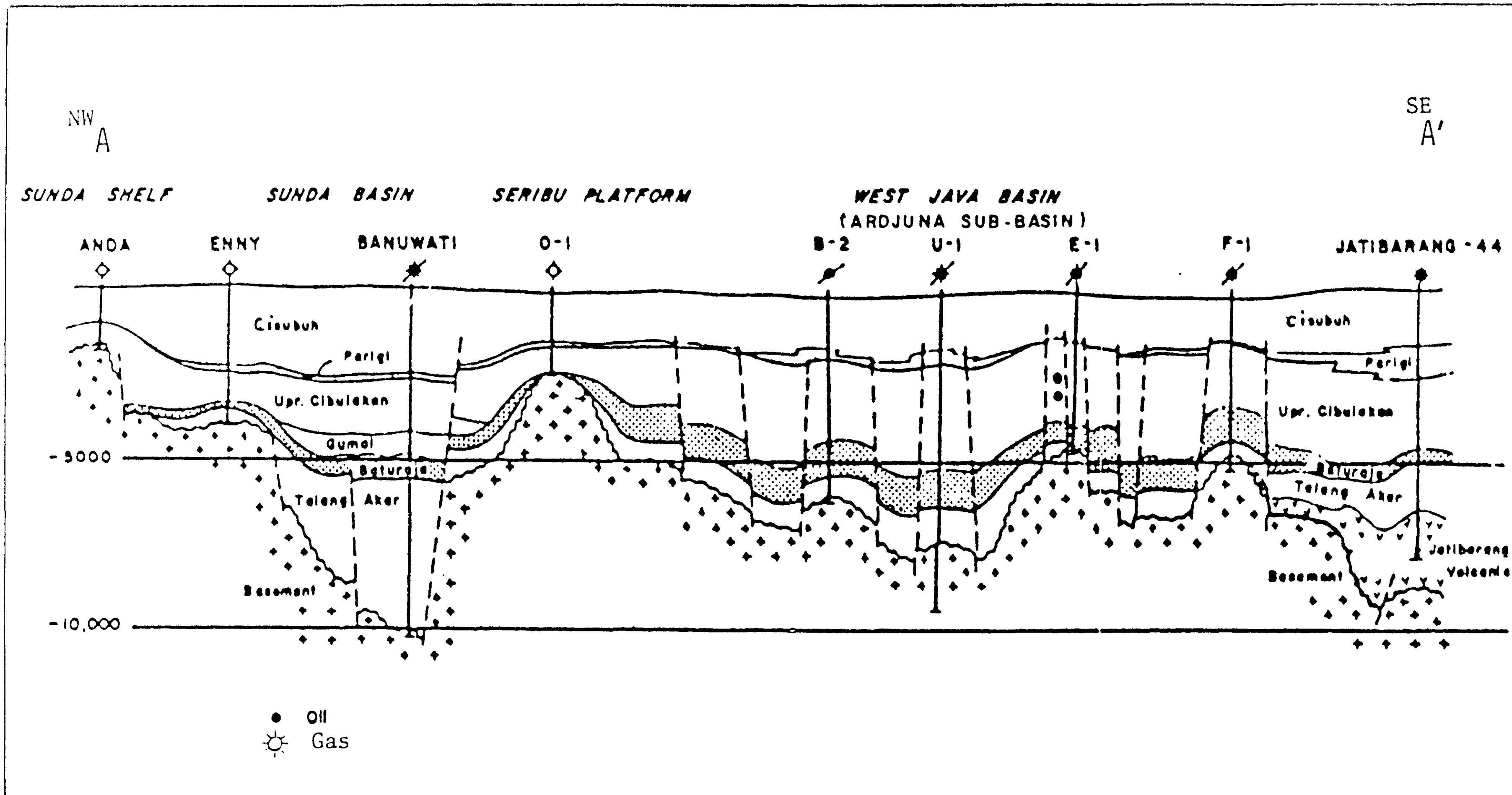


Figure 22.--NW-SE geologic cross section, A-A[1], Northwest Java basin. From World Oil 1973 in Petroconsultants (1980).

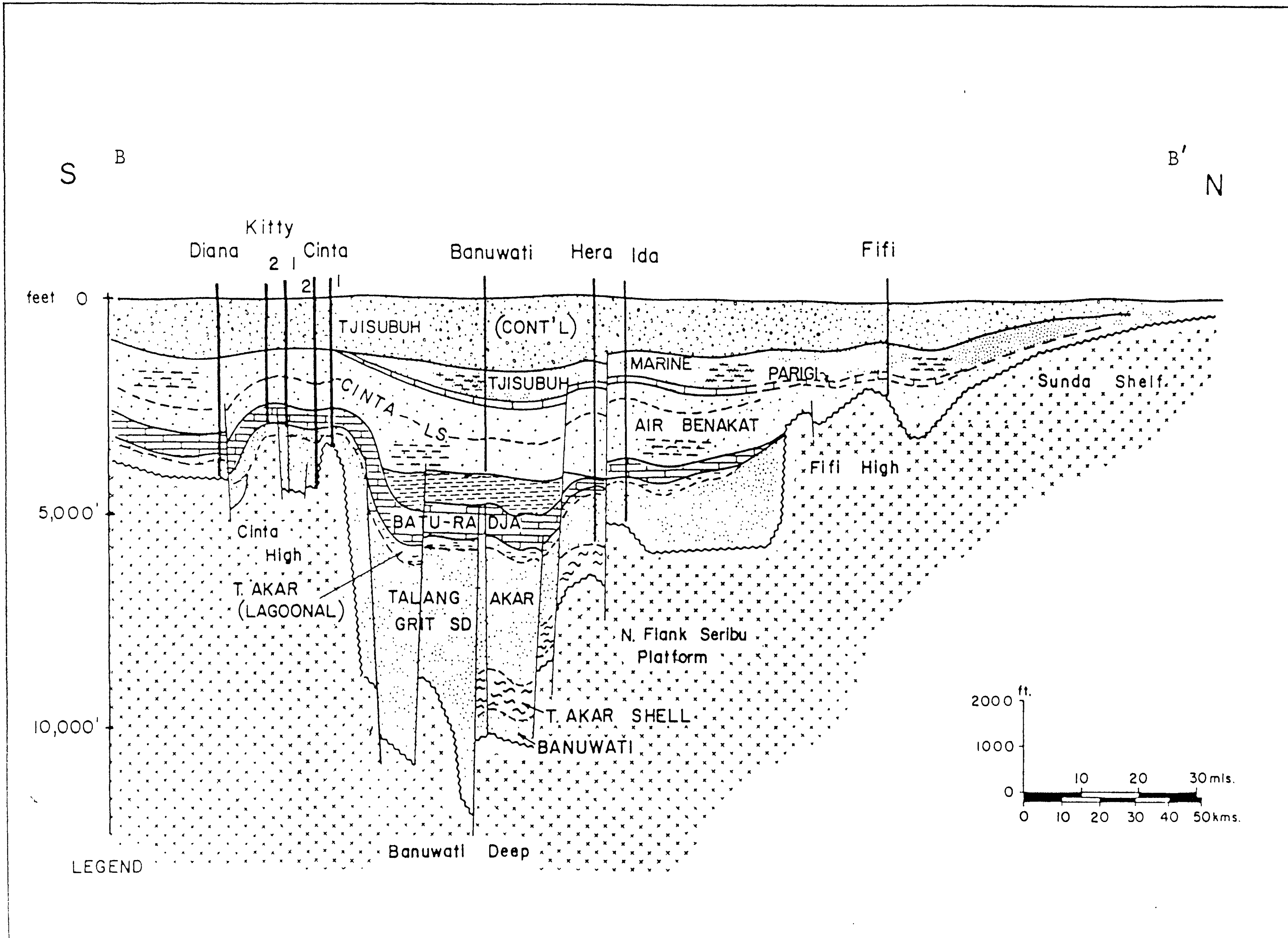
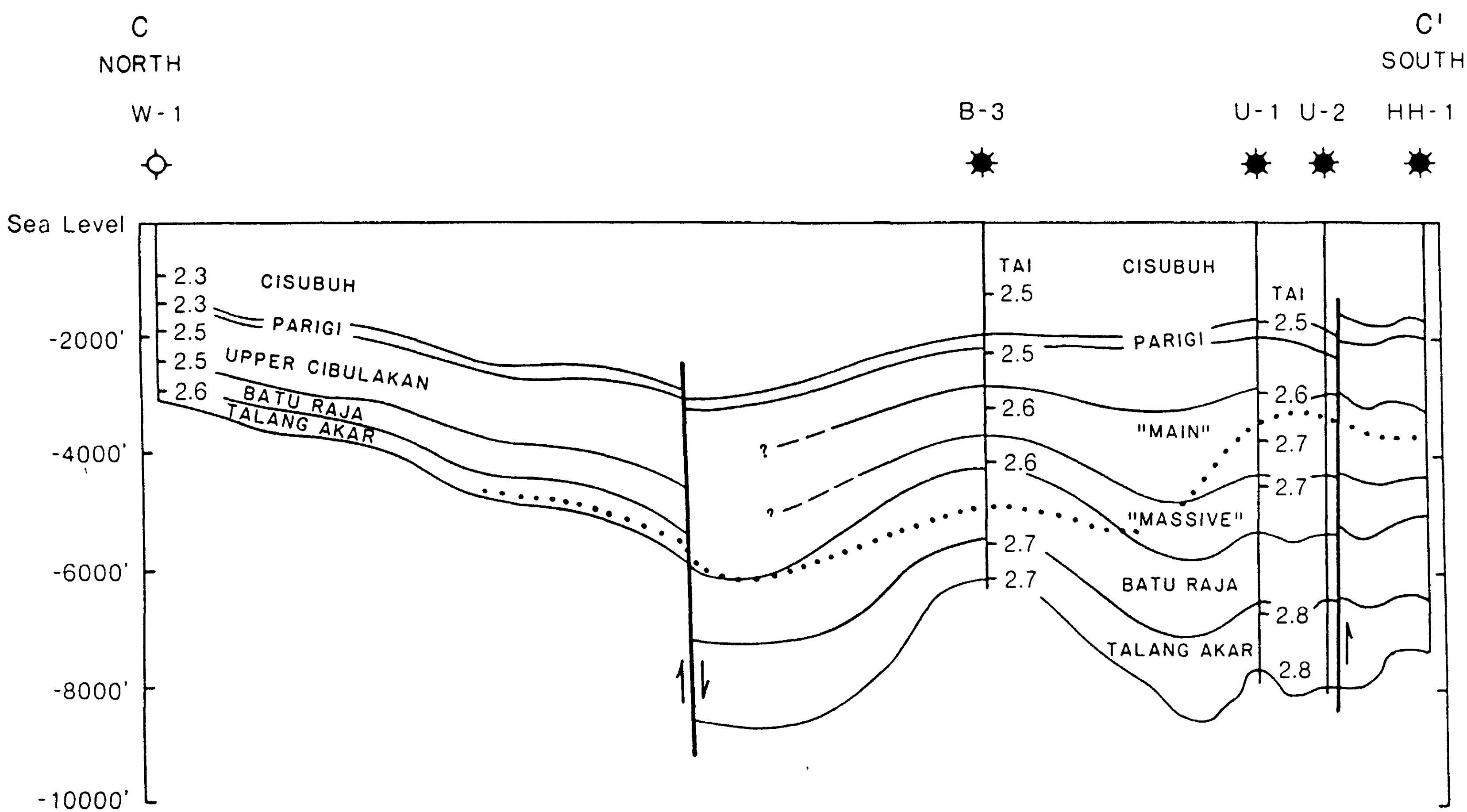


Figure 23.--South-north geologic cross-section, B-B^1, Sunda-subbasin Northwest Java basin. After Todd and Pulunggona (1971).



•••••• Approximate top of thermally mature sedments taken at Ro = 0.7% or T.A.I. ≅ 2.7

Figure 24.--South-north geologic cross-section, C-C[1], Arjuna subbasin, Northwest Java basin. Modified from Fletcher and Bay (1975).

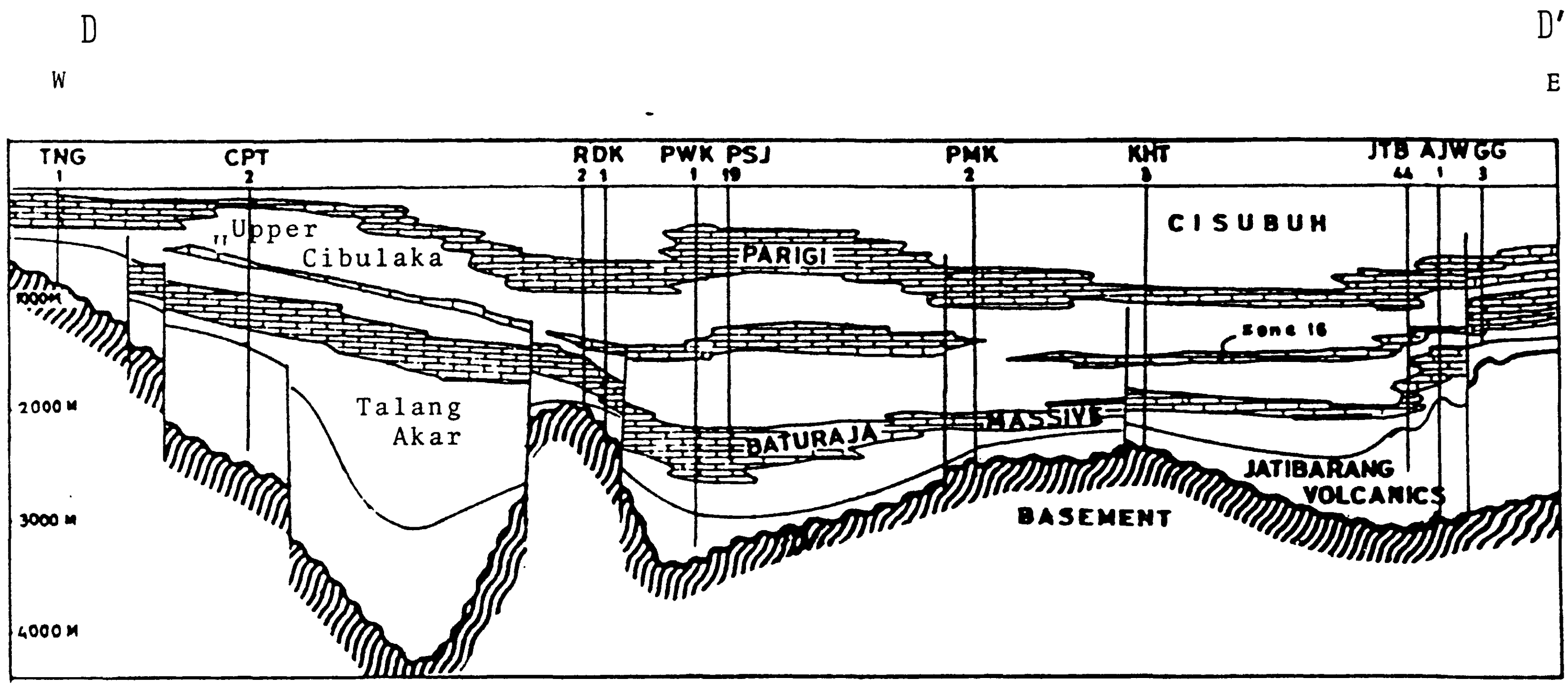


Figure 25.--West-east geologic cross-section, D-D[1], onshore Northwest Java basin.
From Sajanto and Sumantri (1977).

favorable shelf part of the basin, north of a hinge line which is just south of the present Java coast (fig. 20). South of the hinge line the rapidly-deposited, largely shale sedimentation is dominated by pyroclastic material, diluting the organic material and precluding the favorable reservoir development of the shelf.

Initial Paleogene sedimentation was coarse and volcanic (Talang Akar grits and Jatibarang volcanics) sediments filling the bottoms of the north-trending grabens and half-grabens (figs. 22 and 23). This was followed by the Talang Akar (Oligocene-lower Miocene) delta prograding southward from the Sunda craton area carrying quartz sandstones and rich organic material which filled, or almost filled, the graben subbasins coalescing the subbasins into the Northwest Java basin entity. A quiescent period followed where carbonates and shales (Baturaja Limestone) prevailed across the whole basin forming reefs near the top of the section. The carbonate regime was succeeded by a lower to middle Miocene low-energy sequence of shelf shales, sandstones, and carbonates (upper Cibulakan Member or Air Benakat Formation). The sandstone reservoirs, as well as carbonate reservoirs, of this unit are especially abundant in the Arjuna subbasin. Towards the top, the upper Cibulakan gradually became more calcareous, until, in the upper middle Miocene, carbonates (Parigi Limestone) again covered the eastern (Arjuna) part of the basin. The Parigi Limestone is overlain by the Cisubah Claystone.

Reservoirs

There are five principal reservoir groups within the Northwest Java basin. The distribution of each of these reservoirs is somewhat unique to the others, and each is affected by somewhat different traps. They are discussed from oldest to youngest.

1. <u>Eocene-Oligocene fractured volcanics (Jatibarang Volcanics)</u>

This reservoir is essentially limited to one subbasin, the Jatibarang subbasin, with an area of some 740,000 acres. The reservoir is fractured Paleogene tuffs and other volcanics, and its volume as well as its porosity and permeability are difficult to estimate. The average gross thickness of fractured volcanics above the oil-water contact in the Jatibarang field is 800 ft. According to Todd and Pulunggono (1971), the "average cumulative reservoir thickness is 600 feet." Sembodo (1973) illustrates 120 net ft as an example. Controlled by fracture permeability, the effective reservoir thickness is very irregular; an average thickness of 350 ft and a porosity of 22 percent is estimated.

2. <u>Oligocene-lower Miocene deltaic sandstones (Talang Akar Formation</u>

This reservoir is limited to the area of the Paleogene subbasins, an area of some 5.5 million acres. The average cumulative reservoir thickness of the Talang Akar sandstones for the basin is estimated to be 110 ft and the average porosity, 25 percent (Todd and Pulunggono, 1971).

3. <u>Lower Miocene Reefs (Baturaja Formation)</u>

The reefal reservoirs appear to be more abundant in the Sunda subbasin (where oil reserves are estimated to be 540 million barrels versus 40 million barrels for the rest of the reservoirs), but they do extend over the Arjuna and northern Jatibarang subbasins and peripheral areas. An area of some 6,000 mi^2 (3.84 million acres), including 5,000 mi^2 subbasinal and 1,000 mi^2 of peripheral area is estimated.

Little data are available as to how much of the early Miocene carbonates are in the form of porous trap, i.e., reefs, banks, and structural closures of porous zones. A partial map of the Krisna field reef complex (fig. 26) indicates about 18 percent of the mapped area is porous trap (the intertidal-subtidal facies of fig. 26). Away from this field the percent of porosity would be much lower, perhaps an average would be around 10 percent. A regional isopach map of the Baturaja Formation, eastern Northwest Java basin (fig. 27) suggests that about 15 percent of the Arjuna basin area is reef (and infers no reefs on the onshore portions of the basin). On this basis, it is estimated that 12 percent of the entire play area (i.e., .461 million acres) is porous trap area. The average net pay thickness is 66 ft at the FF field, reportedly 125 ft at the Arimba (X) field, 75 ft at the Zelda field, and 40 to 100 ft at the Krishna field. Todd and Pulunggono (1971) report 175 ft "average cumulative reservoirs thickness" for the first wildcats of the basin. It appears that about 100 ft would be a good average net effective reservoir thickness for the remaining prospects of the basin.

4. Lower-Middle Miocene sandstones (Upper Cibulakan Formation)

By Miocene time the subbasins were largely filled and the intervening highlands covered so that the sand came primarily from the Sunda shelf to the north, thinning southwards so that appreciable sand thickness ended approximately at Java's north shore and apparently also thinning westwards into the Sunda subbasin; in effect, largely limiting viable reservoirs to the Arjuna subbasin vicinity. On this basis, the area of lower-middle Miocene sandstone deposition is estimated to be about 1.6 million acres.

According to Todd and Pulunggono (1971), the average cumulative reservoir thickness of these lower-middle Miocene sandstones is 250 ft. An average porosity of 26 percent and a water saturation of 40 percent were found at Arjuna B field, and this is assumed to be an average for the basin.

5. Middle Miocene Carbonates (Parigi Limestone and Upper Cibulakan Formation)

The distribution of the reef facies of the Middle Miocene carbonates is not so closely controlled by the Paleogene structure as that of the underlying Baturaja Limestone. The "Mid Main" reefs (fig. 21) are restricted by the southeastern Seribu Platform (the M and P fields of fig. 20). The Pre-Parigi reefs occur also in this area plus on the highs of the southern Arjuna Basin. The Parigi Limestone is the least affected by the Paleogene structure and extends over the basin. The reef facies, however, does not appear to extend west of the M and P fields nor east of Arimba, nor is it well developed in the Ciputat subbasin nor in the northern Arjuna subbasin (fig. 20). It has an estimated play area of 3.2 million acres.

The buildups of the Seribu Platform, the Arjuna subbasin, and the Jatibarang subbasin have been actively drilled. The considerable reef development of the Central Platform (map, Burbury, 1977) apparently has not been drilled, perhaps because of shallowness causing low gas pressure and concentration, poor seal, and requiring more platforms per trap. As indicated by published maps (Burbury, 1977), there are about 690,000 acres of carbonate trap area (including the Central Platform). Some of this trap area may prove invalid and additional area may be mapped; however, 690,000 acres probably approximates the amount of trap area in the play. The average cumulative pay for the middle Miocene reefs appears to range from 30 ft (Todd and Pulunggano, 1971) to 277 ft (fig. 17 of Burbury, 1977). Taking into consideration the varying and unpredictable porosity, 120 ft is estimated.

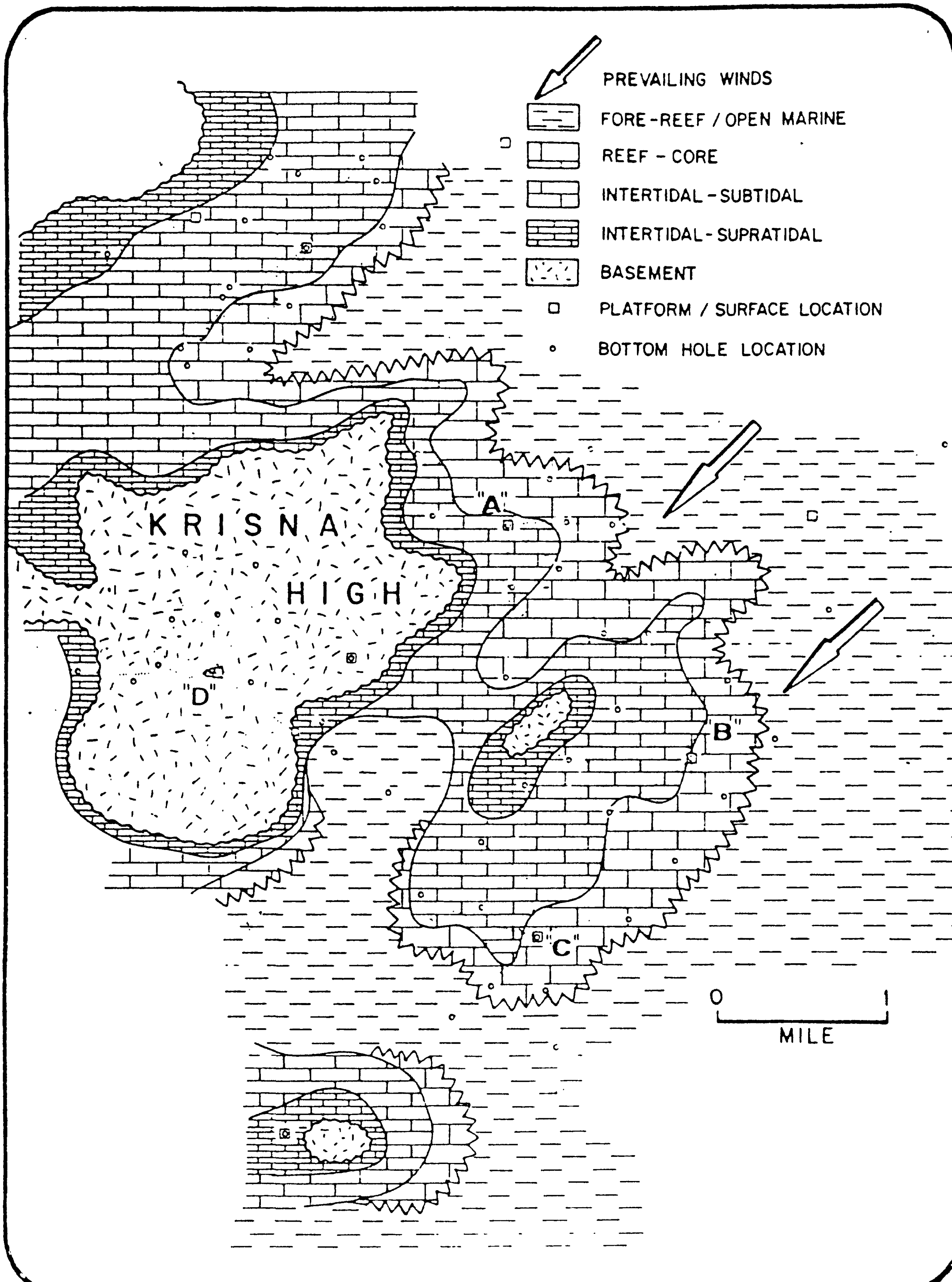


Figure 26.--Map showing details of lower Baturaja paleogeography, Sunda subbasin, Northwest Java basin. After Ardila (1982)

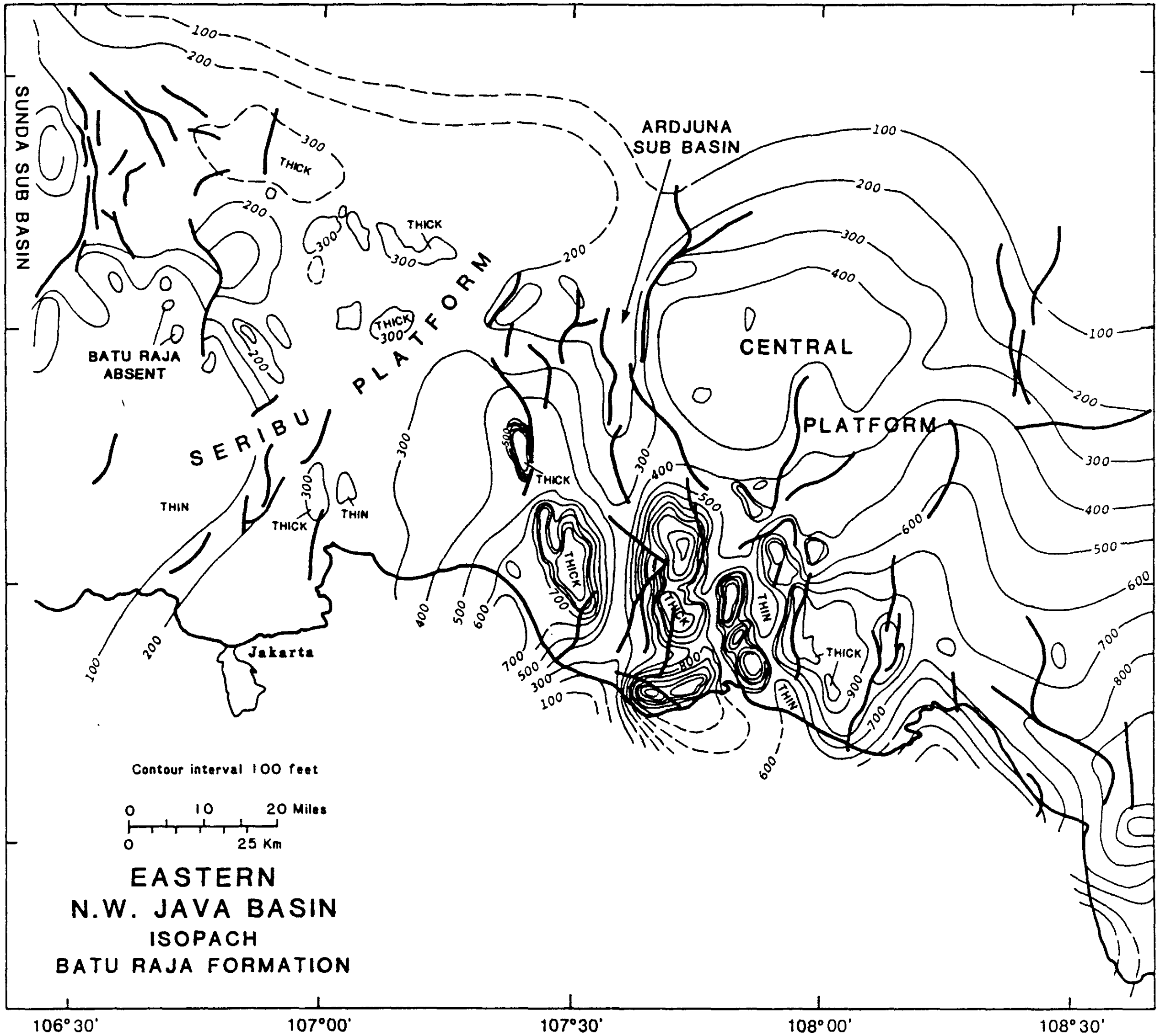


Figure 27.--Isopach map of Baturaju Formation eastern Northwest Java basin. From Burbury (1977).

Seals

Except for perhaps the shallowest of the Upper Cibulakan reefs, lack of seals does not appear to be a problem. In spite of a generally shaly section, however, primary vertical migration does occur, as evidenced by petroleum occurrence in middle Miocene reservoirs, thousands of feet above the thermally mature Paleogene source rock.

Source Section

The source rock appears to be largely limited to the Paleogene part of the section, i.e., the Talang Akar and Jatibarang volcanics. They are discussed in detail below.

Petroleum Generation and Migration

Richness of Source

The organic richness of the Neogene sediments, i.e., the sediments above the Talang Akar Formation, is generally poor (Fletcher and Bay, 1975). The Talang Akar sediments on the other hand are organically rich, particularly in the deeper subbasins. These deltaic sediments are rich in terrigenous, woody plant material; algal-rich coals are common and reputed to be the principal source of the West Java oil (type III kerogen). Total organic carbon ranges from 0.5 to 20 percent. Outside of these deeper subbasins of fine-grained sediments, there is only Talang Akar grits or marine shale facies, and the source rock potential is low, thus essentially limiting appreciable petroleum generation to the vicinity of deep grabens. This richness of source, and also effectiveness of the trap, is attested to by the 70 percent fill in the main reservoir (Miocene sandstone) of the B structure.

Depth and Volume of Source Rock

Fletcher and Bay (1975) report thermal alteration index (TAI) readings for a number of wells. If one assumes that the onset of substantial hydrocarbon generation begins at a maturation level of vitrinite reflectance (Ro) of 0.7 percent, which is approximately equivalent to TAI of 2.75, the top of the mature zone varies irregularly between 4,000 and 6,000 ft, probably averaging about 5,000 ft. At this depth, the mature sediments are limited approximately to the Oligocene Baturaja and Talang Akar Formations (of the Lower Cibulakan) and, more importantly, are limited to the deeper subbasins.

Coincidentally, both organic richness and thermal maturity limit the principal source rocks to the deeper subbasins. Minor amounts of organic material, however, probably exist in the Upper Cibulacun Formation which extends, above the subbasins, throughout the northwest Java Basin at a relatively shallow depth (<3000 ft). The gas in this upper section is likely of biogenic origin.

The volume of source rock in these subbasinal areas is approximately 10,500 mi^3.

Oil versus Gas

The oil reserves of Northwest Java are about 2.75 BBO, and gas is around 2 Tcf. All reservoirs contain oil and gas, but the middle Miocene, relatively shallow (Parigi Formation) reefs are almost exclusively gas, as are the Baturaja reefs in the eastern Adjuna subbasin; this gas is probably of biogenic origin. It is estimated that the overall oil-gas mix is about 70 percent oil and 30 percent gas, ranging from 75 percent oil in the Oligocene (Takang Akar Formation) to 15 percent in the middle Miocene carbonates (Parigi and Baturaja Formation).

Migration Timing versus Trap Formation

Assuming a uniform thermal gradient and subsidence rate through the Tertiary, petroleum generation would begin in the subbasins when the source beds, i.e., the Talang Akar shale, subsided to a depth of about 5,000 ft, which would have been about in the middle Miocene. At that time, the draped Talang Akar sandstones, as well as the Baturaja reefs, would be largely in place, and at least partially sealed, ready to receive the migrating petroleum. Some reservoir deterioration may have occurred during the Oligocene and early Miocene. The Parigi Limestone and other Miocene reefs were deposited somewhat later and probably missed the early migrating petroleum, but were available for biogenic gas.

Plays

Five plays are closely linked to the reservoir groups and are considered in detail in the play analyses.

1. Fractured Paleogene volcanics (.74 MMA)
2. Oligocene-lower Miocene deltaic sandstones (5.5 MMA)
3. Lower Miocene reefs (3.84 MMA)
4. Lower-Middle Miocene draped sandstones (1.6 MMA)
5. Middle Miocene carbonates (3.2 MMA)

East Java Sea Basin

Location and Size

The East Java Sea basin is largely offshore and lies between Kalimantan (Borneo) to the north and the axial range (volcanic arc) of eastern Java and Bali to the south. It extends eastward from a saddle at about Long. 110°30' E., the Karimunjawa Arch, on the west to South Makassar Sea on the east (figs. 1 and 28). Its northern side is a shelf which continues north into Kalimantan. The northern boundary is placed at what is believed to be the northernmost limit of primary petroleum migration from the deeper basin source areas to the south (fig. 28). On this basis, the basin has an area approximately 43,000 mi^2 and a sedimentary fill of 77,000 mi^3.

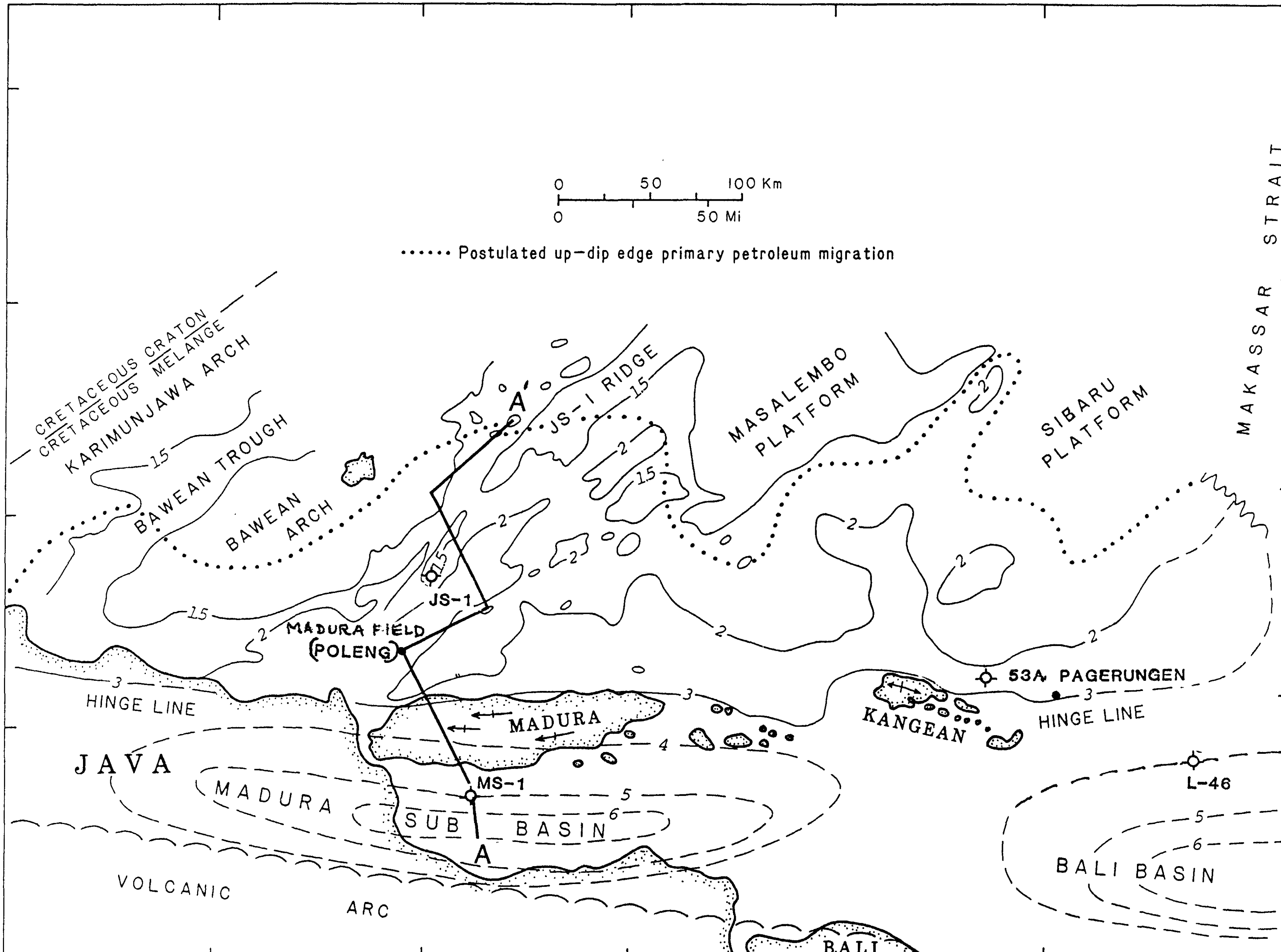


Figure 28.--Sketch map of East Java basin showing depth to basement. After Kenyon (1977) and Hamilton (1979).

Exploration and Production History

The onshore Madura subbasin portion of this basin in northeast Java has produced 170 million barrels of oil from 27 small, shallow fields during the last 80 years. All important discoveries were made prior to 1925, and presently only five minor fields are still operating; peak production was reached in 1940 when 40,000 barrels per day were produced.

Most modern exploration, beginning in 1967, has been offshore; some 60 wildcats have been drilled. Some discoveries, about ten oil and seven uncommercial gas, have been announced, but no production has yet been established. Attempts were made to produce one field, Poleng (fig. 28); production began in 1975 and ended in 1978 when the field was shut-in. Its cumulative production is 1.8 million barrels, and ultimate recovery is estimated at 4 million barrels. Subsequently in 1985, the nearby Madura field was put on stream from presumably the same horizon (Kujung Unit 1) (fig. 29) with recoverable reserves of 22.1 MMBO and some gas; initial production of 15,000 BOPD declined to 3,500 BOPD in less than a year. Two recent significant discoveries are: L-46, between the East Java Shelf and the Bali basin (fig. 28), which tested 1,000 BOPD from Eocene sandstones possibly over a drape feature, and Pagerungan gas field near Kangean Island (fig. 28), which tested 27 MMCFGPD 248 BCPD and has estimated reserves over 3 TCF plus condensate.

Although some 60 wildcats have been drilled in the offshore, the exploration of the province is considered to be only in an immature stage, perhaps 30 percent tested. Many of the wells tested traps too far updip on the shallow shelf to have been accessible to migrating hydrocarbon. Also, because of the many small carbonate traps of unpredictable reservoir properties, many wells will be required to establish the petroleum potential of the carbonate play.

Structure

General Tectonics

This basin is a classic back-arc basin lying between the craton to the north and the volcanic arc to the south (the Java Axial Range). The area of the basin is largely a foreland shelf dipping gently southward with an Eocene to recent hinge line between it and the deeper, basinal area to the south, the Madura subbasin and its eastern extension, the Bali basin (figs. 28 and 30). The hinge line approximates the northern coast of Java and extends eastward along the north coasts of Madura and Kangean Islands. The shelf area is covered by a relatively thin stratigraphic section, averaging less than 6,000 ft (2 km), whereas the basinal area contains probably more than 30,000 ft (5 km) of sediments, predominantly thick, plastic shales. The compressive forces, presumably created by the northward subduction of the India-Australia Plate beneath the Indonesia Island Arc have created numerous east-west folds in the more plastic basinal fill, but not in the thinly covered more rigid shelf.

The shelf is crossed by a series of northeast-trending ridges and basins or half-grabens, controlled by down-to-the-northwest faults of largely Paleogene age with continued movements into the Miocene (fig. 28). The origin of this structure may be marginal rifting of the Sunda Continental Block. The faults parallel the Cretaceous continental edge as indicated by the contact

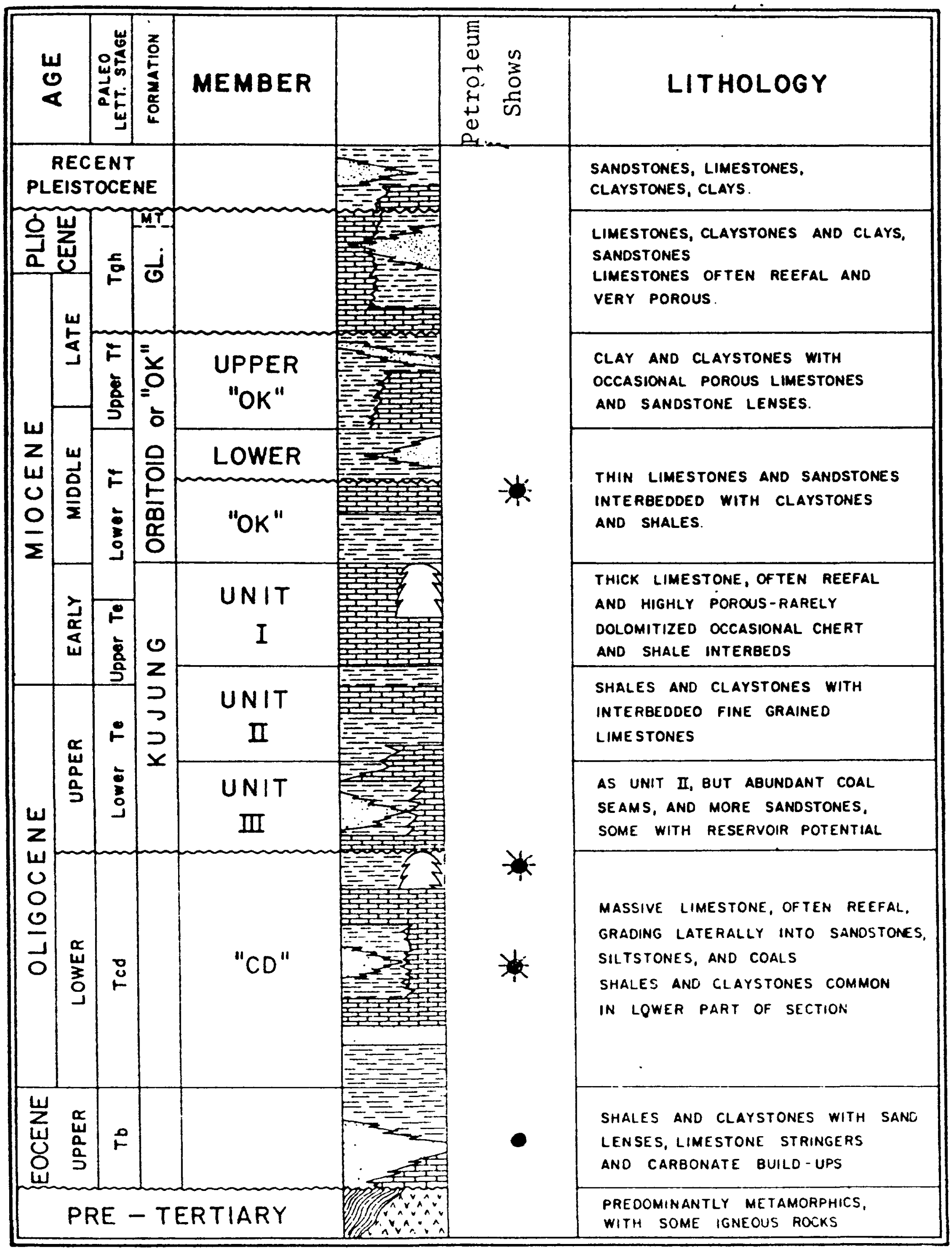


Figure 29.--Stratigraphic chart, East Java basin. From Kenyon (1977).

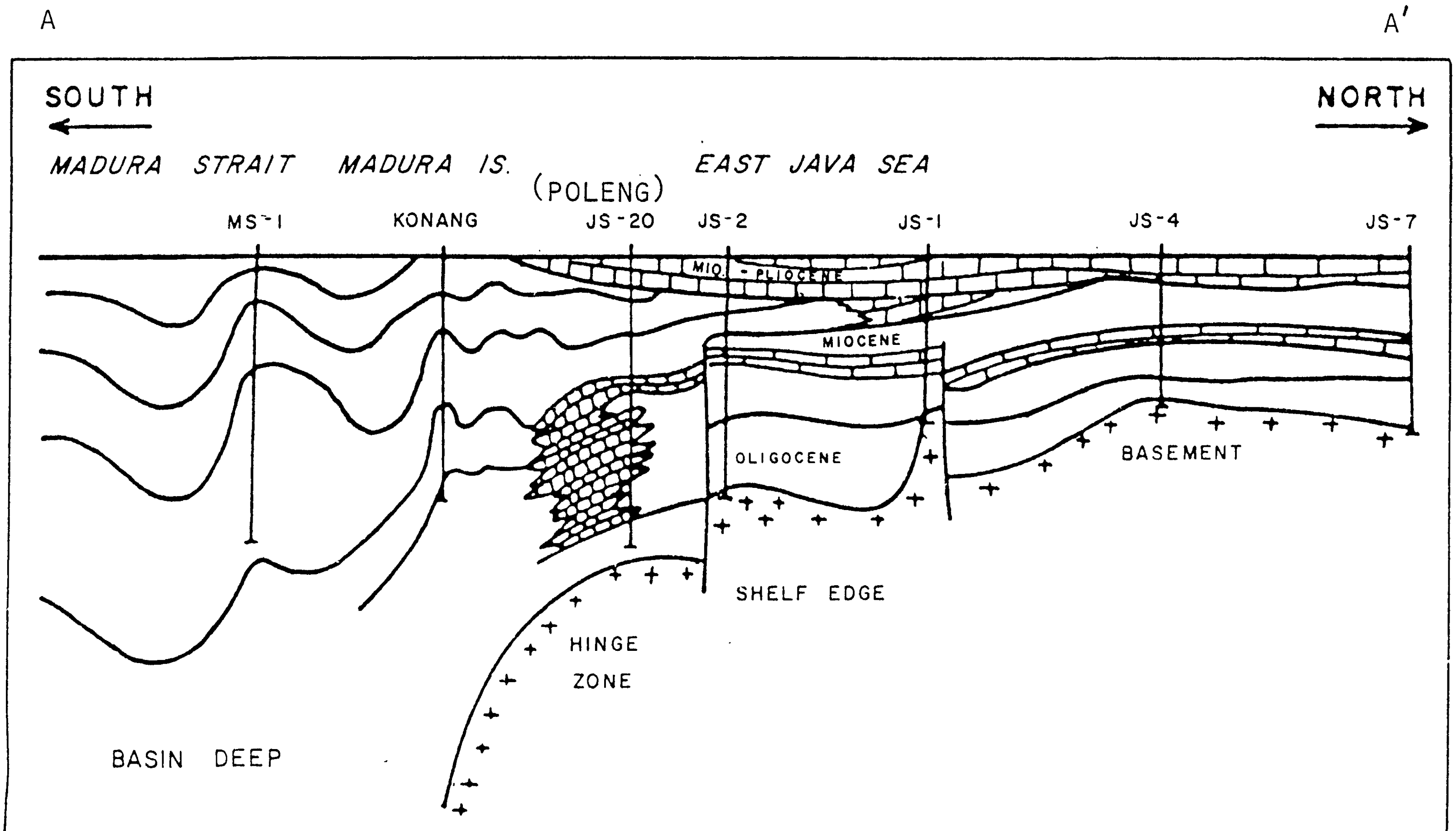


Figure 30.--South-north geologic cross-section, A-A[1], East Java basin. After Koesoemadinato and Pulunggano (1971).

between the granitoid continental crust and the accreted Cretaceous melange, which underlies the East Java basin approximately corresponding with the southeast side of the Karimunjawa Arch (fig. 28).

The plays are controlled to a considerable extent by the tectonics; they are: 1) shelf carbonate reefs localized by the northeast-trending fault-originated ridges and by the east-trending hinge, 2) shelf drapes localized by the northeast-trending ridges, and 3) folded sandstones of the basinal area.

Structural Traps

<u>Shelf Drape Features</u>. From examination of an unpublished map of the shelf area just north of Madura Island, it appears that the drape traps over basement highs, ridges, and hinge lines make up about 5 percent of the area. The examined part of the shelf seems to have more structure (and better cover) than other parts of the play area; so the average percentage of trap area in the whole shelf play may be only half that of the sample area, or 2.5 percent. On this basis, there are about 425,000 acres of trap (2.5 percent of 17 million acres of play area; see Plays). Reefs localized by this structure are discussed under Reservoirs.

<u>Basinal Folds</u>. Onshore, Eastern Java and Madura Island have small, shallow structurally complicated fields (active or abandoned) of some 44,000 acres of closure (Soetaniri and others, 1973). This amounts to less than 1 percent of the 7 million acres of onshore play.

Most of the fields are of such a small size, complicated, and diapiric, that their offshore development probably would not be economically feasible. There are, however, some larger folds east of and on trend with Madura Island, i.e., along and immediately basinward of the shelf edge. Here in a limited zone of about 2.5 million acres are closures which perhaps make up 5 percent of the zone or about 125,000 acres, most of which is untested. Considering these larger offshore, shelf-edge folds along with the few small closures on land, perhaps there are 150,000 acres of untested traps in this play.

Stratigraphy

The rocks are of two environments; over most of the basin the stratigraphy is predominantly shelfal, made up largely of carbonate and shale with some sandstones, whereas in the southern third of the area (south of the hinge line), the rocks are largely basinal, i.e., thick, neritic to bathyal strata, mostly shale with some carbonate and sandstone (figs. 29 and 30).

The stratigraphy of the basinal area progresses rapidly from the shelfal facies to the practically all-shale section of the Madura Strait Well MS-1 (35 km south of the hinge line, fig. 30). Reservoirs of the basinal area are thin and sparse.

The sedimentation of the shelfal area (fig. 29) began with an Eocene transgression from the east over an irregular Mesozoic surface. This was followed by a period of general quiescence, which lasted, with some minor interruptions, through the Tertiary to the present. The sediments are characterized by thick, widespread carbonate units and accompanying shale. More arenaceous deposition was confined to three zones: 1) the initial eastern Eocene transgression, 2) short periods of deposition of Oligocene sandstone derived from the west, and 3) regressive fine-grained sandstone deposition in the middle to late Miocene.

Reservoirs

Principal potential reservoirs of the East Java shelf stratigraphic section (fig. 29) appear to be:

1) Eocene-lower Oligocene transgressive sandstones
2) Eocene carbonate reefs
3) Lower Oligocene "CD Limestone" bank carbonate
4) Upper Oligocene Unit II, Kunjung Formation carbonate reefs and banks
5) Lower Miocene Unit I, Kunjung Formation carbonate reefs and banks

A sixth potential reservoir zone is the middle Miocene clastics of the basinal, off-shelf facies.

All these reservoirs have been tested, and have yielded some hydrocarbon, but only Unit I of the Kunjung Formation has commercial amounts. The lower Miocene carbonate reefs and banks appear to be the prime objective reservoirs (i.e., Unit I, Kunjung Formation), followed by the Eocene carbonate reefs. In the following discussion, the Eocene-lower Oligocene transgressive sandstones are considered together; the objective carbonate reservoirs are grouped as one; and the middle Miocene clastics of the basinal area are considered as one objective.

Transgressive Sandstones

Little data are available; these Eocene to lower Oligocene sandstones are assumed to extend over the entire shelfal area of some 17 million acres. Effective pay would probably have to be at least 50 ft thick to constitute an economic accumulation. An average accumulative effective thickness of 100 ft is assumed.

Miocene Carbonate Reservoirs

The reservoirs are in reefs or carbonate buildups confined to the carbonate shelf of some 5 million acres. By count of reefs in one sector of the shelf north of Madura Island (unpublished map), it appears that a great number of small reefs and bank buildups make up about 7 percent of the carbonate shelf area. Reefs and the buildups appear to be unusually numerous in this sample area, however, so that the percentage trap of the entire play would be somewhat lower. Five percent would seem to be a good average, giving a carbonate trap area of 250,000 acres.

The net pay of Poleng field is 225 ft (Soeparjadi and others, 1975); JS-1-1, another announced early discovery, had 20 ft of net pay. An average pay for a productive accumulation is probably about 200 ft. The porosity varies, and its predictability appears to be a major exploration problem. The average porosity may be low; 18 percent is assumed.

Miocene Basinal Sandstones

These sandstones are limited to the basinal area where they are interbedded in a largely shale section. Great net sandstone thicknesses are reported from 639 to 440 ft in the onshore and 500 ft in MS-1. These figures appear very high considering the small amount of production obtained. It is suspected that the net effective pay thickness is 200 ft or less.

Seals

The average porosity and the permeability of the stratigraphic section generally is poor. Seals made up of shales and low-permeability carbonates abound. Lack of seal does not appear to be a significant problem in this basin, but considerable oil-stained section, especially in the Eocene wildcats, indicates leaking traps.

Source Section

The depth of the thermally mature sediments is about 7,000 ft. This limits the source rock to the Oligocene and earlier.

Petroleum Generation and Migration

Richness of Source

The organic content of rocks in the East Java basin generally is meager. The richest organic carbon values are in the lower "OK" Formation (middle Miocene) (fig. 31), which range up to 7 percent with a median of 1.75 percent. This unit, however, appears to be too shallow over most of the basin to be thermally mature. Units II and III of the Kajung Formation (lower Miocene-Oligocene) have organic carbon contents above 0.5 percent (the accepted lower limit for designating source rock), but it is somewhat meager with median values of .55 and .95. Undoubtely, there is more source rock in Eocene and Oligocene shale, of unknown organic content, of the eastern part of the basin where oil-stained Eocene carbonates have been penetrated in several wells and where 1,000 BOPD have been tested from Eocene sandstones L-46. The petroleum fill ranges from 100 percent at Poleng down to 6 percent at 53A-1, indicating sufficient source, but perhaps leaking traps.

Depth and Volume of Source Rock

The East Java basin with a thermal gradient of 2.2°F/100 ft (Kenyon and Beddoes, 1977) is considerably cooler than the adjoining Northwest Java basin with a thermal gradient of 3.6°F/100 ft. This may be related to its position over Cretaceous melange rather than granitic craton (fig. 29). It does indicate that mature source rock must be considerably deeper within the basin and therefore of less volume, possibly explaining the poorer exploration results in the East Java Sea basin versus the Northwest Java basin.

Thermal Alteration Index (TAI) values from an unknown number of wells scattered over the basin, (Russel and others, 1976) determine the top of the mature zone of the East Java basin to average around 7,000 ft (when TAI > "2+") (fig. 32). On this basis, the volume of source rock on the shelf is approximately 6,000 mi^3, and the prospective area is limited to the graben areas in the southern third of the shelf (26,000 mi^2); i.e., where the sediments are over 7,000 ft (2 km) deep, plus allowance for perhaps 25 miles

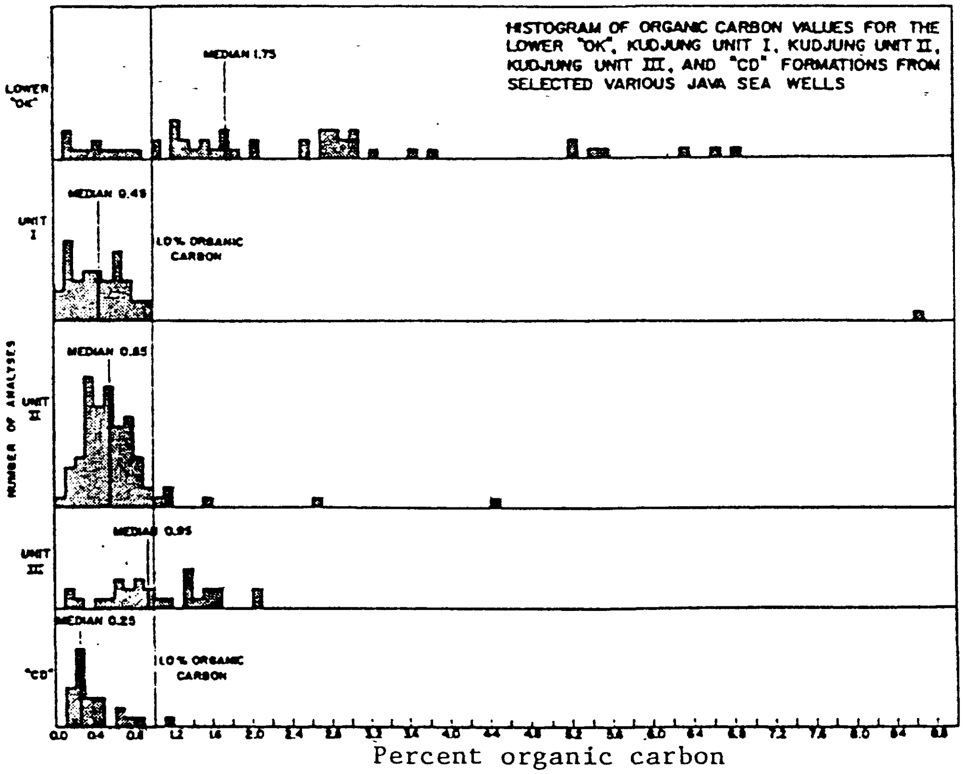


Figure 31.--Histograms of organic carbon values for the formations from selected various east Java sea wells. From Russel et al (1976).

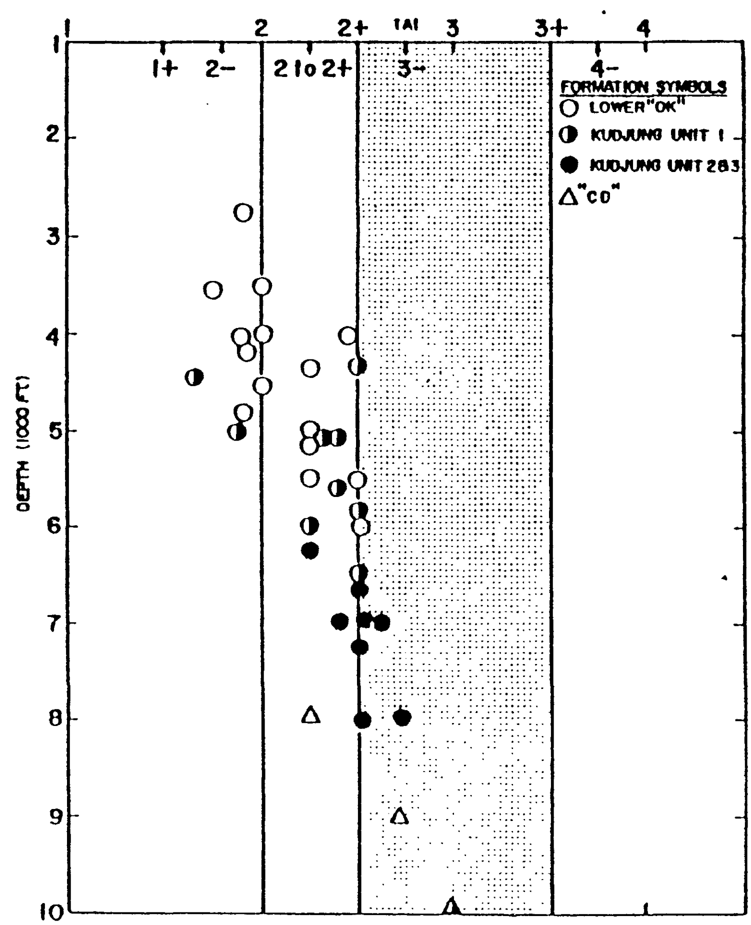


Figure 32.--Chart showing relationship of TAI values, formation, and depth. From Russel et al (1976).

of up-dip migration; this approximate limit is shown by a dotted line in Figure 28.

Oil versus Gas

Gas and oil shows have been encountered in many of the 50 wildcats drilled, but no relative amounts have been recorded. The Poleng field reportedly has 102 ft of net oil pay overlain by 153 ft of net gas pay (Soeparjadi and others, 1975). Assuming a tabular shape, this means that oil takes up about 40 percent of the trap volume, and in the absence of other data, this is assumed to be the average for the shelf. The basinal area may be somewhat more gassy and perhaps oil is only 30 percent of the petroleum mix.

Migration Timing versus Trap Formation

Assuming the thermal gradient and subsidence were constant during the Tertiary, petroleum generation and migration began when the sediments reached a thickness of 7,000 ft (2,000 m), which would be about the end of the Oligocene (top of Unit II) (figs. 29 and 31) in the transverse grabens and shelf edge (hinge line zone). However, a major part of the up-dip shelf subsidence has been slower so that large parts of the sedimentary volume did not become thermally mature (i.e., reaching 7,000 m depth) until more recently. Consequently, reservoirs in those areas particularly the objective lower Miocene Kujing Unit I, may have been damaged by diagenesis before being available to primary petroleum migration from the deeper source-rock areas.

Plays

The untested traps of the East Java Sea appear to be in three principal plays listed below. Details are given in individual play-analysis for each of these plays.

1. <u>Shelf Reefs</u>

Petroleum accumulations occur in Tertiary carbonate reefs and banks on the foreland shelf of the East Java Sea basin. Most of the prospective reefs are lower Miocene carbonates, but some may range from Eocene to late Miocene in age. The area of the foreland shelf is some 17 million acres, but the carbonate platform upon which the reefs grew, and considered the play area, is about 30 percent of the shelf, or about 5 million acres.

2. <u>Shelf Drapes</u>

Hydrocarbon accumulations occur in sandstones or calcarenites which are draped over faulted and tilted basement blocks. Part of the trap may be closures against those block faults which have continued to act intermittently through the Tertiary. The reservoirs are largely confined to Eocene-lower Oligocene transgressive sandstones but may include younger sandstones draped over carbonate buildups. The area of play is the foreland shelf of the East Java Sea basin, which is 17 million acres.

3. <u>Basinal Folds</u>

Petroleum accumulation occurs in Neogene folds involving the sediments of the basinal area, i.e. the Madura and Bali subbasins. Reservoirs are sandstones (or calcarenites) near the shelf edge. The play is limited to the deep basinal area of the East Java Sea basin. The area is about 10.7 million acres (fig. 28), but the zone of the most prospective, undrilled traps is largely limited to an offshore zone basinward of the hinge, an area of approximately 2.5 million acres.

Barito Basin

Location and Size

The Barito basin is near the southeast corner of Kalimantan (Borneo) (figs. 1 and fig. 33). It is bounded on the north by a saddle between it and Kutei basin; on the south it merges onto the shelfal portion of the Java Sea (the boundary is taken to be about at the coast line). On the east it is bounded by the Meratus Range and on the west by the southwestern (Sunda) platform of Kalimantan at about latitude 114°. It has an area approximately 19,000 mi^2 and a sedimentary fill 43,000 mi^3.

Exploration and Production History

Exploration began in 1930 and the first oil discovery was made at Tanjung in 1937. Tanjung and minor satellite fields, Warukin Salatan and Tapian Timur, are now producing oil from the Eocene, Tarakan Formation. Tanjung did not begin production until the early sixties; cumulative production as of the end of 1979 was 93.3 million barrels (includes the other neighboring fields) and is declining rapidly; original reserves of 134 million barrels are reported. In late 1983, a gas discovery was made at Karendan in a carbonate buildup at the top of the Berai Formation at the north end of the Barito basin where it joins the Kutei basin (fig. 33). In late 1986, an oil discovery, Bagok-1, of some 1,000 BOD was made in the Warukin Formation.

Structure

General Tectonics

In the early Tertiary, the Barito basin region was part of a regionally extensive, stable shelf, which extended over northern Java, the Java Sea, southern Kalimantan (Borneo), and western Sulawesi (Celebes). The shelf was underlain by continental crust, Cretaceous granite-intruded craton in the west, with accreted Cretaceous melange east of a line running northeastward from western Java to the Meratus Mountains and northwards along the present east boundary of the Barito basin (fig. 33). This extensive shelf persisted through Oligocene and early Miocene when it was covered by the thick shelfal limestone (Berai Limestone). As indicated by the stratigraphy, a local Paleogene trough, the Meratus Graben, existed along the present trend of the Meratus Mountains on the eastern boundary of the Barito basin (figs. 33 and 34).

The Barito basin did not form as a separate entity until the end of middle Miocene with the rising of the Meratus Mountains, the subsidence of the Barito River drainage area, and the uplift of the shield area to the west. In the Pliocene-Pleistocene, the Meratus Mountains apparently were thrusted to

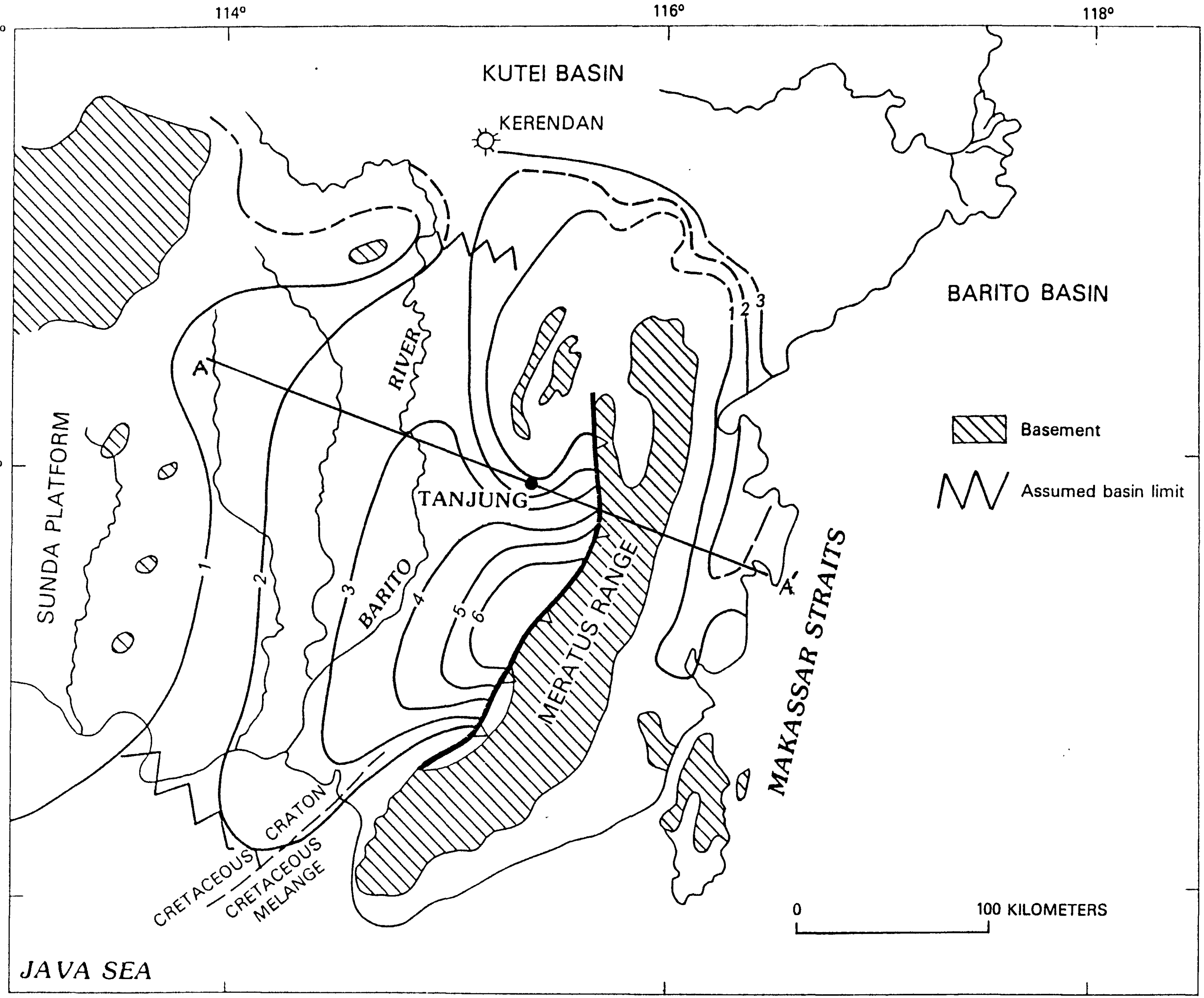


Figure 33.--Structure contour map of Barito basin showing depth to basement. After Hamilton (1979).

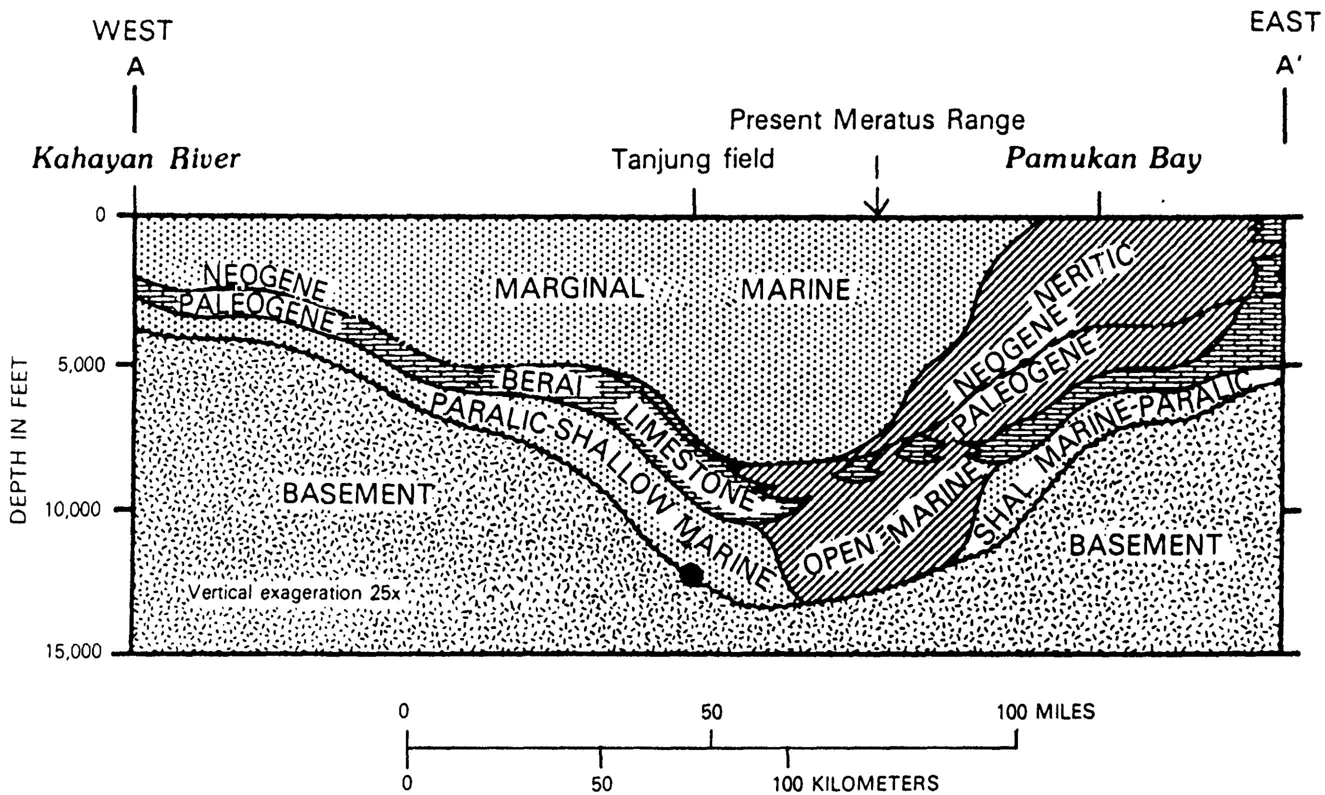


Figure 34.--West-east restored stratigraphic cross-section A-A[1], Barito basin. From Rose and Hartono (1979).

some extent over the Barito basin. It was at this time that the Tanjung and other anticlinal closures of the basin were formed.

Structural Traps

The Tanjung and adjoining closures are north-trending anticlines with steep or thrusted flanks to the west; they are limited to the northeastern part of the basin, an area of some 2.35 million acres. The remaining basin to the west and south, except for some pre-Tertiary topography, appears to be relatively featureless. It is estimated that at the most, the area of trap in this small play area is equivalent to that of two Tanjung fields or 15,000 acres (assuming 50 percent fill).

A second structural trap type in the basin is believed to be drapes of Paleogene sandstones over pre-Tertiary knobs. One unpublished map in the northern part of the basin indicates that these drapes make up about 0.85 percent of the map area; extrapolated over the entire basin, the trap area is about 100,000 acres.

Stratigraphy

As in many other basins of Indonesia, the sediments are Eocene to Recent in age and represent a single general sedimentary cycle. Transgression took place in the Eocene, standstill, or quiescence, in the Oligocene through early Miocene, and regression in the middle Miocene to recent (fig. 35).

The Eocene transgressive formation, the Tanjung Formation, overlies an uneven pre-Tertiary surface. This relatively coarse transgressive marine to deltaic to continental formation has a maximum thickness of 7,000 ft and thins southwestward. It contains the main petroleum reservoirs of the basin. The quiescent Oligocene-early Miocene period is represented by a thick shelfal carbonate with marls and shale, the Berai Formation; at this time the area of the Meratus Range was deep and in that area the formation is represented by marls and shales.

The regressive phase is represented by marine, deltaic and fluvial clastics, primarily the Warukin Formation, which was shed from the rising Meratus Range on the east and the Sunda shield areas on the west. It has some reservoirs; one small probably secondary petroleum accumulation, which may have leaked from the primary Paleogene reservoirs, and a larger accumulation indicated by the 1986 discovery (Bagok-1) of some 1,000 BOD.

Reservoirs

The principal potential reservoirs are:

1. Sandstones within the Eocene transgressive formation

The reservoirs are sandstones in the Tanjung Formation, which is a basal transgressive unit. The reservoirs are a mixture of deltaic, paralic, and neritic, rapidly lensing sandstones. No average pay thicknesses are available from the literature, but the aggregate maximum thickness is estimated to be about 500 ft. Reportedly, there are three principal Eocene sandstones at Tanjung, making some 140 ft in all. An overall average reservoir thickness of 150 ft is estimated for the basin.

2. Oligocene to lower Miocene reefs

In the absence of maps or other concrete information, it is assumed that the reef size and distribution in the Berai Limestone is analogous to that in

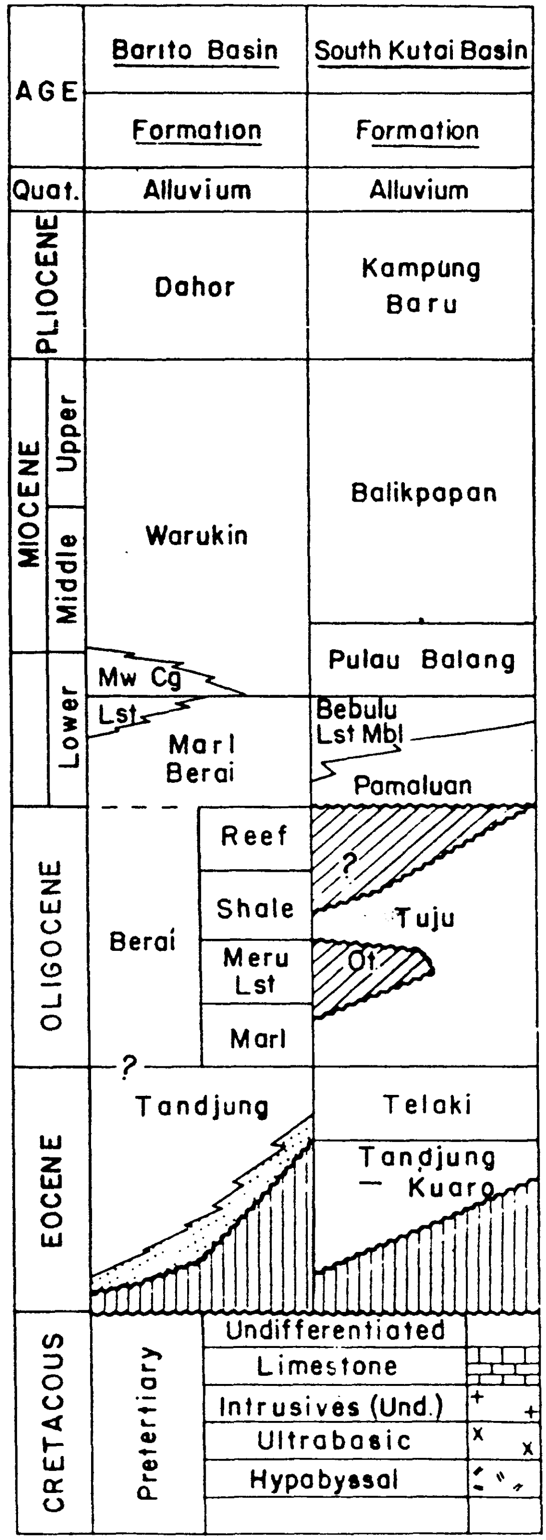


Figure 35.--Stratigraphic chart, Barito basin. From Petroconsultants (1976).

the equivalent carbonate section, that is, the Kujung Formation of the East Java Sea. There, it was estimated that reefal facies make up 30 percent of the play area (12.2 MMA) and that 5 percent of the reefal facies may be trap. Using these analogies, the area of reefal facies in the Barito basin is 3.66 million acres and the untested trap area 0.183 million acres of which very little has been tested.

At Tanta, an adjoining fold to Tanjung, producing zones of 250 ft and at Upper Kapuus, 131 ft, of limestone, "sometimes very porous", have been found in the Berai Formation. In the adjoining East Java Sea, an average thickness of reservoirs was estimated to be 125 ft. It is assumed therefore that average reservoir thickness is around 130 ft.

3. <u>Sandstones within the middle Miocene and younger regressive clastics</u>

These regressive sandstone reservoirs are reportedly of fair quality but generally lack a seal. However, the 1,000 BOD was tested from these reservoirs, Warukin Formation by the Bagok discovery well of 1986. No net reservoir thickness is available, although a gross thickness of 150 ft is reported at Tanjung. The Miocene sandstones are not extensive reservoirs over the basin.

Seals

Hydrocarbon seals appear to be the lower Miocene (Berai) marls and the middle Miocene (Warukin) shales. These argillaceous beds are discontinuous and may not form good seals in the northern Barito basin where the section becomes more sandy.

Source Section

The occurrence of hydrocarbon in Eocene reservoirs plus the maturation depth limits indicate that the probable source section comprises the shales of the Eocene transgressive Tanjung Formation (see below).

Petroleum Generation and Migration

Richness of Source

No specific information is available as to the richness of source, although Siregar and Sunaryo (1980) state "the source rock that provided the oil for the accumulation in the Tanjung reservoirs has been identified within the Tanjung Formation as the shales and marls that were deposited in paralic to neritic environments . . . these source rocks attained a thickness of more than 800 m (2,600 ft)."

Depth and Volume of Source Rock

Based on an average thermal gradient of 1.87°F/100 ft and an average subsidence rate of 236 ft per million years, the top of the thermally mature sediments is at a depth of about 8,000 ft or 2,400 m. This limits the thermally mature rock to mainly the Eocene transgressive beds, and perhaps the lowest part of the carbonate shale sequence, and confirms the observation of

Siregar and Sunaryo (1980) that the Eocene shales of this unit are the principal source rock. The volume of this source is approximately 20,000 mi^3.

Oil versus Gas

The Tanjung field has a small gas cap which occupies about 10 percent of the trap volume. In 1982, gas was found in the wildcat Kerendan 1, at the north edge of the basin, presumably in a reef at the top of the Berai Limestone, indicating the presence of considerable gas in the basin (or the adjoining Kutei basin). Oil is assumed to make up about 50 percent of the basin's oil-gas mix.

Migration Timing versus Trap Formation

The major subsidence began late at the end of the middle Miocene after the deposition of the shelfal carbonate in the lower Miocene. It would appear that in late Miocene time the basin had sufficiently subsided so that the organic shales of the Eocene transgressive series reached thermal maturity and that hydrocarbons began to generate and migrate. At this time the anticlinal structures (e.g., Tanjung) had just started to form, while the carbonate reefs had formed already in early Miocene (e.g., Kerendan Reef), and buried pre-Tertiary topography and lower-Miocene stratigraphic traps would have formed in the Eocene. It would appear that migration began prior to the formation of the anticlines, which may have therefore failed to catch some of the early petroleum. On the other hand, migration was somewhat late for the reefs and drape structures, allowing some reservoir deterioration, especially in the carbonates.

Plays

There are three principal plays in the basin. Details of the plays are discussed in the play analyses.

1. <u>Folded Tertiary Sandstones</u>

The play's objectives are petroleum accumulations in Eocene to Miocene sandstones involved in middle Miocene to Pliocene folds. The transgressive Eocene sandstones are the primary objective, and the Miocene sandstones are considered minor secondary objectives. The area is limited to the 2.35 million acres in the northeastern quarter of the basin.

2. <u>Oligocene-Miocene Reefs</u>

Petroleum accumulations may be in reefs and banks associated with the Oligocene-lower Miocene carbonate formation (i.e., the Berai Formation). Reefal facies have been identified in wildcats, particularly Barito-1, drilled in the southwestern part of the basin, in the far northern part of the basin on the ridge separating the Barito and Kutei basins, at Tanjung field where a thick section of "reefal facies" is reported, and in the outcrops on the western side of the Meratus Mountains. The play extends over the entire basin (12.2 million acres), but by analogy to the adjoining East Java Sea reefs, the reefal facies makes up 30 percent of the carbonate indicating a more favorable area of approximately 3.66 million acres.

3. <u>Drape Sandstones</u>

Petroleum accumulations are possibly in Paleogene sands draped over basement knobs in the shelfal area. The play would extend over the entire basin 12.2 million acres.

Kutei Basin

Location and Size

The Kutei basin is in the northern part of the southeast coast of Kalimantan (Borneo). It includes the Straits of Makassar and extends inland some 170 miles to the northwest (figs. 1 and 36). It has an area 50,000 mi^2 on land and extends offshore to a water depth of 3,300 ft (1,000 m) (78,000 mi^2 including the deep water of of the Makassar Strait). The volume of sediments is about 210,000 mi^3; including the deep water (>3,300 ft) of the Straits of Makassar, the basin volume would be 310,000 mi^3.

Petroleum Exploration and Production History

Oil was first discovered in 1897 in the Sanga Sanga oil field (fig. 37). Other discoveries were made near Balikpapan in 1898, Semberah in 1906, and Samboja in 1908. These were relatively shallow fields producing from upper Miocene-Pliocene sandstones and were discovered by surface geology. The next major discovery was not until 1970 when the offshore Attaka oil field was discovered. This was followed shortly by the major offshore discoveries of Badak in 1971, Bakapai in 1972, Handil in 1974, and other smaller oil fields with a combined 1983 oil (and condensate) reserves of 2.56 billion barrels of oil. During the 1970s, gas and condensate were also discovered in large quantities, especially at Badak and in on-trend Nilam and Tambora fields to the south, and Bekapai further south. The Tanu field of the Attaka-Bekapai trend (fig. 37) was established in the early 1980s. Gas production sufficient to require a four-train LNG gas processing plant, indicating minimum original reserves of some 10 Tcf of gas has been established in the Kutei basin (10.374 Tcf indicated by Hariadi, 1980; Patmosukismo, 1980). Probably at least 15 Tcf of gas reserves have been proven by this time.

Discoveries to date have been concentrated around the Mahakam delta area. Large parts of the inland basin, though probably less prospective, are very sparsely explored. The modern discovery rate has been about 33 percent.

Structure

General Tectonics

At the beginning of the Tertiary, the whole region, including the southern half of Kalimantan (Borneo), the eastern Java Sea, most of Java, the Makassar Straits, and western Sulawesi (Celebes) was an extensive continental shelf. The shelf is granite-intruded continental crust in the west and accreted melange crust to the east, including most of the Kutei basin, the Straits of Makassar, western Sulesi, and the eastern Java Sea. Rifting of the accreted melange shelf in the Kutei basin area apparently began in early Paleogene when the initial Makassar Straits as well as the Kutei basin and the adjoining Meratus graben were formed.

The Kutei basin is bounded to the south and north by two significant but buried transverse fault zones, which were most active in the Paleogene and had significant dip as well as strike-slip movements (figs. 36 and 38). The

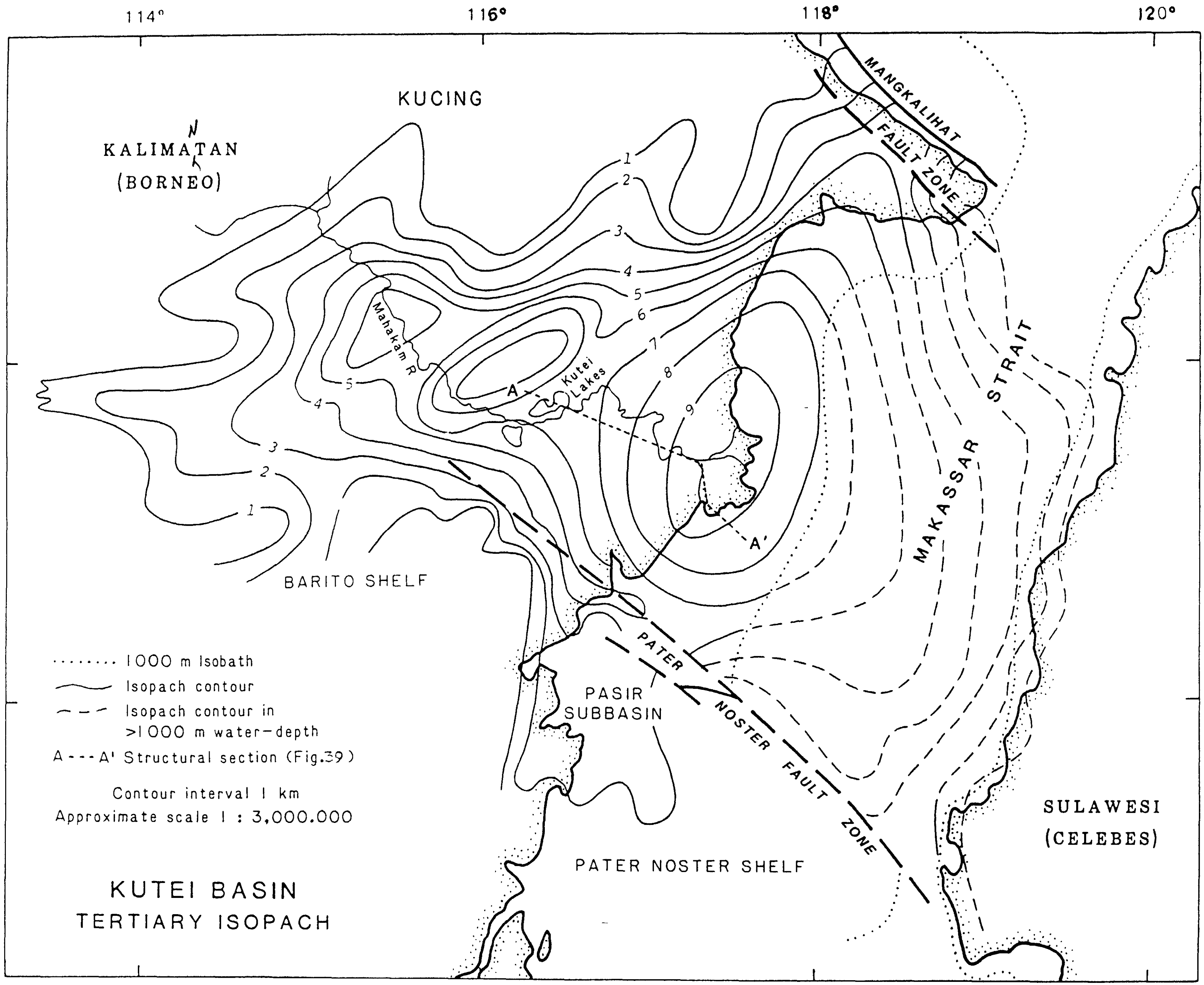


Figure 36.--Structure contour map, Kutei basin, showing depth to basement. After Hamilton (1979).

KUTEI BASIN
FIELD LOCATION MAP

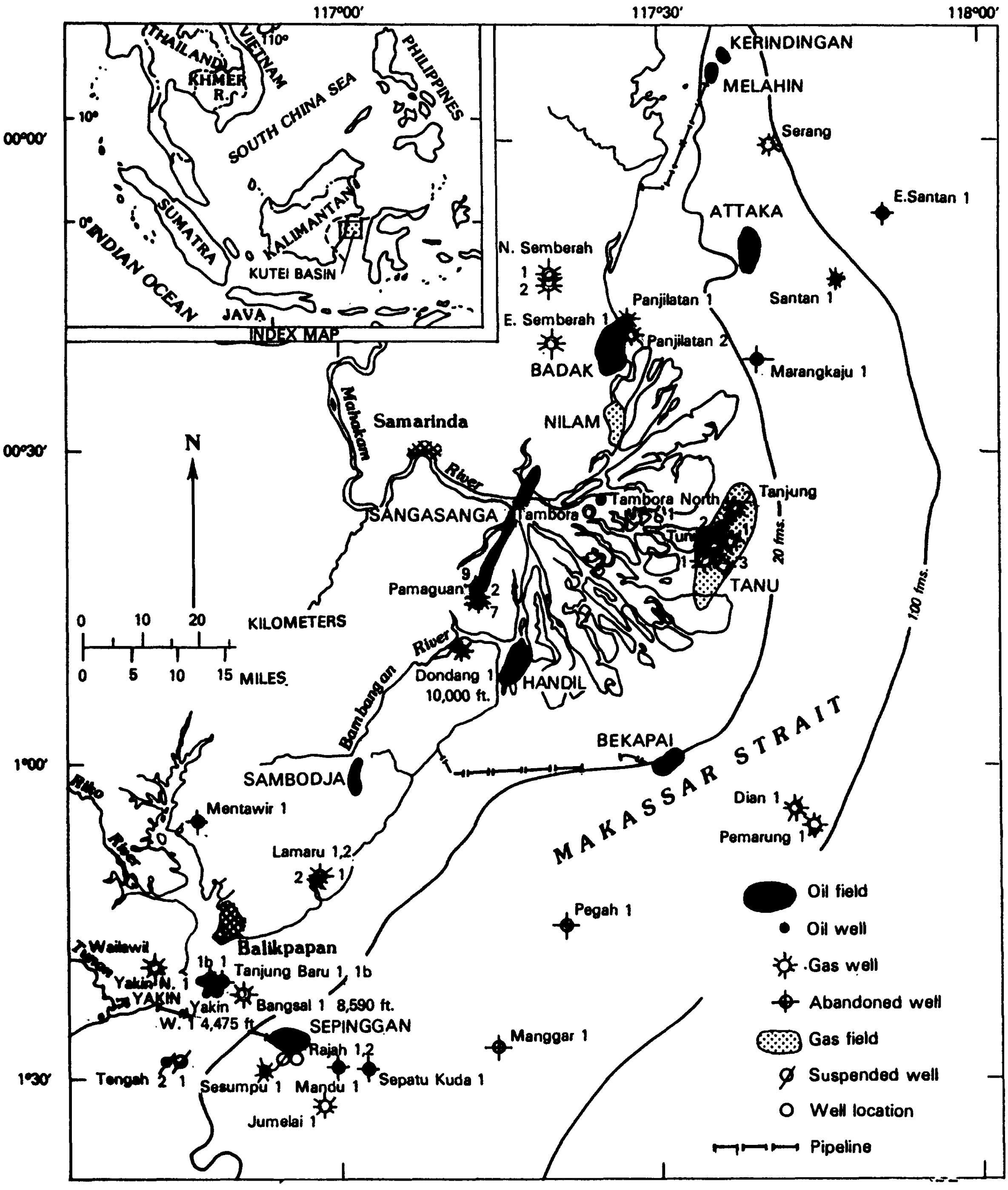


Figure 37.--Index map of Kutei basin showing field locations and significant wildcats.

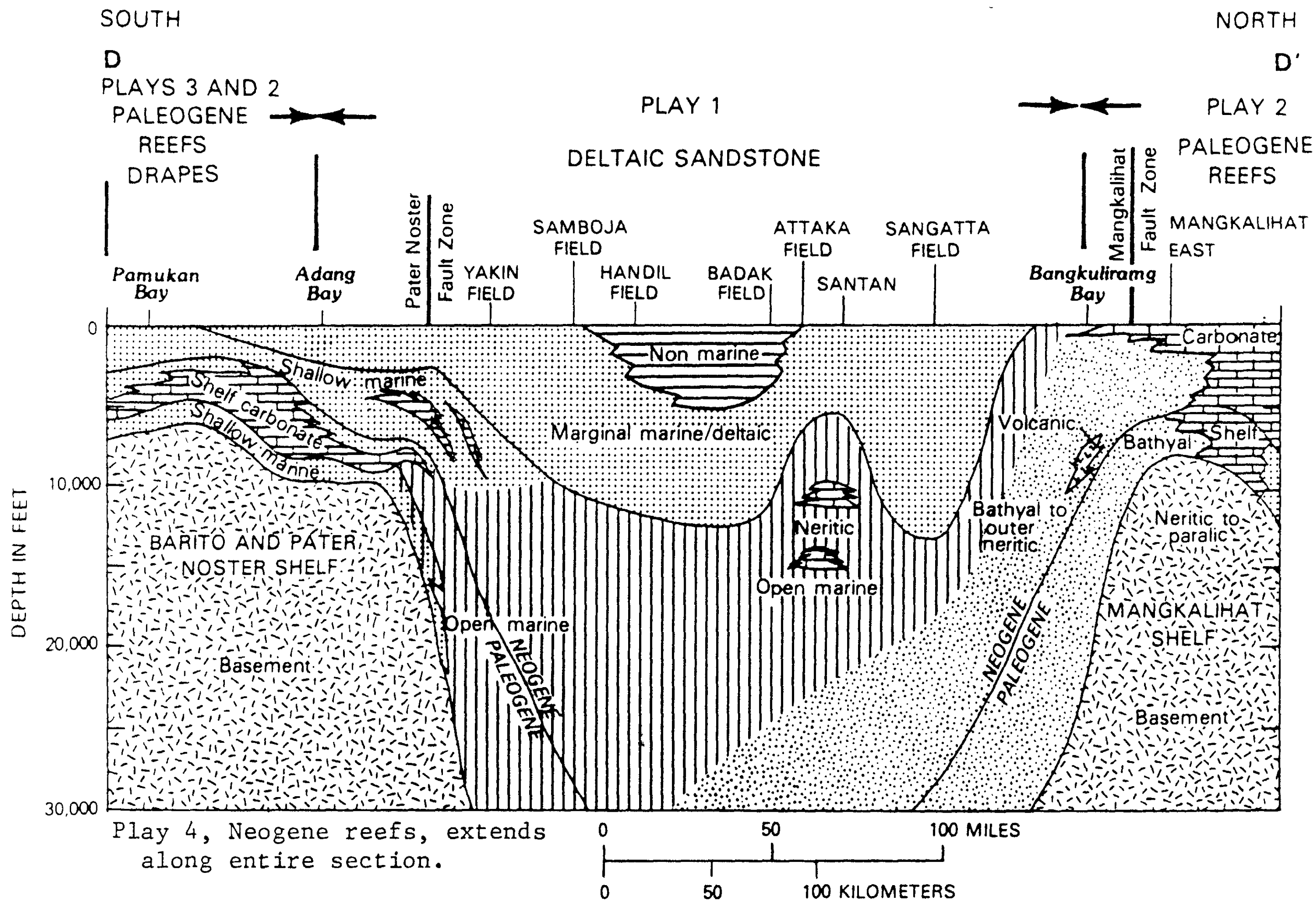


Figure 38.--South-north restored stratigraphic section, D-D[1], Kutei basin. From Rose and Hartono (1978). Location figure 41.

Pater Noster fault, which has a large down-to-the-north component, separates the Kutei basin from the Pater Noster and Barito shelves to the south. The Mangkalihat fault zone similarily forms the north boundary, having a strong down-to-the-south component. Figure 38 shows the approximate position of these features and their effect on the Kutei basin stratigraphy.

Subsidence between these transverse zones continued through the late Paleogene and Neogene with thick sediments, largely derived from the west, prograding eastward. These strata were folded into a number of north to northeast-trending anticlines, which show crestal thinning of late Miocene and younger beds. This indicates that compression is contemporaneous with uplift and folding of the Meratus Range in later Miocene time. These events appear to coincide with the Miocene to recent westward movement and subduction of the Pacific Plate under Sulawesi.

Although these folds apparently were initiated by compression, they are strongly affected by the great thickness of rather incompetent, shale-dominated sedimentary fill. A central north-trending zone of folds or anticlinorium extends in width approximately from the shore line inland to the Kutei Lakes or northwest swing of the Mahakam River (figs. 36 and 39). The folds are characterized by steeply dipping axial beds, sinuous axes, and other aspects of diapirism. To the east of the anticlinorium (i.e., offshore), the folds become less steep but are also affected by diapirism. To the west, i.e. the inner Kutei, the area is low and the folds are rather abruptly subdued, probably reflecting thinner sediments over a shelf (fig. 39). Overmature sediments within drilling depths indicate uplift, probably in the Neogene.

Of special interest is the apparent lack of large scale growth faulting, such as occurs in the Mississippi and Niger deltas.

Subsidence appears to have accelerated during the Pliocene-Pleistocene, the Makassar Strait area dropping so that young neritic sediments are in 7,500 ft of water. Subsidence evidently took place between north-trending fault zones, which occur approximately along the 1,000 m isobaths (excepting the Mahakam delta area) on either side of the deep-water area of the Makassar Strait.

Structural Traps

For assessment purposes, the north-northeast-trending structure of the Kutei basin is divided into three zones, which conform approximately to separate plays: the inner Kutei of draped or folded Paleogene sandstones, the foldbelt of Miocene-Pliocene deltaic sandstones, and the outer Kutei basin, approximately the Miocene-Pliocene reefs and deep water indicated in figures 39, 40, and 41.

Inner Kutei. Most of the inner Kutei (13 million acres) is a low marshy ground with few outcrops and is an area of poor seismic results. Even so, on the basis of the seismic results, plus gravity survey, some broad, poorly defined (largely untested) anomalies or leads totalling some 280,000 acres have been mapped (unpublished). It is estimated that after final mapping about two-thirds of the anomalies, or 187,000 acres, may be drillable trap area.

Fold Belt. The play area (17.5 million acres) is traversed by a large number of parallel northeast-trending anticlinal folds (fig. 41). Many of the folds have been tested, but from the unpublished lead map, untested prospects

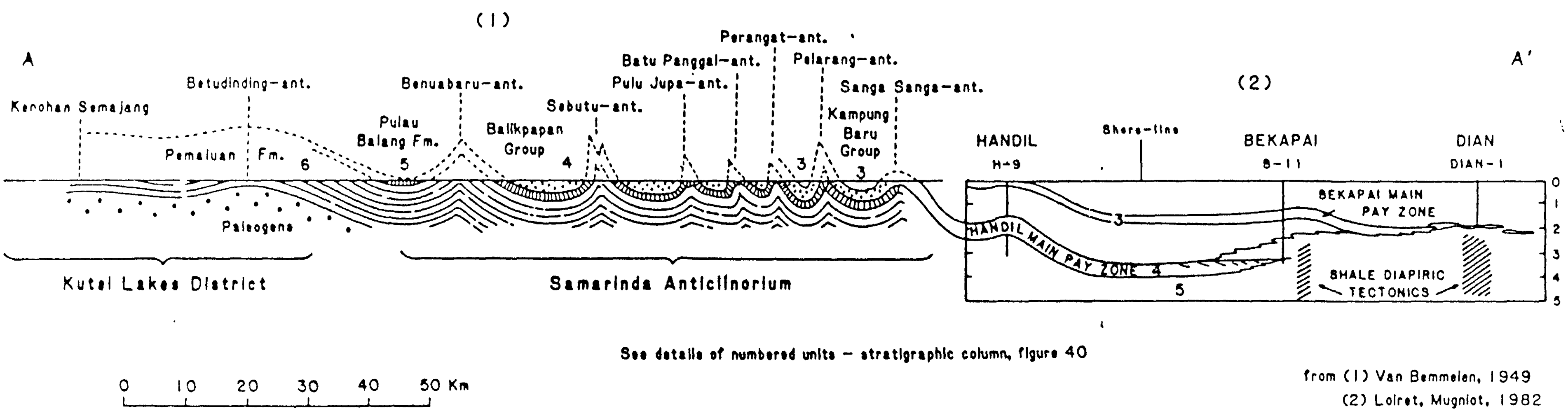


Figure 39.--West-east composite geologic cross-section A-A[1], Kutei basin.

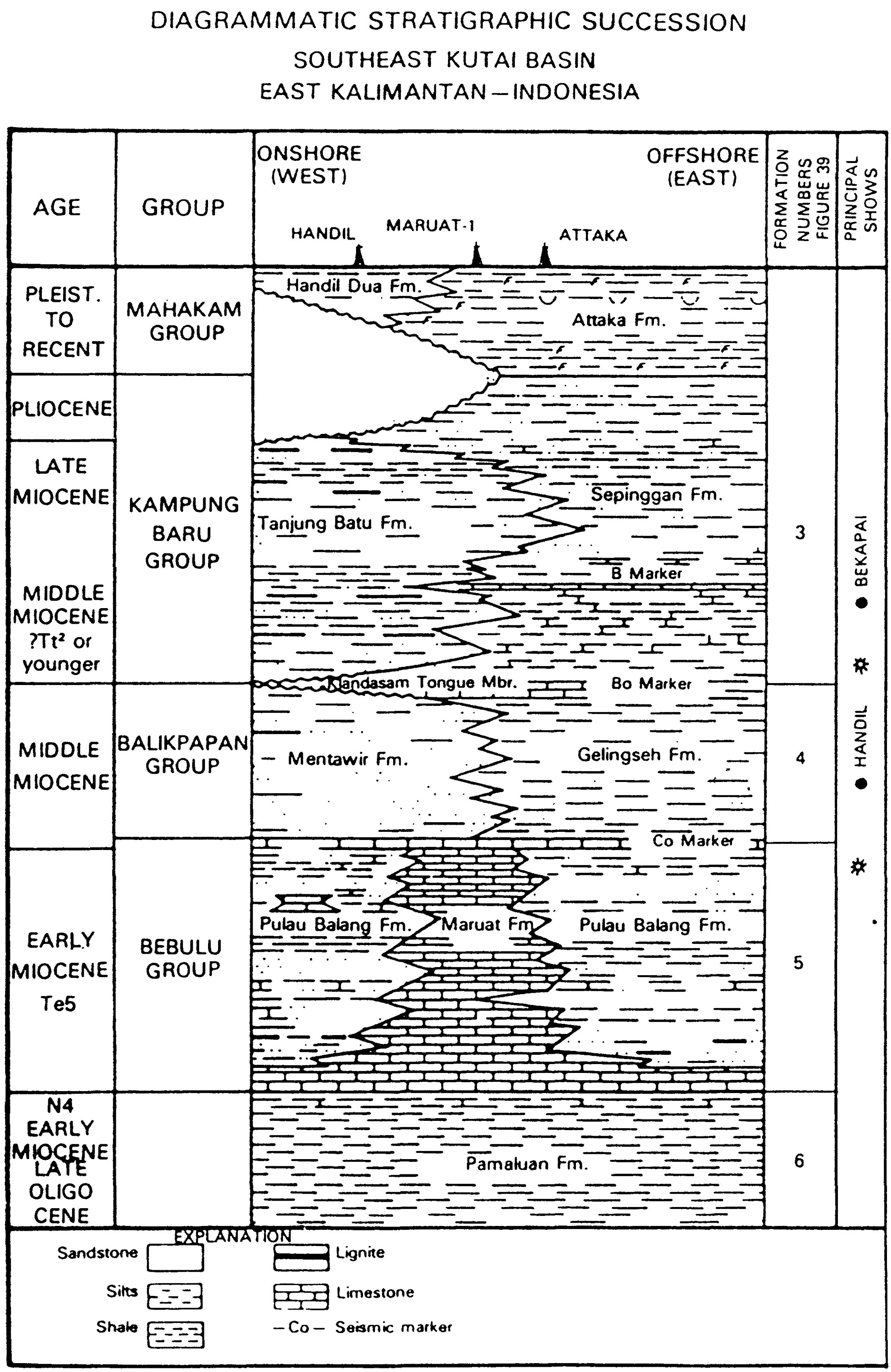


Figure 40.--Diagrammatic stratigraphic chart, southeast Kutei basin. Modified from Marks et al. (1982).

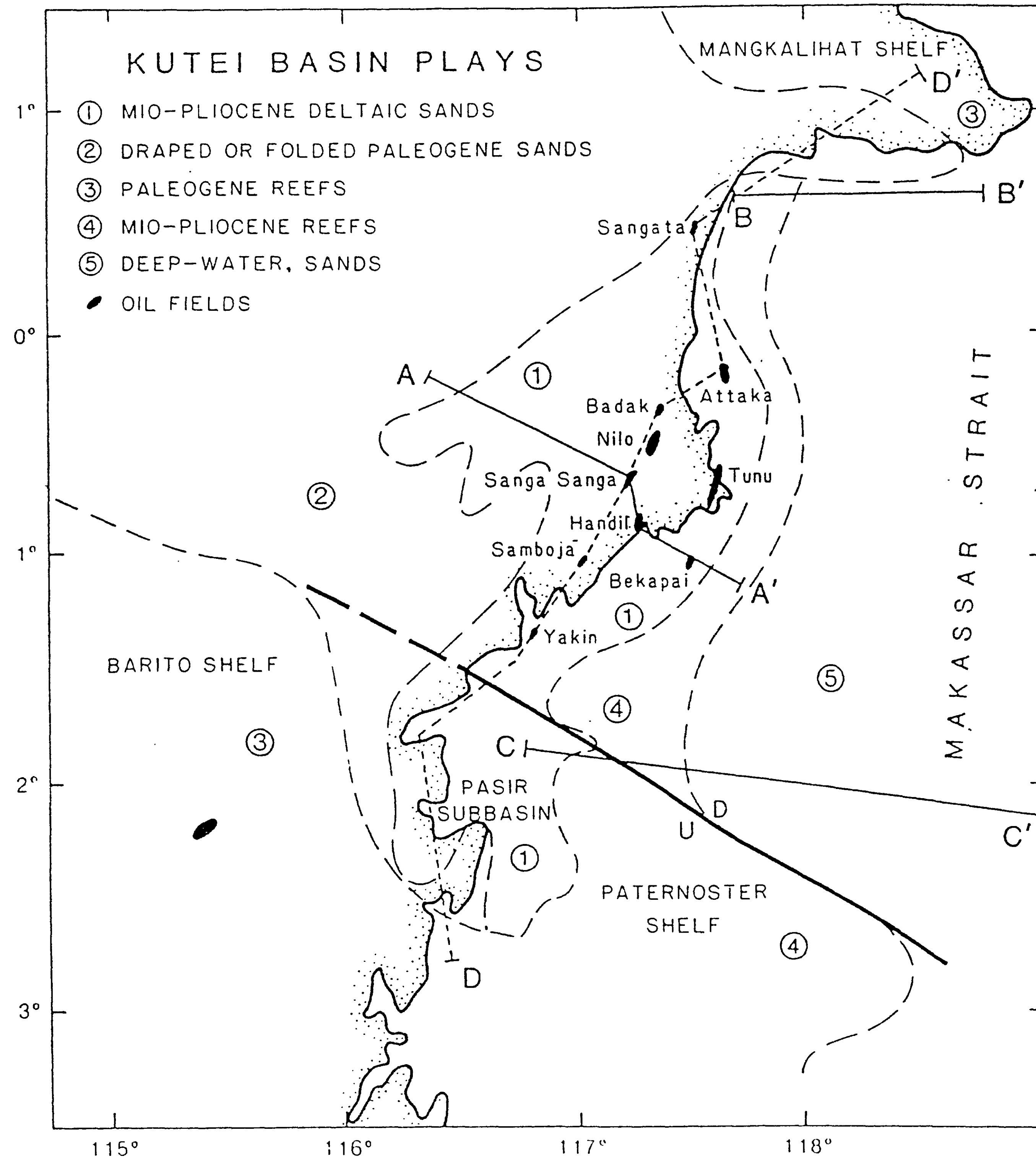


Figure 41.--Map showing distribution of plays, Kutei basin.

and leads are estimated to have a total area of about 400,000 acres, of which, when finally mapped, perhaps two-thirds, or about 270,000, acres may be established as potential traps.

Deep Water. Seismic survey shows the existence of traps in the deeper waters of the Makassar Straits (11.5 million acres). They appear to be largely older drapes and more recent structure traps associated with the faulting along the continental shelf. Some of the traps are very large, up to 50,000 acres in area. On the basis of a partial, unpublished map, the area of prospects and leads is estimated to make up 8 percent of the play area, but possibly only one-half the area or 4 percent would become established closures. No tests have been drilled.

Stratigraphy

The rocks of the Kutei basin range in age from middle Eocene to recent. Essentially they represent a transgressive facies until early Oligocene, a quiescent, standstill facies between early Oligocene and early Miocene, and a regressive facies from early Miocene to Recent. Figure 40 shows the standstill and regressive part of the stratigraphic column.

The transgressive facies is relatively thin and very widespread, extending beyond the Kutei basin in a regional sheet covering all of southeastern Kalimantan (Borneo), the Makassar Straits, western Sulawesi (Celebes), and the eastern Java Sea area. Where seen around the perimeter of the Kutei basin, the transgressive series is generally coarse clastics. In the upper Mahakam River, middle Eocene coarse sandstones grade upward into shales. These beds may be considered potential hydrocarbon reservoirs around the edges of the Kutei basin. Rifting began during this generally transgressive period, and finer grained deep-water Paleogene sediments may be expected in the graben and deeper basinal areas. Local Paleogene deltas, especially from the west and southwestern side of the Kutei basin, built up during this early period of basin formation.

In the Oligocene to early Miocene, most of Indonesia was in a quiescent period with extensive formation of carbonate and shales. Carbonates were formed on the Barito and Pater Noster shelves to the south and the Mangkalihat shelf to the north, while relatively thick bathyal to outer neritic shales and marls were being deposited in the major and central area of the Kutei basin (fig. 38).

Regression began in the late Paleogene with uplift of the basin rim, particularly on the north and west, the so-called Kucing High (area between the Kutei and Sarawak basins). Lower and middle Miocene deltaic and continental deposits, with some volcanics, covered the western Kutei basin. Delta systems prograded southeastwards filling the Kutei basin so that the late Miocene shoreline was somewhat seaward of where it is now. Pliocene deposition is well beyond the present shoreline and covers the continental shelf and beyond. Adding to the southeastern prograding sediments were upper Miocene sediments derived from the rising Meratus Range, filling the Pasir subbasin (figs. 36 and 41). Offshore of the delta and along the continental shelf edge, a line of offshore Pliocene-Pleistocene reefs formed (Play 4, fig. 41).

Reservoirs

In summary, the principal reservoirs of the Kutei basin are:

1. Paleogene transgressive clastics, i.e. basal, and perhaps locally, deltaic sandstones. These would be more abundant, and within drilling depth, on the basin flanks and on the inner Kutei shelf (Play 2, fig. 41). The associated traps would be drapes over basement highs. Although there are oil seeps, no discovery has been made in these reservoirs. No reservoir data have been released, but those who have access to the data estimate an average net reservoir thickness of 170 ft for wells in this play. Good Eocene sandstone reservoirs of unreported thickness are believed to have been encountered on the south flank of the basin. The Tanjung field, which is only separated from this play area by the later-forming, Miocene Meratus Mountain structure, has an estimated net thickness of 140 ft of Eocene sandstones. On this basis, a 140-foot average effective pay is assumed for the play.

2. Upper Oligocene-lower Miocene carbonates. Reefs are developed on the north and south flanks, i.e. on the edges of the Pater Noster and Barito shelves in the south (a significant 1981 gas discovery was made in this play) and the Mangkalihat shelf to the north (Play 3, fig. 41). Unpublished maps of a similar if not equivalent carbonate facies in the shelfal East Java Sea indicate that about 5 percent of that area is in a reefal trap. Most of the play in the Kutei basin also appears to be in a reefal facies, but the reefs seem less developed than in the east Java Sea area, perhaps only half as much or about 2.5 percent of the play area (130,000 acres). A negligible amount of trap appears to be tested. In the absence of any data, the average thickness of carbonate pay is assumed to be approximately that of the Berai reefs of the east Java Sea, or about 200 ft.

3. Miocene-Pliocene folded deltaic sandstones of the ancestral Mahakam delta. These contain all of the petroleum production of the Kutei basin (Play 1, fig. 41). The reservoir sandstones are distributary channel fills, offshore bars, delta plains, and delta front (fig. 42), all of which are limited in extent and vary considerably in thickness. The average cumulative thickness of the hydrocarbon column at Handil appears to be about 624 ft, 164 ft of oil and 460 ft of gas on the crest (Magmer and Ben, 1975). At Badak the discovery well penetrated more than 1,000 ft of "net gas sandstone "and about 120 ft of oil sandstone, or 1,190 ft in all. This averages to about 900 ft of net sandstone, but the two fields appear to have the best and thickest reservoirs, as they are probably situated optimally on the delta front where maximum sand reservoir thickness occurs. An overall estimate for the average reservoir thickness of the play area, which would include much delta plain area, is around 300 ft. Oil is recovered at various depths between 1,500 and 10,300 ft from reservoirs where porosity ranges from 14 to 35 percent, but probably averages around 25 percent. Water saturation is high, ranging from 20 to 50 percent at Bekapai (Materel and others, 1976), but probably averages 35 percent.

4. Miocene-Pliocene reefs. Miocene-Pliocene reefs are developed around the outer perimeter of the Mahakam delta and along the edge of the Makassar Strait continental shelf (Play 4, fig. 41 and fig. 46). At least two gas discoveries have been reported in these reefs. From unpublished maps, the area of untested reefal traps is estimated to be about 100,000 acres, or 7 percent of the play area. Observations from some well logs indicate that these carbonate

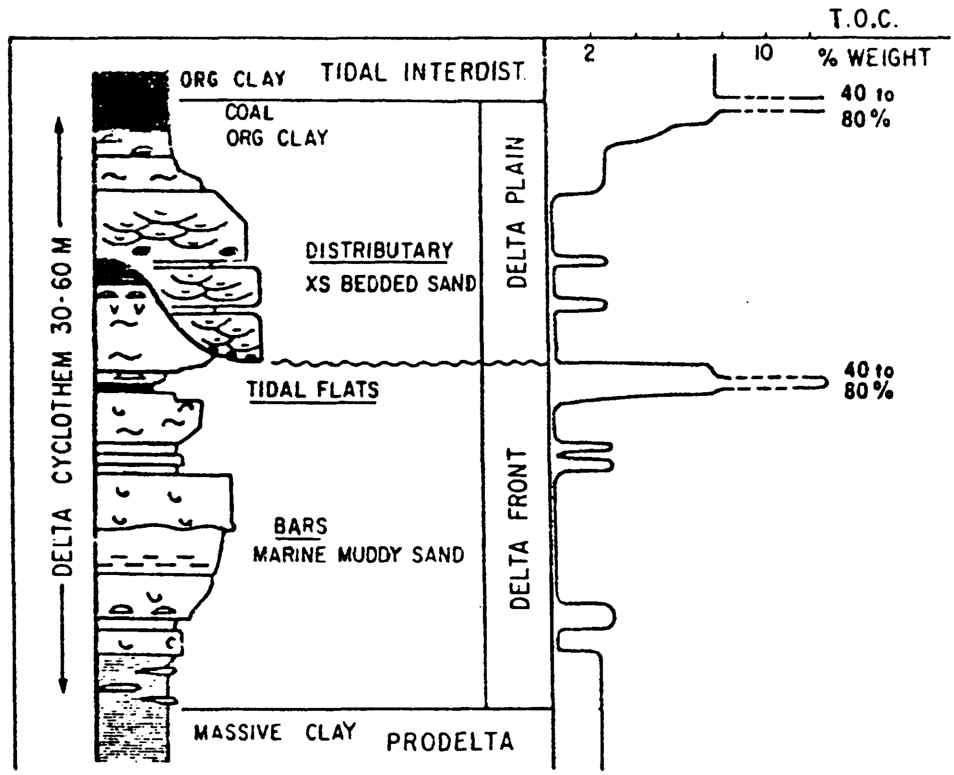


Figure 42.--Section showing organic matter in a sedimentary cyclothem, Kutei basin. After Oudin and Picard (1982).

reservoirs may have an effective net pay of about 110 ft. No reservoir parameters are available.

5. Deep-water sandstones. No reservoir data are available, but it appears that reservoirs may be relatively thin inasmuch as the ancestral Mahakan delta sandstones do not appear to extend into the play area. It appears that for some part of the Tertiary, subsidence was matched by infill ensuring a continued neritic reservoir environment, but in other areas subsidence was more rapid and only turbidite reservoirs may be expected. It is estimated that there may be an average of at least 50 ft of reservoir.

Seals

As the Kutei basin is predominantly shale, seals should be generally good. The 100 percent petroleum fill of the Handil field indicates that seal may not be a problem. Possibly a seal problem exists on the edges of the basin, where carbonates have continued through the Neogene (Mankahilat), or where generally more permeable shallow marine sediments exist.

Source Section

The depth to the thermally mature sediments appears to average about 11,500 ft in the central part of the basin (see below). This places the oil window largely below, but including, the lower part of the deltaic beds. It also includes a good part of the Paleogene section. On the flanks of the basin, the mature source rocks are shallower, about 9,500 ft, and include marine (middle shelf and open marine) beds equivalent to the Miocene deltaic sediments. In the western or inner Kutei basin, overmature source rock may be very shallow, even at the surface.

Petroleum Generation and Migration

Richness of Source

The Miocene deltaic "organic" shales have an organic content of 7 to 8 percent and regular interbedded shales about 2.5 percent. The prodelta massive clays have an average organic content of 2.2 percent. The average organic carbon throughout the whole deltaic column is 3.5 percent (Oudin and Picard, 1982) (fig. 42). No data are available concerning the organic richness of the Paleogene beds, but gas and oil seeps indicate these rocks may also be of source richness. The high paraffin content of the oil suggests a terrestrial source, indicating the deltaic beds are an important part of the source.

Depth and Volume of Mature Sediments

The average thermal gradient is moderate, about 1.6°F/100 ft; given the rate of subsidence in the outer Kutei basin (1,000 ft per million years), this places the top of the mature zone, on an average, at about 11,500 ft (3,500 m). This depth is confirmed with the few vitrinite reflectance data available, which puts the variable top of the mature zone between 9,500 and 11,500 ft if the R_o value of .7 percent is considered the top, or at 7,500 to 10,800 ft if the R_o value of .6 percent is considered the top of the mature zone (Oudin and Picard, 1982). Apparently, this surface, the top of the mature zone, is higher on structural highs. The top of the overmature zone, on the average, appears to be about 17,000 ft in the outer Kutei basin. In the inner Kutei basin recent drilling has encountered overmature strata within drilling depth, indicating that the inner or western part of the basin was hotter, or more probably, uplifted from greater depths in the Neogene. On this basis, about 100,000 mi^3 of sediment have been thermally matured or overmatured.

The fact that at least one trap, Handil, is apparently filled to the spill point indicates adequate source is present in the basin. Lesser amounts of fill, e.g., 37 percent at Attaka and 3.8 percent at Bekapai, may be attributed to leakage. The average fill is estimated at 40 percent.

Oil versus Gas

The relative quantity and distribution of oil versus gas in the eastern or outer Kutei basin appears to be controlled by the effects of overpressured shales. The bulk of sediments within the deep outer Kutei basin are massive shales, which are overpressured below a depth which varies but averages about 10,000 ft. When these overpressured shales become thermally mature and begin to generate and migrate petroleum, theoretically only the smaller petroleum molecules, C_1-C_6 (i.e. gas), can pass through the overpressured shales by molecular diffusion (Leythaeuser and others, 1982). The larger molecules pass very slowly or not at all through the overpressured shales and remain until continued subsidence and consequent overmaturation cause them to crack to methane.

The effect of the distribution of overpressured shale in respect to source rock on gas versus oil accumulation is illustrated in figure 43. Where part of the mature zone (top of zone taken to be at the 0.6 percent vitrinite reflectance level) is above the overpressure zone (top at the "transition zone"), the migration of larger petroleum molecules is less inhibited, and oil finds its way from the normally pressured mature source rocks above the overpressured zone into reservoirs. However, where the mature zone is below or at the same depth as the top of the overpressured shale, only gas can migrate. As shown in figure 43, Handil field (largely an oil producer) is underlain by a 1,500-ft (500 M) section of normally pressured mature source rock, while Badak field (largely a gas producer) is underlain largely by overpressured source rock.

It appears that most of the higher structures, that is those having more mature rocks above the overpressure level and therefore more oil-prone, have been tested. For the last 7 or 8 years, exploration for gas has been actively pursued with many deep 12,000 to 14,000-foot wildcats on the Badak-Nilo-Handil as well as the Bekapai-Tunu-Attaka trend. It is estimated that gas is the dominant undiscovered petroleum fraction of the outer Kutei basin and that future petroleum production will be only 20 percent or less of oil. The inner Kutei basin has overmature shale within drilling depth and is therefore gas prone, the larger oil and gas molecules having been cracked to methane. The gas-oil mix in this region is estimated to contain only 10 percent oil.

Migration Timing Versus Trap Formation

Assuming the average thermal gradient (of around 1.6°F/100 ft) and the rate of subsidence of the depocenter (1,000 ft per million years) remained approximately constant during the Tertiary in the eastern or outer Kutei basin, generation and migration would have begun when the source rock reached

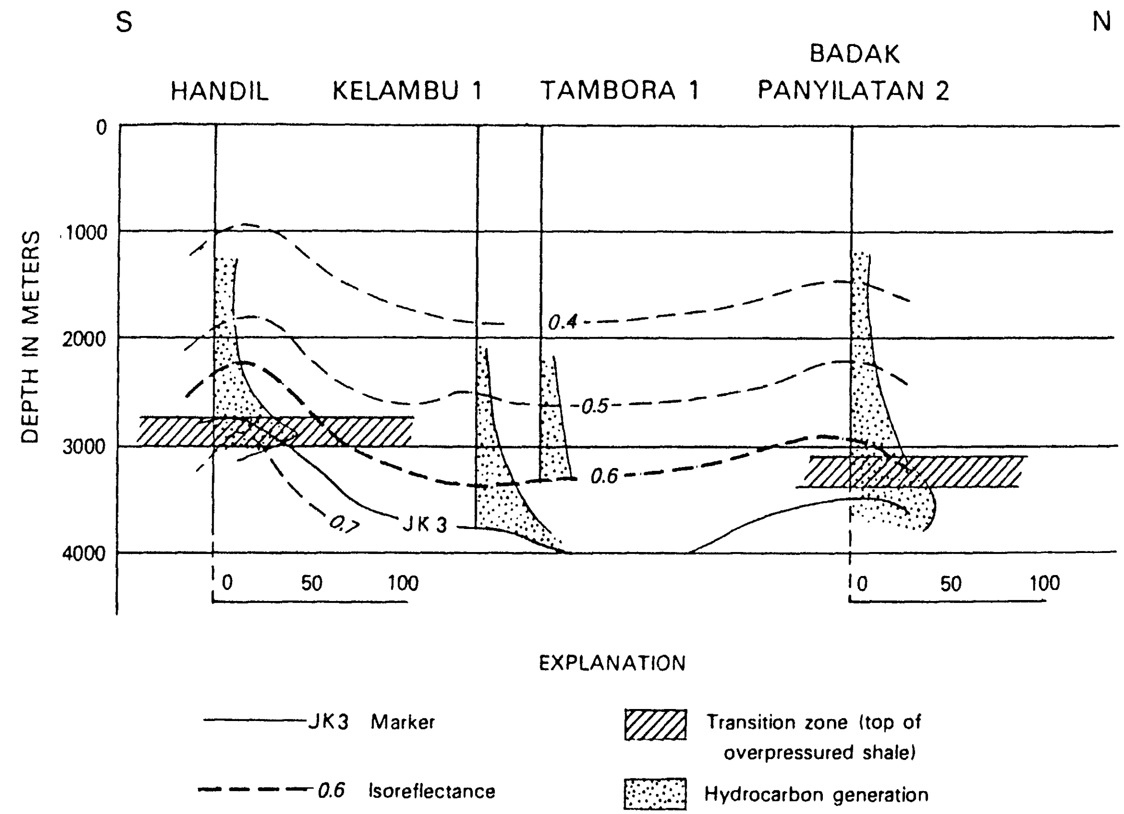


Figure 43.--South-north section showing spatial relations of thermal maturity to overpressured shale, Kutei basin. After Oudin and Picard (1982).

a depth of around 11,000 ft. Geophysical evidence suggests the basement is at least 30,000 ft deep, indicating that the deepest (i.e., just above basement) possible oil source beds reached a depth for oil generation (i.e. 11,000 ft) some 19 million years ago in early Miocene time. This petroleum would be trapped principally in the Paleogene drapes and reefs (Plays 2 and 3), since the main reservoirs of the basin (i.e., the middle and upper Miocene deltaic sandstones) were yet to be deposited and covered.

As the outer Kutei basin continued to subside, progressively younger beds passed through the oil window whose top, presently at least, is at a depth of about 11,000 ft. This depth excludes much of the deltaic shales which are too shallow to be sufficiently heated and puts the source of the oil presently being generated largely in the lower delta and prodelta sequence. The timing appears favorable, since oil was already migrating when young deltaic sandstones became available in traps (i.e., folds, which formed in the late Miocene reaching maximum effectiveness in the Pliocene-Pleistocene); however some early Miocene-generated petroleum probably escaped. The deeper offshore Pliocene-Pleistocene shale-enclosed reefs should also be available for petroleum (perhaps the gas fraction).

On the flanks of the basin, subsidence is slower and the sedimentary cover, particularly the Neogene, thinner; some of the shelfal area may not be deep enough to allow a significant portion of the sedimentary section to thermally mature, but a vast sufficiently deep area remains. The traps in the shelfal area would likely be drapes over basement highs and, therefore, available to entrap early petroleum as it migrates with minimum loss or reservoir deterioration. Shelf carbonates of both the south and north flanks developed in the Paleogene. The shelf on which the reefs were built may never have been deep enough to allow a sufficiently thick thermally mature section, but those reefs along the rather sharp shelf edge would be in position to receive hydrocarbons migrating from the deeper basinal area (fig. 38). The western, or inner Kutei basin, which has overmature sediments within drilling depths, may have had oil accumulations which have since been degenerated largely to gas and shallower accumulations eroded away by uplift on the order of 15,000 ft.

Plays

There are a number of plays in this large complicated basin; the major ones are: 1) Folded Neogene deltaic sandstones, 2) Paleogene drapes, 3) Paleogene reefs along the south and north perimeters, 4) Neogene reefs along the Miocene-Pliocene outer eastern shelf edges, and 5) deep-water sandstones (fig. 41). Only the Miocene-Pliocene folds have produced petroleum, although shows have been encountered in the other plays. Details of the plays are outlined in the play analyses.

1. Neogene Delta Folds

The objective of the play is petroleum accumulations in folded Miocene and Pliocene deltaic sandstones. All the petroleum production of the basin is from these sandstones, which are trapped in two largely offshore anticlinal trends (figs. 39 and 44) and an onshore trend, the Samarinda anticlinorium (fig. 39). The delta deposits which make up the play are shown in figure 45. They include the Mahakam ancestral delta area. The play area is some 27,300 mi^2 or 17.5 million acres (fig. 41).

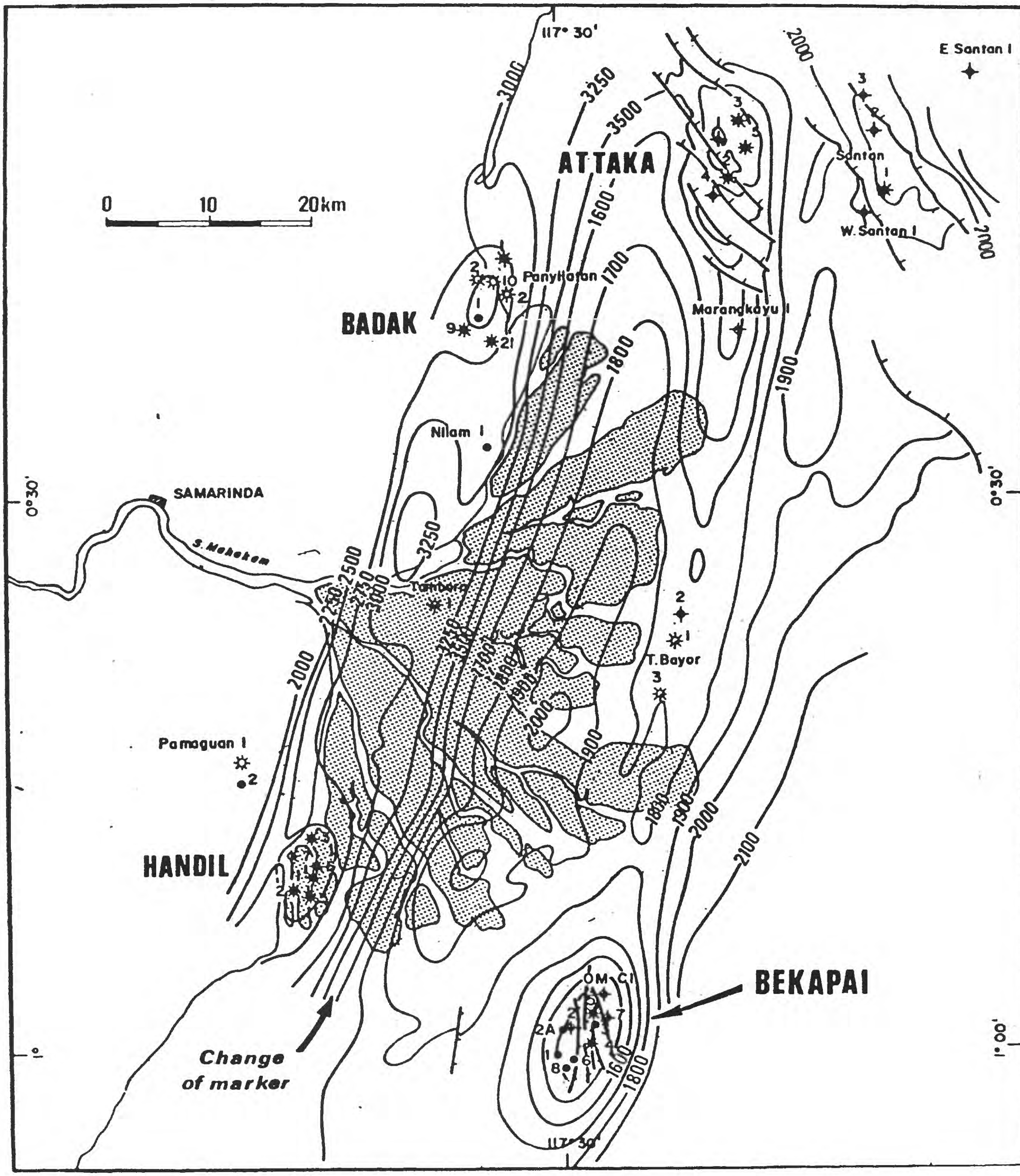


Figure 44.--Structural contour map showing deltaic sandstone play structure based on regional seismic mapping, Kutei basin. After Matharel, Klein, and Oki (1976).

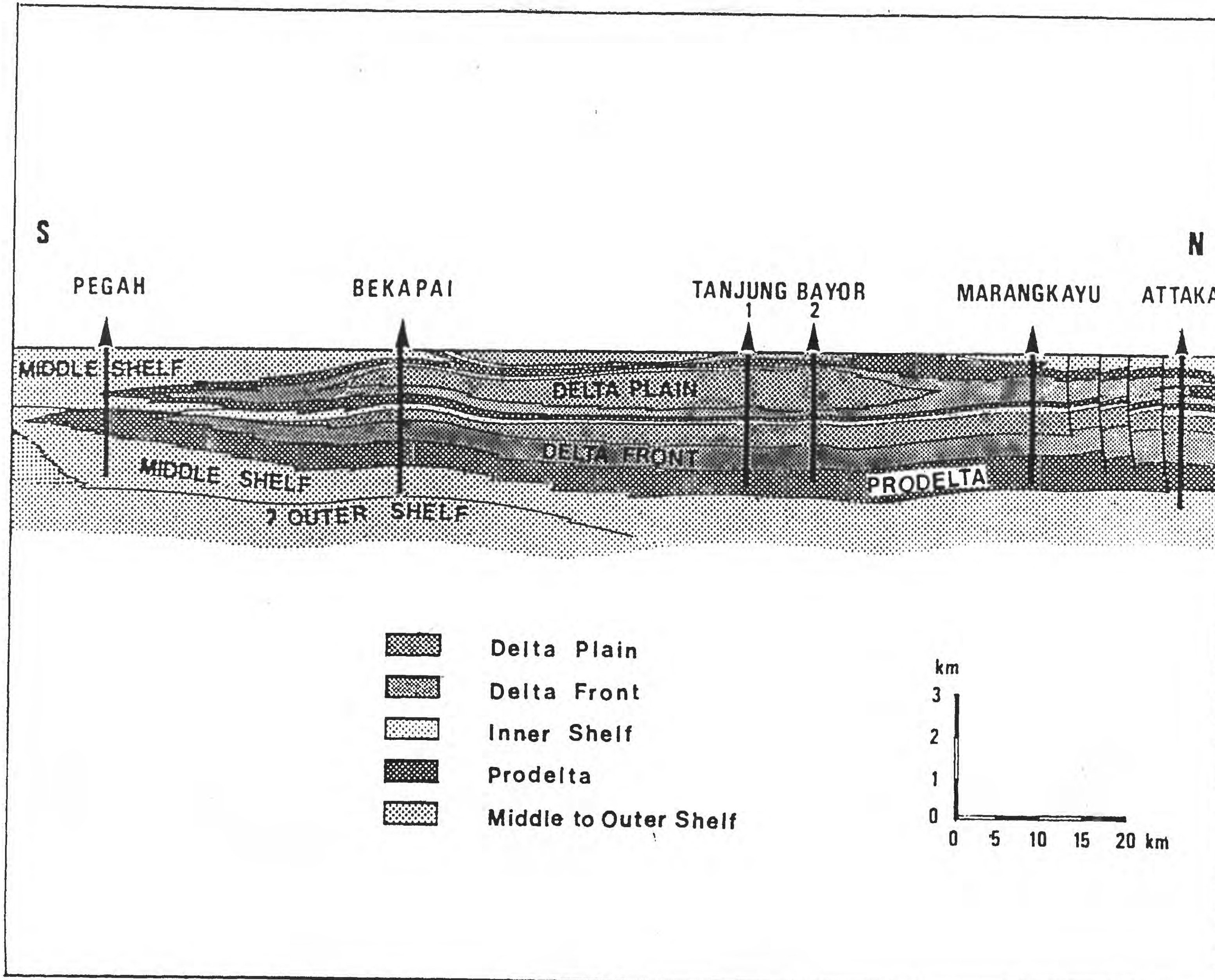


Figure 45.--South-north stratigraphic section along Bekapai-Attaka trend showing delta facies, Kutei basin. After Matharel, Klein and Oki (1976).

2. Paleogene Drape

The objective of the play is petroleum accumulations in Paleogene sandtones draped over basement topographic highs, but includes accumulation of the already reservoired petroleum redistributed by later, renewed fault block movement. This play is largely in the western (Paleogene) shelfal area, or Inner Kutei, of the Kutei basin, i.e., the area including and west of the Kutei Lakes (figs. 36, 39, Play 2 of fig. 41), but also includes the north and particularly the south flank (figs. 38 and 41). This Paleogene shelf has an area approximately 20,240 mi^2 or 13.0 million acres.

3. Late Oligocene-Early Miocene Reefs

The objective of the play is late Oligocene to early Miocene reefs and buildups, which occur in carbonate and shale shelf deposits to the south, the Barito and Pater Noster shelves, and to the north, Mangkalihat shelf (fig. 38 and play 3, fig. 41). The carbonates, equivalent to the Berai Limestone of the East Java basin, are thicker and of a more reefal facies toward the shelf edges, i.e., facing the Kutei basin. Because of the sparse data and the apparent geologic similarity of the north and south boundary zones, they have been grouped as a single play. The area of play can only be broadly estimated at 4.2 million acres for the south margin and 1 million acres for the north border, or 5.2 million acres in all.

4. Miocene-Pliocene Shelf Edge Reefs

The objective of this play is probable gas accumulations in isolated shale-enclosed reefs extending approximately along the present outer continental eastern shelf of the Kutei basin (Play 4, fig. 41, Dian-1 of fig. 39, and in Section B of fig. 46); also scattered shallow reefs are found in the middle of the shelf between the delta and the continental shelf edge. Assuming a strip about 12 miles wide and 175 miles long, the area of play is 2,275 mi^2, or 1.45 million acres.

5. Deep Water Sandstones

The objective of this play are sandstones in the deep-water portion of the basin, i.e., beyond the 600-ft water depth at the edge of the continental shelf. Seismic investigation there reveals a thick sedimentary section (fig. 46). The presence of deep sea-bottom reefs indicates that a relatively recent subsidence has depressed neritic sediments to depths of over 7,500 ft. Eighteen thousand square miles, or 11.5 million acres, are in the deep water, i.e., deeper than 1,000 m in the Makassar Straits.

Tarakan Basin

Location and Size

The Tarakan basin is largely offshore (about 75 percent) on the west side of the Celebes Sea (figs. 1 and 47). Its onshore portion is on the northern east coast of Kalimantan (Borneo). It is bounded on the north by the Semporna Peninsula, an extension of the Sulu Archipelago, at the Indonesian-Malaysian boundary. Its southern flank is the Mangkalihat Peninsula, which separates it from the Kutei basin to the south. It has an area about 16,250 mi^2 and an approximate sedimentary volume of 30,000 mi^3.

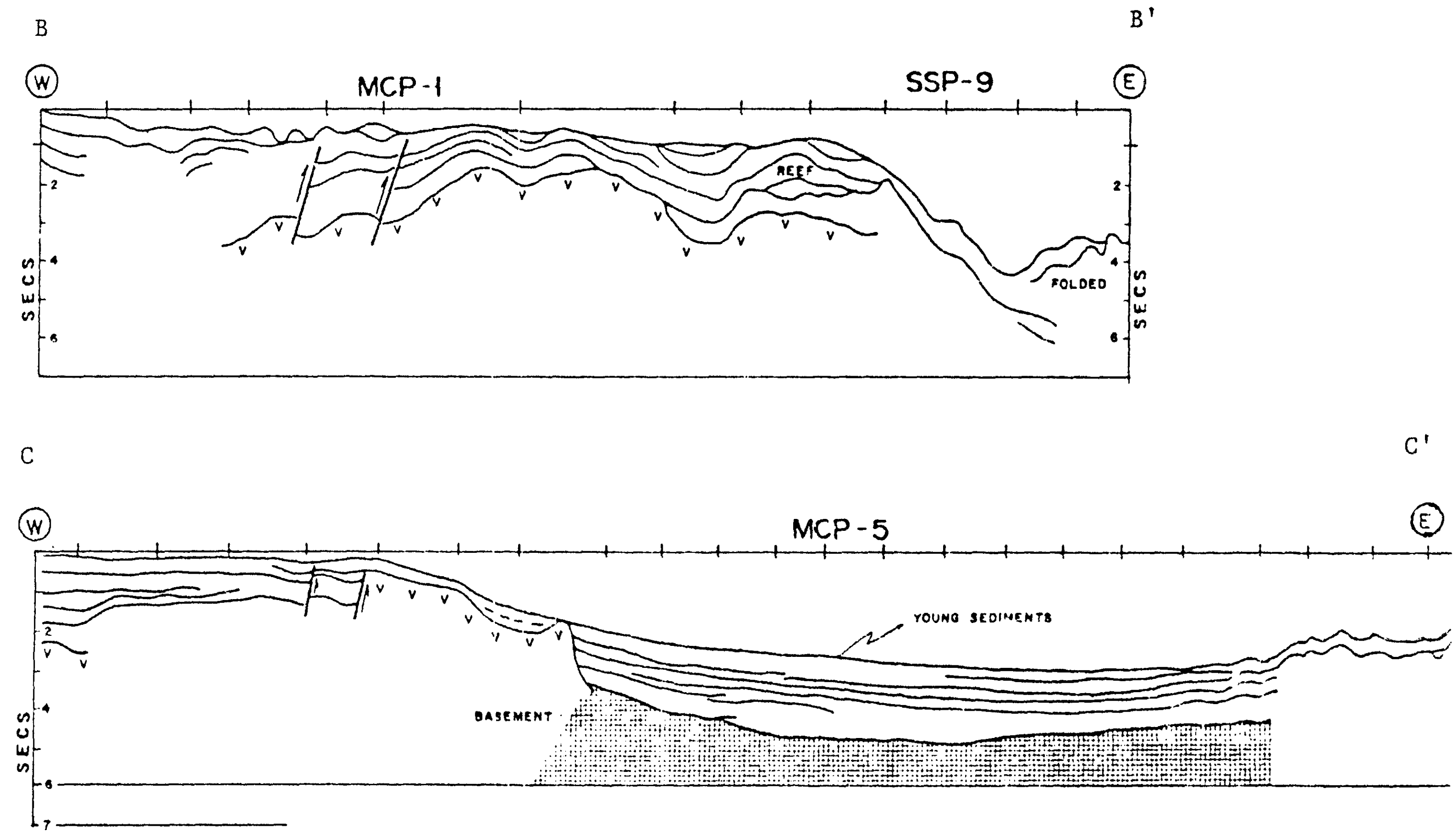


Figure 46.--East-west geologic sections, transverse to the western margin of the Makassar Strait, Kutei basin. From Katili (1977).

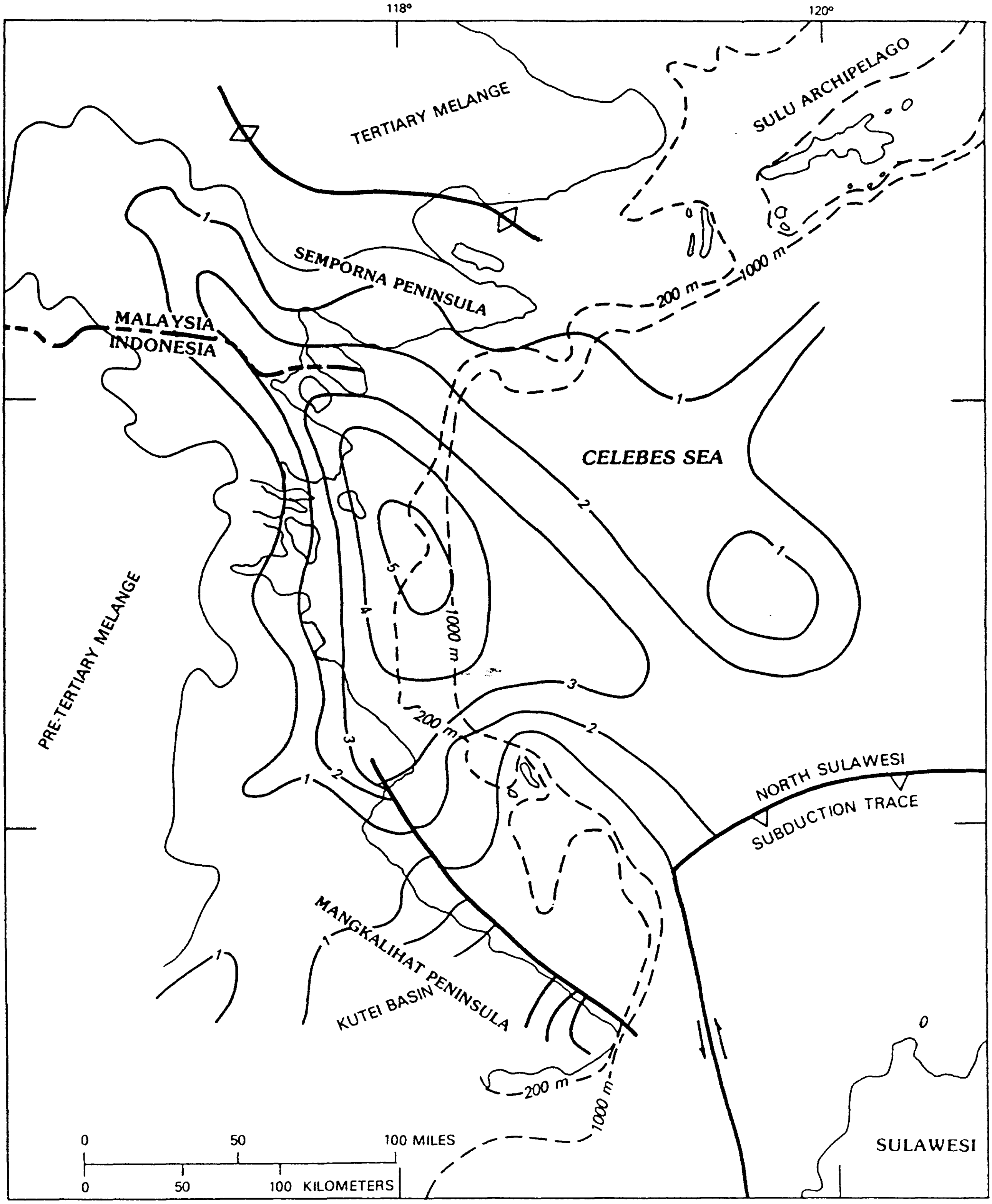


Figure 47.--Structure contour map of Tarakan basin showing depth to basement. After Hamilton (1978).

Exploration and Production History

Oil was discovered on Tarakan Island in 1906. Drilling from 1922 to 1930 on Bunyu Island resulted in the establishment of the Bunyu oil field (fig. 48). The original reserves of Tarakan Island are approximately 200 million barrels and of Bunyu Island about 100 million barrels. Serious exploration outside these islands did not begin until 1969. Since then, 12 offshore wells have been drilled, only one of which has been termed a discovery, the Serban-1, a gas well (fig. 48).

On the Kalimantan mainland, Sembakung oil field was discovered (fig. 48) and put on production in 1977. This was followed by Bangkudulus, Sesayap, and the satellite Sembakung fields during the early eighties. At present, only Sembakung appears to be on production, producing 5,647 BOPD during 1982, after having reached 7,328 BOPD in 1978. In 1984 all the mainland production was relinquished to the government (Pertamina) by Arco, the operator.Estimated original reserves of Tarakan basin as of 1979 are 469 million barrels of oil (EIA, 1984) plus 0.47 Tcf of gas (Hariadi, 1980, Patmosukismo, 1980).

Structure

General Tectonics

The Tarakan basin appears to be largely a shelf or foreland (fig. 47). In respect to the Semporna-Sulu Archipelago volcanic arc, it appears to be an inner-arc (back-arc) basin. There may also be effects of the Paleogene spreading forces, which opened the Kutei basin to the south. The axis of the depocenter trends north-northwest as do two of its major structural trends, i.e., Tarakan and Bunyu Islands. This basin is underlain by accreted melange crust, as is the Kutei basin to the south, and is relatively warm, having an average thermal gradient of 2.35°F/100 ft. The basin was subjected to compression in middle to late Miocene, possibly related to northward subduction beneath the then south-facing Sulu arc. Western uplift at the beginning of the Pliocene resulted in an eastward-dipping unconformity surface (fig. 49). After subsidence, mild compression resulted in Pliocene-Pleistocene folds, e.g., Tarakan and Bunyu Islands, which have been mapped on shallow horizons, and many of which have been tested. Owing to an apparent difficulty in obtaining reliable deep seismic data, the structure below the Pliocene unconformity, particularly in the offshore areas, is obscure. There are some indications of deep shale plugs and carbonate reefs on seismic sections.

Structural Traps

Structural traps are divided into two groups, those below the Pliocene unconformity and those above it.

1) Structures below the unconformity are analogous to the Miocene-Pliocene folds of the Kutei basin (play area of 17.5 million acres), which has an estimated untested trap area of 270,000 acres. Applying this analogy to the smaller (8 million acres) Tarakan basin play, the estimated untested trap area is 123,000 acres.

2) The shallow, simple anticlinal traps affecting strata above the Pliocene unconformity have been mapped onshore and offshore, and all closures,

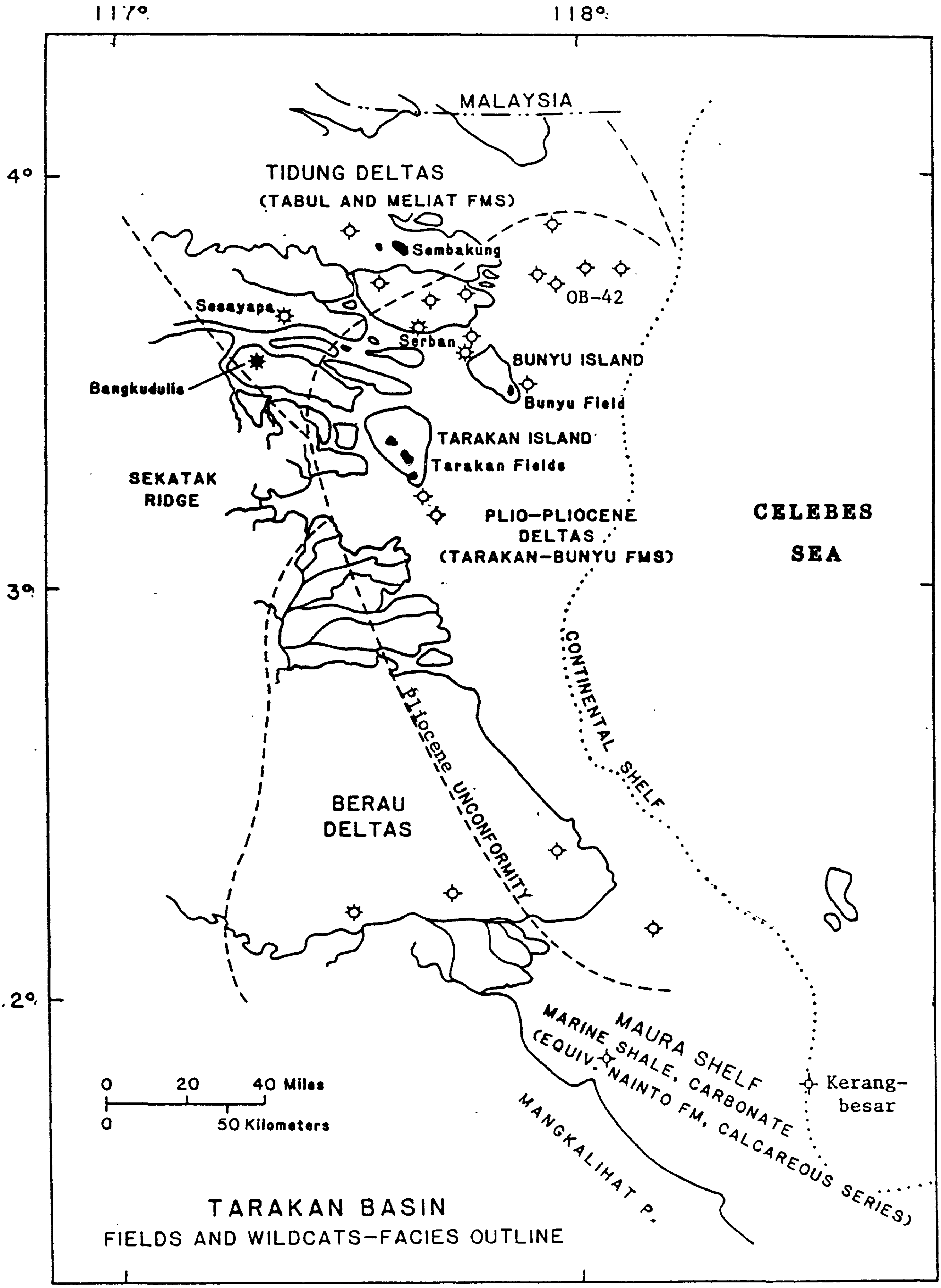


Figure 48.--Index map of Tarakan basin showing facies outlines and significant fields and wildcats. Modified from Samuel (1980).

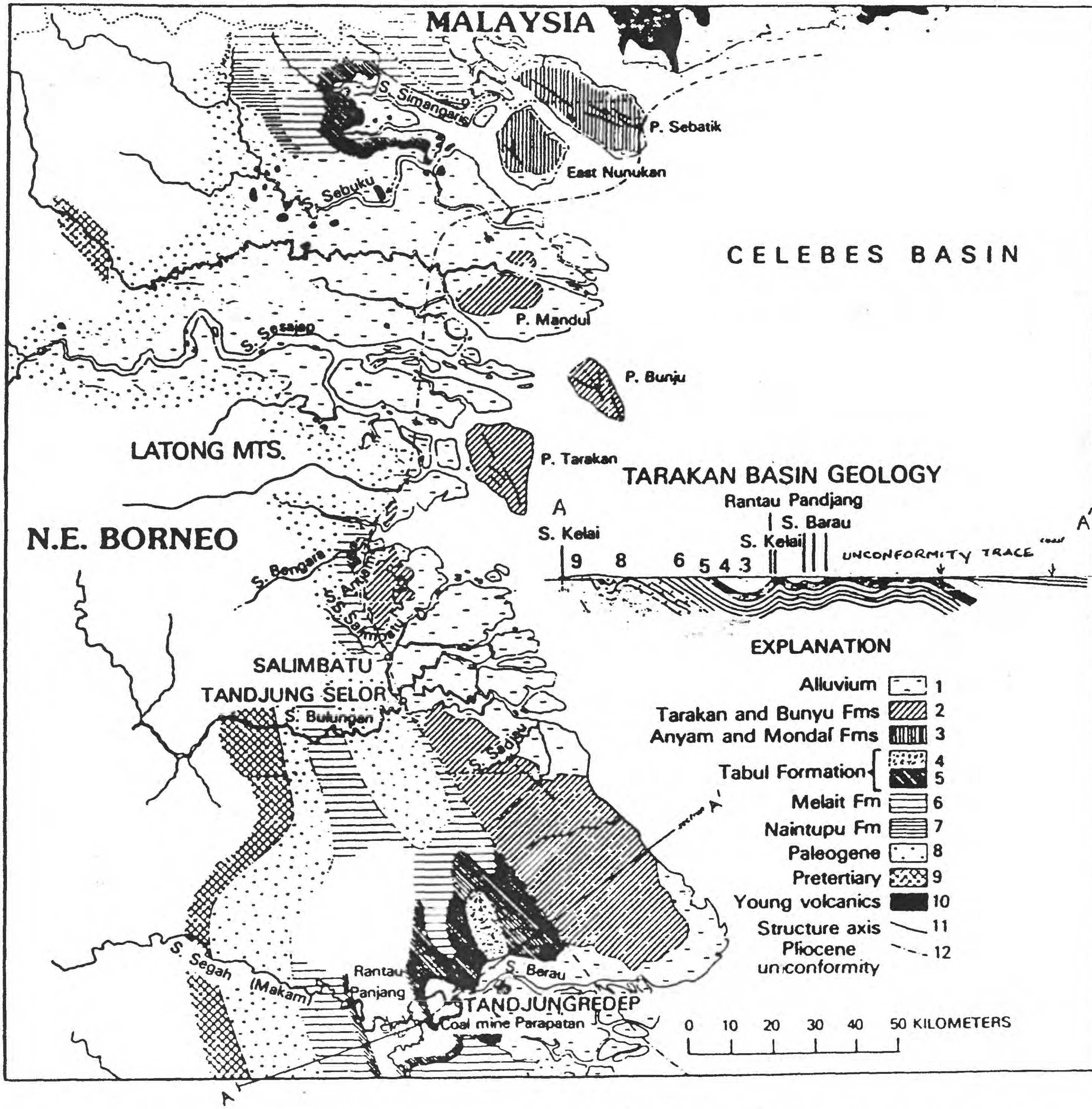


Figure 49.--Geologic map of the Tarakan basin showing in particular the trace of the Pliocene unconformity in map and section view. From Beemelen (1949).

at this level, of any appreciable size apparently have been drilled. Only wildcats on Tarakan and Bunyu Island have found oil. These two islands are northwest-trending anticlinal highs, the most prominent in the basin; a number of separate fields or accumulations have been created by faulting perpendicular to the fold axes. Little significant untested trap area remains at this level, possibly 20,000 acres.

Stratigraphy

The earliest sedimentation was in the Eocene when neritic to terrestrial coarser clastics thousands of meters thick were deposited (Bemmelen, 1949). This was followed by deposition of marls and limestone, which extended through the Oligocene and into the early and middle Miocene. Oligocene carbonates are largely platform carbonates widely distributed over the basin. Miocene carbonates and shales, variously designated either the Naintupo, Latih, or "Calcareous Series" Formations (fig. 50) in the north and the Tabalar Formation of platform carbonate in the Maura Shelf (fig. 48), extend over the basin. This marine sequence is overlain by a number of overlapping and interfingering Miocene deltas, the Berau, Melait, and Tabul Formations. Many formation names further obscure complicated stratigraphy (see Achmad and Samuel, 1984.) These deltaic formations were cut in the Pliocene by a profound unconformity, which in turn was followed by further Pliocene-Pleistocene deltas, locally the Tarakan and Bunyu Formations.

Reservoirs

There are three principal zones of reservoirs: 1) Reefs and carbonate banks in the Oligocene to Miocene marl and carbonate series (the Naintupo, Latih, Domaring, "Calcareous Series" and Tabalar Formations); 2) Miocene deltaic sandstones of the Berau, Melait, and Tabul Formations; and 3) Pliocene-Pleistocene deltaic sandstones (Tarakan and Bunyu Formations).

1. <u>Reefs and Carbonate Banks</u>

Reefs have been a drilling objective onshore in the Mangkalihat Peninsula and adjoining carbonate platform offshore. One offshore wildcat, Karangbesar-1 just north of the Mangkalihat Peninsula, penetrated the Tabalar Limestone (lower Miocene) in a near-reef facies (fig. 48). One of the most northerly offshore wildcats, OB-A2, bottomed in open marine facies consisting of a reef and a reef-bank (fig. 48). Reefs are reportedly indicated in some regional seismic sections, though the data are poor. The size and distribution of the reefs are unknown; they appear to be more developed in the south adjoining the Mangkalihat Peninsula where there appears to be a carbonate platform (Maura Shelf, fig. 48). Carbonate banks and calcarenite beds are also potential reservoirs. By analogy to the geologically similar carbonate shelf reef play of the East Java basin, one would expect carbonate reef and bank traps to make up 5 percent of the reefal facies, which would cover about 30 percent of the play area, leaving an untested trap area of 156,000 acres. These reefs are analogous to other reef plays such as the Oligocene-Miocene reef play of the Kutei basin and the equivalent shelf-reef play of the East Java basin, which have an estimated average pay thickness of about 200 ft. However, the more basinal Oligocene-Miocene section of the Tarakan basin appears to be largely argillaceous and, therefore, it probably contains less porous carbonates. The Tarakan reefs are estimated to have only one-half the average pay of the analogous plays, or 100 ft.

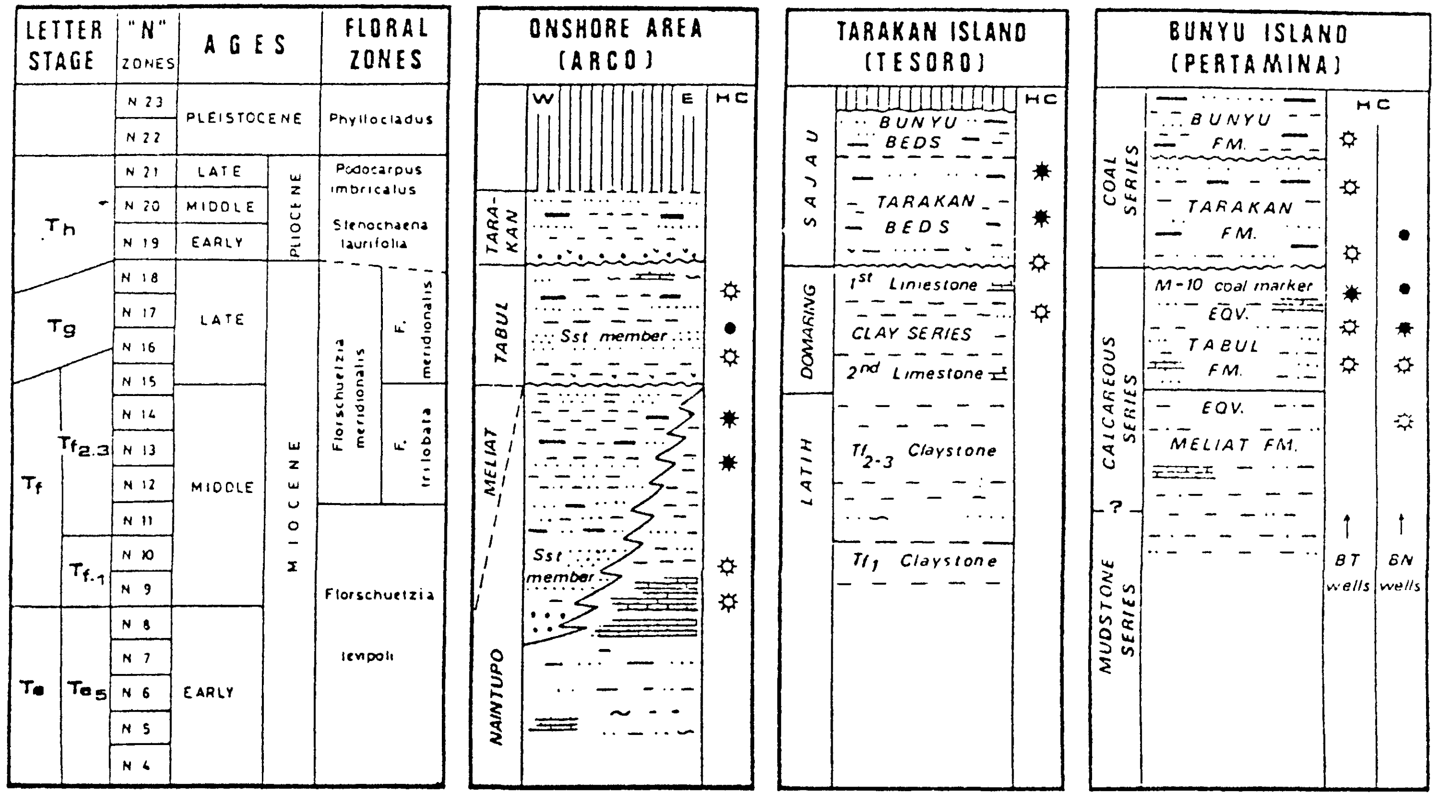


Figure 50.--Generalized Neogene stratigraphic chart, Tarakan basin.
From Samuel (1980).

2. Miocene Deltaic Sandstones

No data are available concerning pay thickness of Miocene deltaic sandstones. The gross producing interval of the only presently producing field, Sembakung, is reportedly 1,200 ft. Discovery wildcat Bangkudulis had a test interval of 300 ft in 4 zones (perhaps 150 ft net?); discovery wildcat Sembakung East, 700 ft; and offshore discovery wildcat Serban, only 40 ft. The analogous play in the adjoining basin, Kutei, has an average pay thickness of 275 ft. From the relatively low production so far obtained, it is surmised that, among other factors, the reservoirs are less developed than those of the Kutei basin, being perhaps about one-half as thick, or about 140 ft. Porosity at the Sembakung field ranges from 20 to 26 percent.

3. Plio-Pleistocene Deltaic Sandstones

The Pliocene-Pleistocene (Tarakan and Bunyu) Formations are predominantly delta sandstone, and effective pay thickness is not a limiting factor; the principal Tarakan field, Pamusian, reportedly has up to 700 ft of net sandstone in 12 pays. For evaluation purposes, 300 ft is assumed.

Porosity in these sandstones appears good, i.e., 20 to 38 percent. The principal limiting factor is that water saturation is extemely high in Tarakan, about 95 percent; the oil recovery factor is about 50 percent. These unusual reservoir conditions are assumed to prevail throughout the play. Even allowing for some improvement in well completions, the oil recovery would be very low, or about 100 barrels per acre-foot.

Seals

Seals in the Miocene and later deltaic sandstones are only fair and it is probable that hydrocarbons have escaped at the time of the base-Pliocene unconformity.

Source Section

The source rock appears to be well below the Pliocene unconformity and largely in the Oligocene to lower Miocene marls and carbonates (see below).

Petroleum Generation and Migration

Richness of Source

No organic richness data are available from the thermally mature Oligocene to lower Miocene marl and carbonate formations, but the middle Miocene Melait Formation has 2 percent organic carbon content, the same as the Kutei basin pro-delta beds (Samuel, 1980). The Tabul Formation, a proximal delta formation, averages 10 percent organic carbon content, largely reflecting coal presence. The Pliocene-Pleistocene Tarakan and Bunyu Formations are the richest of all in organic carbon (23 percent) again reflecting high coal content; however, these younger formations are too shallow to generate hydrocarbons.

Depth and Volume of Mature Sediments

Depth to the top of the thermally mature sediments, as defined by vitrinite reflectance of .7 percent, appears to vary, as anomalously shallow values are reported. Sembakung-1 contained no mature rocks down to 10,000 ft, and the strata in Mengatal-1 on Tarakan Island were deemed to be approaching maturity at 9,000 ft (Samuel, 1980). Data from a second well on Tarakan Island, Barat-1, however, placed the top of the mature rock at 7,500 ft, and determinations at Bunyu suggest 7,000 ft (Samuel, 1980). The average thermal gradient is relatively high (about 2.35°F/100 ft). Because the basin is tectonically and thermally similar to the Kutei basin where the top of the mature zone is estimated at an average depth of 10,000 ft, the average depth of thermally mature rock in the Tarakan basin is assumed also to be about 10,000 ft. On the basis of this similarity to the Kutei basin, the top of the overmature rock (gas-window) is at 17,000 ft. The volume of mature and overmature rock is about 5,000 mi^3.

Oil versus Gas

Both gas and oil are found in Tarakan basin. Oil has been selectively produced but gas has not. It is believed, however, that the best potential lies with gas, especially in the offshore areas. Below the middle Miocene to recent deltaic formations, and largely within the thermally mature zone (below 10,000 ft), is a thick marine section of shales, marls, and carbonate. Although evidence of overpressuring is barely mentioned in the literature, it is believed that this thick, predominantly argillaceous sequence is overpressured. As in the better documented case of the Kutei basin, this overpressured sequence should produce only the lighter hydrocarbons, C_1-C_6; the larger oil molecules remaining locked in the shales and marls until further subsidence and maturation degrades them to methane. It is estimated that the central, deeper part of the basin (the reefal play) is largely gas-prone and only about 20 percent of the hydrocarbon may be oil. In the onshore and continental shelf area, deltaic sandstones would provide conduits to bleed off overpressure and allow primary oil migration, so that the petroleum mix is largely oil, i.e., an estimated 60 to 70 percent.

Migration Timing versus Trap Formation

It is estimated that the depth of the basin averages about 17,000 ft in its central part. Assuming the hydrocarbon generation began when the basin subsided to a depth of 10,000 ft (the estimated present depth to the thermally mature zone), migration would commence about middle Miocene, prior to late Miocene folding and to the base of Pliocene unconformity. Under these circumstances, the timing of migration in regard to pre-unconformity traps, i.e., middle and upper Miocene folds or reefs, would be optimum. The post-unconformity closures are late; much oil must have escaped from the system during the base-Pliocene erosion. The oil of the Pliocene-Pleistocene folds of the Tarakan and Bunyu Islands apparently represents a small surviving remnant of a larger hydrocarbon migration.

Plays

The petroleum prospects of the Tarakan basin are divided into three principal plays: 1) Carbonate reefs and banks in Tertiary shale and carbonate sequence, 2) Late Miocene folds (pre-base Pliocene unconformity), and 3) Pliocene-Pleistocene folds (post base-Pliocene unconformity).

1. Carbonate Reefs and Banks

The objective of the play is in reefs or banks (and possibly some sandstones) in the largely shale and carbonate sequences of early Miocene age (fig. 50). This play underlies the whole basin at varying depths below the middle Miocene to recent deltas that encroach and overlap it from the west and north. The play extends onto the Mangkalihat Peninsula and shelf, which separates the Tarakan from the Kutei basin and is probably more prospective in the southern basin (the so-called Maura Shelf area) (fig. 48); but, in general, the play area coincides with that of the entire basin having an area of 10.4 million acres.

2. Late Miocene Folds

Petroleum accumulations, primarily in Miocene deltaic sandstones and probably calcarenites, are entrapped in late Miocene folds. Onshore, the folds of this play are detectable at relatively shallow depths, but offshore, they are obscured by an overlying east-dipping regional unconformity. The play underlies most of the basin, possibly excluding part of the Maura-Mangkalihat platform and including the Tidung, Berau, and Tarakan deltas (fig. 48). The play area is estimated to include 75 percent of the total basin, or approximately 7.8 million acres.

3. Pliocene-Pleistocene Folds

Shallow petroleum accumulations occur in relatively gentle folds of Pliocene-Pleistocene deltaic sandstones overlying a regional, profound unconformity. The area of the play is largely the offshore portion of the Tarakan basin, approximately two-thirds of the entire basin, or about 6.9 thousand acres.

West Natuna Basin

Location and Size

The West Natuna basin is on the continental shelf of the westernmost South China Sea (figs. 1 and 51). It adjoins on the west the larger and deeper Malay basin, which trends southeastward from the Gulf of Thailand. The boundaries between these two similar, but structurally distinct, basins is coincidentally approximately the Indonesian-Malaysian boundary. The West Natuna basin is further bounded on the east by the Natuna Arch and on the south by the Sunda Shelf. The northern boundary arbitrarily is taken at the Viet Nam-Indonesian boundary (disputed). It has an area of approximately 34,000 mi^2 and a sedimentary fill of some 45,000 mi^3.

Exploration and Production History

Exploration of the region started in 1968 and has been generally active ever since.

Although petroleum exploration has been very rewarding in the similar adjoining Malay basin, exploration in the Indonesian waters has been only moderately successful to date. After two noncommercial "discoveries," A1-1X (gas) and Terubuk 2 (oil) on the Malaysian boundary, the first substantive success was the Udang oil discovery of 1974 on an Oligocene drape closure on

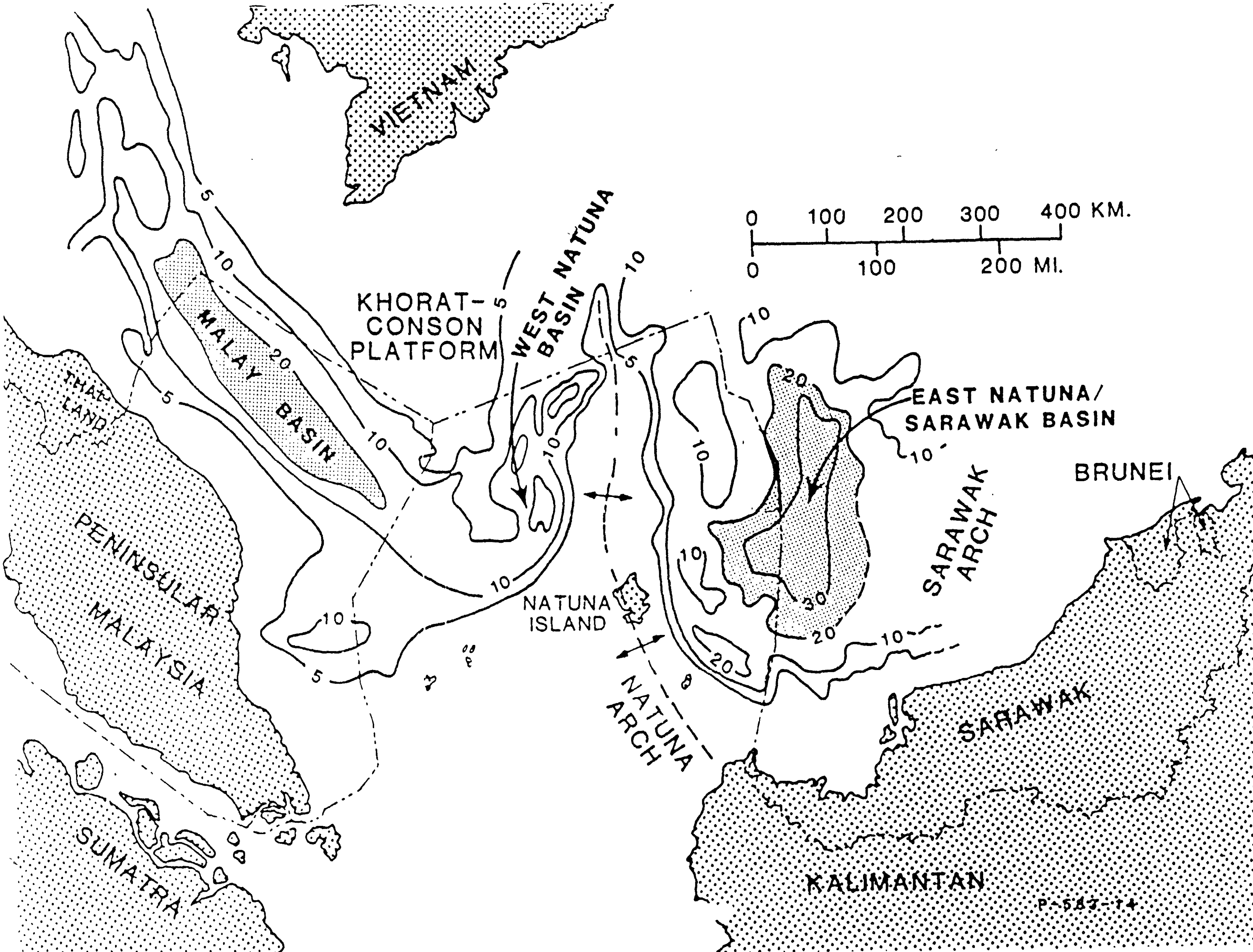


Figure 51.--Isopach map of West and East Natuna basins, southeast Asia. From Eyles and May (1984).

the southern edge of the basin with estimated reserves of some 50 million barrels of oil (fig. 52). In 1978, wildcat KG-IX, followed by KH-1X in 1980, discovered oil in drag fold structures in the central part of the basin (KH-IX went on-stream in 1986, estimated reserves are 30 MMBO). A second oil and gas discovery in a central fold was discovered in 1982, Anoa-1 (granted commerciality in 1983, estimated reserves are 30 MMBO), and seven additional gas and oil discoveries were made through 1984. The basin oil reserves are estimated to be 402 million barrels (EIA, 1984). Gas reserves are unknown.

As of the end of 1984, some 65 wildcats were drilled of which 11 have been announced as discoveries giving a wildcat success rate of 17 percent.

The significant exploration is estimated to be about 40 percent complete.

Structure

General Tectonics

The West Natuna basin is a northeast-trending fault-controlled basin (figs. 51, 53, and 54). It is on the northwestern edge of the granite-intruded craton area of the Sunda Continental Block, a border of accreted Mesozoic melange extending along the east side of the basin, i.e., the Natuna arch (fig. 51). This arch, separating the West and East Natuna basins, appears to be an old feature, perhaps related to the Mesozoic and early Tertiary north-striking subduction zones, traces of which are just west and just east of Natuna Island, respectively.

The basin began to take its present form in early Oligocene when continental crust attenuation (perhaps associated with the beginning of seafloor spreading of the South China Sea to the northeast) caused subsidence and tensional faulting with the formation of northeast-trending half grabens (fig. 53). This structure provides fault and drape closures as well as deep, silled grabens for preserving organic matter.

In the early Miocene, northeast-trending faults, some along the old Oligocene normal-fault zones of weakness, became active (fig. 54). These faults appear to be primarily wrench faults of largely dextral movement. Abrupt and random changes in thickness across faults, anticlines becoming synclines (or half-grabens) at greater depth, and apparent throw reversals along strike and with depth support this interpretation (figs. 55 and 57-2). Drag folds associated with these faults are important petroleum closures, particularly in the Malay basin to the west.

By late Miocene, tectonic activity had diminished, and the area was subject to peneplanation followed by subsidence. Subsequent gentle warping followed along previous structural trends (fig. 55).

Structural Traps

The petroleum-containing closures appear to be of two types:

1) Drag folds associated with Miocene wrenches in the central parts of the basin. Figure 56 shows an example of such a Miocene drag fold; cross sections are shown in figure 57. Most of the large oil fields of the Malay basin to the west appear to be on similar drag structures. An examination of an unpublished map of a limited area of the northwestern part of the area indicates that 5 percent of the play area is under drag-fold closure. This is supported by analogy to other basins; where drag folds associated with wrenching are the dominant structural style (Central Sumatra and Los Angeles),

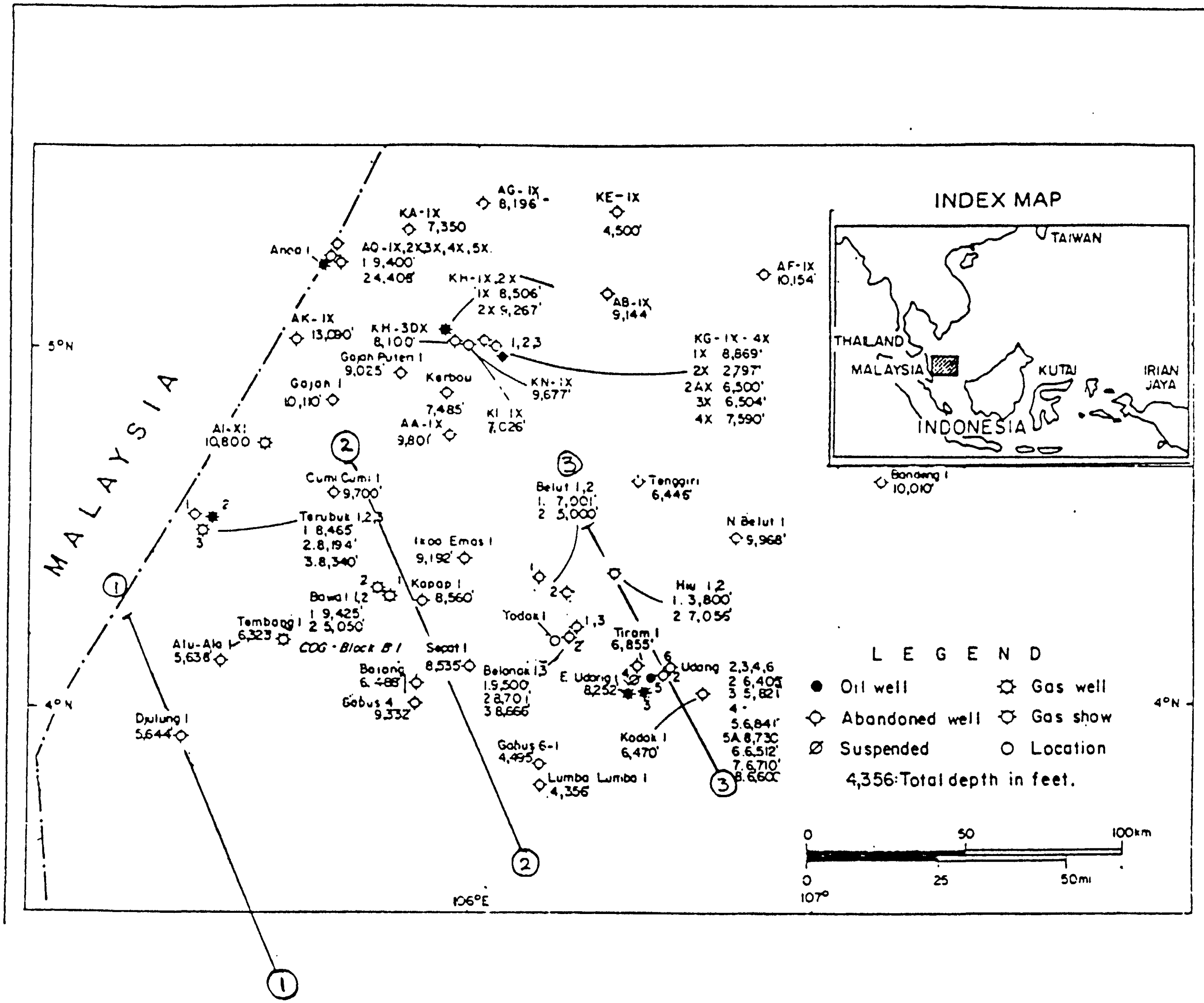


Figure 52.--Well location map, West Natune basin. From Petroconsultants (1982).

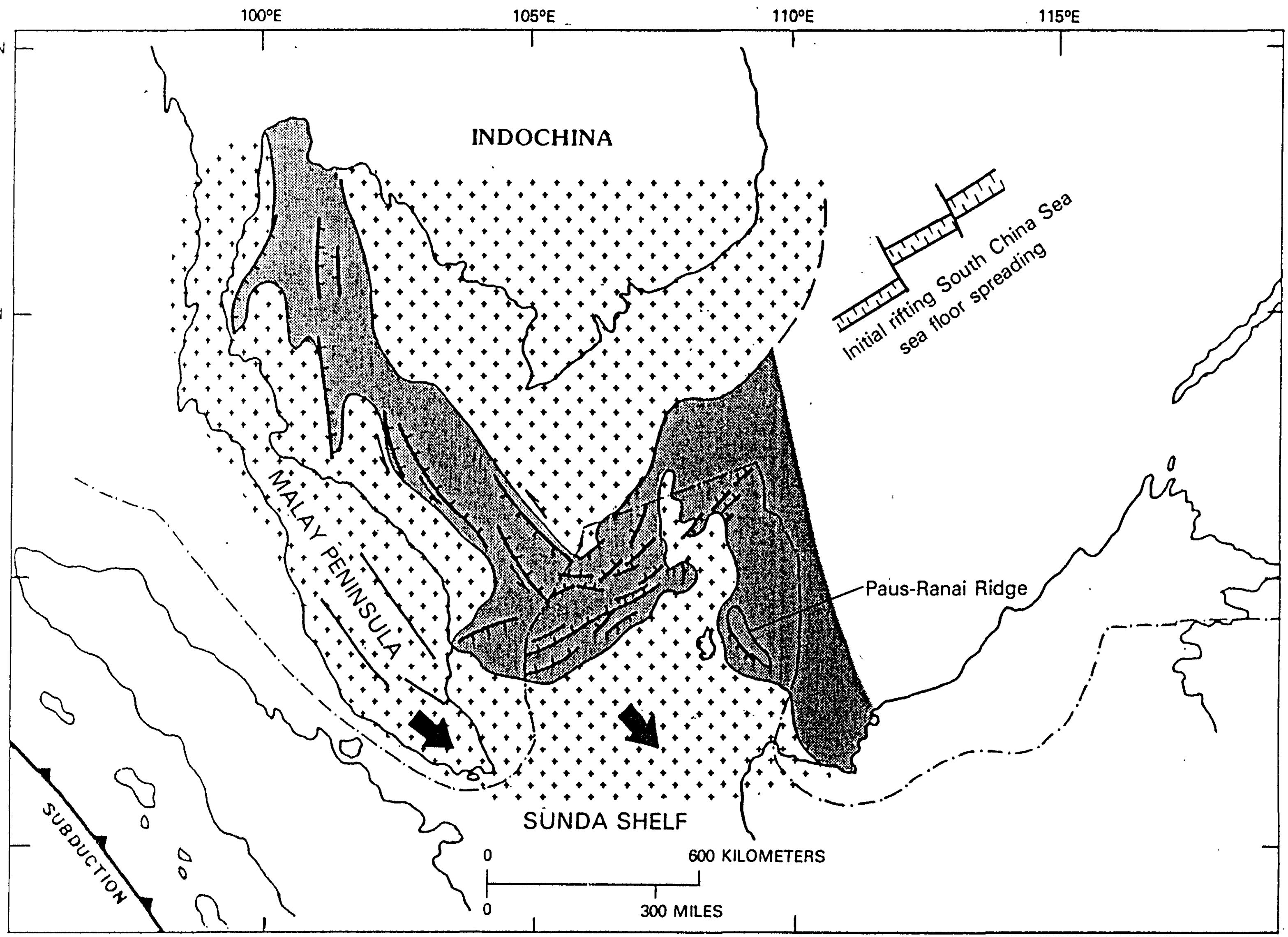


Figure 53.--Map showing early tectonic elements, West and East Natuna basins. Modified from Wirojudo and Wongsosantiko (1983).

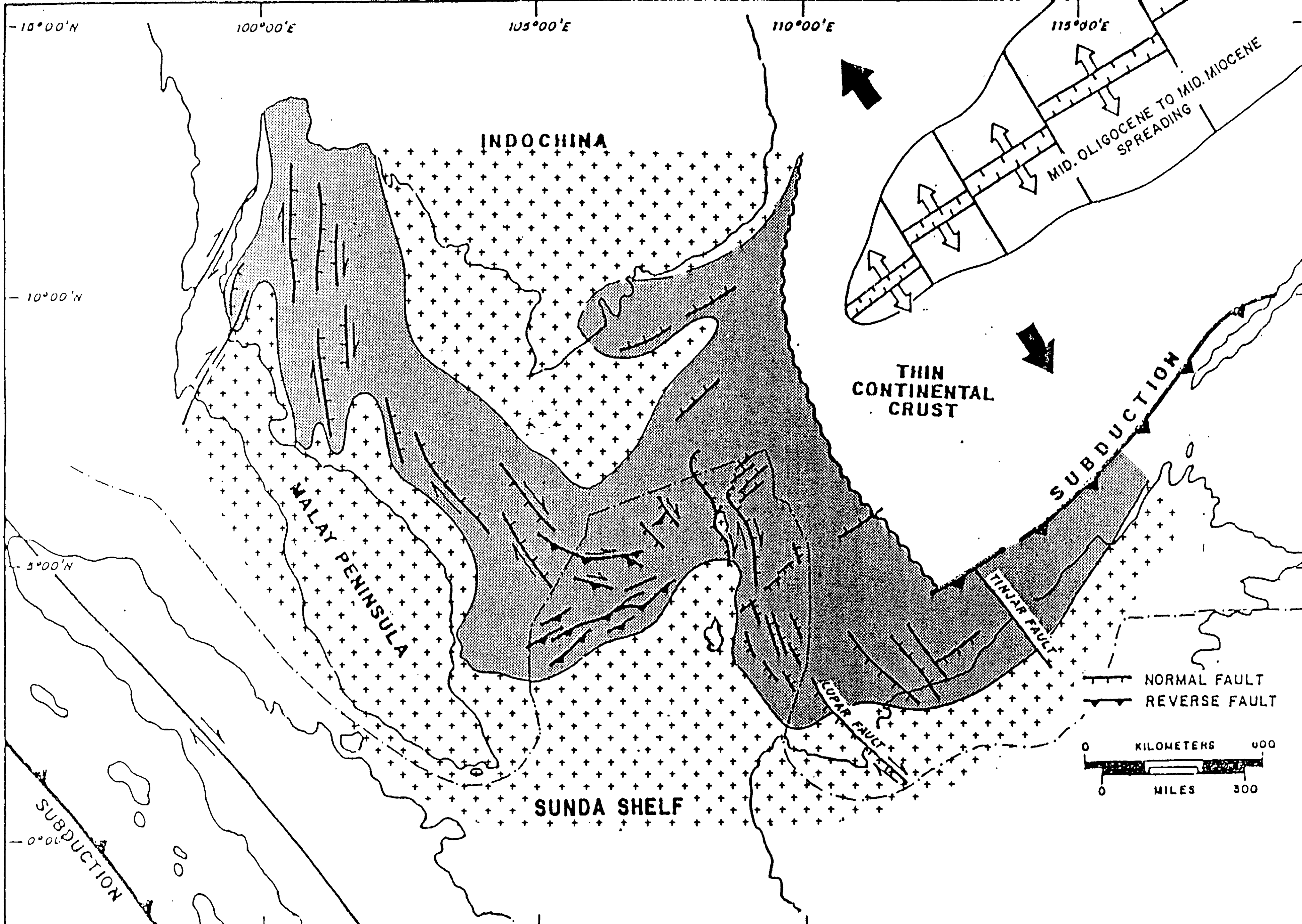


Figure 54.--Map showing early-middle Miocene tectonic elements, West and East Natuna basins. From Wirojudo and Wongsosantiko (1983).

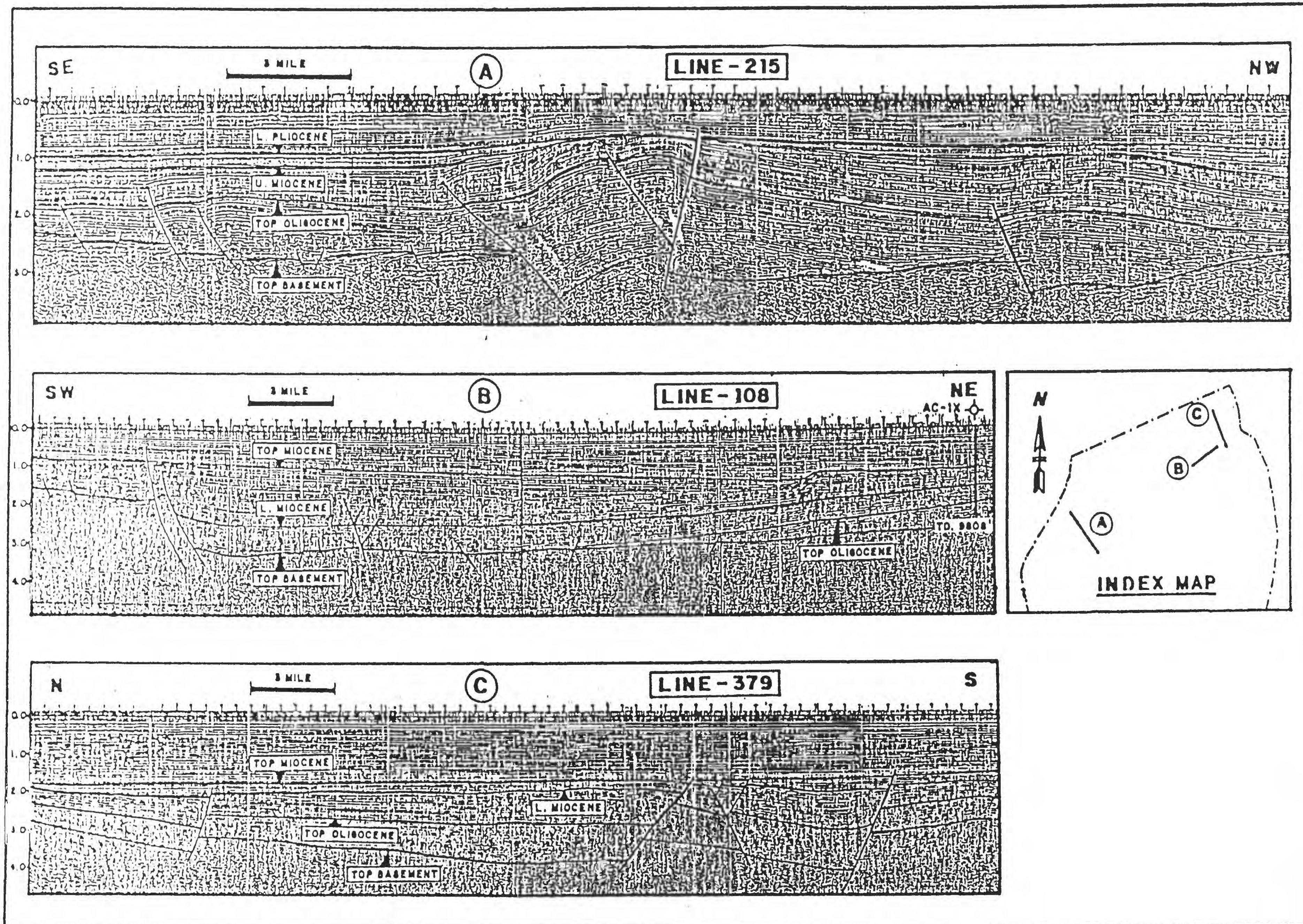


Figure 55.--Seismic sections (A, B, and C) showing structural styles in West Natuna basin (A) and East Natuna basin (B and C). From Wirojudo and Wongsosantiko (1983).

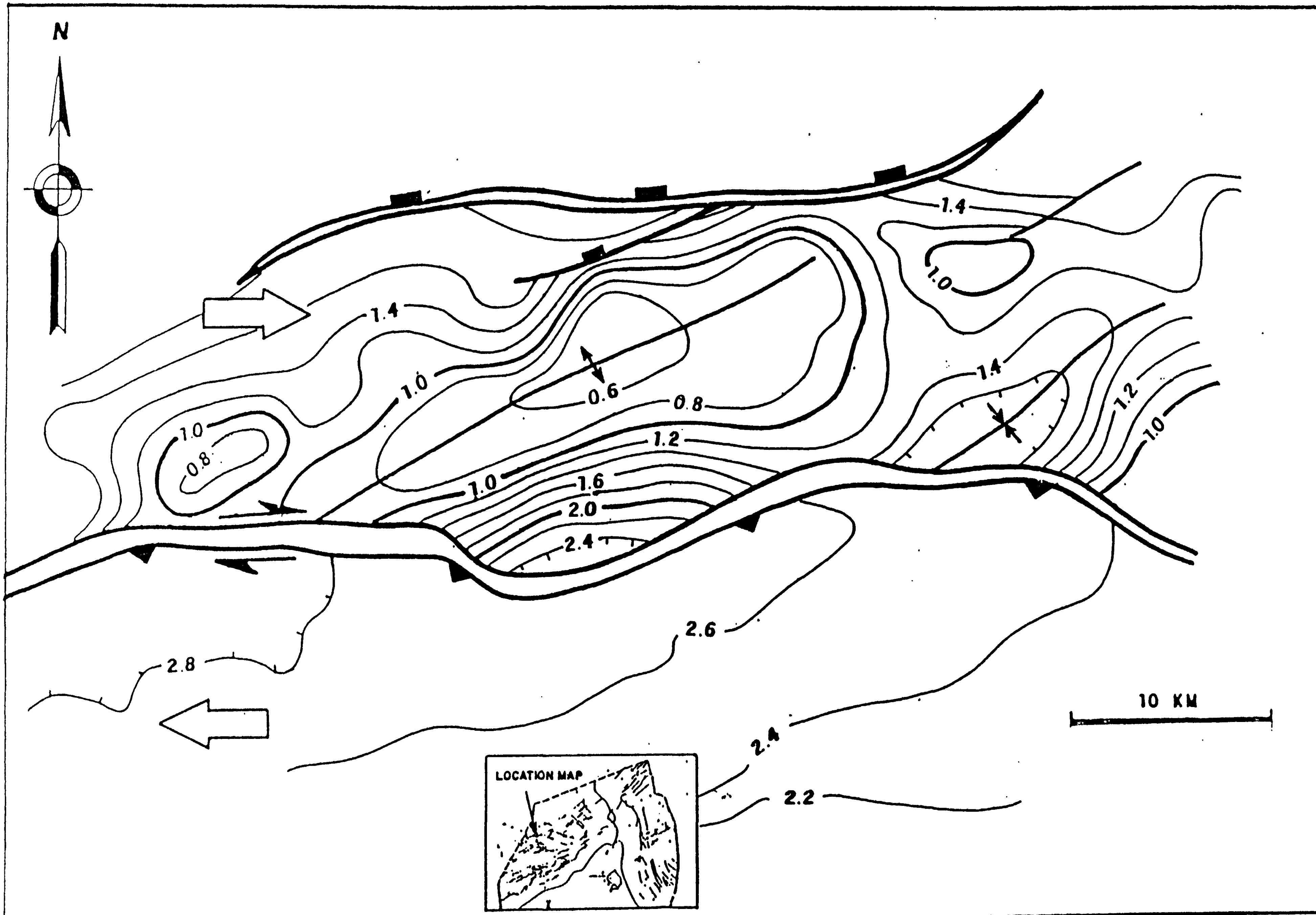


Figure 56.--Seismic structure map showing depth of top Oligocene strata on a typical drag fold, West Natuna. From Wirojudo and Wongsosantiko (1983).

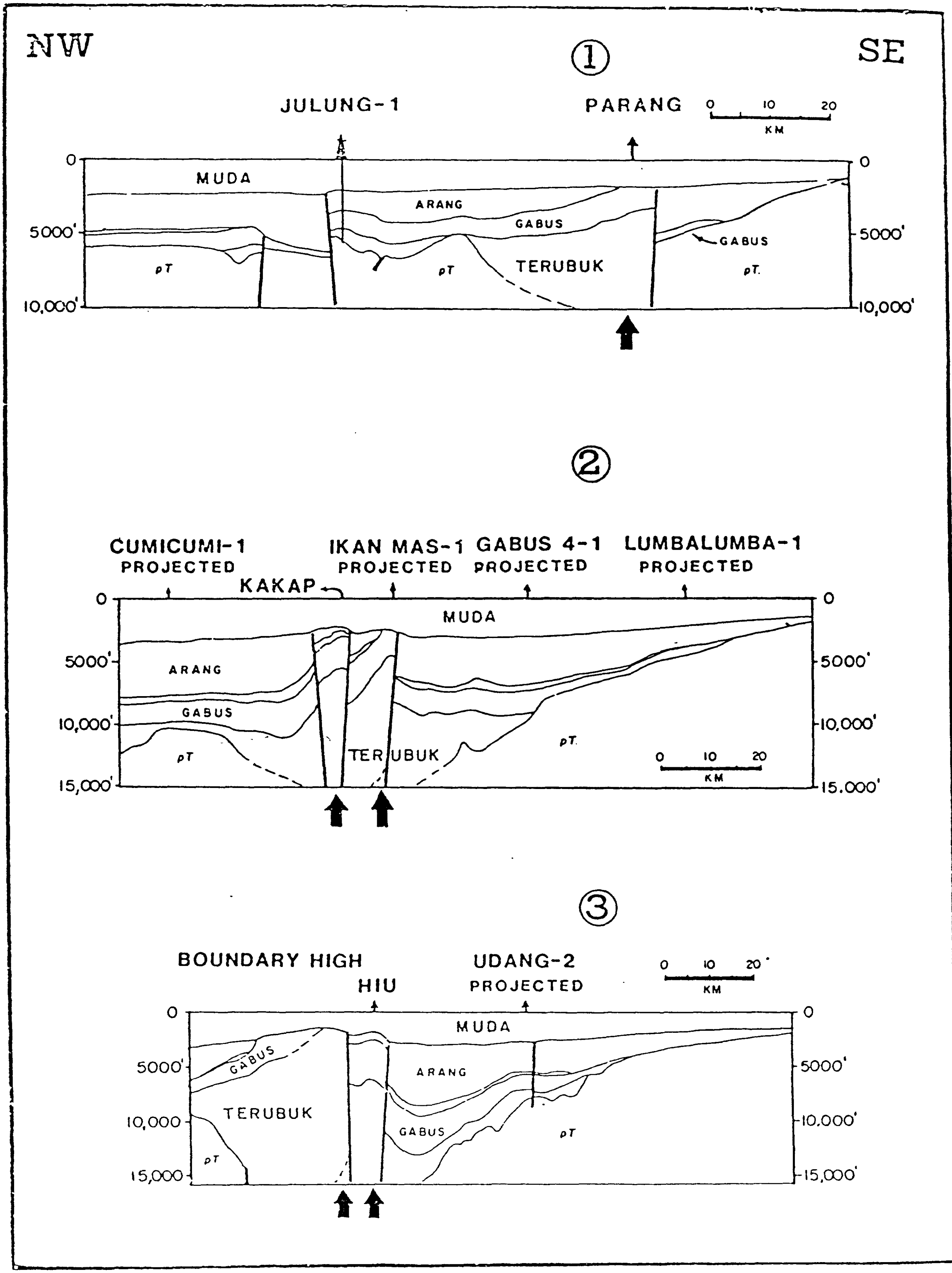


Figure 57.--NW-SE geologic cross-sections, West Natuna basin. After White and Wing (1978) and Eubank and Makki (1981).

the trap area would appear to be about 5.5 percent of the play area. It is estimated, therefore, that dragfold traps make up approximately 5 percent of this play area (7 million acres, see Plays) of which an estimated 40 percent has been tested.

2) Drapes over Oligocene fault blocks are prominent on the basin perimeter. A map of the Udang field is shown in figure 58; a cross section at Udang-2 is shown on figure 57. The Udang basin-edge trend extends westward into Malaysia where it is also petroleum bearing. A measurement of drape closures in an unpublished map of a limited area in the west-central part of the basin indicates that 7 percent of the area was under this type of closure. This is somewhat analogous to the drape closures of East Java Sea where the closure area comes out to be about 5 percent of the total play area (15 million acres, see Plays). On this basis, over one million acres of drape closure is estimated in the play, of which an estimated 40 percent has been tested.

Stratigraphy

The sedimentary fill of the West Natuna basin is made up of Tertiary strata summarized in the stratigraphic column after Armitage and Viotti, 1977 (fig. 59).

The early clastic fill, the "undifferentiated complex" or the Terubuk Formation, is overlain by the Oligocene Keras and Gabus Formations, which occupy the grabens and half-grabens caused by the early Oligocene rifting. These sediments are essentially continental and deltaic clastics and are up to 15,000 ft thick (Wirojudo and Wonsosentiko, 1983).

Overlying the Oligocene section are the Miocene Barat and Arang Formations. They consist of sandstone and shale with some coal and are of deltaic or paralic origin. These strata are relatively thin, averaging 3,000 to 4,000 ft in thickness.

Overlying by profound unconformity are upper Miocene through Pleistocene open-marine sandstones and shales, the Muda Formation. They are usually less than 4,000 ft thick but range up to 10,000 ft in the western part of the basin adjoining the Malaya basin.

Reservoirs

There appear to be two principal reservoir zones in the Tertiary section:

1. The sandstones of the Oligocene Gabus Formation appear in drape structures (e.g. Udang and satellite fields, which are to date the principal petroleum producers of the basin, and in some drag folds, e.g. the KH and KG fields). The average net pay of the Oligocene sandstones in the Udang field is reportedly 86 ft and in the KH field, 40 to 190 ft. In the absence of other data, 86 ft is taken to be the average pay of the drape play.

2. The Miocene Arang Formation sandstones are involved in the drag folds of the central part of the basin. They are the main oil and gas producers of the prolific Malaya basin fields to the west. Three hundred and seventy-five ft of pay (315 ft gas and 60 ft oil) were tested at Anoa-1. However, Anoa-1 is located on the extreme west side of the play area where the Arang Formation is of maximum thickness. The Arang Formation thins eastward and is thin or missing on the higher amplitude folds. For the drag-fold play of the central

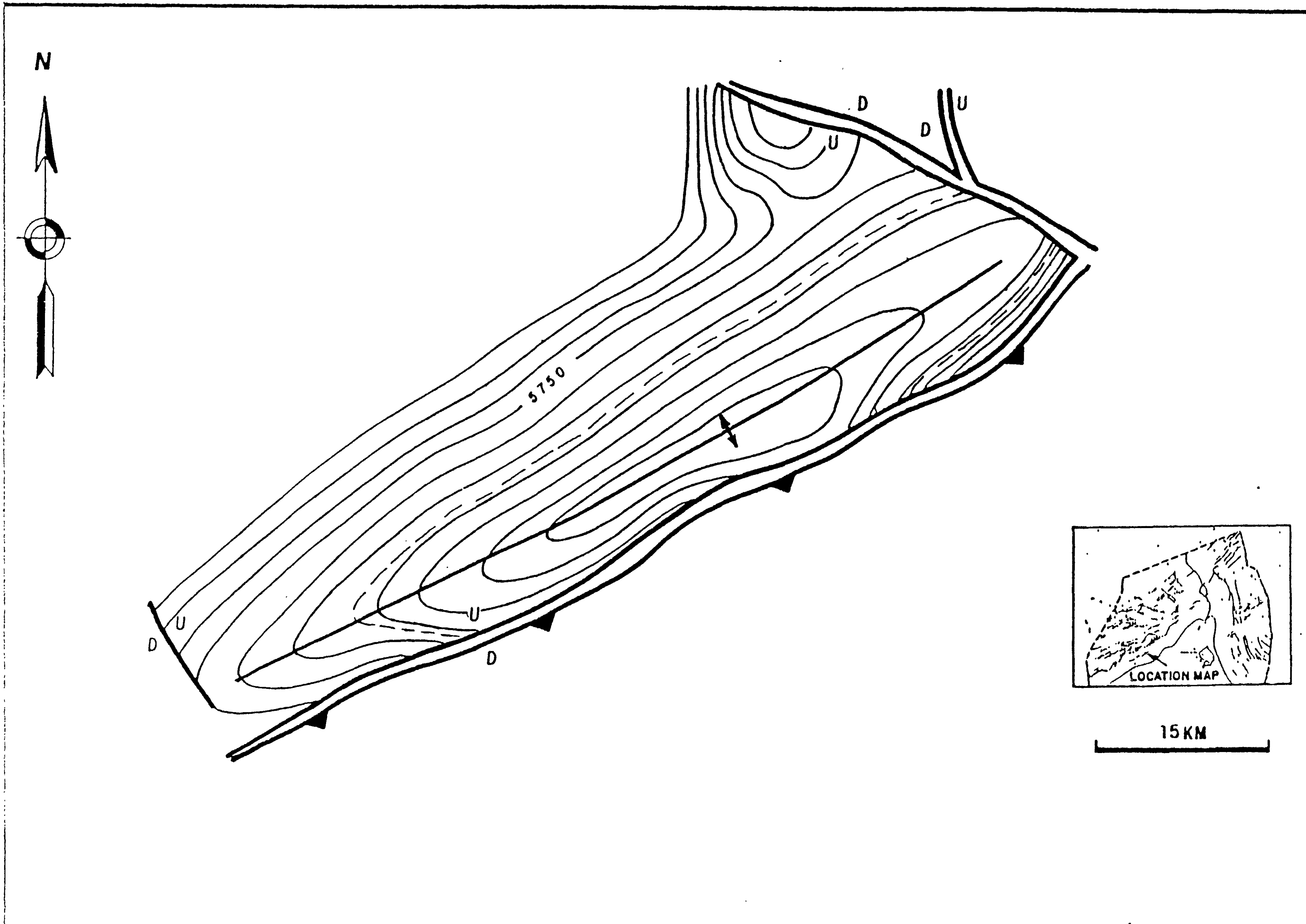


Figure 58.--Structure map showing depth to top of Oliogocene strata, Udang Field, West Natuna basin. From Wirojudo and Wongsosantiko (1983). Contour interval not indicated; dashed contour probably oil-water contact.

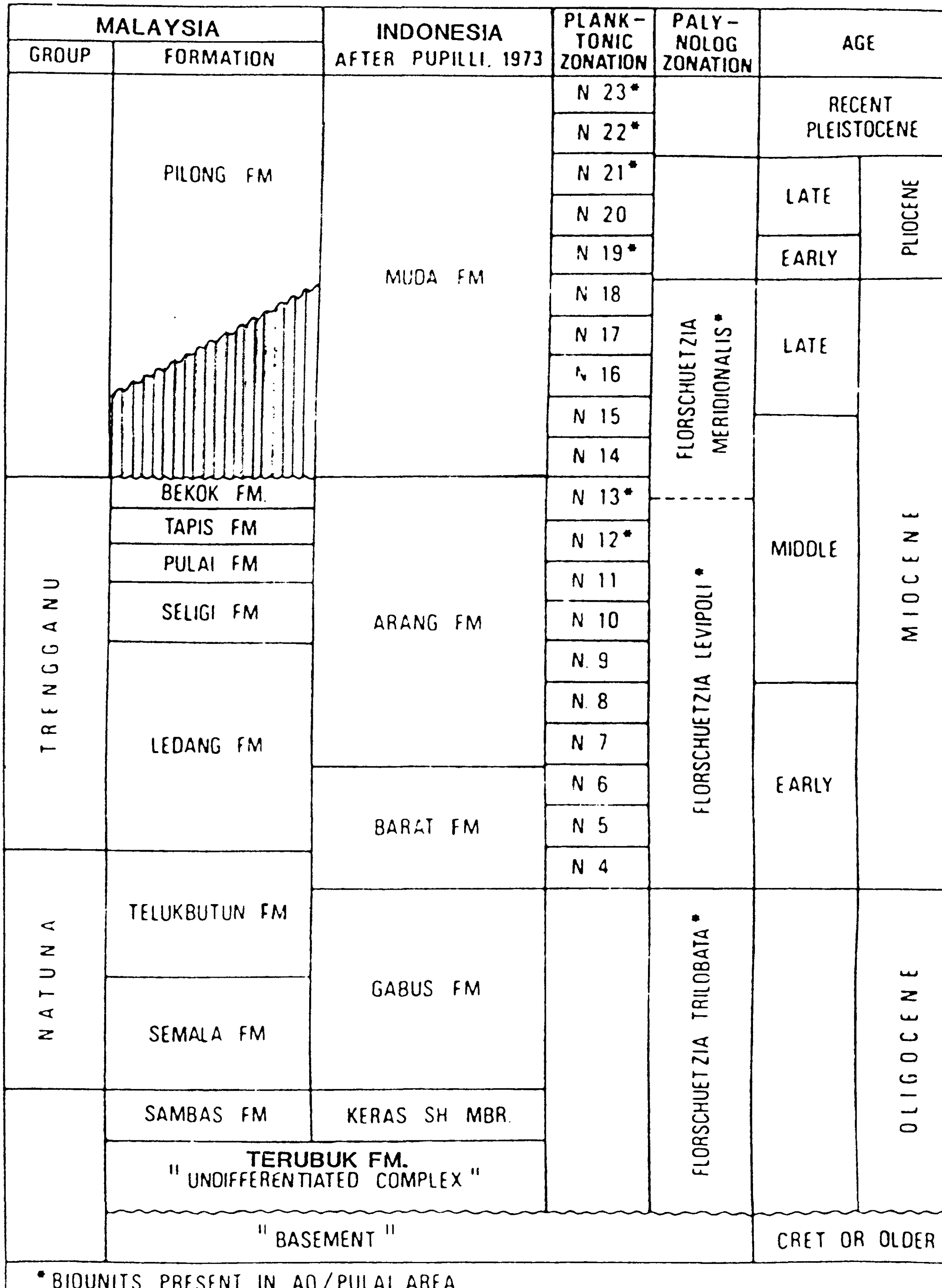


Figure 59.--Stratigraphic chart, West Natuna basin. From Armitage and Viotti (1977).

basin where an unknown amount of the Miocene sandstones have been eroded, the Oligocene and Miocene sandstones have been lumped and are assumed together to have a combined thickness of 200 ft.

Seals

The section is a sequence of sandstone alternating with relatively thick shales. The shales can be considered fairly good seals. Leakage may have occurred in late Miocene time when the area was extensively eroded and faults to the surface prevailed. There has been essentially no faulting since late Miocene, and only small amounts of leakage probably occurred after that time.

Source Section

The Oligocene graben-fill of up to 15,000 ft of coastal-fluvial plain and deltaic sediments are the source rock of the basin (see Petroleum Generation and Migration).

Petroleum Generation and Migration

Richness of Source

According to Wirajudo and Wongsosantiko (1983), geochemical data suggest that the Oligocene graben-fill continental clastics are "good" source rock for gas and "fair" to "good" source rock for oil, at least locally. Cossey and others (1982) report the late Oligocene (Barat Formation) has organic carbon in the range of 0.5 to 2.0 percent. Pollock and others (1984) indicate that claystones of the Barat and underlying Upper Gabus Formations are the likely source of oil, while the overlying section is generally gas prone.

The richness of the source is confirmed by the high percentage of petroleum fill. The KH field appears to be 55 percent filled and the Udang field 44 percent.

Depth and Volume of Mature Sediments

The average thermal gradient is about 2.2°F/100 ft and average rate of subsidence appears to average about 330 ft per million years. This puts the average depth to the top of the mature zone (taken where R_o = 0.7 percent) at 8,000 ft (and overmature zone at 15,500 ft). This checks with the vitrinite measurements at the KH field (Pollock and others, 1984). The 8,000-ft depth is about at the top of the Oligocene. Mature Miocene source rock, however, probably exists along the Malaysian border where the rate of subsidence has been greater. The volume of source rock is estimated to be 20,000 mi^3. The relative shallowness, of the West Natuna basin, and therefore less thermally mature source rock, may be part of the explanation of why less hydrocarbon has been found in the the West Natuna basin versus the adjoining much deeper Malay basin.

Oil versus Gas

Gas has been found in the West Natuna basin and in large quantities in the adjoining deeper Malay basin, but no gas production has yet been developed and no reserve figures are available. It would appear, however, that gas takes up most of the trap volume. The Anoa-1 test found 315 ft of gas and 60 ft of oil. It is estimated that oil is about 30 percent of the petroleum mix in the Miocene drag-fold play. For the Oligocene drape play, 50 percent is estimated for oil; the Udang field is about two-thirds oil, but indications for future fields appear less.

Migration Timing versus Trap Formation

Assuming that the thermal gradient and subsidence rates were approximately constant during the Tertiary, hydrocarbon generation and migration would begin when the source sediments had subsided to the depth of 8,000 ft. This would have happened in the late Oligocene when a considerable portion of the Oligocene graben fill, which is up to 15,000 ft thick, had been deposited. However maximum flood of oil generation and migration probably did not commence until the Barat shales reached these depths in the late Miocene.

Drape closures would have first formed in the Oligocene somewhat earlier than hydrocarbon flood migration, and there may have been some time for reservoir deterioration.

The Miocene drag fold and fault traps associated with Miocene wrenching on the other hand would form considerably after migration began and, therefore, miss some amount of migrating petroleum. Migration, however, would have been going on while the traps were forming, thus preserving the reservoirs to some extent from deterioration.

Limiting Factors

The limiting factors in this basin in comparison to the adjoining prolific Malay basin are its relative shallowness, allowing less volume of source rock, and relative thinness and absence by erosion of some middle Miocene (Arang Formation) reservoir section (the principal reservoir section of the prolific Malaya basin).

Plays

1. <u>Drapes</u>

Potential petroleum accumulations are in Oligocene (and to a less extent, Miocene) sandstones draped over Oligocene (and older) fault blocks. The area of play appears limited to those areas around the perimeter of the basin where the thin, less plastic section inhibits the formation of high-amplitude, large Miocene drag folds (which would tend to redistribute or destroy petroleum earlier accumulated in drape features). It is also in these peripheral areas where Oligocene sandstones are more prevalent. On this very general basis, the play is believed to be of highest potential in the zone around the basin where the section is less than approximately 10,000 ft thick fig. 51, giving an area of about 23,000 mi^2 or 15 million acres.

2. <u>Miocene drag closure</u>

Potential petroleum accumulations occur in Miocene drag-fold closures presumably associated with wrench faults of unknown distribution involving

Oligocene and Miocene reservoirs (although Miocene strata are largely missing from the crestal areas of the larger folds). The area of the play is restricted to the deeper, central parts of the basin where there is a thick enough plastic section to permit major folding. The play area is very approximately 11,000 mi^2 or 7 million acres.

East Natuna Basin

Location and Size

The East Natuna basin is on the continental shelf of the southeastern South China Sea and is the Indonesian portion of the much larger Sarawak basin, which occupies a large portion of the northern offshore of Borneo (figs. 1, 51 and 60). As defined here, the boundary between the so-called East Natuna basin of Indonesia and the Sarawak basin of Malaysia is taken to be at the international boundary. The northern boundary of the East Natuna basin is likewise arbitrarily placed at the Indonesia-Viet Nam boundary (which is in dispute). The south and west edges of the basin comprise the shallow pre-Tertiary basement of the Sunda Shelf and its north-plunging extension, the Natuna Arch. It has an area some 27,000 mi^2 and a sedimentary fill of approximately 57,000 mi^3.

Exploration and Production History

The basin has been under fairly continuous, active exploration since the first wildcat was drilled in 1970. As of the end of 1982, 34 wildcats have been drilled resulting in two gas discoveries, AL-1X and AP-1X (fig. 60), a noncommercial oil discovery, Bursa-1 (12 MMBO?), and three noncommercial gas discoveries, Soklang-1, AV-1X, and Bantenal-1.

Depending on how the present noncommercial discoveries are eventually rated, a discovery rate of as much as 15 percent may be considered. Significant exploration is estimated at 40 percent complete, 20 percent for one play (lower Miocene sandstones) and 50 percent for the other (upper Miocene carbonates).

The L-1X gas discovery is enormous, with hydrocarbon gas reserves estimated to be in the order of 60 Tcf. Along with the hydrocarbon gas is about 200 Tcf of carbon dioxide. The disposal problem of this huge volume of carbon dioxide has been a problem affecting the production feasibility of the L-1X accumulation as well as other potential accumulations in the southern half of this province.

The large size of the L-1X trap appears to be anomalous to the area; no other mapped closure area approaches it in size, and it is evident that remaining untested traps are much smaller.

An oil discovery, Dua-2X, in Vietnam only 20 mi north of the Indonesia-Vietnam (disputed) boundary and within the same geologic province, tested 2,230 BOD and 17,600 MCFGD in 1974 (fig. 60). Two nearby Vietnam gas discoveries were made in 1980.

Structure

General Tectonics

The East Natuna basin is largely underlain by Mesozoic and Tertiary melange accreted with the South China Sea oceanic crust subducted westward

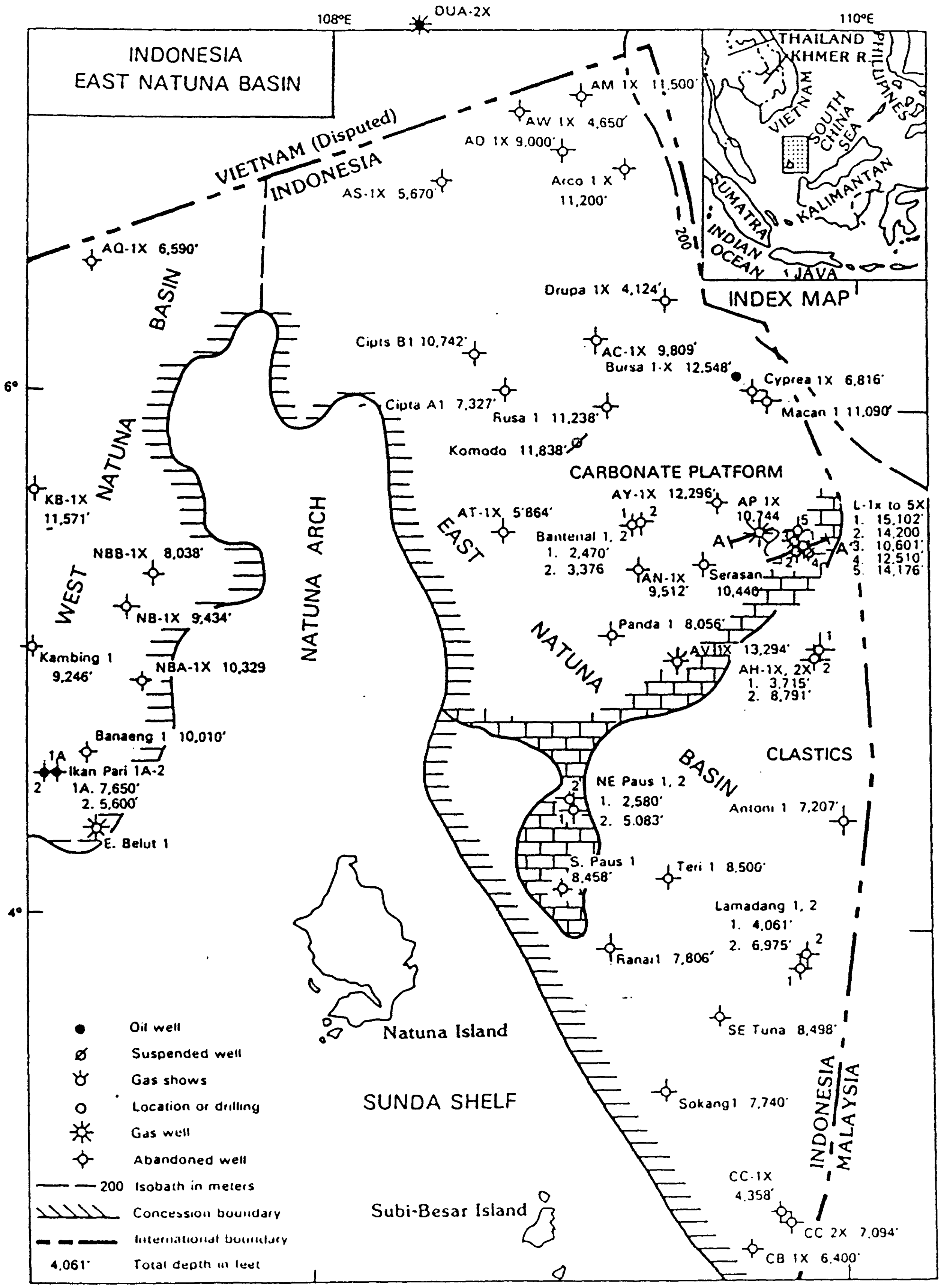


Figure 60.--Index map of East Natuna basin showing facies, and wildcats. Modified from Petroconsultants (1983).

beneath the Sunda continental block. An early Eocene (fore-arc?) ridge, the Paus-Ranai Ridge (fig. 53) trending northwestward across the southern part of the province, appears to be a remnant of that system.

Back-arc, northwest-southeast spreading and opening of the South China Sea began in the Oligocene and continued until middle Miocene. The continental crust underlying a substantial part of the South China Sea, including the Sarawak basin and at least the eastern East Natuna basin, became attenuated. The crustal attenuation, combined with the southward opening movement, resulted in a general foundering or subsidence accompanied by numerous tensional faults and dextral wrench movement in the vicinity of East Natuna basin (fig. 54). Considerably more parallel, dextral wrench movement, not shown in figure 54, is presumed to be just east of the province in Malaysia. Maximum subsidence was in late Miocene after the spreading of the South China Sea had ceased.

Two principal trends developed largely during the early Oligocene and early to middle Miocene periods: (1) a northeast-southwest trend which extends southwestward from the axial spreading ridge of the South China Sea and has considerable strike-slip movement (especially in the adjoining West Natuna basin), and (2) a north-northwest to south-southeast trend of normal faults with some dextral wrench movement in Indonesia (figs. 53 and 54). Associated fault traps and folds are discussed under the pertinent plays. Subsidence continued through the Pliocene and Pleistocene.

Structural Traps

The structural traps are drapes and fault closures associated with the faults of Oligocene to middle Miocene time. Apparently there are few drag folds to accompany the evident, but unmapped, wrench faults. The Al-1X reef, however, may be situated on a possible drag fold along a regional transverse or wrench fault, approximately along the Indonesia-Malaysia border, associated with the Oligocene-Miocene opening of the South China Sea (figs. 54, 60, and 61).

From observation of unpublished maps, approximately 6 percent, or 1.0 million acres, of the play area is estimated to be under drape or fault closure. Possibly 20 percent of the closures are tested reducing the untested trap to 800 thousand acres. Reefal traps are discussed under Reservoirs.

Stratigraphy

The main units of the stratigraphy are displayed in the diagrammatic stratigraphic section across the outer eastern edge near the AL-1X gas accumulation (fig. 61).

About 6,000 ft of lower Miocene (latest Oligocene to middle Miocene) fluvial and deltaic sediments, the Arang Formations (with possible Gabus and Barat Formations at depth) were deposited over the accreted, stable platform. These shales and sandstones contain thin coal beds becoming less common upward; the strata become marine near the top.

At the end of the Arang deposition (middle Miocene) (fig. 61), some tensional faulting and tilting of fault blocks occurred prior to the formation of a stable platform upon which shelf carbonates were deposited (fig. 62). By the end the late Miocene, some 5,000 ft of shelf-type carbonates, the Terumbu Limestone, covered the northern 60 percent of the basin (fig. 60). During late Miocene, reefs and mounds grew on the topographic highs on the carbonate platform (the large AL-1X accumulation is just on the east platform edge (fig. 61).

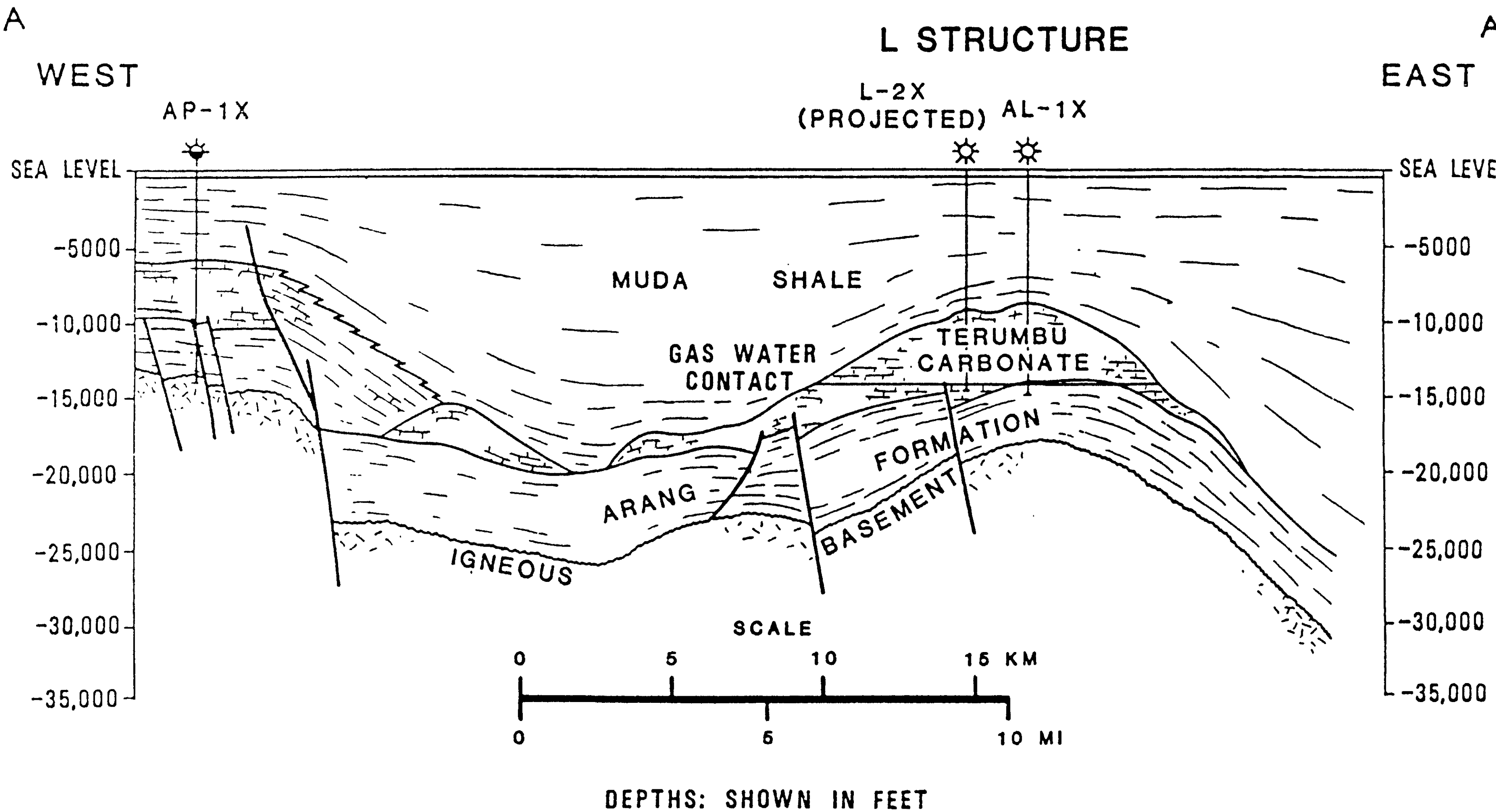


Figure 61.--West-east geologic section across east edge of carbonate platform, East Natuna basin. From Eyles and May (1984). Location on Figure 60.

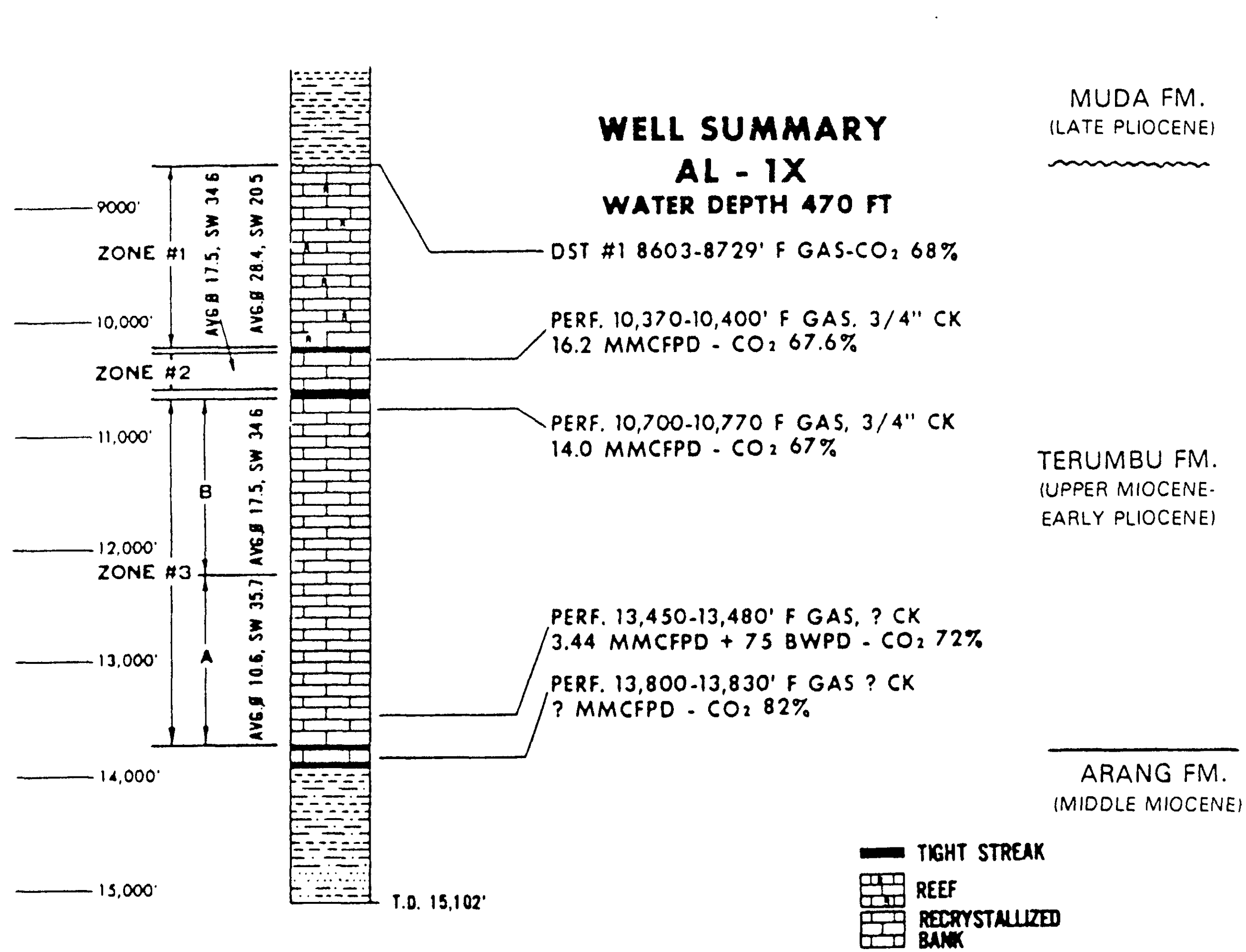


Figure 62.--Well summary, AL-1X wildcat, East Natuna basin. After Sangree (1981).

Deep regional subsidence in late Miocene and Pliocene resulted in thick deep-water shales being deposited directly on Terumbu carbonates. This 8,000 to 20,000 ft of subsidence provided a thick seal, the Muda Formation shales, to potential carbonate reservoirs and provided sufficient depth for maturation of the underlying lower Miocene shales (figs. 61 and 62).

Reservoirs

The two principal sets of reservoirs essentially define the two plays of the basin.

1. Early Miocene drapes and fault traps

No specific data are available concerning the sand reservoirs of the lower Miocene (and Oligocene?) formations. Reportedly, the average pay thickness is around 175 ft in the northern area under the Miocene Terumbu carbonate platform. Further southward, however, the reservoirs become gradually less developed. It is estimated that the average net reservoir thickness for the entire basin is about 100 ft.

2. Miocene (Terumbu) carbonates

From study of unpublished maps of part of the play area, we estimate that 7 percent of the carbonate platform, i.e., the play area, is reefal trap of which about half has been tested.

Although the best reservoirs are the reefs perched on the highs of the carbonate platform, the shelfal carbonates themselves have developed porosity. For example, the AL-IX gas discovery found 5,250 ft of porosity of which only about 2,000 ft are reef or reef complex. The reef (zone 1) averages 28.4 percent porosity; the reef complex (zone 2), 17.5 percent; and the shelf (zone 3), 14.5 percent (fig. 62). These thicknesses seem to far exceed those of the other prospective reservoirs of the play, and the thick porosity zone in the shelf appears to be unusual; for evaluation of undiscovered petroleum, an average pay of 700 ft is assumed, with an estimated average porosity of 22 percent.

In considering the volume of oil and gas in the reservoirs of this basin, one must keep in mind that the chief occupant is carbon dioxide gas, averaging about 60 percent of the pore space.

Seals

The thick, largely shale Muda Formation provides a sufficient seal to petroleum accumulations in the Terumbu reefs and shale of the Arang Formation and should be sufficient for sealing sand reservoirs of the Arang and older formations.

Source Section

The early to middle Miocene shales of the Arang and older formations constitute the principal source rocks of the basin (see Generation and Migration below).

Petroleum Generation and Migration

Richness of Source

No specific organic richness data are available, but according to Wirajudo and Wongsosantiko (1983), geochemical analyses indicate "fair to good source rock potential for both oil and gas" in the lower Miocene Arang Formation. Although primarily gas prone, the coaly beds are reported to contain up to 25 percent waxy sapropels, which are known as oil source kerogen. Sangree (1981) states that "the Arang Formation (lower Miocene) is considered the primary source of hydrocarbons for Miocene reservoirs in the area, based on organic content and evidence of maturation of kerogen."

The source of the principal resource of the basin, carbon dioxide, is not known. There appears to be a direct correlation between the high thermal gradients and the high percentage of carbon dioxide. It is believed by some that carbon dioxide is derived from deeper igneous sources (Sangree, 1981), or thermally altered limestone at depth.

Depth and Volume of Source Rock

The average thermal gradient of the basin is high, averaging about 2.5°F per 100 ft but with a considerable part to the south over 3.0°F per 100 ft. The rate of subsidence (Pliocene and Pleistocene) is very high, around 1,800 ft per million years, placing the top of a rather thin oil-mature zone at about 9,000 ft (2,700 m) and the top of the overmature (gas) zone at 10,000 ft (3,000 m). At this depth, the lower Miocene shales are either mature or overmature in all but the more shallow western side of the basin. Wirojudo and Wongsosantiko (1983) confirm that "mature Miocene exists in the eastern and southeastern part of the study area." Sangree indicates, as quoted above, that the Arang kerogen is mature at AL-IX. In any event, there appears to be sufficient mature and overmature source rock; a volume of 17,000 mi^3 is estimated.

Oil versus Gas

On the basis of occurrence, the basin appears to be gas prone. The nonmarine source and the relatively shallow overmature zone also indicate predominance of gas over oil (although the sapropelic coal indicates some oil potential). At least one small noncommercial oil accumulation, Bursa, exists in the area, and the Vietnam discovery, Dua-2X (20 miles to the north), tested 2,230 BOD.

No pressure data are available, but wildcat AH-2X encountered abnormally high pressures below 4,500 ft. If these abnormal pressures are extensive, it would mean that most of the Miocene reefs would be encased in overpressured massive Muda shale, which would allow the primary migration of only the smaller (i.e., gas) molecules into the reefs. The underlying Arang and older formations have much interbedded sand so that the overpressure conditions may not prevail, allowing the primary migration of the larger molecules of oil. Oil is estimated to make up 5 percent of the oil-gas mix in the carbonate reservoirs and about 20 percent oil for the oil-gas mix in the underlying shale and sandstone series.

Migration Time versus Trap Formation

It appears quite evident that generation and migration began in the Pliocene when the basin very rapidly deepened so that the lower Miocene shale became thermally mature, and in part overmature, in all but the most western area. Additionally, the Pliocene shale would be in part mature.

Trap formation was in two periods: (1) early middle Miocene tensional faulting and fault-block tilting caused closure affecting lower Miocene sandstones (fig. 54 and 61), and (2) growth of reefs in late Miocene and early Pliocene with possibly secondary porosity development as late as late Pliocene (fig. 62). Both sets of reservoirs were formed before the main Pliocene petroleum generation and migration. There would be time for reservoir deterioration of the lower Miocene sandstones, and to a lesser extent the upper Miocene carbonates. In general, it would appear that migration timing for gas at least was fairly optimal, primary oil migration probably being inhibited by overpressured shale.

Limiting Factors

The overriding limiting factor appears to be the great volume of carbon dioxide which largely occupies the reservoirs. Another limiting factor, mostly affecting oil, is the inhibiting effect of overpressured shale on primary migration.

Plays

The prospects of the basin fall into essentially two plays.

1. <u>Miocene drape or fault closures</u>

Potential petroleum accumulations in Oligocene to middle Miocene sandstones are involved in drape or fault-closures. The play area encompasses the entire basin about 27,000 mi^2 or 17.3 million acres.

2. <u>Late Miocene carbonate reservoirs</u>

Potential petroleum accumulations are in upper Miocene (Terumbu Formation) reefs and platform carbonate reservoirs in drapes or fault traps. This play is limited to the carbonate platform area which covers approximately the northern 60 percent of the basin or about 10 million acres (fig. 60). The base of the platform carbonate is at a depth of about 5,000 ft, sloping gently basinward (eastward) to the Malaysian border. It is limited to the south by a diagonal, northeast-trending hinge line at about 5°30'N (fig. 60). A tail of poorly developed carbonate thins southward along the Paus-Ranai Ridge (fig. 60).

Salawati-Bintuni Basin

Location and Size

The Salawati-Bintuni basin is on the Kepala Burung (Birds Head) Peninsula in the western part of the island of New Guinea (the Indonesian province of Irian Jaya) (figs. 1, 63, and 64). It has an approximate area 56,000 mi^2 and a sedimentary volume of 105,000 mi^3. This basin is often divided into two separate basins, i.e., the Salawati and Bintuni basins. However, they are here regarded only as subbasins of the Salawati-Bintuni basin, since the

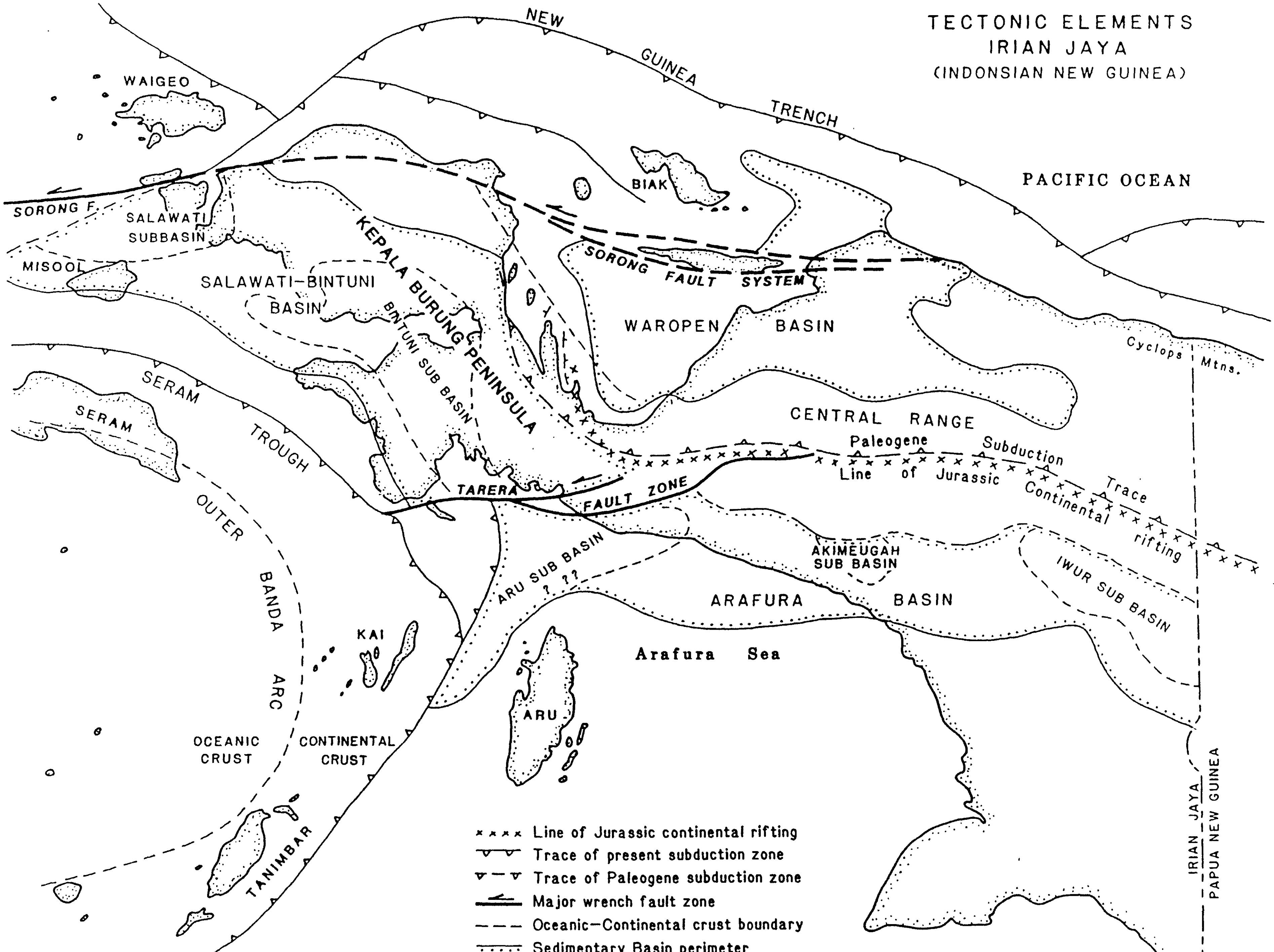


Figure 63.--Map showing tectonic elements of Irian Jaya (Indonesian New Guinea). Modified after Hamilton (1979).

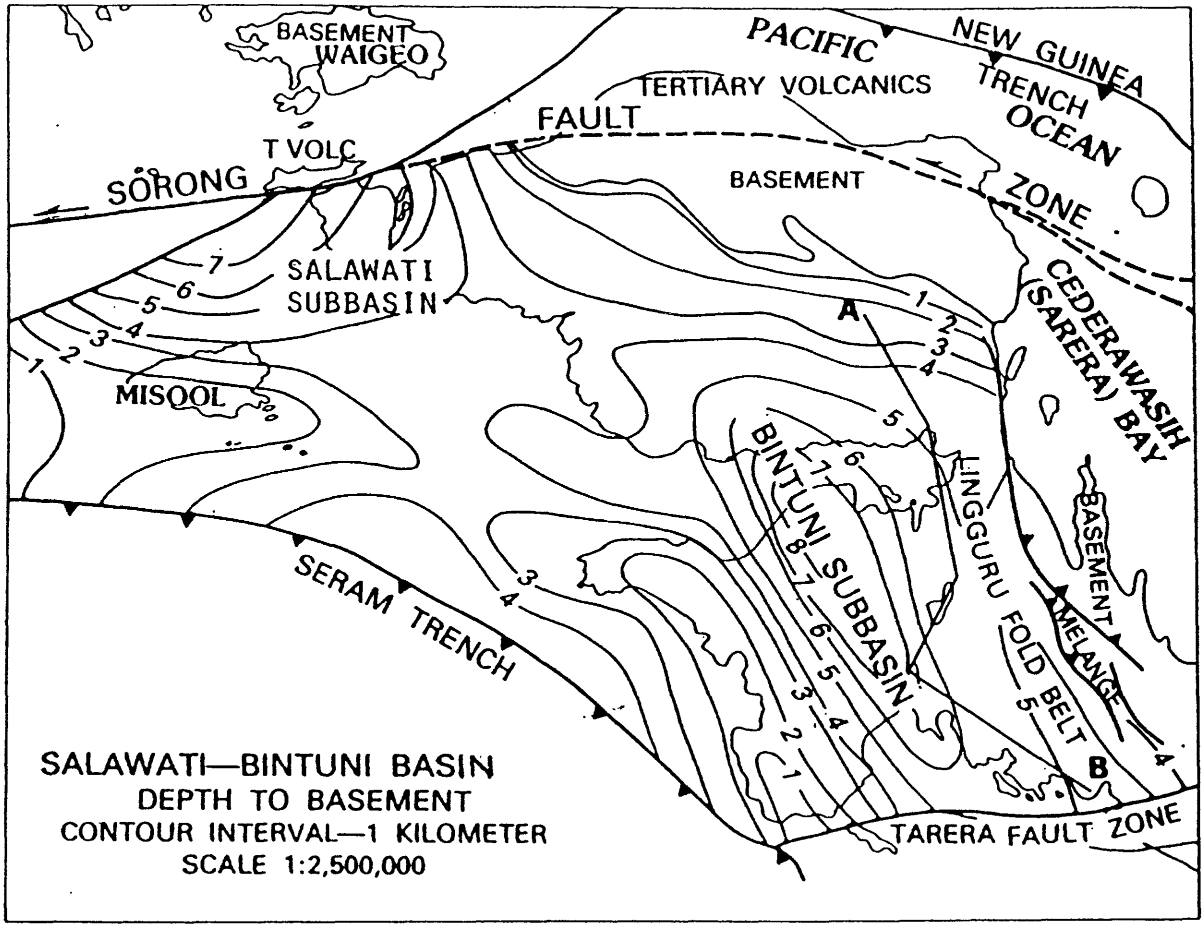


Figure 64.--Structure contour map of the Salawati-Bintuni basins showing the depth to basement and principal tectonic elements. After Hamilton (1979).

saddle between the two is more than 10,000 ft deep and some plays appear to extend across the basin.

Exploration and Production History

The first wildcat was drilled in 1936 and it discovered the first oil, Klamono field (fig. 65). Prior to 1962, 25 additional wells drilled in the Salawati subbasin resulted in the finding of two small noncommercial oil accumulations (Klamumuk and Sele), but no further discoveries were made in this phase of the exploration. In renewed exploration, the second discovery was made at Kasim in 1972. In all, some 145 wildcats have been drilled in the Salawati subbasin since then, resulting in 23 oil discoveries and 7 gas discoveries for a success rate of about 20 percent. In the Bintuni subbasin 40 wildcats have resulted in four discoveries (Mogo, Wasian, Wiriagar, and Suga), giving a discovery rate of about 10 percent. Original reserves of 415 million barrels have been established in the Salawati subbasin. Production is yet to be initiated in the Bintuni subbasin.

Although the exploration of the Salawati subbasin has been described as intensive, considering the apparent small size of most of the carbonate buildups, appreciably more oil and gas fields probably will be found as the seismic grid is refined and techniques improved; exploration is judged to be in early maturity, i.e., about 70 percent complete. The Bintuni subbasin, on the other hand, may be only 30 percent complete.

The production is unusual because of the high permeability of the fractured Kias reservoirs. As a consequence, initial production rates are high, e.g., up to 32 MBOD from a single well. For the same reason, decline rates are high; e.g., Phillips production from a combined development of six small accumulations on Salawati Island was originally projected for 55 MBOD (Pulling and Spinks, 1978) and produced 35.6 MBOD in 1978, 8.5 MBOD in 1979, 6.0 MBOD in 1980, 4.3 MBOD in 1981, and 3.4 MBOD in 1982. The decline is accelerated by the breakthrough or coning of water in the smaller fields. This problem is being alleviated to some extent by the application of gas lift. For example, Kasim (fig. 65) peaked at 15.3 MBOD, declined to 5.2 MBOD in 1981, and rose to 8.4 MBOD in 1982 after gas injection.

Structure

General Tectonics

The tectonics of the New Guinea Island, including Irian Jaya and the Kepala Burung Peninsula, are complicated and obscure but relevant to the petroleum occurrence of the area (fig. 63). There are various interpretations of the regional tectonics; this study generally follows those of Hamilton (1979).

As inferred from Permo-Carboniferous interior-platform type sediments and older north-trending structure, the New Guinea-Australia continental block was part of a larger block extending to the north. The block was rifted apart in mid-Jurassic, as indicated by Triassic-Jurassic typical terrestrial graben-fill sediments. The resultant rifted continental margin trace extended east-west through medial New Guinea, the Central Range, and along the Kapala Burungs Peninsula's then north side (now the east side since the peninsula has subsequently apparently rotated almost a quadrant clockwise) (fig. 63). Horst and graben structure, developed during this rifting, affected the detailed configuration of the Neogene basins, i.e., the pre-Tertiary ridges formed

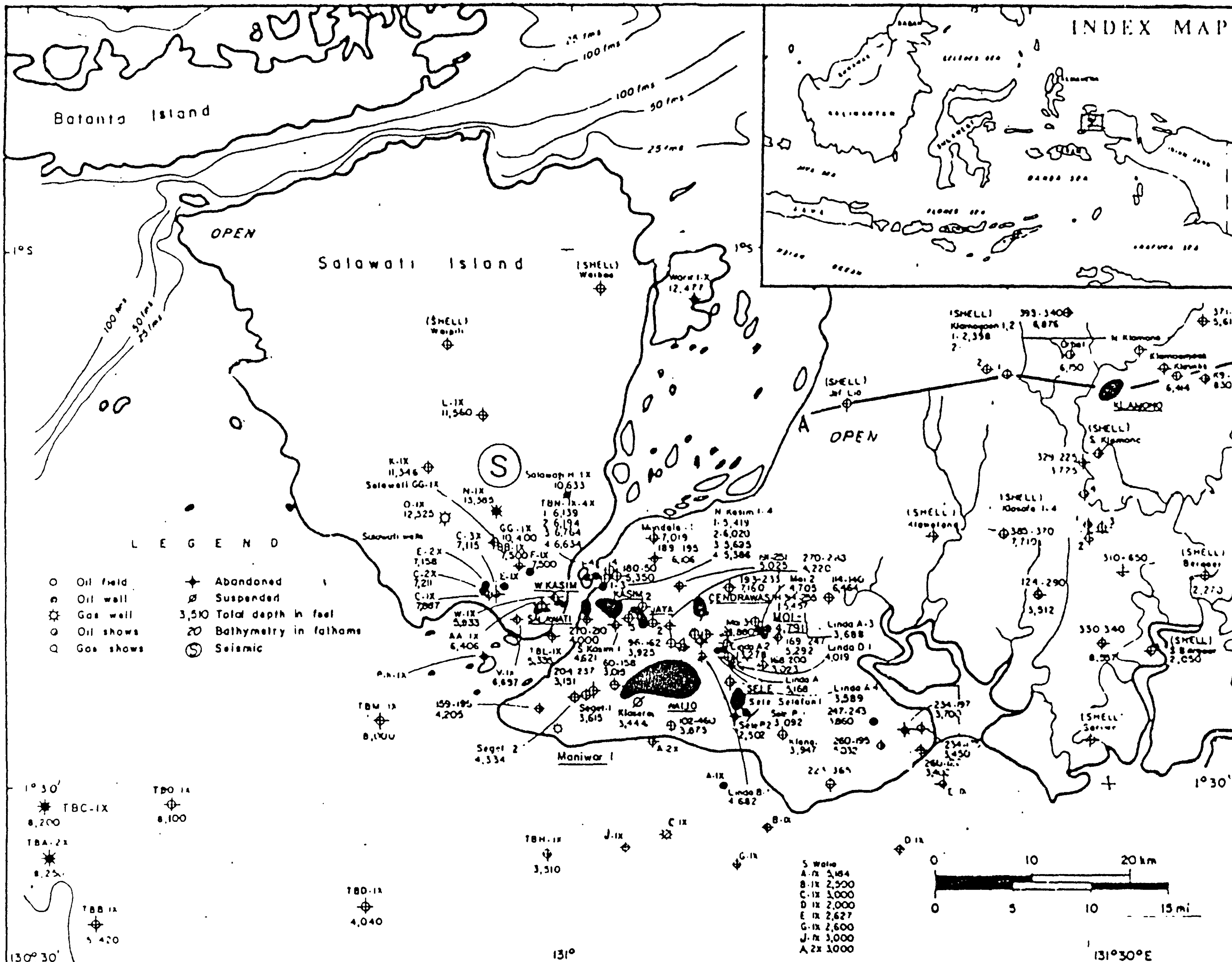


Figure 65.--Index map showing location of fields and significant wildcats, Salawati basin. From Petroconsultants (1981).

Cretaceous and Tertiary drapes and loci for Tertiary reef development (fig. 66).

A later Mesozoic (Late Jurassic) rifting separated the New Guinea-Australian continental block from a more western continental block (India?). The resultant north- trending rifted continental margin is clearly evident along the west margin of Australia, but in the region of the Kepala Burung Peninsula, it is obscured by the later Tertiary tectonics involving the push of the Sunda Arc to the east and the effects of the Pacific plate movement to the west (fig. 63). However, this Mesozoic rift-tectonics framework and attendant horsts and grabens may not have been entirely obliterated and it appears that these fault patterns may have controlled to some extent the distribution of Miocene subbasins and reef distribution.

After the Jurassic continental margin rifting, the New Guinea-Australia continental block was fairly stable through the Paleocene, the southern half of New Guinea being essentially a marginal shelf sloping northward to the block-edge (i.e., the rift zone through medial New Guinea).

The New Guinea-Australia continental block riding on a north-moving plate during the Paleogene collided in the Miocene with a Paleogene island arc under which the north-moving plate was subducting. This collision caused the uprising of the Central Range of New Guinea (including the then west-trending, now north-trending, east side of the Kapala Burung Peninsula). Along this zone are crumpled and south-thrusted shelfal sediments on the continental (southern) side, and melange and island-arc volcanic material on the oceanic (northern) side.

With the arrival of the buoyant New Guinea-Australia continental block, the northward subduction choked and stopped. The continuing north-south compression of the lithosphere was then taken up along a newly-formed, Neogene, southdipping subduction zone. This subduction zone is still active, offshore of, and dipping under, northern New Guinea, i.e., the New Guinea Trench (fig. 63). Neogene activity on this southward subduction has raised the northern edge of New Guinea into intermittent ranges or outer-arc ridges, concurrently forming an fore-arc Neogene basin to the south, the Waropen basin (fig. 63). Renewed uplift of the medial or Central Range shed sediments to fill both the Waropen basin to the north and the old north-sloping shelf or foreland area, the Arafura basin, to the south (fig. 63).

There is a strong westward, strike-slip component to the Neogene southward subduction forces, manifested by great west-trending sinistral wrenches along northern and central New Guinea, particularly in the western part. Most of the recognized faults are in the so-called Sorong Fault zone, which extends from north-central Irian Jaya to the Celebes, and the Terara Fault zone, which extends from south-central Irian Jaya into the Seram Trough of the Banda Arc (figs. 63, 64, and 66). Large continental fragments have been wrenched westward from the New Guinea-Australian continental block smashing into the Banda Arc area and the Celebes (Sulawesi). The Kepala Burung Peninsula itself is considered by some to be such a detached continental block transported from the east.

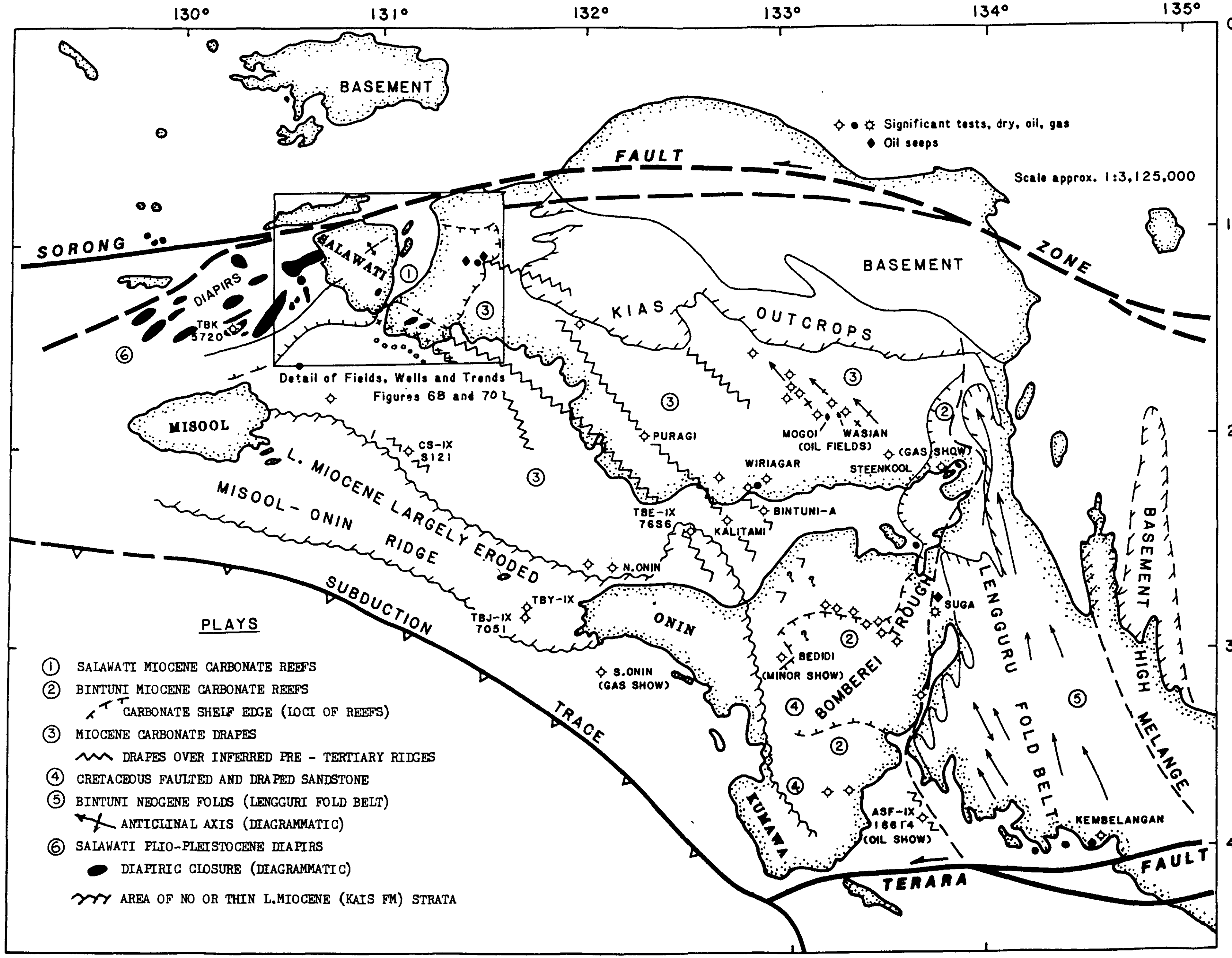


Figure 66.--Map of Salawati basin showing area of plays, trends, and significant tests.

Structural Traps

Structural traps are in three groups: 1) drapes and fault traps along a northwest-trending, pre-Tertiary rift pattern of ridges, horsts or tilted fault blocks (fig. 66), 2) late Tertiary north-northwest-trending relatively tightly folded and thrusted anticlines of the Lengguru foldbelt, and 3) diapirs in the western depocenter of the Salawati subbasin.

The drape and faulted features follow northwest-trending buried rift features apparently paralleling the pre-Tertiary (Jurassic?) rifted northern margin of the Australia-New Guinea continental block (orginally east-west, now northwest-trending after the clockwise rotation of the Kepala Burung Peninsula). This drape play probably extends over all of the Bintuni subbasin, excluding the later compressional Lengguru Foldbelt but including the Misool-Onin-Kumawa Ridge (fig. 66). The play area is approximately 18.6 million acres for the Cretaceous reservoirs (largely missing from the Salawati subbasin). The Tertiary reservoirs on the other hand are missing from the Misool-Onin-Kumawa Ridge, giving a play area of 12 million acres. From information in published and unpublished structural maps of the area, drape closures are estimated to make up about 5.5 percent of the drape play area. This works out to be a million acres for the Cretaceous reservoirs and 660,000 acres for the draped reservoirs at Miocene level.

The relatively tightly folded and thrusted, north-northwest-trending Lengguru Foldbelt (fig. 66) covers 6.14 million acres. By analogy to somewhat similar foldbelts of Indonesia (e.g., Kutei basin folds with trap area making up 3 percent of the play area and North Sumatra with traps making up 8 percent), traps are estimated to make up 5 percent of the play area or about 307,000 acres.

Diapir folds involving Pliocene sandstones and shales occur in the deeper basinal area of the Salawati subbasin (fig. 66). Information from an unpublished map shows there are approximately 154 thousand acres of trap.

Stratigraphy

The stratigraphy of the Salawati-Bintuni and of the Arafura basins is similar, but the pre-Tertiary formations are better exposed in the Arafura basin. The general stratigraphy of these two basins (as exposed in the Arafura basin) is shown in figure 67.

Western Irian Jaya sedimentation began when upper Carboniferous to Permian, often highly carbonaceous, clastics of the Aifam Group were laid down in a stable, probably interior, platform. This was succeeded by the Tipuma Formation of graben-deposited Triassic terrestrial red and green shales and sandstones, undoubtedly associated with the faulting, attenuation, and final rifting along the north margin of the Australian-New Guinea continent.

The Kembelangan Group of Middle Jurassic to upper Cretaceous marine sand stones and mudstones, derived from the New Guinea-Australian continent to the south, were deposited on the broad north-sloping shelf which extended across the present southern half of Irian Jaya and occupied the Bintuni subbasin, but was largely missing from the Salawati subbasin of the Kapala Burung Peninsula.

With waning clastic deposition, a carbonate regime set in and persisted over the shelf through the late Cretaceous to late Miocene, resulting in the thick New Guinea Limestone Group covering all of southern Irian Jaya and the Kapala Burung Peninsula. The youngest unit of this group, the Kias Formation, contains the principal petroleum-bearing reservoirs of the Salawati subbasin (fig. 68).

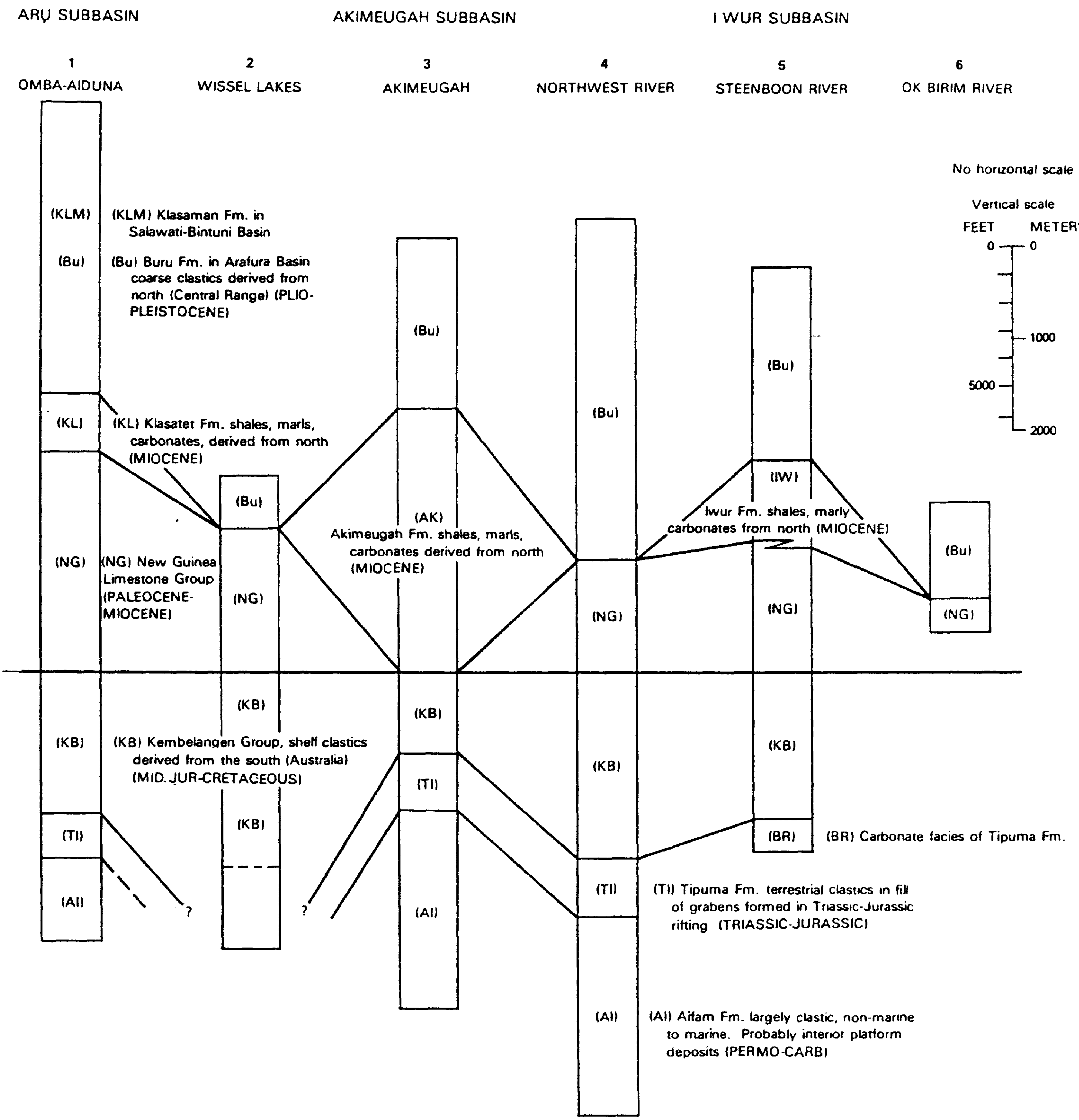


Figure 67.--West-east outcrop sections, Arafura basin, Irian Jaya; also applicable to the Salawati-Bintuni basin. Sections from Wisser and Hermes (1962).

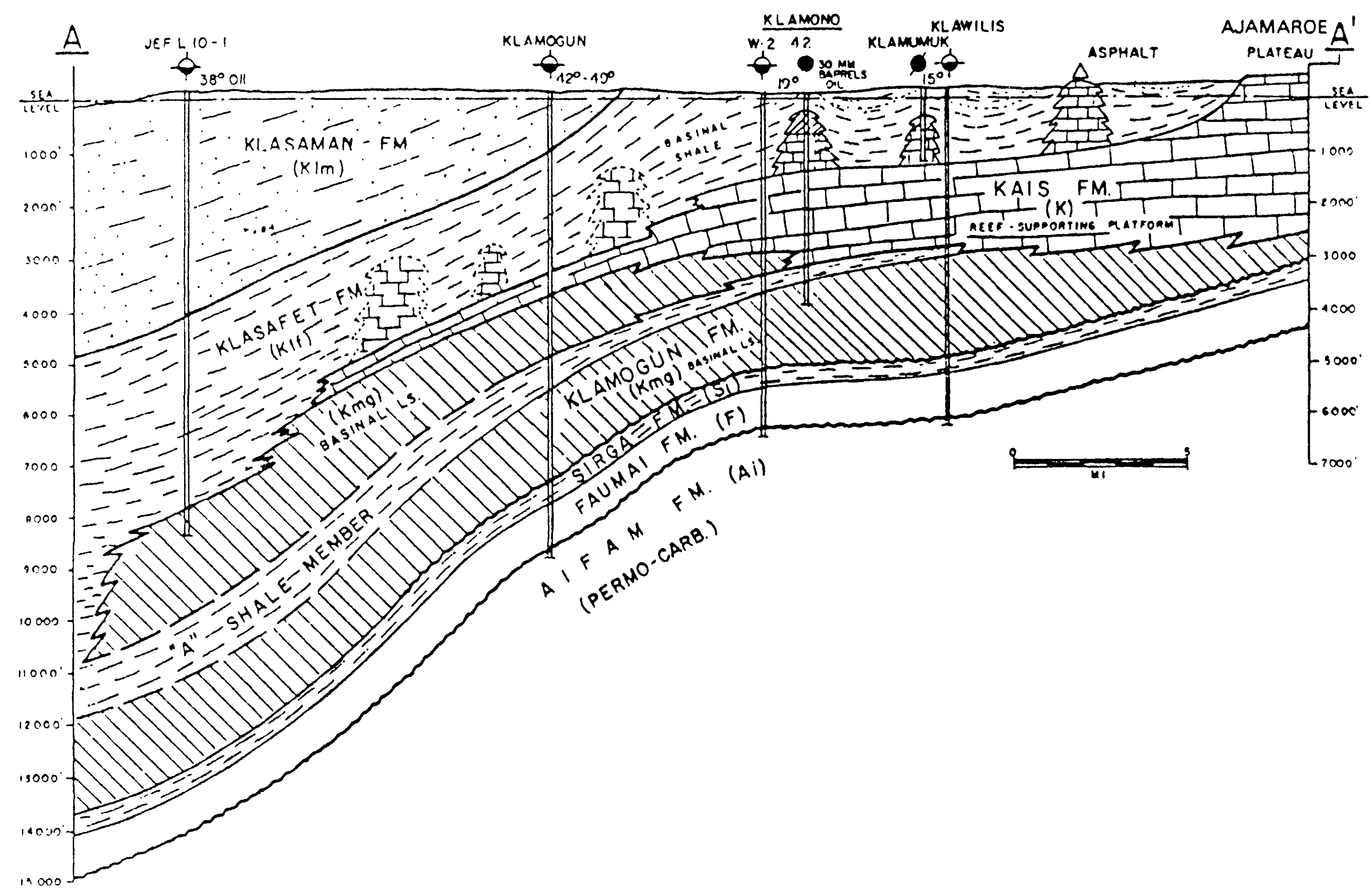


Figure 68.--West-east geologic cross-section A-A[1], Salawati subbasin. From Vincelette (1973). Location figure 65.

During the Miocene, the carbonates were succeeded by shales and marls of the Klasafet Formation, the transition apparently occurring earlier in the deeper, more basinal areas (fig. 68). In both the Salawati and Bintuni subbasins, the Klasafet Formation occupies the basinal areas but is thin or missing on the perimeter of the basins. Figure 68 demonstrates this condition for the Bintuni subbasin. Similar shale-carbonate subbasins occur along the strike of this Paleocene-Miocene carbonate shelf, i.e., the Aru, Akimeugah, and Iwur subbasins of Arafura basin (figs. 63 and 67).

Unconformably overlying the Klasafet shales in the deeper subbasins and the New Guinea Limestone Group in the perimeter areas are Pliocene coarser clastics, the Klasaman, Buru, and Steenkool Formations (figs. 66 and 68). These clastics moved southward from the Central Range (and its extension, the Lengguru foldbelt, presently along the east side of the Kepala Burung Peninsula).

Reservoirs

Potential reservoir zones exist in three general zones: 1) Cretaceous upper Kembelangan Group sandstones, 2) Miocene upper New Guinea Limestone Group carbonate (Kais Formation), and some sandstone reservoirs, and 3) Pliocene Klasaman-Steenkool sandtones. Of these reservoirs only the Kais Formation has produced oil.

1. Kembelangan Group Sandstones

The Kembelangan Group is a 6,000-ft thick sandstone and shale unit with subordinate carbonate, which extends the length of southern New Guinea-Irian Jaya; and in fact equivalent formations cover a great area of southern Papua, New Guinea and the Australian offshore. The Kembelangan Formation thins southward; and in the Kepala Burung Peninsula thins northwestward so that it is generally missing from the Salawati subbasin. According to Visser and Hermes (1962), the sandstones as found in outcrop are "mineralogically mature, consisting mainly of quartz, very subordinate feldspar and clay minerals. Sorting is generally good." The Kembelangan outcrops reportedly become more sandy toward Australia.

As encountered in the few wildcats, however, the reservoirs appear to be fair to marginal, the best reservoirs appearing to be in the sandstones near the upper part of the formation, as variously reported from the following wells:

Kembelangan-1 - Although tight in the well, these upper sandstones grade laterally into well sorted, clean sandstones in adjacent outcrops. (There is a lost circulation zone near the base of the Kembelangan Formation.)

Puragi-1 - The uppermost 165 ft of Kembelangan contains some 100 ft of porous sandstone; a weak flow of brackish water was tested.

Sago-1 - Some 130 ft in the upper Kembelangan had porosities ranging from 3 to 24 percent.

TBF-1 - A "few tens of meters" of porosity ranging from 8 to 17 percent are in this interval.

TBE-1 - Some good porosities were measured from cores but with low permeabilities.

TBJ-1 - In a more calcareous facies, there was found a net thickness of 1,650 ft in carbonate, a porosity with values of 5 to 24 percent, and 100 ft of porous sandstone with even "better porosity."

ASF-1 - Found a zone of 84 ft of net sandstone thickness of porosities of 8 to 17 percent, which when tested recovered 6,900 ft of gas cut mud.

For evaluation purposes, we assume a basin-wide average thickness of 100 ft with a porosity of 15 percent for the Kembelangan sandstones.

2. <u>Miocene Kais Reservoirs</u>

The Kais reservoirs are largely carbonates in the form of reefs, banks, or porous zones in back-reef environments. Some sandstones are present at the equivalent to the base of the Kais (the Sirga Formation).

The reefs and buildups are associated with the carbonate platform edges in the Salawati and Bintuni subbasins (figs. 66, 68, 69, and 70). Only the Salawati carbonates have produced oil, and accordingly their reservoir characteristics are better known. Maximum vertical bank buildup of the Salawati reefs is about 1,600 ft. The net thickness of the porous zone varies from 30 to 700 ft, and an average net pay of 165 ft for reefal closures is estimated. The play area of the Salawati reefs is some 1.5 million acres (see Plays). A published map (fig. 70) indicates that carbonate reefs make up about 6 percent of the play area, or about 90,000 acres.

The porosity of producing reservoirs varies up to 24 percent in the Walio and Klamono fields, but is as low as 15 percent in Linda or 12 percent in Sele, perhaps averaging about 20 percent. Apparently most of the porosity is secondary, vuggy and moldic. Fractured zones have large permeabilities, e.g., a dolomite zone in Kasim, Utara-1, tested over 32,000 barrels per day. The oil recovery rate for the Klamono oil field is 531 barrels per acre-foot (Vincelette, 1973).

Of particular note should be the high permeability, which, together with an active water drive, introduces not only high initial flow rates, and consequently relatively steep decline rates, but also early breakthrough of water, particularly in the smaller accumulations, requiring secondary recovery procedures, mainly gas lift.

The reefs of the Bintuni subbasin would theoretically be developed along the carbonate platform or shelf-edge (second play of fig. 66), an area of some 5 million acres (see Plays). Wildcatting to date has failed to find any viable reef or porous carbonate buildup in this play. It has been postulated that this absence is because of an unstable, migrating shelf-edge or low wave energy level (i.e., low topographic position). However, pinnacle reefs, having small areas, could be missed in this area where, except for the northern edge of the Bomberai Trough, the average seismic grid is only 6 by 10 km. For assessment purposes, it is estimated that some 3 percent of the reef-edge play area may have reef traps (versus 6 percent for the Salawati subbasin).

The generally back-reef facies of the Kais Formation, which is involved in the Miocene drape play, has some porosity; it ranges over a large part of the Salawati-Bintuni basin, south of the Kais outcrops, between the shelf-edge area of the Salawati subbasin and that of the Bintuni subbasin (play 3 of fig. 66) and covers an area of 12 million acres. Within this regional back-reef facies, there are carbonate banks which appear to be localized along old structural/topographic highs. Most of these porous zones appear to be in part reefal. Porosities are irregular and lower than the Salawati reefs. At the Wasian and Magor oil fields, and in nearby wildcats, porosities are at most 14 percent, except where fracturing raised it to 22 percent at Kaibur. Porosities are likewise low in central Bintuni except where there is fracturing. Porosities are higher, however, at Bintuni A-1, averaging 32 percent, and are presumably equally as good at Wiriagor. Twenty percent porosity is estimated for the back-reef facies play.

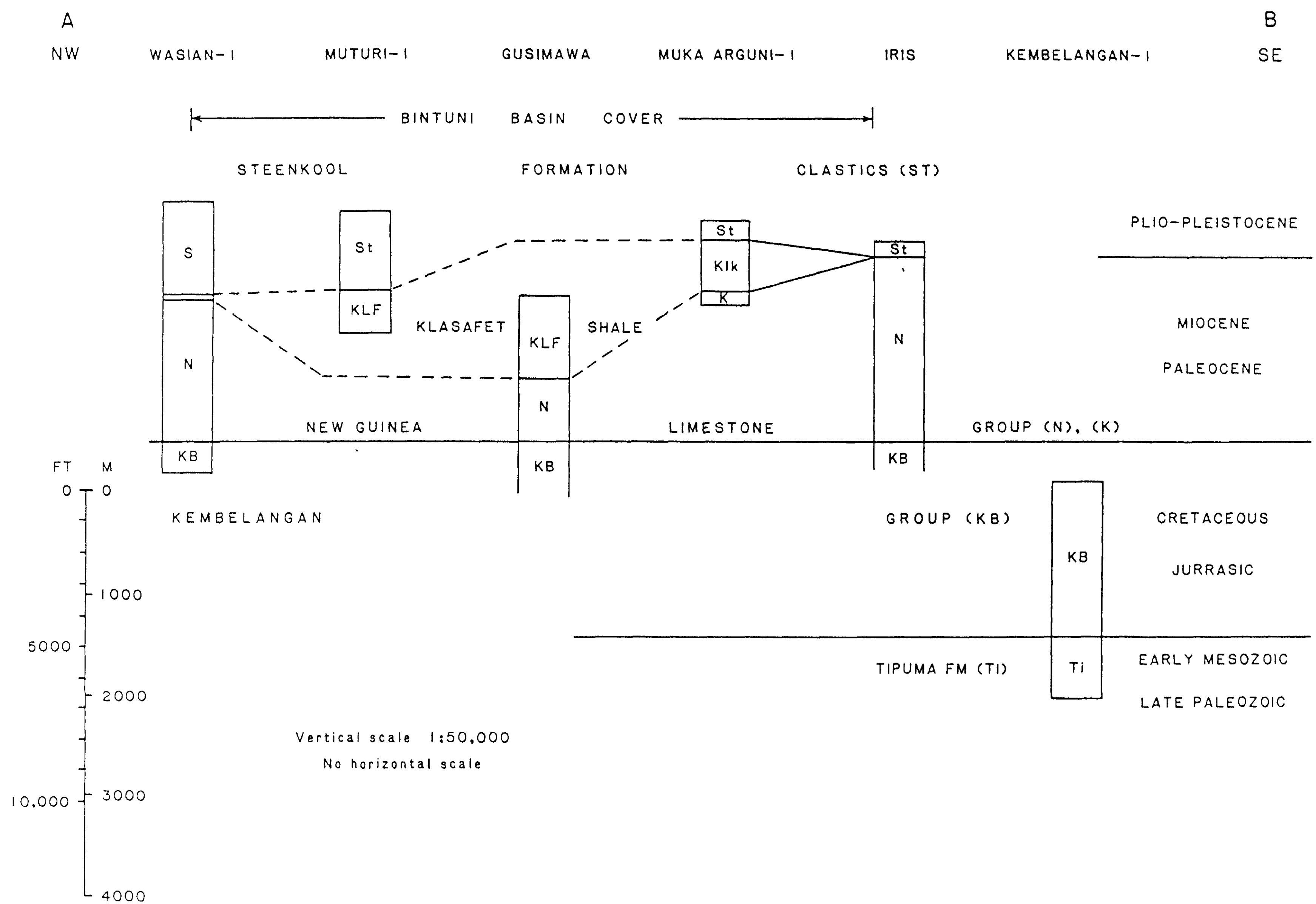


Figure 69.--NW-SE stratigraphic sections, A-B, Bintuni subbasin. Sections from Visser and Hermes (1962).

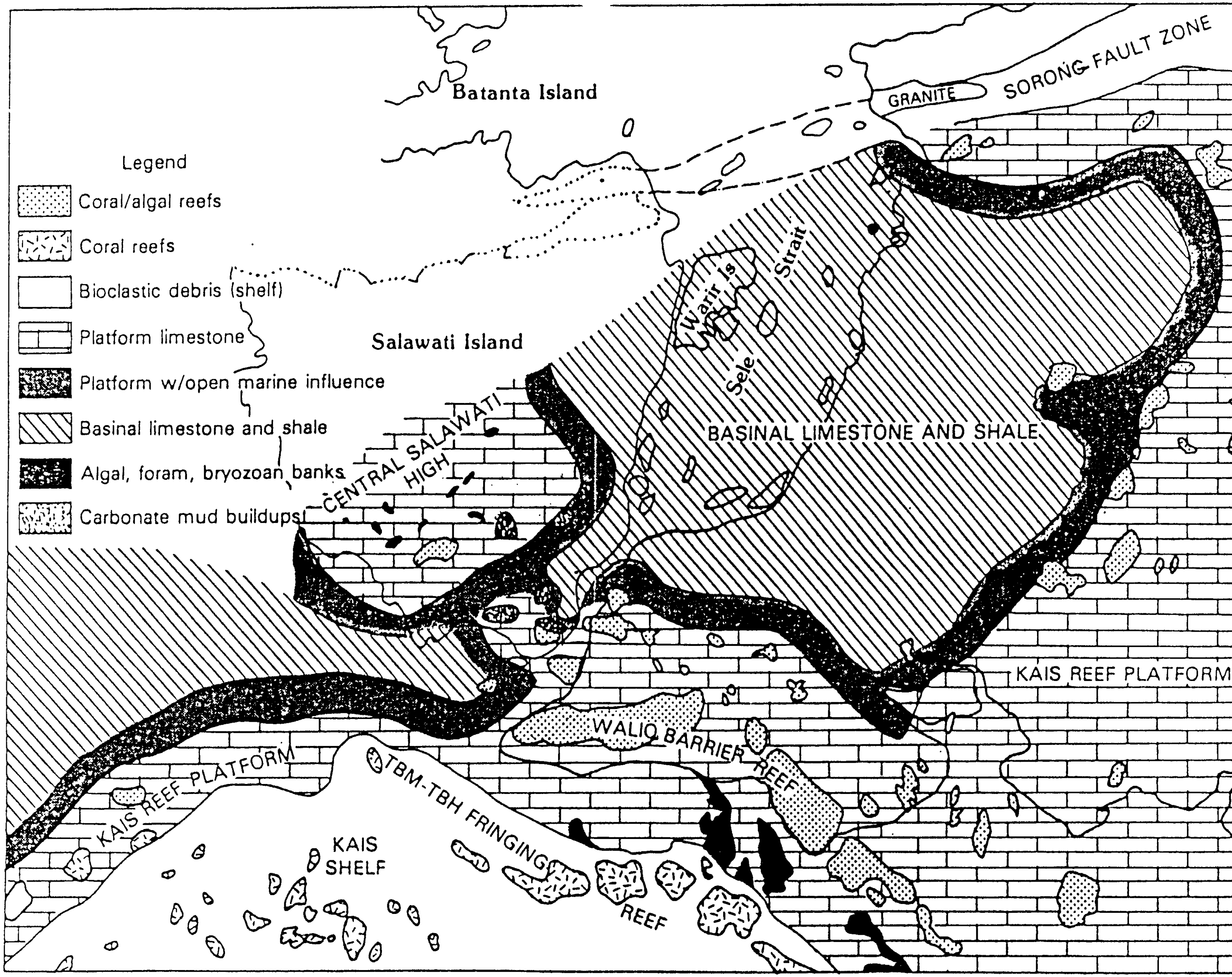


Figure 70.--Kais facies map, Salawati subbasin. From Pulling and Spinks (1978).

Thickness data are not available, but an effective pay thickness of about half that of the Salawati reefs or about 83 ft appears reasonable.

3. Klasaman steenkool Sandstones

The Pliocene-Klasaman-Steenkool rock group is a 15,000-ft paralic sequence of sandstones and shale with some marine interbeds. It overlies the Klasafet shales in the basinal areas, and older rocks on the basin periphery, by an evident hiatus. Little reservoir data are available. Steenkool-1 (fig. 66) drilled in the northern Bintuni subbasin found "many well developed sands of good reservoir characteristics" (Visser and Hermes, 1962). For assessment purposes, it is assumed that average net pay thickness is at least 100 ft with a porosity of 20 percent. These shallow reservoirs are not regarded to be of much significance because they generally lack sufficient cover.

Seals

From oil stains below the present oil-water contacts, it appears that considerable amounts of oil, probably at least half, have escaped present reefal closures in the Salawati subbasin. At Walio, the largest field, there appears to have been only 30 ft of oil stain below the oil-water contact, but at Kasim and Joya, it appears that at least half the oil has been flushed away. At the relatively shallow Kalamano field nearer the edge of the basin, the original oil column, as indicated by staining, was 1,300 ft versus the recent oil column of 440 ft; the even shallower Klamnuk had an indicated oil column of 600 ft versus the recent 200-ft hydrocarbon column (fig. 68).

Flushing is also indicated by the character of the oil, which ranges from 35° gravity oil at a depth of 2,100 ft at Sele in the central basin deep to 19° and 15° gravity oil with a high residual sulfur content at Klamono and Klamumuk reefs near the basin edge (fig. 68). Outcropping reefs at the basin edge contain only asphalt residue (fig. 68).

One of two controlling factors in the flushing of the Salawati reefs appears to be the thickness and impermeability of the overburden, primarily the Klasafet shales, which may not only provide seal but source for the petroleum accumulations. In fact, the prospective area of the Salawati and Bintuni subbasins is best defined and limited by the Klasafet cover strata. The overlying, more porous Klasaman-Steenkool-Buru clastics rest directly on the eroded New Guinea Limestone around the basin perimeter (figs. 67 and 69).

The second factor in flushing appears to be late Pliocene-Pleistocene uplift accompanied by widespread normal faulting and fracturing, which allowed fresh water into the Kais Formation.

In the Bintuni subbasin where late Neogene subsidence was greater, a much thicker cover of Klasafet or Steenkool marls, shales, and Klasaman sandstones and shales may have inhibited the considerable leakage such as affected the Salawati subbasin.

Source Section

The presence of source rock is assured by the presence of oil and gas seeps and shows from all through the section from the Kembelangan Group (Cretaceous) at the south end of the Bintuni subbasin to the oil and gas shows in the Kais reefs (Upper Miocene) of the Salawati subbasin and to the Steenkool Formation (Pliocene) of the western Bintuni subbasin (fig. 66).

Petroleum Generation and Migration

Richness of Source

The existence of sufficiently rich source rock in the Salawati-Bintuni basin is evidenced by seeps and shows from Cretaceous (Kembelangan Group) through to the middle Miocene, Kais Formation, but few definitive analyses are available.

Unlike the rest of Indonesia, there appears to be definite pre-Tertiary source rock in Irian Jaya. In offshore wildcat Kalitami-IX, near the mouth of Bintuni Bay, a pre-Tertiary thermally mature (vitrinite reflectivity of .75 percent) shale of unknown thickness with an organic content of 6 percent was reportedly encountered at a anomalously shallow depth, 4,331 to 4,656 ft. Good Kembelangan "source rock" was reported from Sago-1 (northern Bintuni subbasin) also at a shallow depth, 3,202 to 3,402 ft. Visser and Hermes (1962) report organic mudstones in the Kembelangan outcrops.

The source of the Kais carbonate reservoir accumulations appear to be the enclosing and overlying Klasafet shales and marls and the down-dip platform equivalent, the Klamogen marls and shales (fig. 68). According to Visser and Hermes (1962), these Miocene shales are rich in organic matter and possibly the source rock for much of the oil in the basin. Some believe the underlying Oligocene, gray pre-Kais shales, the Sirga Formation (fig. 68) are the principal source rocks of the Kais reservoirs, but recent work suggests Mesozoic source for the Kais oils. No definitive source richness data are available.

Depth and Volume of Source Rock

Although geologically similar in many ways, the Salawati and Bintuni subbasins differ in that the Bintuni subbasin's Neogene subsidence was much greater and deeper and its thermal gradient is lower, averaging 1.6°F/100 ft versus the average thermal gradient for Salawati subbasin of 3°F/100 ft.

The Salawati subbasin's heat gradients combined with the Neogene subsidence puts the average top of the mature petroleum generation zone at about 6,800 ft and the volume of mature or overmature sediment at about 1.6 thousand cubic miles.

In the cooler more rapidly subsiding Bintuni subbasin, the mature sediments calculate to be much deeper, about 13,500 ft (supported by wildcat Terie-1 where vitrinite reflectance reportedly indicated near thermal maturity at 13,765 ft). In spite of this depth, a large volume of mature sediments, approximately 21.6 cubic miles, may exist owing to the deep presence of the thick Cretaceous Kembelangan Group sediments (which are thin or missing in the Salawati basin).

Oil versus Gas

The oil versus gas content in the traps of the six different plays varies widely. The estimated oil content ranges from the 30 percent in the Cretaceous drapes of the deep Bintuni subbasin and the diapirs of the deep southwestern part of the Salawati subbasin to 90 percent in the poorly covered, fractured Miocene reefs of the Salawati subbasin and the folded and fractured Neogene sandstones of the Lengguru foldbelt. As an average for the whole basin, the accumulated petroleum is estimated to be 60 percent oil.

Migration Timing versus Trap Formation

In the Salawati subbasin there is one principal play, the Neogene carbonate reservoirs. Assuming that the same thermal gradient and the same rate of subsidence continued through the Tertiary, substantial oil generation would have begun in the Pliocene (about the beginning of the Klasaman subsidence, fig. 68) when the source Tertiary shales would have subsided to below 7,000 ft in the basin center. At this time the reefs were largely in place and largely covered, and migration timing would be near optimum. That oil accumulation was largely prior to reservoir deterioration is suggested at the Jaya and Kasim fields by secondary calcite filling of vuggy and moldic pores immediately beneath the oil-water contact, reducing the reservoir porosity from 30 to 20 percent (Vincelette and Soeparjadi, 1976).

Assuming a constant thermal gradient and subsidence rate through the late Mesozoic and Tertiary in the Bintuni subbasin, generation and migration would have begun after the source rocks had subsided to about 13,500 ft in this rapidly subsiding basin. Assuming the Kembelangan and New Guinea Limestone Groups were near their combined maximum thickness of about 14,000 ft (9,000 ft and 5,000 ft respectively), generation from Kembelangan shales in the deeper parts of the basin would have begun sometime near the end of New Guinea Limestone deposition (Miocene) and concurrent with the formation of the Miocene carbonate reservoirs and after the Kembelangan (Cretaceous) sandstones deposition.

The structure involving the Kembelangan Group outside the steeply folded Lengguru foldbelt appears to be of low relief with faults and low-amplitude gentle warps or drapes. The drapes (and faults) have a northwest trend (fig. 66) suggesting that they follow earlier Mesozoic rifting patterns and are therefore old closures predating the petroleum generation. Probably there was some reactivation of old faults reaching a maximum at the same time as the Lengguru folding, i.e., late Neogene.

The Kais reefs and reservoirs of the Bintuni subbasin, having presumably formed after generation and migration of Kembelangan sourced-petroleum had started, would be available soon after reservoir trap formation, an optimum time for reservoir preservation, but would presumably fail to catch much of the earlier primary migration.

Assuming continued Bintuni subbasin subsidence at a constant rate, generation and migration of the petroleum derived from Miocene shales and marls began when they subsided to 13,500 ft, an event which has only happened recently and in the deeper parts of the basin so that there has been little time for these shales to contribute.

Steenkool reservoirs were deposited in the Pliocene and the structural traps formed in the Pliocene-Pleistocene. These traps were available for petroleum from the Klafelt (Miocene) shales, which only recently reached petroleum generation maturity.

Plays

The apparent petroleum prospects of the Salawati-Bintuni may be divided into six plays, in order of their apparent prospectivity: 1) Salawati Miocene Carbonates, 2) Bintuni Miocene Carbonates, 3) Miocene Carbonate Drapes, 4) Cretaceous Faulted and Draped Sandstones, 5) Bintuni Neogene Folds, and 6) Salawati Pliocene Diapirs. The play areas are defined below and described in detail in the play analyses (fig. 66).

1. Salawati Miocene carbonates

Potential petroleum accumulations are in Miocene carbonate buildups in the Salawati subbasin. The areal extent of the play is limited by the Miocene environment favorable for reef development and by the area of effective cover. Both are related to the pattern of Mesozoic-Tertiary subsidence. No isopach of the sealing Miocene shales is available, but it is assumed to be parallel to the isopach of the overall basin fill, i.e., the sealing shales are thicker and more effective in the deeper basinal areas. Tending to confirm this is the confinement of the oil accumulations and shows to where the basin isopach approaches a 4-km thickness. On the other hand, the deeper parts of the subbasin in Miocene time would be unfavorable for high-energy carbonate reservoir development; this deeper area approximates the Salawati subbasin isopach thickness greater than 5 km. On this basis, the area of petroleum accumulation in carbonates would be approximately limited to the area between the 4 and 5 km isopachs of the basin fill (fig. 64) or some 1.5 million acres.

2. Bintuni Miocene carbonates

Potential petroleum accumulations are in Miocene carbonate buildups in the Bintuni subbasin. As in the Salawati subbasin, the area of play is limited by the effective cover. The area which was favorable for reef development is more difficult to estimate since the young, deep Bintuni subbasin has a present configuration largely unrelated to the configuration of the reef-forming period. The subbasin has an irregular shape which probably reflects the Mesozoic extensional fault pattern, which in part has a strong east-west component, e.g., the Bomberai Trough (fig. 66). Part of the carbonate reservoirs are involved in the much faulted Lengguru foldbelt and have probably leaked to such an extent that they can be excluded from the play. The play is probably concentrated along the edge of the carbonate shelf edge (play 2, fig. 66), an estimated area of about 5 million acres.

3. Miocene Carbonate Drapes

Potential petroleum accumulations are in Miocene back-reef carbonate and sandstone reservoirs draped over northwest-trending pre-Tertiary highs, the structure paralleling to some extent the Cretaceous Drape Play (fig. 66). The reservoirs are within the upper New Guinea Limestone Group, largely the Kais Formation. Although the reservoirs may be in part reefal, they do not include reefal buildups extending into the overlying shales as in plays 1 and 2, but are interbedded with less permeable Kais carbonates and shales. The play is, therefore, not so dependent on younger shale cover and extends over both subbasins for a total of some 12.0 million acres.

4. Cretaceous Faulted and Draped Sandstones

Potential oil and gas accumulations are in Cretaceous shelfal sediments (the Kembelangan Group). The structures appear to be largely drapes or fault closures associated with northwest-trending ridges, reflecting horst and graben structure of the Mesozoic rifting (fig. 66). The area of play is restricted largely to the Bintuni subbasin since the Kembelangan Group of sandstones and shales thins northward and has little appreciable thickness in the Salawati subbasin. To the west, however, the Kembelangan or equivalent strata may underlie the Onin-Kumawa ridge. Assuming that Kembelangan sandstones underlie the entire Bintuni subbasin, including the Onin-Kumawa ridge as far west as the Seram Trough but excluding the foldbelt, the play area amounts to 18.6 million acres.

5. Bintuni Neogene Folds

Potential petroleum accumulations are in Neogene anticlinal folds involving Tertiary and Mesozoic reservoirs in the Lengguru foldbelt of the eastern Bintuni subbasin. The play area is limited to the Lengguru foldbelt and has an area of some 6.14 million acres (fig. 66).

6. Salawati Pliocene Diapirs

There appears to be some potential for petroleum accumulations in Pliocene sands involved in diapiric anticlines in the deeper, basinal part of the Salawati subbasin. The estimated area of play is some 1.5 million acres (fig. 66).

Arafura Basin

Location and Size

The Arafura basin of Tertiary and Mesozoic rocks extends along the southern half of Irian Jaya (figs. 1, 63, and 71). It is bounded on the north by the so-called Central Range and separated from the Salawati-Bintuni basin to the northwest by the Terara Fault zone. Southward, it merges into the Australian Shelf containing upper Precambrian sediments. To separate the Arafura basin from these nonprospective older shelf rocks, the southern basin edge is somewhat arbitrarily placed where the entire southward-thinning sedimentary section becomes less than 3 km thick. This necessarily excludes a thin wedge of Cretaceous sediments which extends southwestwards along the west side of the New Guinea-Australian continental block (fig. 71). The Arafura basin is bounded on the west by the Banda Arc Trough, and to the east, it continues on into Papua New Guinea. It has an area 50,000 mi^2 and an approximate volume 120,000 mi^3 within Irian Jaya.

Exploration and Production History

Three wells were drilled in the southern part of Irian Jaya prior to 1962. Of these, only Jaosakor-1 is within the basin as here defined (fig. 71), the other being on the Australian Shelf. In 1970-74, Phillips Oil Company drilled three offshore wildcats, ASA, ASB, and ASM, within the Arafura basin. In the same period, Champlain Oil Company drilled three wells in the extreme updip (southern) part of Irian Jaya waters on the Australian shelf outside of what we are here considering the Arafura basin. In 1980 and 1981, Amoseas (Standard Oil of California and Texaco) drilled two onshore wells, Kumbai Satu-1 and Kuruwai-1. In 1984, Koba-1 was drilled on the Aru hinge area also outside of what we are considering the Arafura basin. All wildcats were dry (fig. 71).

Structure

General Tectonics

Extensive Permo-carboniferous sedimentary rocks (Aifam Formation) appear to be of an interior cratonic mixed marine and terrestrial facies, whereas more restricted Triassic-Jurassic sediments appear to be terrestrial infill of rifts as seen along the south flank of the Central Range (fig. 66). Late Jurassic, Cretaceous, and Paleogene sediments are of a marine shelfal facies, thickening northward. On the basis of these changes, plus truncation of a

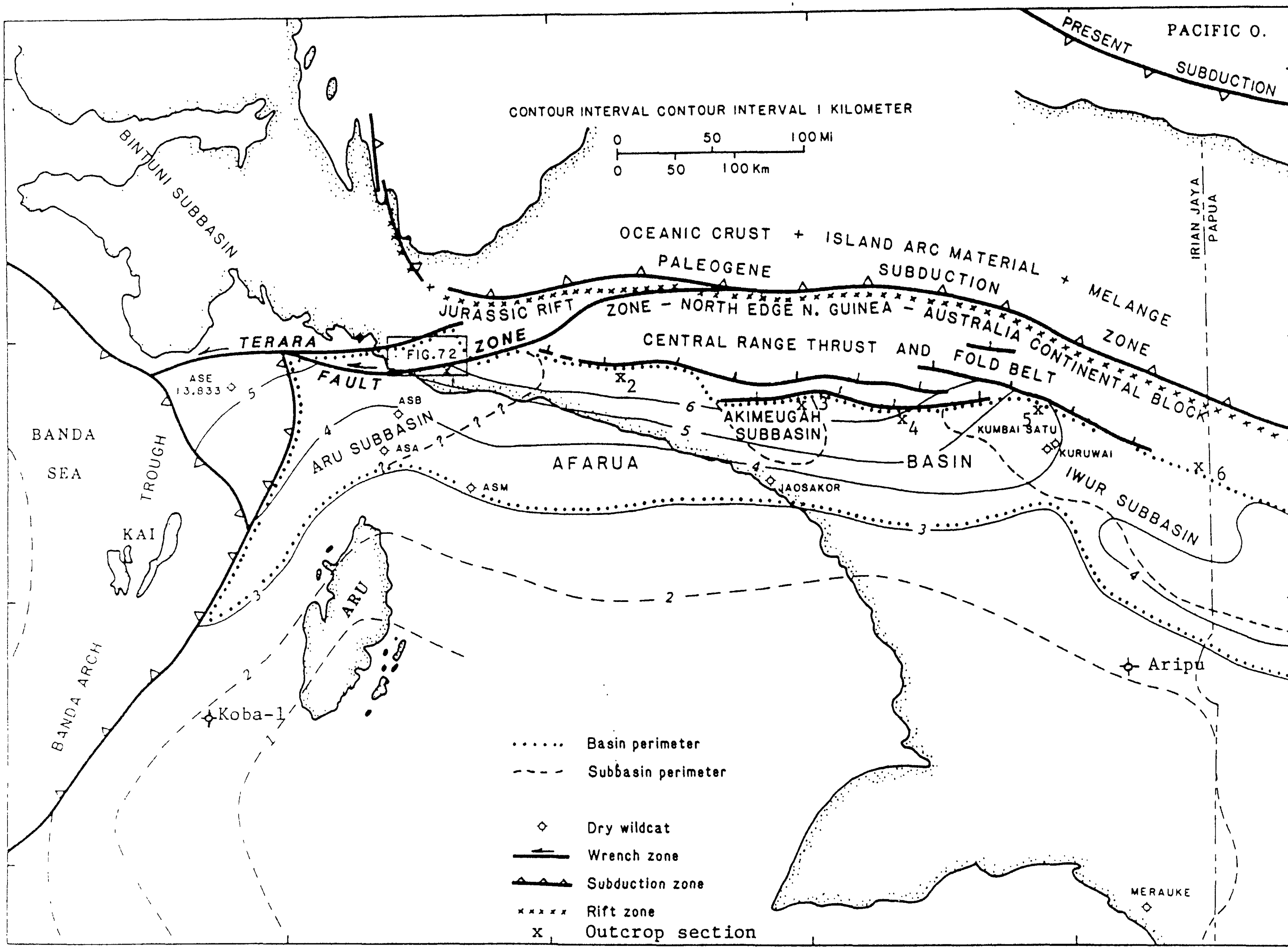


Figure 71.--Map showing tectonic elements and basement depth, Arafura basin. After Hamilton (1979).

major north-trending orogenic feature of east New Guinea, Hamilton and others suggest a mid-Jurassic east-west zone of rifting of a Permo-carboniferous continent along the present Central Range, which separated the present New Guinea-Australia continent to the south from a northern segment (Sunda Block?), which subsequently moved away.

In the late Paleogene-early Neogene, the New Guinea-Australia continental block, moving northward on a subducting plate, collided with an island arc under which the plate was being underthrust along a north-dipping subduction zone. With the collision, the subduction in this zone ceased.

Continued north-south compression of the lithosphere in the Neogene caused further shortening to be renewed on a Neogene, south-dipping subduction zone north of the Paleogene island arc, i.e., north and just offshore of the present Irian Jaya (figs. 63 and 71). At the same time, renewed uplift of the Central Range (reaching a maximum in the Plio-Pleistocene) caused sediments to be shed into the Arafura basin to the south and the Waropen basin to the north.

The Arafura basin is on the New Guinea-Australian continental block, its northern flank being the Central Range collision zone and the southern flank being the gently northward dipping New Guinea-Australia shelf. The north edge of the basin has been affected by a number of regional west-trending sinistral wrenches, which are particularly evident in the west; the major wrench is the Terara Fault zone (figs. 71 and 72). The western end of the basin is a north-trending, west-dipping, normal-faulted monocline into the trench of the Banda Arc (figs. 71 and 73). A low structural arch runs along the north-trending hinge line of the monocline in line with Aru Island.

Structural Traps

There are four possibilities of structural traps.

1. Horsts and grabens provide fault closures and drapes associated with the mid-Jurassic rifting. They also provide a framework for Tertiary sedimentation including reef localization.
2. Compression folds associated with the late Paleogene-early Neogene continental-island arc collision.
3. A number of large drag folds caused by sinistral wrenches along the western quarter of the northern basin boundary.
4. The normal faulted monocline into the Banda Arc trench and the associated faulted hinge-line arch through Aru Island.

A fifth type of trap, not structural, would be Miocene reefs.

Concerning the first structural trap, there are no subsurface hard data available indicating the presence of horst or tilted fault blocks associated with supposed east-trending mid-Jurassic rifting along the north edge of the New Guinea-Australia continental block (the Central Range), although geophysical data on some cross-section lines of Visser and Hermes, 1962 (Tectonic Sections 22 and 23) suggest block-faulting. Although drapes of Cretaceous sandstones over these fault blocks would be a play with considerable potential, in the absence of more data and because of the possibility that this structure would be overprinted by later tectonics so that early accumulations would be redistributed, this play is grouped with other later structural traps.

Concerning the compressional folds of the continental-island arc collision zone (Central Range), there have been some small, tight, sometimes thrusted, anticlines mapped in the outcrop belt. A potential gas and condensate field, Jahu, has been discovered (1983) in similar structure on

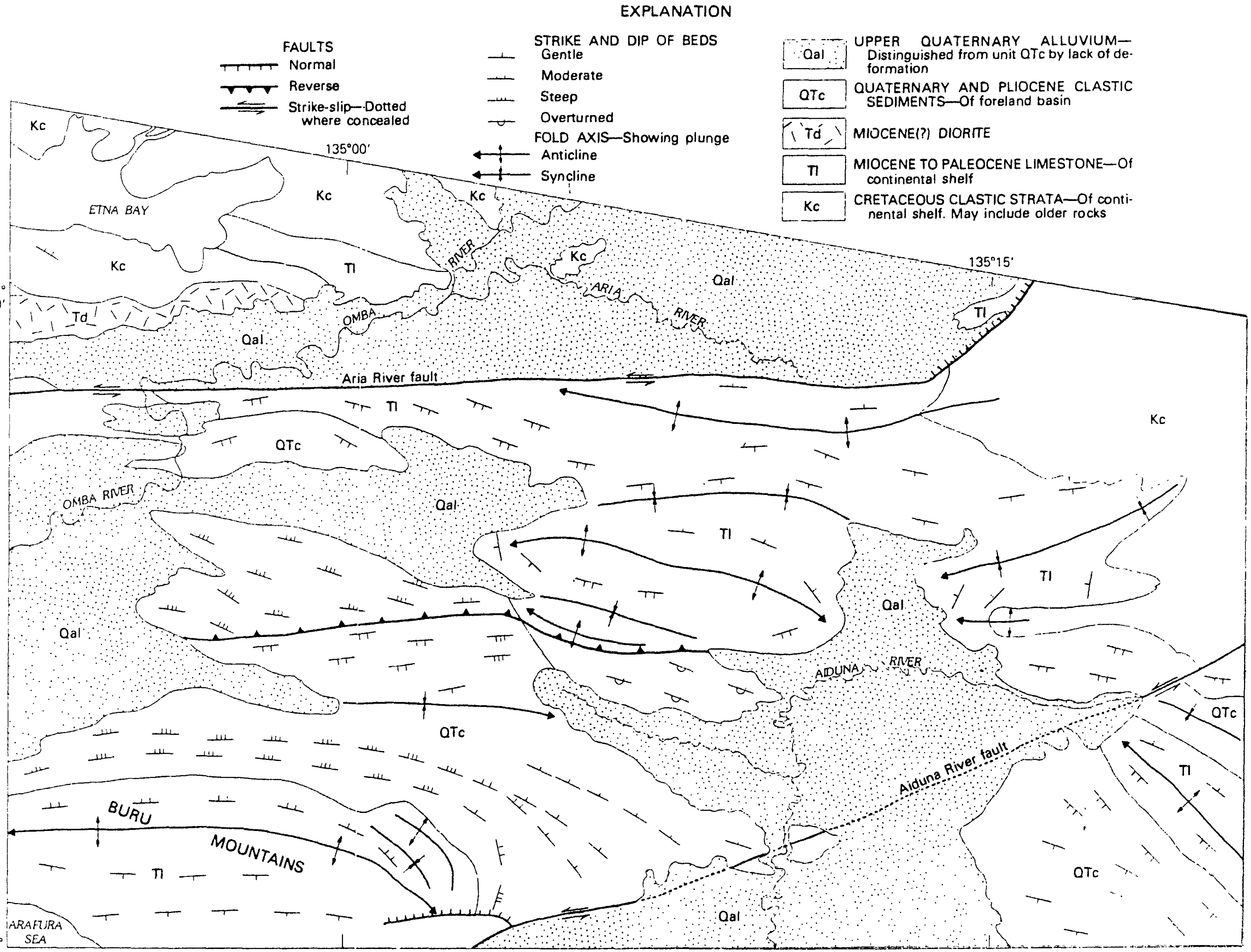


Figure 72.--Geologic sketch map of part of the Terara fault zone and other features, southwest New Guinea. After Hamilton (1979).

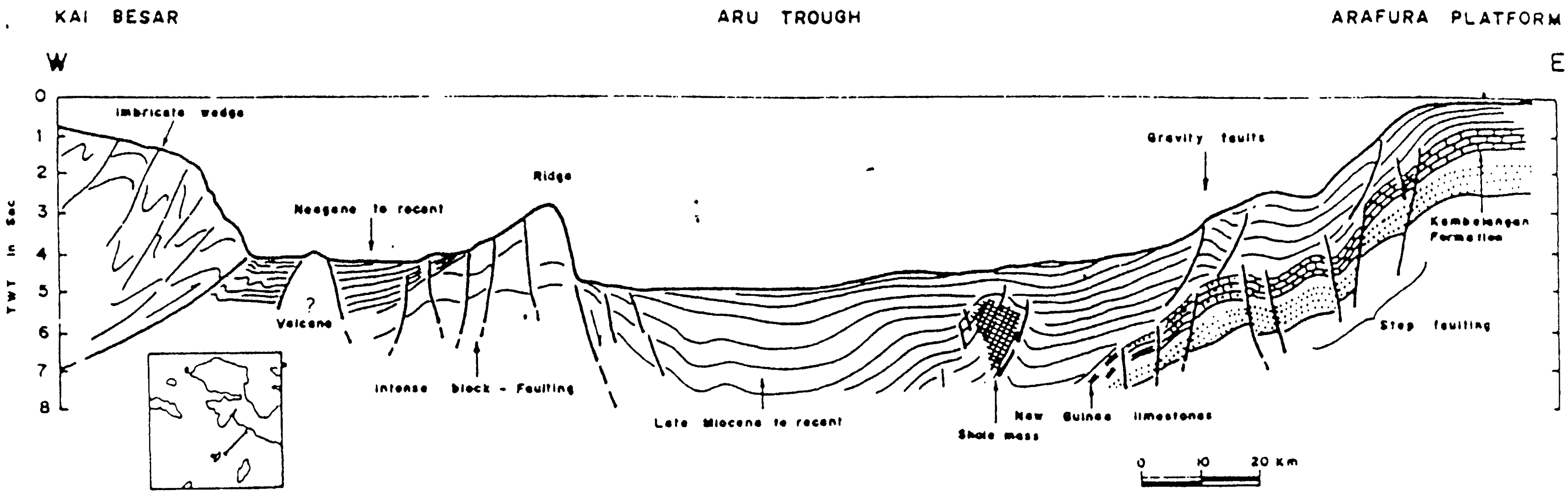


Figure 73.--Aru trough cross section, Arafura basin. From Kartaadiputra (1982).

strike 100 miles to the east in Papua New Guinea. Presumably, additional more open folds are found under the alluvium of the basin. The area of this play is an approximately 20-mile-wide Tertiary and alluvium-covered strip along the eastern three-fourths of the foothill and adjoining plains area with an estimated play area some 10,000 mi^2 (6.4 million acres). The amount of effective closure would be small in this complex, faulted zone; examination of Visser and Hermes' (1962) outcrop map induces an estimate of 1 or 2 percent of the play area or an approximate 96,000 acres.

The drag folds associated with prominent wrench faults (mainly the Terara and associated fault zones) along the western part of the north boundary of the basin, are large and prominent (figs. 71 and 72). They have not been tested; although a wildcat, Kembelangan-1 (fig. 66) in the adjacent Bintuni subbasin has tested an apparently similar structure, the Kembelangan Dome, but with negative results. The drag folds play extends over an area some 8,000 mi^2 (5.1 MMA). By analogy to the drag fold frequency of the wrench-faulted Central Sumatra basin, the area of drag-fold closure is estimated to be 5.5 percent of the play area or about 280,000 acres of trap closure. Because of difficulty in distinguishing the drag and compression fold plays from the data at hand, they have been combined into a single play, "Anticlines," with a combined area of 11.5 million acres.

The faulted, westward-dipping monocline into the Banda Arc trench and associated Aru Island arc trend is crossed by a published section (Kartaadiputra and others, fig. 73) and other unpublished geophysical profiles which indicate faulting with horst and tilted-fault-block closures on the west side of the so-called Arafura platform (Aru subbasin, fig. 71). Two offshore wildcats (ASB and ASA) apparently have tested Mesozoic or Paleogene sandstones in these structural closures, as well as the Miocene strata atop them, with no success (a third wildcat, Koba, 100 miles on-strike to the southwest was also unsuccessful). It appears, from the unpublished seismic lines, that the traps depend largely on somewhat weak fault closures which may not have been very effective. The play area, within the basin as here defined, extends approximately from a point 100 km west of mid-Aru Island northward to the shore (the Terara Fault), approximately the Aru subbasin (fig. 71), an area of about 3.5 million acres. It is estimated from unpublished maps that the fault closures make up 2 percent of the play area or 70,000 acres.

Stratigraphy

The stratigraphy of the Arafura and Salawati-Bintuni basins is almost the same; time-equivalent, lithologically similar formations extend through both basins (fig. 67).

As much as 40,000 ft of stratigraphic section are exposed along the south flank of Central Range (fig. 66). The sediments range in age from Paleozoic to Pliocene. The Permian (Aifam Formation) is probably the oldest entirely unaltered sedimentary unit. This carbonate and clastic sequence has been penetrated in several wells and seen in outcrop; in general, it appears to be of an interior platform facies. It has low organic content and poor to very poor reservoirs.

The overlying Triassic to mid-Jurassic strata are largely terrestrial sediments (the Tipuma Formation), which appear to be laid down in a rifted, attenuated-crust environment preceding the final separation of the Australian-New Guinea block from a continental block to the north.

Mid-Jurassic to upper Cretaceous rocks are marine shelf sandstones and shales (the Kembelangan Group), thinning southeastward onto the north-sloping

Australian Shelf. The pinchout line runs west-southwest from about Kumbai-1 (where it is absent) to south of Aru Island where, as the wedge progressively thins, the pinchout line swings southwestwards (fig. 71). These clastics are derived from the Australian continent to the south.

From late Cretaceous through Miocene there was a tectonically quiescent period, and the section was dominated by carbonates (New Guinea Limestone Group) on the same shelf. The upper unit of this group, the Kais Formation, is often in a reefal facies and is considered a principal reservoir formation of the basin.

Immediately overlying and in part equivalent to the Kais Formation is a section of marly shales with some carbonates, sourced from the north, which form in local subbasins where Miocene subsidence has been greater. In the Arafura basin these shales are variously called the Klasefet, Akimeugah, and Iwur shales (fig. 67). They occur in three separate subbasins from west to east along the depoaxis of the basin, the Aru, Akimeugah, and Iwur subbasins (fig. 71). Similar to the Bintuni and Salawati subbasins, these subbasins of reef-sealing shales define the areas of Miocene reef play. The Arafura Miocene subbasins, as here defined, have an area of 60 percent of the Arafura basin or about 20 million acres.

Overlying the Cretaceous to Miocene carbonates and marly shales is a section of Pliocene-Pleistocene clastics derived from the Central Range in the north (Buru Formation). They immediately overlie the Klasafet, Akimeagah, or Iwur shales in the structurally lower subbasinal areas, and the New Guinea Limestone Group carbonates in the intervening areas (fig. 66).

Reservoirs

Potential reservoirs exist in three general zones, the same as the reservoir zones of the better known Salawati-Bintuni basin. They are: 1) the sandstones of the mid-Jurassic to Cretaceous Kembelangan Group, 2) carbonate reservoirs (reefs and banks) of the Miocene upper New Guinea Limestone Group (the Kais Formation), and 3) Plio-Pleistocene sandstones (Buru Formation).

Kembelangan Reservoirs

Little specific information is available concerning Kembelangan reservoirs within the basin. The sandstones appear to be thin and sparse in the lower part. Some potential reservoirs seem to exist in the middle part, but the well sorted, clean sandstones (as seen in outcrop) appear to be mainly in the upper part of the Kembelangan Group.

In Papua New Guinea, 100 miles east of the boundary, wildcat Juha-2 tested two zones resulting in a potential flow rate of 24 and 26 MMCFGD with condensate flows of 1,680 and 1,900 BCPD respectively, indicating good reservoir sandstone (Katz and Herzer, 1985).

For evaluation purposes, an average effective pay of 200 ft with perhaps 20 percent porosity is estimated for the Kembelangan sandstones of the Arafura basin.

New Guinea Limestone Reservoirs

The carbonate reservoirs at the top of the New Guinea Limestone Group, i.e., the Kais and basal Akimeugah (and equivalent) Formations, have been penetrated in ASA-IX and ASB-IX and found to have zones of porosity ranging from 12 to 25 percent but with rather low permeability (5 md).

For the Salawati-Bintuni basin (for which there are many more published observations of reservoirs at an equivalent horizon), an average effective pay of 165 ft and a porosity of 20 percent was estimated. For the Arafura basin, where reefal buildups are not so obvious, a lower average pay thickness, say 80 ft, in the Aru, Akimeugah, and Iwur subbasins is expected. Porosity of 20 percent is assumed.

The reef-trap area would be only half as prevalent as in the undoubtedly more developed reef facies in the Salawati subbasin, or about 3 percent of the 20-million-acre play area, i.e., 600,000 acres.

Buru Reservoirs

Reservoirs in the Pliocene Buru Formation are reportedly poor in the Arafura basin; however, in the adjoining Salawati-Bintuni basin where more data are available, the geologically comparable Klasafet Formation is estimated to have an average effective pay of 100 ft with an average porosity of 20 percent. In the absence of data, these assumed parameters also apply to the Buru Formation of the Arafura basin.

Seals

The Cretaceous sandstones appear to be associated with an adequate thickness of interbedded shales to seal to some extent any potential petroleum accumulation. Likewise, the Pliocene-Pleistocene sandstones are accompanied by sufficient shales to ensure some sealing. The Miocene carbonates, however, are probably only adequately sealed where they are covered by Miocene marly shales (i.e., the Klasefet, Akimeugah, or Iwur Formations). These shales are developed and preserved in three or more subbasins along the depoaxis of the Arafura basin (fig. 71). Outside these local basins, the more clastic Pliocene-Pleistocene rocks (Buru Formations) rest directly on the New Guinea Limestone Group, providing only minimum and late seal.

Source Section

Source rock occurs in the Cretaceous (Kembelangan) shales and mudstones and in Akimeugah and Iwur marly shales and is discussed in detail below.

Petroleum Generation and Migration

Richness of Source

Unpublished studies report on the basis of meager evidence that the pre-Kembelangan Group (i.e., pre-upper Jurassic) strata, with minor exceptions, are generally poor in organic content. The Kembelangan Group (upper Jurassic to Paleocene) has fair to very good levels of organic richness in its middle and basal parts. The Miocene Akimeagah Formation is found to have fair levels of organic carbon (TOC values of 0.5 to 1.32 percent).

Depth and Volume of Source Rock

Reportedly, wildcat ASM-IX (fig. 71) encountered rock of somewhat less than thermal maturity (considered to be Ro = 0.7 percent) at 10,000 ft in the Aifam Formation (Permian). Thermal gradients from two other wildcats are available, 1.65°F per 100 ft at Jaosakor-1 and 3.2°F per 100 ft at ASA-IX (3.2°F per 100 ft seems anomalously high, perhaps owing to its position on the edge of the Aru Trough). Using 1.65°F per 100 ft together with an estimated average Plio-Pleistocene subsidence rate of 750 ft per million years, the top of the mature zone is indicated to be around 11,000 ft. At this depth, the thermally mature source rock is limited to the pre-Tertiary and relatively organic-rich Kembelangan Group in a narrow zone at the base of the foothills of the Central Range. The volume of mature source rock is estimated to be around 3,500 mi^3.

Oil versus Gas

No data are available, but discovery wildcat, Juha-2, drilled some 100 miles on strike to the east in Papua New Guinea, produced from strata equivalent to the upper Kembelangan Group gas and condensate flows of 24 and 26 MMCFGPD, accompanied by 1,680 and 1,900 BCD, respectively (Katz and Herzer, 1985). There is a small oil seep just outside the western end of the basin (Kembelangan). The average petroleum mix of most of the basin is estimated to be 30 percent oil and 70 percent gas. In the more poorly sealed Aru hinge area, the mix is 50 percent oil.

Migration Timing versus Trap Formation

The thermal gradient is assumed to have been fairly constant since the Mesozoic, but the subsidence rate appears to have accelerated in the Pliocene-Pleistocene thereby accelerating the heating of the source rock and inducing petroleum generation. The beginning of substantial generation probably did not occur until the Pliocene.

The principal trap formation apparently occurred in three episodes: 1) Jurassic rifting resulting in horsts and tilted fault blocks later draped by Jurassic-Cretaceous sediments, 2) Carbonate reef and buildup formation in middle to late Miocene, 3) compressional folding developed with continental-island arc collision in late Miocene-early Pliocene, and 4) drag folding along wrench faults active during the Pliocene to present.

It would appear that the Mesozoic drape closures may have been early to most effectively trap the predominantly Pliocene petroleum before reservoir deterioration, but the compressional and drag folds formed at a near optimum time to entrap any petroleum.

Plays

There appear to be two principal drilling objectives in the Arafura basin: Cretaceous to Tertiary sandstones and Miocene carbonate reefs and banks.

The Cretaceous sandstones are presumably (1) draped over fault-block structures of Jurassic-Cretaceous age, (2) folded in Pliocene-Pleistocene compressional anticlines, (3) folded in drag anticlines, and (4) fault-trapped in the Pliocene-Pleistocene faulted Aru arch and hingeline area. Each of these trap types can be considered a separate play, but since the drapes are only surmized (and in any case are likely to be altered by later tectonics) and the drag folds in many cases cannot be distinguished from the compressional folds, they have been lumped into a single anticlinal trap play.

Therefore, only three plays are considered in the analysis.

1. Anticlines (involving Cretaceous to Paleogene sandstones) (11.5 MMA)
2. Miocene Reefs (20.0 MMA)
3. Aru Hinge area (involving Kembelangan sandstones) (3.5 MMA)

Waropen Basin

Location and Size

The Waropen basin is in northeastern Irian Jaya. It extends eastward from Cenderawasih (Sarera) Bay to the Papua New Guinea border and southward from the Pacific Ocean to the Central Range. It has an area 24,000 mi^2 and a sedimentary volume of approximately 40,800 mi^3 (figs. 1, 63, and 74).

The basin is defined here to include only the post-melange and post-island arc sediments, i.e., post-Auwewa (Oligocene) Formation (fig. 75).

The basin has four structural lows or subbasins (fig. 74). Although it is not done here, some authors have designated the two deeper (4 km) subbasins as separate basins, the "Waropen basin" to the north of the Sorong Fault and the "Waipago basin" on the east shore of Cenderawasih Bay.

Exploration and Production History

The Waropen basin was explored from 1935 to 1959 by a Shell group culminating in the drilling of three wells, Mamberamo-1, Niengo-1, and Gesa-2. Mamberamo-1 was only a stratigraphic test; Niengo-1 tested methane with no higher hydrocarbons; and Gesa-2 also tested methane with no higher hydrocarbons. Resumed exploration in the early seventies of the offshore, along the east side of Cenderawasih (Sarera) Bay, by a Tesoro-Arco group resulted in six 1973 wildcats, A-1, E-1, H-1, O-1, P-1, and R-1. R-1 tested 21.6 MMCFGD plus 402 BOPD. Production sharing contracts of the western part of the basin are currently held by Shell and Phillips. Shell drilled three dry wildcats in 1985. The exploration of this basin is immature; the success rate to date is nil.

Structure

General Tectonics

The Waropen basin as defined here is made up of upper Miocene to Recent sedimentary rocks overlying island-arc and melange material resting on oceanic crust. During the Paleogene, the oceanic plate which bore the Australian continental block, subducted northward under an island arc (now apparently represented by the mountains along the north edge of Irian Jaya). After further subduction, in the early Neogene, the continental block of Australia collided with the island arc and the melange material which had accumulated in front (i.e., south) of it. This raised the continental edge, the Central Range, and caused sediments to wash northward into the structural low of the Waropen basin between the Central Range and the accreted island arc, i.e., the northern ranges. Plate movement down the north-dipping subduction zone ceased with the arrival of the buoyant Australian continental crust. The regional north-south compression was apparently then taken up in a new, reversed, i.e., south-dipping, subduction zone. The trace of the new subduction zone is off the north coast of Irian Jaya, and it dips southward under Irian Jaya, including the Waropen basin and island arc now accreted to the New Guinea-Australian continent (fig. 74).

This essentially north-south compression apparently has a strong, more recent, sinistral component, the Pacific plate pushing westward. Recognizable fragments of the Australian continental crust have been wrenched westward and now form part of the Sulawesi (Celebes), Ceram, Buru, and smaller islands of

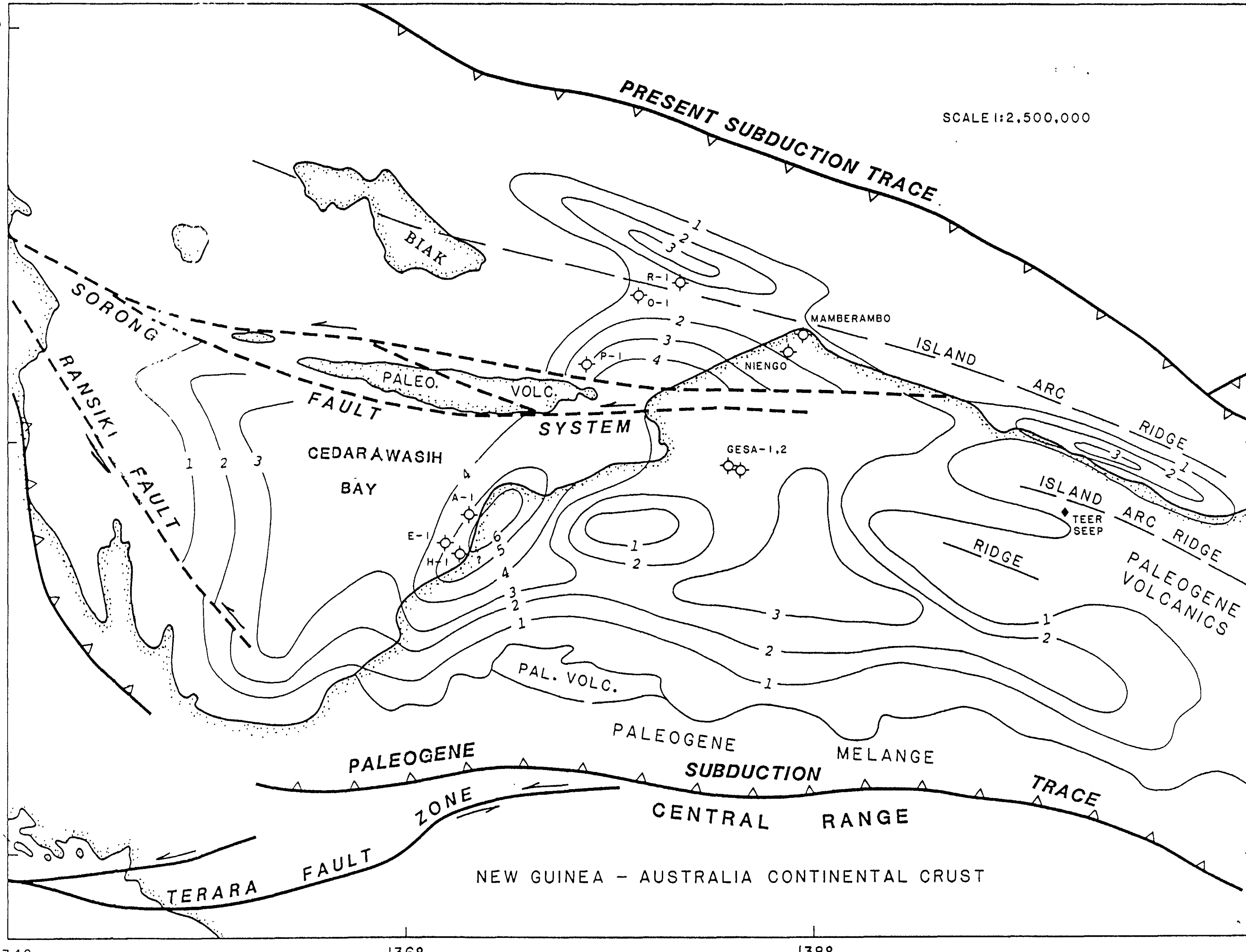


Figure 74.--Map showing tectonic elements, isopach of Neogene sediments, wildcats and outcrop stratigraphic column locations (fig. 75) Waropen basin, Irian Jaya. From Hamilton (1979).

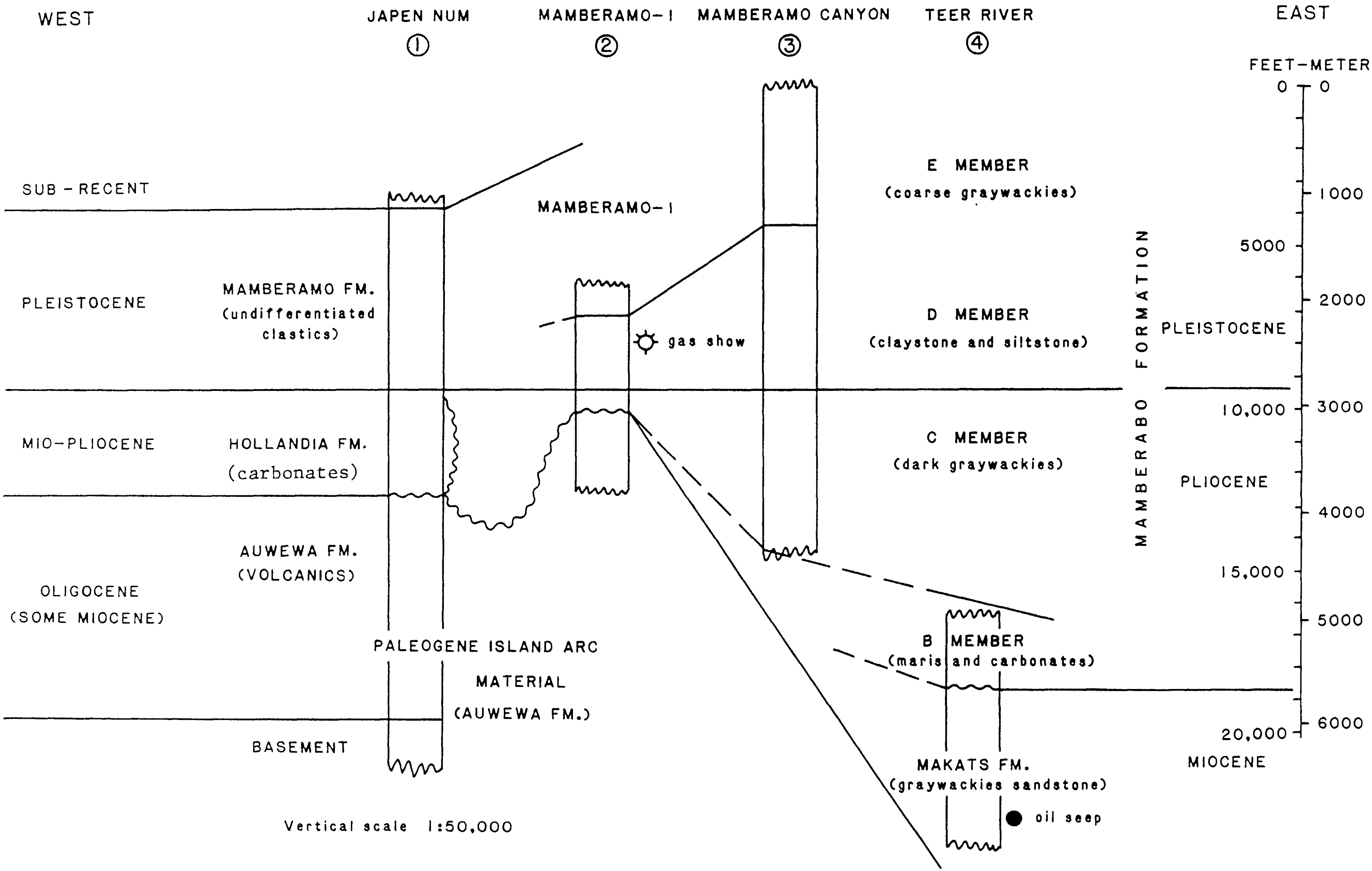


Figure 75.--Stratigraphic columns along north flank of Waropen basin; location of columns (fig. 74), columns from Visser and Hermes (1962). Sections from Visser and Hermes (1962).

eastern Indonesia. Large west-trending sinistral wrenches cut northern and central Irian Jaya (fig. 74).

The Waropen basin is structurally complicated, but most of the potential structural traps appear to fall into three groups: 1) drag folds associated with the largely unmapped but presumably numerous, west-trending wrenches that are believed to transect the entire basin, 2) carbonate buildups and drapes of Pliocene sand reservoirs over the rugged Paleogene island-arc topography (fig. 74), and 3) diapiric, semi-diapiric, and other flow structures affecting the thick Pliocene Mamberamo shales.

For assessment purposes it is assumed that the wrench folds are the primary trap structure and, in the absence of more data, these are lumped with the diapirs, some or all of which may be initially of drag-fold origin. On this assumption, the basin would be structurally analogous to the Central Sumatra Basin, which is also much affected by wrench faulting and drag folding and which is deemed to have a structural trap area making up 5.5 percent of the play area. By this analogy, there should be 845,000 acres under drag-fold trap in this play, which is assumed to cover the entire Waropen basin.

The drape reef structure play area would be limited to the buried part of the Paleogene island arc ridge (fig. 74). This discontinous, fragmented ridge trends east-southeast from Biak Island through the Mamberamo-1 and Niengo-1 wells and approximately along the north coast of Irian Jaya; the sedimentary thickness is generally less than 6,000 ft (2 km) but more than 3,000 ft (1 km) (fig. 74). An area of 2,500 mi^2 or 1.6 million acres is estimated. Structures in this area would be buried topographic highs on the old volcanic arc surface, perhaps altered by faulting, particularly sinistral wrench faults. From an unpublished map, it is estimated that closed highs make up 18 percent of the area or 288,000 acres. These highs are the loci of reef development and drape closures.

Stratigraphy

The Waropen basin, formed between an island arc and a continental block in the Miocene, is underlain by melange, island-arc volcanic material, and oceanic crust. The fill is Miocene to Recent largely clastic sediments derived largely from the Central Range to the south, and to a lesser extent from the island arc to the north.

The fill is largely in two units. The lower unit is a Miocene marine clastic formation (Makats Formation). This formation is up to 6,000 ft thick and made up primarily of graywackes or subgraywackes with some marl and carbonate intercalations. A combination of graded bedding and deep-water fauna indicates the strata may be mainly turbidites. Detritus of silicified claystone, abundant Mesozoic microfossils and metamorphic rock, combined with a low volcanic content suggests the formation is derived from the Central Range to the south rather than the volcanic arc to the north. The Makats is rather highly faulted compared to the overlying formations. Reportedly Tesoro-Arco have found the Makats Formation to be so tectonized that it was considered economic basement. It should be noted, however, that the only appreciable oil seep (figs. 74 and 75) seems to derive from this formation. It appears that although the Makats Formation would not have significant reservoirs (owing to graywacke facies and to tectonization), it may have some source capability.

Overlying the Makats Formation, probably unconformably, is the second unit, a Pliocene-Pleistocene formation, defined by Visser and Hermes, 1962, i.e., the Mamberamo Formation, which variously overlies the Miocene clastics of the Makats Formation, island arc volcanics (the Auwewa Formation), and oceanic crust. It is primarily clastics with some intercalations of limestone (fig. 75). It has a full thickness of some 20,000 ft and is in four members where sedimentation was most complete: (B) a lowest member of marls and carbonates with siltstones, (C) a graywacke and sandstone member, (D) a claystone member with both abundant foraminifera and plant remains, and (E) an upper member of graywackes. Probably the C member offers the best chance for adequate reservoirs. Volcanic material is essentially absent, and it is concluded that most of the sediment is derived from the south rather than from the volcanic arc to the north. The amount of sand in the section appears to lessen northward.

Northward toward the higher part of the relict Paleogene island arc, the Mamberamo Formation clastics thin and are replaced with shoal carbonates, the 300-foot thick Hollandia Formation (fig. 75) indicating that in the Pliocene the area of the old arc was still a positive area.

Reservoirs

The Makats apparently has little appreciable reservoir, limiting reservoir occurrence to the Pliocene Mamberamo Formation. The Mamberamo Formation has some sandstones, but they are generally of a graywacke type and therefore poor reservoirs. Since the sandstones would be largely derived from the upraised Central Range to the south containing considerable melange and oceanic crust, good quartz sandstone is not abundant. The sandstones thin northward; sandstone beds, which commonly reach 500 to 600 ft in gross thickness in the E-1 and H-1 wildcats to the south, do not exceed 30 ft in the northern R-1 well. Sandstones appear to be largely concentrated in the "C" and "E" Members. The "C" Member of the E-1 well reportedly is 30 percent sandstone. One hundred ft appears to be a reasonable average net sandstone pay. Porosities would be fair to poor; probably the average would have porosities of about 20 percent.

The other reservoirs are in the Hollandia or equivalent Pliocene-Pleistocene carbonates, which occur intermittently on topographic highs along the Paleocene island arc ridge. Wildcat 0-1 found 735 ft of limestone with three zones of porosity as indicated by gas-cut water flow. On other highs, R-1, Niengo-1, and Mamberambo-1, the limestone is missing, but there are Mamberamo draped sandstones. Niengo tested gas from a 110-foot thick sandstone and R-1 tested from a 22-foot thick sandstone. There are insufficient available data to separate the highs having carbonate buildup from those having only draped sandstones. It is estimated that the average reservoir over a high would have 80 ft of effective (sandstone or carbonate) reservoir. A porosity of 20 percent is assumed.

Seals

The Mamberamo Formation is made up largely of low permeability shale as measured in outcrops and as attested by overpressured shale found in at least some of the wildcats drilled, e.g. Gesa, E-1(?), and H-1(?). Wildcat Gesa found overpressure at 6,000 ft. E-1 and H-1, as well as Gesa, apparently tested diapirs or flow-effected closures. The presence of overpressured shale is not only a seal but it strongly inhibits primary migration to all hydrocarbon but gas.

Shell (Visser and Hermes, 1962) believed that extensive faulting generally precluded adequate cover in many places, and this may be true, at least in the perimeter of the basin.

The Pliocene reefs along the north rim of the basin partly outcrop or are only thinly covered. A good part, probably half the reef play, falls outside of and north of the 1-km isopach of the Waropen basin (fig. 74).

Source Section

Whether or not there is sufficient source rock to support considerable amounts of petroleum is a moot point. If there is any, it would be in the basal part of the Mamberamo or in the Makats Formation. See discussion below.

Petroleum Generation and Migration

Richness of Source

Marly shales near the base and dark gray shales with lignite streaks near the top of the Mamberamo Formation could contain sufficient organic material, but the Shell group (Visser and Hermes, 1962), who originally investigated this basin prior to 1962, concluded an "apparent poverty of source material" after testing "geochemically" the shales penetrated by wildcat Gesa. Later unpublished T.O.C. values largely between 0.5 and 1.0 percent indicate rather meager organic richness. Taking into account the apparent rapid deposition (500 or 600 ft per million years) in the deeper parts of the basin, organic material may be too diluted, particularly for oil.

The only appreciable oil seep in the vicinity of the Teer River appears to emanate from the Miocene Makats Formation. Although the Makats may be too tectonized to trap appreciable amounts of petroleum, it may, under some circumstances, be a source.

Depth and Volume of Source Rock

There are little data concerning thermal maturity of the basin sediments. Vitrinite reflectance of samples from wells E-1 (7,508 ft) and H-1 (depth ?) indicates immaturity.

Only one thermal gradient is available; wildcat H-1 reportedly had a thermal gradient of 1.34°F per 100 ft. This low value seems about right for what is essentially a fore-arc basin and is assumed to be the average for the entire basin. The Neogene fill has an average depth of 10,000 ft (3 km) (fig. 74), giving average subsidence of 400 ft per million years. With this subsidence and thermal gradient, the average top of the thermally mature sediment is estimated to be at about 15,000 ft (4.5 km). This would allow only little mature rock in the basin restricted to only the deepest part of the sedimentary fill. However, the melange formation could generate some petroleum. It appears that a small volume of thermally mature sediment is the principal limiting factor to the amount of petroleum resources in this basin. On this basis, the average petroleum fill of any trap is estimated to be only 20 percent.

Oil versus Gas

Most of the wildcats drilled to date have encountered some gas, but reportedly, the gas was dry and no appreciable oil shows have been seen. Oil seeps occur in the areas of outcropping Makats Formation.

The Mamberamo Formation is largely shale, and the indications suggest that much of the shale is overpressured. This condition inhibits primary oil migration, and it, together with wildcat shows, indicates the basin to be gas prone. For assessment purposes, it is estimated that the oil and gas mix in most of this basin is 80 percent gas and 20 percent oil. The drapes and reefs over the topographic highs of the buried island arc surface to the north, however, are not overpressured and more likely to leak and are, therefore, deemed less gassy, i.e., 60 percent gas.

Migration Timing versus Trap Formation

Generation and migration of gas and oil would have started relatively recently in this cool basin, which has barely subsided sufficiently so that the lowest sediments have reached thermal maturity.

The principal structural traps, i.e., drag folds, are also relatively young, having reached their effectiveness in the Pliocene when wrench faulting became most pronounced. So the drag fold timing was favorable, forming traps at about the same time migration began.

The older reefs and drape features over the Paleocene island-arc topography were formed in the Miocene, and the associated reservoirs may have deteriorated to some extent before Pliocene or younger, necessarily long-distance migration affected these shallow traps.

Plays

The two principal plays considered in detail in the analyses are:

1. Petroleum accumulating in Pliocene sandstones in drag folds associated with east-west sinistral wrench faults, which transect the entire basin. Diapir folds are, because of data-lack, included in this play.

2. Petroleum accumulations in reefs or draped sandstones localized by topographic highs on the buried Paleogene island-arc surface. Play area is taken to be the shallow-basin area approximately along the northern coast.

PLAY ANALYSIS SUMMARIES

One-page summary play analysis for each basin or play follow in the same order as the pertinent geology is discussed in the text. Estimates of the five principal geologic factors, which have been discussed and quantified in the text, are summarized. Estimates are given in ranges to show the degree of certainty. The ranges include three values, a low number (95 percent probability the quantity will exceed that value), a most likely quantity, and a high number (5 percent probability the quantity will exceed that value). For conciseness, only the rationale for arriving at the most likely (mode) estimate is discussed.

The product of the most likely values for each of the key factors generally indicates the quantity of undiscovered oil and gas resources. This product is shown at the base of the tabulations for each play. The overriding limiting factor, or factors for each play, used as a judgement check on the estimates is shown at the bottom of the remarks.

In addition to the principal basins and plays discussed in the text, there are play analysis summaries for four marginal basins; South Makassar, Sumatra, Outer Arc, Java Outer Arc, and Bone-Senkeng.

The summary play analyses served as guides to the consensus estimates of the amount of undiscovered petroleum in the basins of Indonesia.

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN North Sumatra, No. 1 COUNTRY Indonesia PLAY Deep Reef No. 1

AREA OF BASIN (Mi^2) 33,000 AREA OF PLAY (MMA) 0.55

VOLUME OF BASIN (Mi^3) 97,000 PLAY EST. ORIG. RESERVES,

ESTIMATE ORIGINAL RESERVES 2.1 BBO* 16.25 TCFG .755 BBNGL 14.25 TCFG

TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Gas accumulation in lower Miocene carbonate reefs and banks on platforms developed over horst blocks. Play area is about .55 million acres (area 1, fig. 6).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.03	.071	.10
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	3	12	12
C. AVERAGE EFFECTIVE PAY (feet)	100	350	500
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	0.1	5	10
E. OIL RECOVERY (BBLS/AF)	150	190	300
F. GAS RECOVERY (MCF/AF)	1,000	1,650	2,000
G. NGL RECOVERY (BBLS/MMCFG)	11	53	100

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .028 BB, GAS 4.674 TCF, NGL .248 BB, OE 1.055 BBOE

REMARKS

A. Reefs have grown on higher parts of a carbonate platform over an irregular surface. Some reefs have coalesced forming reef complexes (e.g., Arun complex of 42,000 acres). Thirteen percent of play area is estimated to be untested closure, or about 71,000 acres.

B. Future success rate estimated to be about 20 percent. Gas fill at Arun Field is 60 percent, which is assumed as average for play. On this basis, gas-containing closure is 12 percent of untested trap area.

C. Arun gas reservoir is 503 ft but is probably the thickest of the play. An estimated average pay thickness for the play is about 350 ft.

D. No oil is produced at Arun, or from other tests of these reefs. Enveloped as they are in overpressured shale, little oil would be expected.

E. Assuming the reservoir parameters of Arun are average for the play 16 percent porosity, 17 percent water saturation, primary oil recovery would be 190 barrels per acre-foot.

F. Gas recovery rate, enhanced by the effects of overpressure, reportedly averages about 1,650,000 ft^3 per acre-foot at Arun, which is assumed to be average for the play.

G. Gas-condensate ratio at Arun is 53 barrels per million cubic ft of gas, which is assumed to be the average for the play.

Limiting Factor: Overpressured shales have inhibited primary oil migration into the reef reservoirs.

Total resources of all plays in basin: .362 BBO, 9.0 TCFG, .412 BBNGL, 2.274 BBOE

* Includes NGL.

PLAY ANALYSIS SUMMMARY OF UNDISCOVERED PETROLEUM

BASIN North Sumatra, No. 1 COUNTRY Indonesia PLAY Neogene Sandstones, No. 2
AREA OF BASIN (Mi^2) 33,000 AREA OF PLAY (MMA) 5.6
VOLUME OF BASIN (Mi^3) 97,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 2.1 BBO 16.25 TCFG 1.1 BBO ? TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Petroleum accumulations in middle Miocene to lower Pliocene sandstones folded in Neogene anticlines. Play area approximately coincides with basinal part of basin, as opposed to shelf, and covers 5.6 million acres (area 5, fig.6).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.056	.116	.140
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2.5	5.6	10.0
C. AVERAGE EFFECTIVE PAY (feet)	30	150	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	40	60	75
E. OIL RECOVERY (BBLS/AF)	100	190	350
F. GAS RECOVERY (MCF/AF)	1,600	840	075
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .111 BB, GAS .327 TCF, NGL .004 BB, OE .170 BBOE

REMARKS

A. Extrapolation from a map of part of play (area "A", fig. 9) indicates that about 8.3 percent of area is under closure. Since the play is deemed 75 percent explored, 2.1 percent of play area remains untested trap.
B. Wildcat success rate for one operator from 1967 to 1979 was 14 percent, which is assumed to be average for play. The areal fill is estimated to average 40 percent, indicating about 5.6 percent of untested trap area to be productive.
C. Reservoir sandstones range through three formations, Miocene to Pliocene; maximum gross thickness in principal reservoir formation, the Keutapang Formation, is 468 ft in 14 zones, averaging 10 to 20 ft thick. I estimate 150 ft as an average net pay.
D. There are no data as to gas versus oil production because gas has been flared since 1900. Gas/oil ratios vary. Estimated fill is 60 percent oil.
E. Based on an estimated low average porosity of 15 to 20 percent (shaly reservoirs), and assumed 25 percent water saturation, primary oil recovery is estimated to be 190 barrels per acre-foot.
F. Assuming the same reservoirs, an average depth of 7,000 ft, and a temperature gradient of 2.5°F, gas recovery is estimated to be 840,000 ft^3 per acre-foot.
G. World average figures.

Limiting Factors: Meager source richness (see text), shaly reservoirs, and impeded oil migration by overpressured shale.

Total resources of all plays in basin: .362 BBO, 9.0 TCFG, .412 BBNGL, 2.274 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN North Sumatra, No. 1 COUNTRY Indonesia PLAY Shallow Shelf Reefs, No. 3
AREA OF BASIN (Mi^2) 33,000 AREA OF PLAY (MMA) 2.7
VOLUME OF BASIN (Mi^3) 97,000 * PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 2.1 BBO 16.25 TCFG .25 BBO 2 TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc * Est. only, no production established

DEFINITION AND AREA OF PLAY: Oil and gas accumulations in Miocene carbonate build-ups on the relatively shallow foreland shelf. Area of play appears limited to the northern fourth of shelf or about 2.7 million acres (area 3, fig. 6).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.02	.047	1.200
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	6	18	25
C. AVERAGE EFFECTIVE PAY (feet)	100	200	700
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	20	25	50
E. OIL RECOVERY (BBLS/AF)	130	237	290
F. GAS RECOVERY (MCF/AF)	400	770	1,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .100 BB, GAS .977 TCF, NGL .011 BB, OE .274 BBOE

REMARKS

A. Extrapolation from published (McArthur and Helm, 1982) and unpublished maps indicate that approximately 3.5 percent of the play is reefal trap area of which about half has been tested.
B. From published cross sections (McArthur and Helm, 1982), the petroleum fill appears to average about 80 percent. Wildcat success rate is high, 66 percent, but I estimate this will decline to about one-third (22 percent), giving a productive area of about 18 percent of the untested trap area.
C. Reportedly, petroleum columns vary up to 680 ft. Perhaps a good average would be 200 ft, including the smaller reefs.
D. Four oil and four gas discoveries have been made. On basis of a published map (McArthur and Helm, 1982), it is estimated that on an areal basis, oil is 25 percent of the oil-gas mix.
E. Porosities range from 7 to 31 percent (McArthur and Helm, 1982). They estimate an average of 22 percent. Permeability is appreciably affected by fracturing Assuming 25 percent water saturation, the primary oil recovery would average 237 barrels per acre-foot.
F. Assuming same reservoir, an average depth of 5,000 ft and a temperature gradient of 2.5°F per 100 ft, about 770,000 ft^3 per acre-foot would be produced.
G. World-wide average.

Limiting Factor: Probably the small size and shallowness of the reefs may preclude economic production, particularly of gas, in some cases.

Total resources for all plays in basin: .362 BBO, 9.0 TCFG, .412 BBNGL, 2.274 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN North Sumatra, No. 1 COUNTRY Indonesia PLAY L. Miocene Shelf Sandstones No. 4
AREA OF BASIN (Mi^2) 33,000
VOLUME OF BASIN (Mi^3) 97,000
ESTIMATE ORIGINAL RESERVES 2.1 BBO 16.25 TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc
AREA OF PLAY (MMA) 8.0
PLAY EST. ORIG. RESERVES, -- BBO, -- TCFG

DEFINITION AND AREA OF PLAY: Petroleum in lower Miocene sandstones and calcarenites in drapes over north-trending basement knobs of shelf. Play extends over foreland shelf exclusive of northern fourth where reefs dominate. Play has an area of some 8 million acres (area 4, fig. 6).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.120	.200
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	4	6	12
C. AVERAGE EFFECTIVE PAY (feet)	50	150	600
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	20	55	80
E. OIL RECOVERY (BBLS/AF)	100	160	400
F. GAS RECOVERY (MCF/AF)	400	520	800
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .095 BB, GAS .253 TCF, NGL .003 BB, OE .140 BBOE

REMARKS

A. From unpublished maps of part of onshore area, it has been estimated that perhaps 2 percent of play area, or 160,000 acres, is under trap. Onshore exploration has found six gas and oil accumulations of only marginal economic size. Onshore and offshore perhaps 20 drapes, or about 40,000 acres of closure have been tested leaving an untested trap area of 120,000 acres.

B. The discovery rate of one operator is 47 percent, but the discoveries are of marginal economic size and the wells may include step-outs or appraisals. A true future discovery rate might be 20 percent. Trap fill varies widely reflecting uneven carbonate cementation on one hand and flushing on the other; I estimate an average of 30 percent, giving a productive area of 6 percent.

C. Pay thickness is very irregular depending on the amount of cementation or flushing. From unpublished data, the average effective pay is estimated to be about 150 ft.

D. Two of the small discoveries are reported as gas, four as gas and oil. I estimate the trap area is about 55 percent oil.

E. Recovery tends to be low because of carbonate cementation. I estimate 15 percent average porosity and water saturation of 25 percent, indicating about 160 barrels per acre-foot.

F. Assuming same reservoirs, average depth of 5,000 ft, and a thermal gradient of 2.5°F per 100 ft, gas from an acre-foot of reservoir would be 520,000 ft^3.

G. World-wide average.

Limiting Factors: Uncertain reservoir quality, flushing, access of hydrocarbon to reservoirs in primary migration.
Total resources of all plays in basin: .362 BBO, 9.0 TCFG, .412 BBNGL, 2.274 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN North Sumatra, No. 1 COUNTRY Indonesia PLAY Paleogene Basal Drapes No. 5
AREA OF BASIN (Mi^2) 37,200
VOLUME OF BASIN (Mi^3) 97,200
ESTIMATE ORIGINAL RESERVES 2.1 BBO 16.25 TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc
AREA OF PLAY (MMA) 5.6
PLAY EST. ORIG. RESERVES, 0 BBO, 0 TCFG

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Paleogene basal sandstones draped over horst blocks in deeper, basinal part of North Sumatra basin, these sands being missing from foreland shelf. Play area is approximately 5.6 million acres (area 5, fig. 6).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.112	.308	.560
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2.0	3.5	5.0
C. AVERAGE EFFECTIVE PAY (feet)	50	100	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	5	10	20
E. OIL RECOVERY (BBLS/AF)	50	130	300
F. GAS RECOVERY (MCF/AF)	800	1,170	1,300
G. NGL RECOVERY (BBLS/MMCFG)	11	53	100

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .014 BB, GAS 1.135 TCF, NGL .060 BB, OE .26 BBOE

REMARKS

A. From unpublished maps of part of play, I estimate that the untested trap area is about 5.5 percent or .308 million acres.

B. Wildcat success to date is nil, but wildcats may have been largely positioned for shallower primary targets. I assume wildcats targetted specifically on this play would be more successful, perhaps 5 to 10 percent. Fill is estimated to be 50 percent (60 percent for equally deep Arun), indicating 3.5 percent of trap area productive.

C. No data, but this would probably not be a limiting factor; I assume 100 ft.

D. The few slight shows encountered have been both oil and gas, but owing to the play's deep basinal position either enveloped in overpressured shale (see text) or within the zone of thermally overmature sediments, I estimate only 10 percent of petroleum is oil.

E. Where encountered, these reservoirs have been relatively poor. I estimate 12 percent average porosity and 25 percent water saturation.

F. Assuming same reservoirs as for oil, a temperature gradient of 3°F per 100 ft, and a depth of over 10,000 ft in overpressured zone (7,100 psi in Arun), I estimate 1,170,000 ft^3 of gas would be produced per acre-foot.

G. I estimate the same gas-condensate ratio of Arun would prevail, i.e., 53 barrel/MMCFG.

Limiting Factors: Low porosity, and generally great depth and impedance of primary oil migration by overpressured shale.

Total resources of all plays in basin: .362 BBO, 9.0 TCFG, .412 BBNGL, 2.274 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN North Sumatra, No. 1 COUNTRY Indonesia PLAY Offshore Slope, No. 6
AREA OF BASIN (Mi^2) 37,200 AREA OF PLAY (MMA) 7.0
VOLUME OF BASIN (Mi^3) 97,200 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 2.1 BBO 16.25 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: In the absence of any data, the play can only be defined as possible petroleum accumulations in an appreciable volume of sediments, which are part of a petroliferous basin. Area of play is about 7 million acres on the north offshore slope of Sumatra (area 6, fig. 6).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.10	.42	.90
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1	3	8
C. AVERAGE EFFECTIVE PAY (feet)	50	100	500
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	1	7.5	25
E. OIL RECOVERY (BBLS/AF)	100	150	300
F. GAS RECOVERY (MCF/AF)	800	1,400	1,800
G. NGL RECOVERY (BBLS/MMCFG)	11	53	100

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .014 BB, GAS 1.63 TCF, NGL .086 BB, OE .371 BBOE

REMARKS

A. Structural trends of the onshore basin extend into play area though perhaps diminishing away from the higher relief topography. Paleogene trends appear to antedate the structural low north of Sumatra so that the Deep Reef and Paleogene Basal Drapes may prevail. An area-weighted average of the percentage trap area in the play is 6 percent.

B. The percentage of trap that would be productive is 5 percent if I average the two deeper plays, but considering the likelihood of poorer reservoirs and less developed structure, 3 percent is assumed.

C. The weighted average pay of the Deep Reef and Paleogene reefs is 140 ft, but would perhaps be diminished in this further offshore position; I estimate 100 ft.

D. Analogous to the adjoining deep plays, it is deemed that only 7.5 percent of the petroleum is oil.

E. Oil recovery would be about the same as for the adjoining deep plays or about 150 barrels per acre-foot.

F. Gas recovery also would about average that of the adjoining deep plays of North Sumatra or about 1,400,000 ft^3 per acre-foot.

G. It is assumed that the NGL recovery would be about the same as Arun.

Limiting Factor: The overriding limiting factor may be the lack of adequate reservoirs.
Total resources for all plays in basin: .362 BBO, 9.0 TCFG, .412 BBNGL, 2.274 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Central Sumatra, No. 2 COUNTRY Indonesia PLAY Lower Miocene Sandstones No. 1
AREA OF BASIN (Mi^2) 27,000
VOLUME OF BASIN (Mi^3) 29,000
ESTIMATE ORIGINAL RESERVES 8.746 BBO 0.21 TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc
AREA OF PLAY (MMA) 17.2
PLAY EST. ORIG. RESERVES, 8.746 BBO 0.21 TCFG

DEFINITION AND AREA OF PLAY: Petroleum accumulations in lower Miocene deltaic sandstones which are affected by drag folding or draping. The play area includes practically all of the Central Sumatra basin (figs. 1, 11, 12).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.236	.350
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	3.0	6.0	8.8
C. AVERAGE EFFECTIVE PAY (feet)	70	200	600
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	80	95	98
E. OIL RECOVERY (BBLS/AF)	260	350	500
F. GAS RECOVERY (MCF/AF)	400	760	1,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	22

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .942 BB, GAS .108 TCF, NGL .001 BB, OE .961 BBOE

REMARKS

A. Traps are sedimentary drapes, e.g., Minas and Duri Fields, or drag folds associated with wrenches. Extrapolation from field maps leads one to an estimate that about 5.5 percent of the play is trap area. Assuming 75 percent of the traps have been tested, untested trap area is 236,000 acres.
B. The wildcat discovery rate is about 22 percent but will probably decline. I estimate that perhaps 15 percent of untested traps will contain petroleum. The amount of fill varies from 22 percent to 100 percent; I estimate 40 percent may be a good average. This indicates that about 6.0 percent of the untested trap area contains petroleum.
C. Net effective sandstone reservoir thickness varies. It is often 200 to 400 ft and may be as much as 800 ft. Perhaps 200 ft would be a good average in the less favorable prospects remaining.
D. Gas to oil ratios appear unusually low (35 CFG/BO at Minas). Perhaps gas has leaked from basin. I estimate undiscovered petroleum will be 95 percent oil.
E. Oil recovery varies with porosity, which ranges from 10 to 40 percent; it averages 27 percent at Minas, which I take as average for the basin. The primary oil recovery factor varies from a low of 7.4 percent at Duri Field to presumably 25 percent. I estimate an average recovery of about 350 barrels per acre-foot.
F. There is little gas potential, but assuming an average reservoir depth of 5,000 ft and given the temperature gradient of 3.7°F per 100 ft, I estimate 765,000 ft^3 per acre-foot.
G. World-wide average.

Limiting Factors: The thorough exploration to date of relatively uncomplicated geology and the apparently limited volume of source rock to generate much more petroleum than already discovered.

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN South Sumatra, No. 3 COUNTRY Indonesia PLAY Lower Miocene Sandstones, No. 1
AREA OF BASIN (Mi^2) 18,300
VOLUME OF BASIN (Mi^3) 40,000
ESTIMATE ORIGINAL RESERVES 1.7 BBO 4.0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc
AREA OF PLAY (MMA) 11.7
PLAY EST. ORIG. RESERVES, 1.3 BBO 2.0(?) TCFG

DEFINITION AND AREA OF PLAY: Accumulations in Oligo-Miocene (Talang Akar Formation) deltaic sandstones trapped in anticlines of drape or drag-fold origin. The play area includes practically all of South Sumatra basin or some 11.7 million acres (figs. 15 and 18).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.164	.250
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	3	5	20
C. AVERAGE EFFECTIVE PAY (feet)	50	200	500
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	40	50	60
E. OIL RECOVERY (BBLS/AF)	130	205	400
F. GAS RECOVERY (MCF/AF)	400	1,030	1,600
G. NGL RECOVERY (BBLS/MMCFG)	8	11	22

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .168 BB, GAS .845 TCF, NGL .009 BB, OE .317 BBOE

REMARKS

A. A structure map of part of area indicates traps make up 11.5 percent, but it is in an area of concentrated fields; over the whole play I estimate that, by area, traps may make up 7 percent. Assuming 80 percent of traps have been tested, 164,000 acres remain to be tested.

B. In recent years, the wildcat success rate has been about 10 percent where it is likely to remain for some time. I estimate from oil field maps the average fill is 40 percent, indicating 4 percent of trap area will be productive. There are some prospects of stratigraphic traps (as Abab) perhaps raising percentage to 5.

C. Although the deltaic sandstones are discontinuous and lensing, I estimate an average net thickness of 200 ft in the Raja Field and assume it to be a representative sample of the play.

D. Volume-wise the gas-oil ratio at Raja Field appears to be 3 to 1. Other fields appear to have only small gas caps. I estimate 50 oil in the petroleum mix.

E. Porosity at Raja Field ranges from 15 to 23, averaging perhaps 19 percent. Water saturation of 25 percent and oil recovery factor of 25 percent are assumed.

F. Assuming the same reservoirs, an average depth of 10,000 ft, and a thermal gradient of around 2.15°F per 100 ft.

G. World-wide average.

Limiting Factor: Extensive exploration to date may have left few undiscovered petroleum accumulations.

Total resources for all plays in basin: .250 BBO, 1.518 TCFG, .016 BBNGL, .518 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN South Sumatra, No. 3 COUNTRY Indonesia PLAY Miocene carbonates, No.2
AREA OF BASIN (Mi^2) 18,300
VOLUME OF BASIN (Mi^3) 40,000 AREA OF PLAY (MMA) 11.7
ESTIMATE ORIGINAL RESERVES 1.7 BBO 4.0 TCFG PLAY EST. ORIG. RESERVES, ? BBO 2.0(?) TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Petroleum, mainly gas, accumulations in lower Miocene (Baturaja) carbonate reefs and banks. The play area is taken to be practically the entire basin (figs. 15, 18, and 19).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.070	.140	.250
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2	4	10
C. AVERAGE EFFECTIVE PAY (feet)	50	170	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	5	30	30
E. OIL RECOVERY (BBLS/AF)	150	230	300
F. GAS RECOVERY (MCF/AF)	300	1,000	1,600
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .066 BB, GAS .666 TCF, NGL .007 BB, OE .184 BBOE

REMARKS

A. Extrapolation of a reef distribution map (fig. 11) indicates 1 percent of the play area has identified carbonate buildup, but it is suspected that double this amount will be discovered as the demand for gas increases and more advanced seismic techniques become available. Assuming 40 percent of eventually discovered reef has been tested, I estimate 140,000 acres of untested trap remain.
B. Recent wildcat success rate is 13 percent. The hydrocarbon fill of Baturaja reservoirs in the Raja Field appears to be about 30 percent, indicating productive trap area of 4 percent.
C. In the Raja Field, the Baturaja limestone "ranges from thin shaly limestone sections to intervals of 170 ft of extremely porous limestone" (Basuni, 1978). I assume 170 ft is an average thickness of limestone buildups of the basin.
D. The carbonate reefs are largely gas filled; however oil has been produced in some recent discoveries (e.g., Ramba). I estimate oil makes up about 30 percent of the oil-gas mix.
E. At the Raja Field, porosity averages 20 percent and water saturation 20 percent. This is taken as an average for the play, indicating an oil recovery of 230 barrels per acre-foot.
F. Assuming the same reservoirs, an average thermal gradient of 2.15°F per 100 ft and an average depth of 9,000 ft, the gas recovery would be about 1 million cubic ft per acre-foot.
G. World-wide average.

Limiting Factor: The relative sparseness of reservoirs limits the amount of petroleum in this play.

Total resources for all plays in basin: .250 BBO, 1.518 TCFG, .016 BBNGL, .518 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN South Sumatra, No. 3 COUNTRY Indonesia PLAY Mio-Pliocene Sandstones, No. 3
AREA OF BASIN (Mi^2) 18,300
VOLUME OF BASIN (Mi^3) 40,000 AREA OF PLAY (MMA) 11.7
ESTIMATE ORIGINAL RESERVES 1.7 BBO 4.0 TCFG PLAY EST. ORIG. RESERVES,
TECTONIC CLASSIFICATION OF BASIN: Back Arc 0.2(?)BBO -- TCFG

DEFINITION AND AREA OF PLAY: Petroleum accumulations in middle Miocene to Pliocene sandstones in drag fold and drape anticlines. The area of play is approximately that of the basin, i.e., 11.7 million acres (fig. 15).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.030	.082	.120
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	0.5	1.5	2.5
C. AVERAGE EFFECTIVE PAY (feet)	50	75	150
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	30	70	90
E. OIL RECOVERY (BBLS/AF)	150	250	350
F. GAS RECOVERY (MCF/AF)	100	300	600
G. NGL RECOVERY (BBLS/MMCFG)	8	11	22

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .016 BB, GAS .008 TCF, NGL .00 BB, OE .017 BBOE

REMARKS

A. In the absence of data, I assume the structure is approximately parallel to that of the underlying early Miocene. However these sandstones have been eroded from crestal portions of structures and have been subject to more intensive exploration so that the trap area is only about half the untested trap-area of the early Miocene play.

B. The wildcat success rate is low since this thoroughly explored play is now only considered a secondary drilling objective. I estimate a 5 percent wildcat success and assume a 30 percent fill, indicating 1.5 percent of the untested trap is productive.

C. In the absence of any data and considering the small amount of production, I estimate a net pay thickness of 75 ft.

D. The percent of oil in the petroleum mix would initially be the same as the Oligo-Miocene play except probably more gas has escaped these shallow sandstones. I estimate 70 percent oil.

E. Assuming average reservoir conditions (porosity of 20 percent), oil recovery of 250 barrels per acre-foot is estimated.

F. Assuming same reservoirs, an average depth of 2,500 ft, and a thermal gradient of 2.15°F per 100 ft, I estimate a gas recovery of 300,000 ft^3 per acre-foot.

G. World-wide average.

Limiting Factor: The advanced stage of exploration in this shallow play limits any further discoveries.

Total resources for all plays in basin: .250 BBO, 1.518 TCFG, .016 BBNGL, .518 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Northwest Java, No. 4 COUNTRY Indonesia PLAY Paleogene Volcanics, No. 1
AREA OF BASIN (Mi^2) 20,600
VOLUME OF BASIN (Mi^3) 25,600 AREA OF PLAY (MMA) .74
ESTIMATE ORIGINAL RESERVES 2.754 BBO 2.1 TCFG(1979) PLAY EST. ORIG. RESERVES,
TECTONIC CLASSIFICATION OF BASIN: Back Arc .16 BBO -- TCFG

DEFINITION AND AREA OF PLAY: Petroleum accumulations in fractured Paleogene volcanics in traps formed by block-faulting and drapes. Play area essentially restricted to Jatibarang subbasin of some 740,000 acres (figs. 20 and 22).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.005	.018	.025
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	6	12	20
C. AVERAGE EFFECTIVE PAY (feet)	100	350	1,000
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	40	75	80
E. OIL RECOVERY (BBLS/AF)	130	237	400
F. GAS RECOVERY (MCF/AF)	400	800	1,600
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .134 BB, GAS .151 TCF, NGL .002 BB, OE .161 BBOE

REMARKS

A. By analogy to the overlying Talang Akar play in other parts of the basin, the trap area is 6 percent of the play area. If 60 percent of the traps are deemed tested, .018 million acres of trap area remain.

B. By analogy to the Talang Akar play, the untested trap area which may be productive is estimated at 12 percent.

C. The average gross thickness of fractured volcanics above the oil-water contact in the Jatibarang Field is 800 ft. According to Todd and Pulanggano, 1971, "average cumulative reservoir thickness is 600 ft." Sembodo, 1973, illustrates 120 ft as a sample. Controlled by fracture permeability, reservoir thickness is irregular. I estimate 350 ft as average for play.

D. By analogy to the Talang Akar play, 75 percent of the petroleum mix is oil.

E. Estimating 22 percent porosity and assuming other reservoir parameters are average, the primary oil recovery is 237 barrels per acre-foot.

F. Assuming same reservoirs, average reservoir depth of 6,600 ft, and thermal gradient of 3.0°F per 100 ft, the gas recovery would be 800,000 ft^3 per acre-foot.

G. World-wide average.

Limiting Factors: The reservoir quality from prospect to prospect is unpredictable.

Total resources for all plays in basin: .953 BBO, 1.941 TCFG, .011 BBNGL, 1.024 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Northwest Java, No. 4 COUNTRY Indonesia PLAY Paleogene (Talang Akar) Sandstones No. 2
AREA OF BASIN (Mi^2) 20,600
VOLUME OF BASIN (Mi^3) 25,600 AREA OF PLAY (MMA) 5.5
ESTIMATE ORIGINAL RESERVES 2.754 BBO 2.1 TCFG(1979) PLAY EST. ORIG. RESERVES, .4(?) BBO ? TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Petroleum accumulations in traps formed by fault closures of Paleogene deltaic sandstones or by draping of these sandstones onto flanks or over fault-block highs. Play largely restricted to subbasins or half-grabens (figs. 20 and 22).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.05	.099	.250
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	5	12	20
C. AVERAGE EFFECTIVE PAY (feet)	40	110	250
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	40	75	90
E. OIL RECOVERY (BBLS/AF)	150	269	400
F. GAS RECOVERY (MCF/AF)	400	812	1,600
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .264 BB, GAS .265 TCF, NGL .003 BB, OE .311 BBOE

REMARKS

A. From extrapolation of small map portion of Sunda basin, trap area is 9 percent of play area. By analogy to geologically similar South Sumatra basin, trap area is 5.5 percent and by analogy to the somewhat similar East Java Sea basin, 7 percent. I estimate 6 percent, or 330,000 acres, of which 70 percent has been tested.

B. The overall wildcat success rate for the basin is high - 31 percent, but this is largely attributable to later Miocene plays; I estimate a somewhat lesser rate, perhaps 25 percent for the Talang Akar sandstones. Fill is thought to be 70 percent for Miocene traps of this basin and 35 percent for analogous Paleogene traps of South Sumatra. Accordingly I estimate an average of 50 percent fill, giving an average productive area of 12 percent.

C. The average cumulative reservoir thickness is reportedly 110 ft (Todd and Pulunggono, 1971).

D. No precise data available. I estimate that 75 percent of the petroleum mix is oil at this level.

E. Based on a reported average porosity of 25 percent and assuming 25 percent water saturation and 25 percent oil recovery.

F. Assuming same reservoirs, an average depth of 8,000 ft, and a thermal gradient of 2.8°F per 100 ft.

G. World-wide average.

Limiting Factor: No salient limiting factor. Since closures appear half-filled, source rock richness may be a limiting factor.
Total resources for all plays in basin: .953 BBO, 1.941 TCFG, .011 BBNGL, 1.024 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Northwest Java, No. 4 COUNTRY Indonesia PLAY Lower Miocene carbonates
AREA OF BASIN (Mi^2) 20,600 No. 3
VOLUME OF BASIN (Mi^3) 25,600 AREA OF PLAY (MMA) 3.84
ESTIMATE ORIGINAL RESERVES 2.754 BBO 2.1 TCFG(1979) PLAY EST. ORIG. RESERVES,
TECTONIC CLASSIFICATION OF BASIN: Back Arc .6(?) BBO 1(?) TCFG

DEFINITION AND AREA OF PLAY: Petroleum accumulation in lower Miocene (partly Oligocene) porous carbonate (Baturaja Formation) drapes and buildups. Area of play is the Sunda, Arjuna and northern Jatibarang subbasins, and peripheral area - about 6,000 mi^2 (figs. 20, 25, and 26).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.138	.400
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	5	9	20
C. AVERAGE EFFECTIVE PAY (feet)	50	100	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	15	70	90
E. OIL RECOVERY (BBLS/AF)	150	280	400
F. GAS RECOVERY (MCF/AF)	400	690	1,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .243 BB, GAS .257 TCF, NGL .003 BB, OE .289 BBOE

REMARKS

A. From partial maps of basin, I estimate about 12 percent of play area (.461 MMA) is trap area, of which 30 percent (.138 MMA) is untested.

B. Discovery rate for all plays is 31 percent; in absence of data, I assume this is about the rate for this play. Estimating a 30 percent fill (analogy to late Miocene reefs), the untested trap area would be 12,000 acres (9 percent).

C. Average net pays are 66 ft at FF Field, 125 ft at Arimba Field, 75 ft at Zelda Field, and 40-100 ft at Krishna Field. Todd and Pulunggono (1971) report an "average cumulative reservoir thickness of 175 ft for the basin." I believe 100 ft is a good average for net effective thickness.

D. The Sunda Subbasin appears to be largely oil-prone; Arimba Field in the eastern basin, on the other hand, is largely gas. I estimate petroleum fill is 70 percent oil, somewhat less than in the underlying Paleogene sands.

E. Assuming 25 percent porosity and 25 percent water saturation, primary oil recovery would be 280 barrels per acre-foot.

F. Assuming same reservoirs, as for oil, an average reservoir depth of 3,000 ft, and a temperature gradient of 2.8°F/100 ft, the average gas recovery is about 690,000 ft^3 per acre-foot.

G. World-wide average is assumed.

Limiting Factor: Porosity distribution in the carbonate reservoirs.

Total resources for all plays in basin: .953 BBO, 1.941 TCFG, .011 BBNGL, 1.024 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Northwest Java, No. 4 COUNTRY Indonesia PLAY Miocene Draped Sandstones, No. 4
AREA OF BASIN (Mi^2) 20,600
VOLUME OF BASIN (Mi^3) 25,600 AREA OF PLAY (MMA) 1.6
ESTIMATE ORIGINAL RESERVES 2.754 BBO 2.1 TCFG(1979) PLAY EST. ORIG. RESERVES,
TECTONIC CLASSIFICATION OF BASIN: Back Arc 1.2(?) BBO (?) TCFG

DEFINITION AND AREA OF PLAY: Petroleum accumulations in middle to mainly upper Miocene sandstones (Air Benakat or Upper Cibulakan Formations) in drape closures over fault blocks or carbonate buildups. Play limited by effective sandstone distribution to Arjuna subbasin (1.2 MMA) and peripheral (0.4 MMA) (figs. 22 and 23).

	PROBABILITY DISTRIBUTION		
MAJOR GEOLOGICAL/EXPLORATION FACTORS	95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.010	.030	.050
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	10	21	30
C. AVERAGE EFFECTIVE PAY (feet)	50	250	350
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	30	60	80
E. OIL RECOVERY (BBLS/AF)	100	224	350
F. GAS RECOVERY (MCF/AF)	300	457	1,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .212 BB, GAS .288 TCF, NGL .003 BB, OE .263 BBOE

REMARKS

A. By analogy to closures at Talang Akar level (see play 2), 6 percent of play is in trap or about 100,000 acres. I estimate that about 70 percent of closure has been found and tested, leaving an untested trap area of 30,000 acres.

B. The basin's wildcat success is about 31 percent, which we assume is average for this play. The petroleum fill of the principal sand (B-28) in the Arjuna B Field is 70 percent. I assume this to be average for play, giving a productive area of about 21 percent.

C. Average net pay is reportedly 250 ft (Todd and Pulunggono, 1971).

D. The percent of oil should be about the same as the underlying Talang Akar sandstones since they have a common source; however the gas-oil ratio is higher in these sandstones, i.e., 40:60 in contrast to 25:75 for the Talang Akar.

E. Assuming average porosity of 26 percent and water saturation of 40 percent (Arjuna B Field) is average for basin, and primary oil recovery of 25 percent.

F. Assuming same reservoirs, average depth of 3,000 ft, and thermal gradient of 2.6°F per 100 ft.

G. World-wide average.

Limiting Factor: The most limiting factor is probably sand distribution, confining the production to the Arjuna subbasin area.

Total resources for all plays in basin: .953 BBO, 1.941 TCFG, .011 BBNGL, 1.024 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Northwest Java, No. 4 COUNTRY Indonesia PLAY Mid-Miocene carbonates, No. 5
AREA OF BASIN (Mi^2) 20,600 AREA OF PLAY (MMA) 3.2
VOLUME OF BASIN (Mi^3) 25,600 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 2.754 BBO 2.1 TCFG(1979) .01 BBO 1(?) TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Gas and some oil accumulations in middle Miocene carbonate reefs and banks. Play not limited to subbasinal areas but extends across basin. Appears not to be developed in vicinity of the Sunda subbasin (3.2 MMA) (figs. 20 and 22).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.150	.250	.400
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	4	8	20
C. AVERAGE EFFECTIVE PAY (feet)	50	120	400
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	5	15	30
E. OIL RECOVERY (BBLS/AF)	150	270	350
F. GAS RECOVERY (MCF/AF)	300	480	1,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .10 BB, GAS .980 TCF, NGL .010 BB, OE .273 BBOE

REMARKS

A. As indicated by published maps (Burbury, 1977), there are 690,000 acres of carbonate trap. From distribution of wildcats that 36 percent or 250,000 acres remain to be tested.

B. On basis of wildcat activity, a 20 percent success rate is indicated for the play as a whole, although it may vary from subbasin to subbasin. Petroleum fill also varies, but in this rather shallow play it may be lower than the 70 percent of the deeper Miocene drapes, perhaps 40 percent, indicating a productive area of 8 percent.

C. Effective pay appears to range from 30 to 400 ft. Taking into consideration the varying and unpredictable porosity, the average carbonate porous zone would average some 120 ft in thickness.

D. Production indicates these reservoirs to be gas prone though some oil is produced. Oil is considered to make up 15 percent of the oil-gas mix.

E. No data; assuming poor to average reservoir parameters.

F. Assuming similar reservoir parameters, an average depth of 3,000 ft, and a thermal gradient of 3.6°F per 100 ft.

G. World-wide average.

Limiting Factors: The overall limiting factor for petroleum appears to be limited and unpredictable porosity and lack of thick cover. The limiting factor for the oil fraction is lack of migration avenues to the shale encased reefs from the deeper mature source rock.
Total resources for all plays in basin: .953 BBO, 1.941 TCFG, .011 BBNGL, 1.024 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN East Java Sea, No. 5 COUNTRY Indonesia PLAY Shelf Reef, No. 1
AREA OF BASIN (Mi^2) 43,000 AREA OF PLAY (MMA) 5
VOLUME OF BASIN (Mi^3) 77,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .207 BBO -- TCFG .02 BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Tertiary reefs and banks of the basin shelf and shelf margin. Play area limited to carbonate platform area, which makes up about 30 percent of basin shelf or 5 million acres (figs. 28 and 30).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.200	.500
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	3	6	15
C. AVERAGE EFFECTIVE PAY (feet)	100	200	400
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	20	40	80
E. OIL RECOVERY (BBLS/AF)	140	194	300
F. GAS RECOVERY (MCF/AF)	350	568	1,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .186 BB, GAS .818 TCF, NGL .009 BB, OE .331 BBOE

REMARKS

A. An unpublished map of part of area indicates that carbonate buildups make up 7 percent of play area, but for entire play, I would judge percentage to be somewhat lower, about 5 percent, giving a trap area of 250,000 acres. Perhaps 20 percent of this area has been tested leaving 200,000 acres of untested trap.

B. Announced discoveries indicate success rate of 18 percent, but none of discoveries were developed, and a realistic estimate would perhaps halve this rate to about 10 percent. Fill ranges from 100 percent at Poleng Field, and 6 percent at 53A-1. I estimate 60 percent fill, indicating 6 percent of untested trap area will be productive.

C. Net pay of Poleng Field is 255 ft and an early discovery, JS-1-1, had 20 ft of net pay (Soeparjadi and others, 1975). Average figure for productive accumulation would probably have to be at least 200 ft; which is assumed as an average.

D. From the Poleng Field reef, which is filled by 102 ft of oil overlain by 153 ft of gas (Soeparjadi and others, 1975), it is assumed that average fill is 40 percent oil.

E. Porosity distribution in these carbonate reservoirs is often poor and unpredictable. Assuming a somewhat low average porosity of 18 percent, the yield is 194 barrels per acre-foot.

F. Assuming the same reservoirs, a reservoir depth of 5,000 ft, and a thermal gradient of 2.2°F per 100 ft, the gas recovery is 568,000 ft^3 per acre-foot.

G. World-wide average.

Limiting Factors: Evident small size of traps and unpredictability of favorable reservoir parameters.

Total resources for all plays in basin: .356 BBO, 1.592 TCFG, .018 BBNGL, .638 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN East Java Sea, No. 5   COUNTRY Indonesia   PLAY Shelf Drapes, #2
AREA OF BASIN (Mi^2) 43,000   AREA OF PLAY (MMA) 17.0
VOLUME OF BASIN (Mi^3) 77,000   PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .207 BBO -- TCFG   0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Tertiary sands or calcarenites draped over basement tilted fault blocks. Play area is that of the basin shelf - about 17 million acres (figs. 28 and 30).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.10	.30	.60
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2	4.5	6
C. AVERAGE EFFECTIVE PAY (feet)	50	100	400
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	20	40	80
E. OIL RECOVERY (BBLS/AF)	150	270	350
F. GAS RECOVERY (MCF/AF)	350	770	1,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .145 BB, GAS .624 TCF, NGL .007 BB, OE .255 BBOE

REMARKS

A. An unpublished structure map of part of area indicates drape traps make up 5 percent of play, but if one includes the less structured parts of the shelf, I think this percentage would be half that of the mapped area or 2.5 percent or 425,000 acres, of which perhaps 30 percent has been tested leaving 300,000 acres.

B. The wildcat success rate is 18 percent on the basis of announced discoveries, but none have been developed; perhaps half this rate would be more realistic. Assuming a fill somewhat less than for the carbonate play, say 50 percent, the percent of untested trap likely to be productive is 4.5 percent.

C. No data are available. Effective pay of at least 50 ft would be required for an economic offshore prospect. I assume an average of 100 ft.

D. In the absence of data, I estimate the percent of oil in the petroleum fill is the same as that for the reef play, i.e., oil is 40 percent.

E. Assuming average reservoir parameters, I estimate 270 barrels per acre-foot.

F. Assuming same reservoirs, a reservoir depth of 5,000 ft, and a thermal gradient of 2.2°F per 100 ft, gas recovery is estimated to be 770,000 ft^3 per acre-foot.

G. World-wide average.

Limiting Factor: Reservoir quality is likely to be poor in this very calcareous sedimentary section.

Total resources for all plays in basin: .356 BBO, 1.592 TCFG, .018 BBNGL, .638 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN East Java Sea, No. 5 COUNTRY Indonesia PLAY Basinal Folds, #3
AREA OF BASIN (Mi^2) 43,000 AREA OF PLAY (MMA) 10.7
VOLUME OF BASIN (Mi^3) 77,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .207 BBO -- TCFG .201(?)BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Neogene folds of the deep, basinal part of East Java basin. Play area between relatively shallow shelf to the north and the volcanic arc to the south is about 10.7 million acres (figs. 28 and 30).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.50	.150	.500
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)		1.5	
C. AVERAGE EFFECTIVE PAY (feet)	100	200	700
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	10	30	90
E. OIL RECOVERY (BBLS/AF)	100	195	350
F. GAS RECOVERY (MCF/AF)	300	475	1,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .026 BB, GAS .150 TCF, NGL .002 BB, OE .053 BBOE

REMARKS

A. Onshore traps are small and play exploration very mature. Deep prospects are relatively unevaluated. Offshore there are some larger folds, east of and on trend with Madura Island, i.e., along and immediately basinward of shelf edge. In a limited zone of 2.5 million acres, closures make up about 5 percent of play area or about 125,000 acres, most of which are untested. Considering the onshore small closures, perhaps 150,000 acres remain to be tested.
B. Recent drilling in the offshore found one gas discovery plus a blowout and an oil show. I estimate a discovery rate of perhaps 15 percent. Percentage fill in onshore traps is 10 percent (Soetantri, 1973); that is assumed average for play indicating 1.5 percent of untested trap area would be productive.
C. Large net sand figures are reported, 440 to 639 ft in onshore and 500 ft in offshore well, MS-1. These figures appear high considering the small amount of production obtained. I would estimate 200 ft as an average net thickness.
D. Onshore wells produced only oil but gas was only flared in those early years. One gas discovery and one blowout in offshore along with thick, probably overpressured shale suggests gas. I estimate petroleum mix is 30 percent oil.
E. Porosity is reportedly relatively low, about 18 percent in onshore wells. On this basis I estimate an oil recovery of about 194 barrels per acre-foot.
F. Assuming the same reservoirs, a reservoir depth averaging 4,000 ft, and a thermal gradient of 2.1°F per 100 ft, I estimate a gas recovery of 475,000 ft^3 per acre-foot.
G. World-wide average.

Limiting Factor: Most of effective trap formation happened very late after a good part of the migrating petroleum may have escaped updip.

Total resources for all plays in basin: .356 BBO, 1.592 TCFG, .018 BBNGL, .638 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Barito, No. 6 COUNTRY Indonesia PLAY Folded Sandstones, No. 1
AREA OF BASIN (Mi^2) 19,000 AREA OF PLAY (MMA) 2.35
VOLUME OF BASIN (Mi^3) 43,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .134 BBO .005 TCFG .134 BBO .005 TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland plus collision zone

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Eocene to Miocene sandstones involved in Miocene and Pliocene folds. The area of folds is largely limited to the northeastern quarter of the basin (figs. 33 and 34).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.08	.015	.050
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2	5	10
C. AVERAGE EFFECTIVE PAY (feet)	50	150	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	30	50	80
E. OIL RECOVERY (BBLS/AF)	150	244	400
F. GAS RECOVERY (MCF/AF)	300	467	600
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .014 BB, GAS .026 TCF, NGL .001 BB, OE .018 BBOE

REMARKS

A. No map available, but it is assumed that in the relatively small area exploration has reached a mature state. The Tanjung Field is about 3,700 acres, and the Warukin Field is smaller. It would appear that the equivalent of only two Tanjung Fields can remain, which would amount to some 15,000 acres of trap closure (assuming 50 percent fill).

B. Little drilling history is available; I estimate a success rate of 10 percent. Fill at Tanjung is estimated to be 50 percent and this is taken as average for the basin, indicating that 5 percent of untested trap area would be productive.

C. Reportedly there are three principal Eocene sandstones at Tanjung making some 230 ft in all plus an estimated 150 ft of Miocene sand. The Miocene sandstones are not likely to extend over the play area. I estimate an average reservoir thickness of 150 ft for the play.

D. The Tanjung Field has a small gas cap, 10 percent of trap volume as a guess. A gas discovery has been made in the overlying Berai Formation carbonate on the edge of basin. I estimate that oil makes up 50 percent of petroleum mix.

E. On basis of 20 to 25 percent porosity (Tanjung) and assuming average reservoir parameters, I estimate an oil recovery of 244 barrels per acre-foot.

F. Assuming same reservoirs, an average depth of 3,000 ft, and a thermal gradient of 1.87°F per 100 ft, I estimate a gas recovery of 467,000 ft^3 per acre-foot.

G. World-wide average.

Limiting Factors: Small size of play coupled with maturity of exploration.
Total resources for all plays in basin: .184 BBO, .483 TCFG, .007 BBNGL, .270 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Barito Basin, No. 6 COUNTRY Indonesia PLAY Oligo-Miocene Reefs, #2
AREA OF BASIN (Mi^2) 19,000 AREA OF PLAY (MMA) 12.2
VOLUME OF BASIN (Mi^3) 43,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .134 BBO .005 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland plus collision zone

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Oligo-Miocene (Berai Formation) reefs. Reefs identified in southwestern, far northern, central (Tanjung Field) and eastern parts and therefore assumed to cover basin (figs. 33 and 34).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.05	.183	.400
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2	6	11
C. AVERAGE EFFECTIVE PAY (feet)	50	130	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	30	50	80
E. OIL RECOVERY (BBLS/AF)	150	200	300
F. GAS RECOVERY (MCF/AF)	300	568	800
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .143 BB, GAS .405 TCF, NGL .005 BB, OE .215 BBOE

REMARKS

A. Assumed analogous to Berai Formation of adjoining East Java Sea shelf where I estimated the reefal facies took up 30 percent of shelf and that 5 percent of the reef facies was trap. 1.5 percent of 12.2 million acres is 183,000 acres of which very little has been tested.

B. A wildcat success rate of 12 percent is estimated. Assuming petroleum fill of Tanjung, 50 percent, could apply to this play; 6 percent of untested trap area is productive.

C. At Tanta (adjacent to Tanjung), 250 ft of producing reservoir was found, in the Upper Kapuas River (NW of basin), 131 ft was found. In adjoining East Java Sea, average thickness of 125 ft was assumed for equivalent reservoir. I estimate an average thickness of 130 ft for the play.

D. I assume percentage of oil is same as for the Folded sandstones play.

E. No data, by analogy to equivalent reservoirs of East Java Sea, primary oil recovery would be about 200 barrels per acre-foot.

F. By analogy to reefs of adjoining East Java Sea, which have about the same average depth, 5,000 ft, and about the same thermal gradient, i.e. 2.2°F versus 1.67°F per 100 ft, the average gas recovery would be 568,000 ft^3 per acre-foot.

G. World-wide average.

Limiting Factors: Small size of reefs, and uncertain reservoir characteristics and insufficient thickness for much oil and gas generation.
Total resources for all plays in basin: .184 BBO, .483 TCFG, .007 BBNGL, .270 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Barito, No. 6 COUNTRY Indonesia PLAY Drape Sandstones, No. 3
AREA OF BASIN (Mi^2) 19,000 AREA OF PLAY (MMA) 12.2
VOLUME OF BASIN (Mi^3) 43,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .134 BBO .005 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland plus collision zone

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Paleogene sandstones draped over basement knobs in the shelfal area. Play extends over entire basin (figs. 33 and 34).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.040	.100	.200
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	0.5	1.5	5.0
C. AVERAGE EFFECTIVE PAY (feet)	50	150	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	30	50	80
E. OIL RECOVERY (BBLS/AF)	150	244	400
F. GAS RECOVERY (MCF/AF)	300	467	600
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .027 BB, GAS .052 TCF, NGL .001 BB, OE .037 BBOE

REMARKS

A. In one unpublished map in northern part of the play, the trap area made up .85 percent of the map area; extrapolated to the whole play area this comes to about 100,000 acres.

B. No wildcats have been successful. I estimate success rate will be low - about 3 percent. The fill is assumed to be the same as the folded sands, i.e. 50 percent.

C. By analogy to the Folded sandstone play.

D. By analogy to the Folded sandstone play.

E. By analogy to the Folded sandstone play.

F. By analogy to the Folded sandstone play whose reservoirs are at about the same depth.

G. World-wide average.

Limiting Factors: Small size of knobs and uncertainty of closure.

Total resources for all plays in basin: .184 BBO, .483 TCFG, .007 BBNGL, .270 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Kutei, No. 7 COUNTRY Indonesia PLAY Neogene Delta Sandstones, No. 1
AREA OF BASIN (Mi^2) 50,000 (78,000 includ. water >600')
VOLUME OF BASIN (Mi^3) 210,000 (310,000 in. water >600') AREA OF PLAY (MMA) 17.5
ESTIMATE ORIGINAL RESERVES 2.56* BBO 10.4 TCFG(1979) PLAY EST. ORIG. RESERVES, 2.56 BBO 10.4 TCFG
TECTONIC CLASSIFICATION OF BASIN: Rifted Pull-Apart

DEFINITION AND AREA OF PLAY: Petroleum accumulations in folded Miocene and Pliocene deltaic sandstones. The area of play includes the Mahakam ancestral delta plus the so-called Pasir subbasin (area 1, fig. 41).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.100	.270	.400
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	5	13	30
C. AVERAGE EFFECTIVE PAY (feet)	50	300	900
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	5	20	50
E. OIL RECOVERY (BBLS/AF)	100	233	500
F. GAS RECOVERY (MCF/AF)	800	1,900	2,500
G. NGL RECOVERY (BBLS/MMCFG)	5.0	25.7	50.0

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .490 BB, GAS 16.0 TCF, NGL .411 BB, OE 3.57 BBOE

REMARKS

A. Many traps have been mapped and tested, but I estimate from an unpublished map that there are some 400,000 acres of prospects and leads, of which approximately two-thirds, as finally mapped, will be untested potential traps, or about 270,000 acres.
B. Wildcat success rate is about 33 percent. Percent of areal fill ranges from 3.8 percent fill (of original prospect) at Bekapai to 37 percent at Attaka, to 100 percent at Handil; 40 percent is taken as average. 33 x 40 = 13 percent trap area.
C. Sandstone thicknesses vary considerably. Handil appears to have about 624 ft of effective pay and Badak 1,120 ft, but these fields are located near the delta front; average for whole delta area would perhaps be only one-third or about 300 ft.
D. At a recent stage, 320 MBOD and 550 MMCFG were being produced. I estimate that new oil discoveries may do little more than balance declining reserves, but new gas discoveries will more than double present production. Petroleum resources are believed to be only 20 percent oil versus gas.
E. Porosities appear to range from 14 to 35, averaging perhaps 25 percent; water saturation averages about 35 percent; a 25 percent recovery is assumed.
F. Most gas from 10,000 to 12,000 ft. Allowing for a higher (double) pressure gradient below 10,000 ft (top of overpressure), a high gas recovery is estimated.
G. Badak Field data.

Limiting Factors: Amount of available trap and reservoir; for oil, lack of primary migration channels.
Total resources for all plays in basin: .631 BBO, 20.171 TCFG, .492 BBNGL, 4.487 BBOE

* Includes NGL.

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Kutei, No. 7 COUNTRY Indonesia PLAY Paleogene Drapes, No. 2
AREA OF BASIN (Mi^2) 50,000 (78,000 incl.water >600 ft) AREA OF PLAY (MMA) 13.0
VOLUME OF BASIN (Mi^3) 210,000 (310,000 in.water >600') PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 2.56 BBO 10.4 TCFG(1979) 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN:
Rifted Pull-Apart

DEFINITION AND AREA OF PLAY: Petroleum accumulation in Paleogene sandstones draped over topographic highs; includes accumulations of reservoired oil redistributed by later, renewed fault-block movement. Western (Paleogene) shelfal area or inner Kutei; includes north and south flanks (area 2, fig. 41).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.187	.400
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	5	4	30
C. AVERAGE EFFECTIVE PAY (feet)	50	140	500
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	5	10	60
E. OIL RECOVERY (BBLS/AF)	100	233	500
F. GAS RECOVERY (MCF/AF)	800	1,900	2,500
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20.0

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .024 BB, GAS 1.8 TCF, NGL .020 BB, OE .344 BBOE

REMARKS

A. Unpublished prospect and lead map indicates 280,000 acres of poorly defined, untested trap area; some leads will not develop, but others may be found. I estimate that two-thirds of the indicated area may, when finally mapped, be potential trap.

B. Few wildcats have been drilled in this large area, and they were dry. Recent drilling indicates that the Paleogene of the inner Kutei basin is overmature. I estimate that the success rate would be at most 10 percent. Petroleum fill is estimated to be that of the delta play or 40 percent, giving a 4 percent productive area.

C. From Paleogene sandstones of Tanjung Field (of the Barito basin) but only separated from the Kutei basin by the relatively recent (L. Miocene) Meratus Range.

D. I assume that this play's source rock is largely overmature, and the oil-gas mix is only some 10 percent.

E. In the absence of data, I estimate the same reservoirs as the delta sandstones.

F. Gas would probably be deep enough, coming from basal sandstones , to be in or near the overpressured zone and 1,900 MCF/AF (same as Neogene delta play) is assumed.

G. Estimated same as for the Neogene delta play (Badak Field data).

Limiting Factor: Source rocks are overmature.

Total resources for all plays in basin: .631 BBO, 20.171 TCFG, .492 BBNGL, 4.487 BBOE.

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Kutei, No. 7 COUNTRY Indonesia PLAY U.Oligocene-L.Miocene
AREA OF BASIN (Mi^2) 50,000 (78,000 inc. water >600 ft) Reefs, No. 3
VOLUME OF BASIN (Mi^3) 210,000 (310,000 inc. water >600') AREA OF PLAY (MMA) 5.2
ESTIMATE ORIGINAL RESERVES 2.56 BBO 10.4 TCFG(1979) PLAY EST. ORIG. RESERVES,
TECTONIC CLASSIFICATION OF BASIN: 0 BBO 0 TCFG
Rifted Pull-Apart

DEFINITION AND AREA OF PLAY: Shelf-edge late Oligocene-early Miocene carbonate buildups on south and north flank of basin. 4.2 million acres in south and 1.0 million acres on the north, giving 5.2 million acres in all (area3, fig. 41).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.130	.400
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1	4	20
C. AVERAGE EFFECTIVE PAY (feet)	50	200	600
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	10	20	70
E. OIL RECOVERY (BBLS/AF)	100	194	500
F. GAS RECOVERY (MCF/AF)	600	1,000	2,000
G. NGL RECOVERY (BBLS/MMCFG)	5	25.7	50

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .040 BB, GAS .832 TCF, NGL .022 BB, OE .201 BBOE

REMARKS

A. In the geologically similar carbonate shelfal area of the East Java Sea, buildups make up 5 percent of play area; however these buildups are large and easily mapped. These buildups appear half as well developedand concentrated along the shelf edge; I estimate 2.5 percent of the play area. A negligible amount of trap has been tested.

B. The number of wells drilled primarily to test this play could not be ascertained, but one gas discovery has been made. I estimate discovery rate of 10 percent. Fill is assumed to be the same as East Java carbonate shelf or 40 percent, indicating 4 percent of the play area to be productive.

C. I assume the effective pay to be the same as that estimated for the reefs of the East Java Sea or an average of 200 ft.

D. The percentage of oil in the aerial fill is unknown, but I assume it to be between the 10 percent fill of the Paleogene drapes or the 50 percent of the buildups of the East Java Sea carbonate platform, say 20 percent.

E. Assumed to be the same as the average of the East Java Sea reefs.

F. Also analogous to the East Java Sea but about twice as deep, giving a recovery of a million cubic feet per acre-foot versus 500,000.

G. Assumed to be the same as the Neogene deltaic sands.

Limiting Factors: Source rock and seal distribution is critical.

Total resources for all plays in basin: .631 BBO, 20.171 TCFG, .492 BBNGL, 4.487 BBOE.

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Kutei, No. 7 COUNTRY Indonesia PLAY Mio-Pliocene Reefs, #4
AREA OF BASIN (Mi^2) 50,000 (78,000 inc. water >600 ft) AREA OF PLAY (MMA) 1.45
VOLUME OF BASIN (Mi^3) 210,000 (310,000 inc.water >600') PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 2.56 BBO 10.4 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN:
Rifted Pull-Apart

DEFINITION AND AREA OF PLAY: Petroleum, probably gas, in isolated shale enclosed reefs along the outer continental shelf, an area of about 1.45 million acres. (area 4, fig. 41).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.020	.100	.300
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2	12	40
C. AVERAGE EFFECTIVE PAY (feet)	40	110	500
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	1	10	75
E. OIL RECOVERY (BBLS/AF)	100	300	500
F. GAS RECOVERY (MCF/AF)	600	800	2,000
G. NGL RECOVERY (BBLS/MMCFG)	5	25.7	50

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .040 BB, GAS .95 TCF, NGL .024 BB, OE .222 BBOE

REMARKS

A. From unpublished maps, I estimate that the acreage in untested reef traps is about 100,000 acres (or about 7 percent of the play area).

B. Two, and perhaps three, gas discoveries have been made in this play, giving a success rate of possibly 25 percent, but this play does not appear to have been seriously pursued, given the nearby higher prospective delta sandstones and the small size of the reefs. The amount of fill is assumed to be 50 percent.

C. Observation of well logs indicates an average of 110 ft.

D. Most reefs are deep, 8,000 to 10,000 ft (but some are shallower, ranging up to sea bottom). The more prospective deeper reefs, enclosed as they are in shale and near or within the overpressured shale, are deemed to be largely occupied by gas, say 10 percent oil.

E. No information; an average of 300 barrels per acre-foot is assumed.

F. Assuming an average depth of 9,000 ft and average reservoir parameters, I estimate 800,000 ft^3 per acre-foot.

G. Assumed to be same as the delta sandstones, 25.7 B/MMCFG (Badak Field data).

Limiting Factors: The small size and depth, limiting commerciality for some reefs and lack of seals on those reefs extending to the sea floor.

Total resources for all plays in basin: .631 BBO, 20.171 TCFG, .492 BBNGL, 4.487 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Kutei, No. 7 COUNTRY Indonesia PLAY Deep Water Sandstones, No. 5
AREA OF BASIN (Mi^2) 50,000 (78,000 inc. water >600 ft)
VOLUME OF BASIN (Mi^3) 210,000 (310,000 inc. water >600)
AREA OF PLAY (MMA) 11.5
ESTIMATE ORIGINAL RESERVES 2.56 BBO 10.4 TCFG(1979)
PLAY EST. ORIG. RESERVES, 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Rifted Pull-Apart

DEFINITION AND AREA OF PLAY: Sands in structures in deep water beyond the continental shelf. Sandstones are of neritic origin recently depressed to depths up to 8,000 ft, an area of about 11.5 million acres (area 5, fig. 41).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.05	.46	.90
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2	4	16
C. AVERAGE EFFECTIVE PAY (feet)	30	50	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	5	20	80
E. OIL RECOVERY (BBLS/AF)	100	200	500
F. GAS RECOVERY (MCF/AF)	600	800	2,000
G. NGL RECOVERY (BBLS/MMCFG)	5	25.7	50

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .037 BB, GAS .589 TCF, NGL .015 BB, OE .150 BBOE

REMARKS

A. On the basis of a partial, unpublished map, the area of untested prospects and leads is about 8 percent of the play area in older drapes and more recent fault traps. Probably only half the leads will finally be developed into good prospects.

B. On basis that traps, reservoirs, and source are present, a wildcat success rate of 10 percent is estimated. I assume a 40 percent petroleum fill as is estimated for the other plays of the basin.

C. Thin reservoirs are assumed in this area, largely beyond the confines of the ancestral Mahakan delta.

D. The percentage of oil is assumed to be the same as for the delta sandstones.

E. Reservoir parameters may be poorer in this area, more distal than other plays from sedimentary sources. I estimate 200 bbs/AF.

F. Gas recovery is also expected to be lower on the basis of poorer reservoirs and shallowness.

G. Same as for other plays (Badak field data).

Limiting Factor: Possible absence of adequate reservoirs and deep water economic feasibility.

Total resources for all plays in basin: .631 BBO, 20.171 TCFG, .492 BBNGL, 4.487 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Tarakan, No. 8 COUNTRY Indonesia PLAY Carbonate Reefs & Banks No. 1
AREA OF BASIN (Mi^2) 16,250
VOLUME OF BASIN (Mi^3) 30,000
ESTIMATE ORIGINAL RESERVES .469 BBO .47 TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc
AREA OF PLAY (MMB) 10.4
PLAY EST. ORIG. RESERVES, 0 BBO 0 TCFG

DEFINITION AND AREA OF PLAY: Petroleum accumulations in carbonate reefs and banks in the largely shale and carbonate sequence of Oligocene to early Miocene age. Play probably extends over basin but is best developed in south over the Maura Shelf and adjoining Mangkalihat Platform (fig. 48).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.150	.156	.800
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1.0	3.5	10.0
C. AVERAGE EFFECTIVE PAY (feet)	50	100	500
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	10	20	50
E. OIL RECOVERY (BBLS/AF)	100	216	350
F. GAS RECOVERY (MCF/AF)	400	1,400	2,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .024 BB, GAS .612 TCF, NGL .007 BB, OE .133 BBOE

REMARKS

A. Reef or near-reef facies have been penetrated by wildcats in the south and north and are indicated on seismic sections, but size and distribution are largely unknown. The play area may be analogous to the reefal area of the East Java Sea, i.e.,30 percent of the play area is in a reefal facies of which 5 percent is trap.

B. By analogy to the Oligo-Miocene reef play of the Kutei basin and East Java Sea basins, I assume a 10 percent wildcat success rate. I also assume a 35-percent fill indicating that 3.5 percent of untested trap area will be productive.

C. The analogous carbonate plays of Kutei and East Java Sea basins have an estimated average net reservoir thickness of 200 ft. Tarakan basin with less carbonate platform and generally less carbonate development is judged to have 100 ft.

D. In this largely shale sequence a blowout was encountered, and I suspect overpressure, in which case primary oil migration would be impeded in favor of gas. I estimate 80 percent gas.

E. In the absence of data and assuming average quality reservoirs, I estimate 216 barrels per acre-foot.

F. Estimating reservoir depth of 11,000', a thermal gradient of 2.35°F per 100 ft, and average quality reservoirs, I estimate 1.4 million cubic ft per acre-foot.

G. World-wide average.

Limiting Factor: Evidence for the amount of trap and reservoirs is weak.

Total resources for all plays in basin: .234 BBO, 1.2 TCFG, .014 BBNGL, .449 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Tarakan, No. 8 COUNTRY Indonesia PLAY Late Miocene Folds, No. 2
AREA OF BASIN (Mi^2) 16,250 AREA OF PLAY (MMA) 7.8
VOLUME OF BASIN (Mi^3) 30,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .469 BBO .47 TCFG .069(?) BBO .47(?) TCFG
TECTONIC CLASSIFICATION OF BASIN: Back Arc

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Miocene, primarily deltaic, sand and probably some calcarenites which are involved in late Miocene folds. Play occupies about 75 percent of basin, exclusive of the Muara-Mangkalihat Platform (fig. 48

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.123	.300
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	4	8	12
C. AVERAGE EFFECTIVE PAY (feet)	75	140	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	20	60	80
E. OIL RECOVERY (BBLS/AF)	100	250	350
F. GAS RECOVERY (MCF/AF)	400	1,076	2,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .207 BB, GAS .593 TCF, NGL .007 BB, OE .312 BBOE

REMARKS

A. The analogous Neogene Delta Play of Kutei basin of 17.5 million acres has an estimated 270,000 acres of untested trap. By analogy, this smaller (8 million acres) play would have 123,000 acres of untested trap.

B. Onshore exploration has been very successful with wildcat success rate of about 39 percent. Offshore this rate is only 8 percent, hampered by poor trap resolution caused by shallow base-Pliocene unconformity and seismic reflection-dampening bottom conditions. I estimate future wildcat success as exploration moves offshore to be 20 percent. This, with a fill of 40 percent (analogous to Kutei folds), indicates 8 percent of untested trap to be productive.

C. As discussed in the text, the best estimate I can make is 140 ft.

D. Production to date indicates both oil and gas. I estimate that in this relatively shallow play, i.e., less than 10,000 ft, oil would predominate, say 60 percent.

E. Estimated porosity is 25 percent (20 to 26 percent at Sembakung). Assuming reservoir parameters to be average, I estimate a primary recovery of 250 barrels per acre-ft.

F. Assuming an average depth to gas reservoirs (near base of play) of 8,000 ft and a thermal gradient of 2.35°F per 100 ft, I estimate a gas recovery of 1.076 million cubic ft per acre-foot.

G. World-wide average.

Limiting Factor: Amount of trap in offshore part of area is very conjectural.
Total resources for all plays in basin: .234 BBO, 1.2 TCFG, .014 BBNGL, .449 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Tarakan, No. 8 COUNTRY Indonesia PLAY Plio-Pleistocene Folds, No. 3
AREA OF BASIN (Mi^2) 16,250 AREA OF PLAY (MMA) 6.9
VOLUME OF BASIN (Mi^3) 30,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .469 BBO 0.5 TCFG .400(?) BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Back-arc

DEFINITION AND AREA OF PLAY: Shallow petroleum accumulations in relatively gentle folds of Plio-Pleistocene deltaic sandstones overlying a regional, profound unconformity. Play covers largely offshore two-thirds of basin, an area of about 6.9 million acres (fig. 48).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.005	.020	.050
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	.5	.7	1.5
C. AVERAGE EFFECTIVE PAY (feet)	75	300	800
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	20	70	90
E. OIL RECOVERY (BBLS/AF)	100	100	200
F. GAS RECOVERY (MCF/AF)	100	100	500
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .003 BB, GAS .001 TCF, NGL 0 BB, OE .004 BBOE

REMARKS

A. These shallow, simple anticlinal traps have been mapped and drilled, and only relatively small untested traps appear to remain; I estimate possible 20,000 acres.

B. Aside from small production-adjoining closures on Tarakan and Bunju Islands, no discoveries have been made since 1930's. A low success rate of 2 percent is assumed. If fill is 35 percent, untested trap area which would contain petroleum is 0.7 percent.

C. 700 ft of net sand in 12 pays is reported at Tarakan, I estimate an average of about 300 ft for the entire play.

D. No gas is produced at Tarakan, but some is at Bunju. Because of generally poor seal, I estimate that oil is at least 70 percent of the gas-oil mix.

E. Porosities appear good, i.e. 20 to 38 percent, but water saturation is extremely high in Tarakan, i.e. about 95 percent; oil recovery factor is 50 percent. If these characteristics prevail over the play, the average recovery is 100 barrels per acre-foot - barely commercial onshore.

F. Considering the shallow reservoir depth (perhaps 1,500 ft) and the high water saturation, only about 100,000 ft^3 per acre-foot may be expected.

G. World-wide average.

Limiting Factors: Lack of remaining untested traps and high water saturation in reservoirs.

Total resources for all plays in basin: .234 BBO, 1.2 TCFG, .014 BBNGL, .449 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN West Natuna, No. 9 COUNTRY Indonesia PLAY Oligocene Drapes, No. 1
AREA OF BASIN (Mi^2) 34,000 AREA OF PLAY (MMA) 15.0
VOLUME OF BASIN (Mi^3) 45,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .402 BBO -- TCFG .2(?) BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Rift

DEFINITION AND AREA OF PLAY: Potential petroleum accumulations in largely Oligocene sandstones draped over Oligocene (or older) fault blocks. Play largely restricted to basin perimeter (depth <10,000 ft) where redistributing drag folds are less prevalent and where basal sandstones developed (fig. 51 and 53).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.25	.63	1.00
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2.5	7.0	10.0
C. AVERAGE EFFECTIVE PAY (feet)	50	86	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	30	50	70
E. OIL RECOVERY (BBLS/AF)	100	216	350
F. GAS RECOVERY (MCF/AF)	400	790	1,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .410 BB, GAS 1.500 TCF, NGL .016 BB, OE .676 BBOE

REMARKS

A. Extrapolation from a limited area map indicates 7 percent of play under closure. With play area of 15 million acres on basin perimeter, this is 1.05 million acres of trap area. An estimated 40 percent has been tested leaving 630,000 acres untested.

B. Wildcat success rate for all plays appears to be 17 percent; it is assumed the Oligocene drape play has about the same success rate. The Udang Field appears to be about 44 percent filled. Assuming this is an average for the basin, it appears that about 7 percent of the untested trap area may be productive.

C. The average net pay of the Udang Field is reportedly 86 ft, and this is assumed to be the average for the play.

D. Udang Field production is about two-thirds oil, but this may be selective. I estimate oil may average half of the oil-gas mix.

E. Assuming average, conservative reservoir parameters, I assume 216 barrels per acre-foot.

F. Assuming an average reservoir depth of 5,000 ft, a thermal gradient of 2.2°F per 100 ft, a gas recovery of 790,000 ft^3 per acre-foot is indicated.

G. World-wide average.

Limiting Factor: Small volume of source rock available in this shallow basin.

Total resources for all plays in basin: .655 BBO, 3.410 TCFG, .037 BBNGL, 1.259 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN West Natuna, No. 9 COUNTRY Indonesia PLAY Miocene Drag Folds, No. 2
AREA OF BASIN (Mi^2) 34,000 AREA OF PLAY (MMA) 7.0
VOLUME OF BASIN (Mi^3) 45,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .402 BBO -- TCFG .2(?) BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Rift

DEFINITION AND AREA OF PLAY: Potential petroleum accumulations in Miocene drag folds of central basin areas involving Oligocene and Miocene reservoirs. Play area largely limited to thicker (>10,000 ft) part of basin fill where this type of folds can develop (figs. 51 and 54).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.20	.21	.80
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	2.5	9.0	15.0
C. AVERAGE EFFECTIVE PAY (feet)	50	200	400
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	15	30	70
E. OIL RECOVERY (BBLS/AF)	100	216	350
F. GAS RECOVERY (MCF/AF)	400	723	1,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .245 BB, GAS 1.91 TCF, NGL .021 BB, OE .583 BBOE

REMARKS

A. Extrapolation from an unpublished map limited area indicates that about 5 percent of the play area is drag fold closure. This corresponds with other areas of analogous drag folds associated with wrench faults, e.g. Central Sumatra has 5.5 percent drag fold closure. 40 percent of these drag folds may have been tested, leaving an untested trap area of 210,000 acres.
B. The wildcat success rate (1982) for all plays was 17 percent; I assume this holds also for this play. The KH Field has a fill of 55 percent, and this is taken as the average percentage fill for this play, indicating that 9 percent of the untested trap area may be productive.
C. Although 375 ft of pay (gross?) was reportedly tested at Anoa-1, the sandstones thin eastward and are thin or missing over the larger anticlines. Oligocene sandstones of 40 to 190 ft thickness occur in the anticlines, and a combined average thickness of 200 ft is assumed for both Oligocene and Miocene sandstones.
D. The Anoa-1 test found 315 ft of gas and 60 ft of oil. I estimate that oil is about 30 percent of the petroleum mix in this play.
E. Assuming average conservative reservoir parameters, I estimate an oil recovery of 216 barrels per acre-foot.
F. Assuming an average reservoir depth of 4,500 ft and a thermal gradient of 2.2°F per 100 ft, the average gas recovery is 723,000 ft^3 per acre-foot.
G. World-wide average.

Limiting Factor: The limiting factor, especially in contrast to this same oil play, prolific in the adjoining Malay basin, is probably the smaller volume of source rock in this shallower basin.

Total resources for all plays in basin: .655 BBO, 3.410 TCFG, .037 BBNGL, 1.259 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN East Natuna, No. 10 COUNTRY Indonesia PLAY Drapes, No. 1
AREA OF BASIN (Mi^2) 27,000 AREA OF PLAY (MMA) 17.3
VOLUME OF BASIN (Mi^3) 57,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 0 BBO 60* TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN:
Rifted Continental Margin

DEFINITION AND AREA OF PLAY: Potential petroleum accumulations in Oligocene to Middle Miocene sandstones in drape or fault closures. Play area encompasses the entire basin (fig. 60).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.20	.80	1.50
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	5	10.5	16
C. AVERAGE EFFECTIVE PAY (feet)	75	100	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	15	20	60
E. OIL RECOVERY (BBLS/AF)	75	86	200
F. GAS RECOVERY (MCF/AF)	100	467	900
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .145 BB, GAS 3.13 TCF, NGL .035 BB, OE .703 BBOE

REMARKS

A. From observation of unpublished maps, I estimate that some 6 percent, or about 1.0 million acres of play area is under drape or fault closure. If 20 percent of the closures have been tested, the remaining untested trap is .80 million acres.
B. Early wildcat success was nil possibly because this was usually a secondary objective of wells testing younger carbonates. Eight recent wildcats with this play as an objective were dry but with some shows. Deep Vietnam wildcat, Dua-IX, 20 miles to north was an oil discovery. I estimate future wildcat success will be about 15 percent. On the basis of almost 100 percent fill at AL-IX, 70 percent fill is estimated for the basin, indicating 10.5 percent of trap area will be productive.
C. Reportedly the net reservoir thickness is 175 ft in the northern, shelfal, part of the basin but it thins to the south. I estimate 100 ft as average for basin.
D. The basin appears to be gas prone from occurrence to date. While the younger reefs encased in overpressured shale produced gas, these lower sandstones may not be so overpressured, allowing some primary migration of C_6 + molecules. I deem this play has at least 20 percent oil.
E. Assuming 20 percent porosity and average reservoir parameters, and estimating the 60 percent of reservoir space occupied by carbon dioxide.
F. Assuming same reservoirs, average depth of about 12,000 ft, thermal gradient of 2.5°F per 100 ft, and that reservoir 60 percent occupied by carbon dioxide.
G. World-wide average.

Limiting Factors: Principal one is occupation of reservoirs by carbon dioxide. Limiting for oil is an inhibiting effect on primary migration by overpressured shale.

* An estimated 60 TCFG is discovered but unproduced at AL-1X.

Total resources for all plays in basin: .308 BBO, 20.07 TCFG, .221 BBNGL, 3.665 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN East Natuna, No. 10 COUNTRY Indonesia PLAY Miocene Reefs, No. 2
AREA OF BASIN (Mi^2) 27,000 AREA OF PLAY (MMA) 10.0
VOLUME OF BASIN (Mi^3) 57,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 0 BBO 60* TCFG 0 BBO 60* TCFG
TECTONIC CLASSIFICATION OF BASIN: Rifted Continental Margin

DEFINITION AND AREA OF PLAY: Potential petroleum accumulations are in upper Miocene (Terumbu Fm.) reefs and platform carbonate reservoirs in drapes or fault traps. Play limited to carbonate platform area, which covers approximately 60 percent of basin (fig. 60).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.05	.35	.50
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	5	14	20
C. AVERAGE EFFECTIVE PAY (feet)	100	700	4,000
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	2	5	50
E. OIL RECOVERY (BBLS/AF)	80	95	300
F. GAS RECOVERY (MCF/AF)	100	520	900
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .163 BB, GAS 16.94 TCF, NGL .186 BB, OE 2.962 BBOE

REMARKS

A. From observation of unpublished maps of part of play area, I estimate about 7 percent of carbonate platform is reefal, of which about half has been tested.
B. There is one substantial discovery, AL-IX, with indicated reserves of some 60 TCFG. However some wildcats have had sizeable oil and gas shows which may eventually be considered commercial. I estimate an eventual success rate of 20 percent. The AL-IX trap appears completely full while the shows only fill small parts of the closure, e.g. Bursa-1 is 15 percent. I estimate 70 percent fill, indicating 14 percent of untested trap area will be productive.
C. The only substantial recovery, AL-IX, has 5,250 ft of porosity, 1,750 ft reef porosity of 28.4 percent and 3,500 ft of platform porosity of 14.5 percent. This thickness is exceptional, and I estimate the remaining, smaller traps will average around 700 ft.
D. Although some oil is present (notably Bursa-IX), this play is gas prone, particularly the deeper reefs which may be amid overpressured shale. I estimate that the petroleum mix is 95 percent gas.
E. On basis of an average 22 percent porosity (C above) and assuming average parameters, primary recovery only, and 60% of pore space occupied by carbon dioxide.
F. Assuming above reservoirs, an average depth of 10,000 ft, a 2.5°F per 100 ft thermal gradient, and 60 percent pore occupancy by carbon dioxide.
G. In absence of data, assume world-wide average.

Limiting Factor: Overall, a high carbon-dioxide reservoir content. For oil, it is the apparent lack of primary migration through overpressured shales.

*An estimated 60 TCFG is apparently discovered but unproduced at AL-1X.

Total resources for all plays in basin: .308 BBO, 20.07 TCFG, .221 BBNGL, 3.665 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Salawati-Bintuni, No. 11 COUNTRY Indonesia PLAY Salawati-Miocene Reefs, No. 1
AREA OF BASIN (Mi^2) 56,000 AREA OF PLAY (MMA) 1.5
VOLUME OF BASIN (Mi^3) 105,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .415 BBO -- TCFG .415 BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland and collision zone

DEFINITION AND AREA OF PLAY: Potential petroleum accumulations in Miocene carbonates of Salawati subbasin. Area confined between 4 and 5 km basin-fill isopachs, the thinner fill area having insufficient cover and the thicker fill being deficient in reservoirs (fig. 64; area 1, fig. 69).

	PROBABILITY DISTRIBUTION		
MAJOR GEOLOGICAL/EXPLORATION FACTORS	95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.020	.027	.040
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	3	5	12
C. AVERAGE EFFECTIVE PAY (feet)	30	165	700
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	60	90	95
E. OIL RECOVERY (BBLS/AF)	300	530	600
F. GAS RECOVERY (MCF/AF)	800	450	1,700
G. NGL RECOVERY (BBLS/MMCFG)	8	50	100

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .106 BB, GAS .010 TCF, NGL .00 BB, OE .108 BBOE

REMARKS

A. A published map (fig. 70) indicates that carbonate reefs make up 6 percent of the play area or about .09 MMA. Exploration deemed 70 percent complete, leaving 27,000 acres untested trap.

B. Late wildcat success rate has been about 20 percent. Fill is extremely variable (Walio-23, Sele-2, Kasim-25, Kasim Utera-50 percent). I estimate average fill of 25 percent, indicating a productive trap area of 5 percent.

C. Net pay thickness varies from 30 to 700 ft. I estimate an average of 165 ft.

D. On the basis of evident water drive and poor seal (fracturing) for gas, I estimate 90 percent oil.

E. Oil recovery varies considerably because of unpredictable fracturing and porosity; I assume that the published recovery of the Kamono Field, 530 bbls per acre-foot, may be average.

F. Assuming average reservoir conditions, a thermal gradient of 3°F per 100 ft, and an average depth of 3,500 ft, I estimate the average gas recovery to be about 450 MCF/AF.

G. Average of Magoi and Wasian Fields.

Limiting Factor: The factor appears to be the seal. On the edges of the basin where cover is thin, large traps are empty or have a low percentage of fill.

Total resources for all plays in basin: .647 BBO, 2.322 TCFG, .115 BBNGL, 1.145 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Salawati-Bintuni, No. 11 COUNTRY Indonesia PLAY Bintuni Miocene Reefs, No. 2
AREA OF BASIN (Mi^2) 56,000 AREA OF PLAY (MMA) 5.0
VOLUME OF BASIN (Mi^3) 105,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .415 BBO -- TCFG -- BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland and collision zone

DEFINITION AND AREA OF PLAY: Potential petroleum accumulations in Miocene carbonate buildups in Bintuni subbasin. Area of play limited by effective cover of Klasafet shales and concentrated along carbonate shelf edge (area 2, fig. 69).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.05	.15	.25
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1	1.5	6
C. AVERAGE EFFECTIVE PAY (feet)	30	165	700
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	20	50	90
E. OIL RECOVERY (BBLS/AF)	300	530	600
F. GAS RECOVERY (MCF/AF)	800	1,750	2,000
G. NGL RECOVERY (BBLS/MMCFG)	8	50	100

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .098 BB, GAS .324 TCF, NGL .016 BB, OE .168 BBOE

REMARKS

A. Reefs analogous to Salawati are indicated but not proven, therefore 3 percent of area is assumed reef trap (versus 6 percent for Salawati). Nine wildcats have have failed to find a viable reef (Wiriagar is considered primarily a drape structure). Reefs appear to be small requiring a fine seismic net.
B. Although Miocene reefal carbonate is evident, no reef accumulations were discovered. However, I estimate a 5 percent success rate will develop. Because of better cover, the fill is deemed to be somewhat more than the similar Salawati subbasin traps, or about 30 percent, indicating approximately 1.5 percent of the untested trap area will be productive.
C. In the absence of data, the average effective pay is deemed the same as the geologically similar Salawati subbasin.
D. Originally the percent of oil in oil-gas mix was probably similar in both Salawati-Bintuni subbasins, but owing to thicker cover, less gas escaped from the Bintuni subbasin; so about 5 times as much gas is postulated, or about 50 percent.
E. Oil recovery is assumed to be the same as that for the Salawati subbasin.
F. The objective carbonate traps appear to average about 12,000 ft in depth and the thermal gradient is about 1.6°F per 100 ft, indicating a gas recovery of about 1,750 MCFG/AF.
G. Average of Magoi and Wasian Fields.

Limiting Factors: The limiting factors are the apparent small size and depth of the reefs.

Total resources for all plays in basin: .647 BBO, 2.322 TCFG, .115 BBNGL, 1.145 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Salawati-Bintuni, #11 COUNTRY Indonesia PLAY Miocene Drapes, No. 4
AREA OF BASIN (Mi^2) 56,000 AREA OF PLAY (MMA) 12.0
VOLUME OF BASIN (Mi^3) 105,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .415 BBO 0 TCFG -- BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland and collision zone

DEFINITION AND AREA OF PLAY: Drapes over northwest-trending pre-Tertiary ridges. Area of play limited to Bintuni subbasin outside Lengguru Foldbelt, but including recently folded carbonates in northeast Bintuni subbasin (area 3 and 4, fig. 69).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.500	.528	1.00
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1	3	7
C. AVERAGE EFFECTIVE PAY (feet)	30	83	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	20	70	90
E. OIL RECOVERY (BBLS/AF)	100	215	300
F. GAS RECOVERY (MCF/AF)	400	819	1,700
G. NGL RECOVERY (BBLS/MMCFG)	8	50	100

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .198 BB, GAS .323 TCF, NGL .016 BB, OE .267 BBOE

REMARKS

A. By estimation from unpublished map of part of play area, traps make up 5.5 percent of area. On this basis there are .66 MMA of trap of which 20 percent has been tested.

B. Discovery rate has been about 10 percent. Assumed fill is 30 percent (world average), indicating 3 percent untested trap area will be productive.

C. These drapes are over older ridges, which may be sites for reef carbonates; however reservoir development would be less than expected for the strictly reef plays. I estimate carbonate and sandstone reservoir would average perhaps half as thick as the Salawati Reef reservoirs, or some 83 ft.

D. Assumed to be intermediate to Salawati and Bintuni reef plays reflecting the intermediate depth of burial.

E. Assuming that the average porosity is about 20 percent (Mogoi and Wasian average about 14 percent, but porosities at Bintuni-A1 averaged 32 percent, and Wiriager is assumed to be about the same).

F. Assuming the same reservoirs and an average depth somewhere between that of the Bintuni subbasin (12,000 ft) and the Salawati subbasin (3,500 ft), say 9,000 ft.

G. Average of the Mogoi and Wasian Fields.

Limiting Factor: The limiting factor is probably the presence of reservoir development and, therefore, favorable traps along these pre-Tertiary ridges.

Total resources for all plays in basin: .647 BBO, 2.322 TCFG, .115 BBNGL, 1.145 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Salawati-Bintuni, No. 11 COUNTRY Indonesia PLAY Cretaceous Drapes No. 3
AREA OF BASIN (Mi^2) 56,000
VOLUME OF BASIN (Mi^3) 144,000
ESTIMATE ORIGINAL RESERVES .415 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland and collision zone

AREA OF PLAY (MMA) 18.6
PLAY EST. ORIG. RESERVES, 0 BBO 0 TCFG

DEFINITION AND AREA OF PLAY: Accumulations in faulted and draped Cretaceous which are largely limited to the Bintuni subbasin, exclusive of the foldbelt and including the Misool-Onin-Kumawa ridge area (area 3 and 4, fig. 69).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.500	.920	2.000
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1	3	10
C. AVERAGE EFFECTIVE PAY (feet)	50	100	500
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	15	40	50
E. OIL RECOVERY (BBLS/AF)	150	180	450
F. GAS RECOVERY (MCF/AF)	400	960	2,500
G. NGL RECOVERY (BBLS/MMCFG)	8	50	100

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .200 BB, GAS 1.60 TCF, NGL .080 BB, OE .543 BBOE

REMARKS

A. Cretaceous shelfal sediments are faulted or draped over low-relief tilted horst ridges. Examination of unpublished maps over parts of subbasin indicate an average of 5.5 percent of subbasin is under drape closure. Of this, perhaps 10 percent has been tested, leaving about 920,000 acres.

B. Six wildcats have been unsuccessful. However, on basis of generally favorable geology, I assume a future success rate of 10 percent. With no data, I assume a 30 percent fill indicating about 3 percent of trap would be productive.

C. Great thicknesses of sandstone (Kembelangan Group) are reported in outcrops, but no specific reservoir parameters are available. I assume at least 100 ft of effective reservoir (with porosity of 15 percent).

D. Because of great depth, over 20,000 ft in central part of Bintuni subbasin, I estimate the petroleum to be largely gas, perhaps 60 percent.

E. Assuming average reservoir parameters, it is estimated that 300 barrels of oil would be produced per acre-foot of trap volume.

F. Assuming average reservoir, and reservoir depths of 10,000 to 12,000 ft.

G. Average of Magoi and Wasian Fields.

Limiting Factor: Although average estimates are made for reservoir volume on the basis of outcrops, the existence of viable reservoirs at depth is unknown.

Total resources for all plays in basin: .647 BBO, 2.322 TCFG, .115 BBNGL, 1.145 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Salawati-Bintuni, No. 11 COUNTRY Indonesia PLAY Neogene Folded Sandstones, No. 5
AREA OF BASIN (Mi^2) 56,000 AREA OF PLAY (MMA) 6.14
VOLUME OF BASIN (Mi^3) 144,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES .415 BBO 0 TCFG -- BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland and collision zone

DEFINITION AND AREA OF PLAY: Potential accumulations in Pliocene anticlinal folds involving essentially Neogene clastics and limited to Lengguru Foldbelt of the Eastern Bintuni subbasin (area 5, fig. 69).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.100	.307	.500
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1	1.5	6
C. AVERAGE EFFECTIVE PAY (feet)	30	50	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	30	90	95
E. OIL RECOVERY (BBLS/AF)	120	200	350
F. GAS RECOVERY (MCF/AF)	300	750	1,000
G. NGL RECOVERY (BBLS/MMCFG)	8	50	100

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .041 BB, GAS .017 TCF, NGL .001 BB, OE .045 BBOE

REMARKS

A. By analogy to the percentage of trap area to play area of similar young foldbelts in Indonesia (e.g. Kutei basin about 3 percent, North Sumatra about 8 percent), I estimate 5 percent.

B. About four wildcats have tested this play, but perhaps only one was definitive, Suga-1, which was a reported gas discovery. Traps will be difficult to find in these complex folds; I estimate a success rate of only 10 percent. Leakage would be high; we estimate a fill of 15 percent, indicating 1.5 percent of trap area would be productive.

C. Visser and Hermes, 1962, indicate poor reservoir development; I estimate average net pay of only 50 ft. Reservoirs may be from the Kembalangan Group, the New Guinea Limestone Group, or the Klasaman-Steenkool sandstones.

D. Two oil seepages occur. Sealing is weak. By analogy to the Salawati subbasin, I estimate oil is 90 percent of oil-gas mix.

E. Poor reservoirs are indicated; I estimate 200 BO/AF.

F. Assuming average depth of 8,000 ft, the average gas recovery is estimated to be 750 MCFG/AF.

G. Average of Mogoi and Wasian Fields

Limiting Factors: The limiting factors, according to Visser and Hermes, are the amount and quality of the reservoirs. Rich source rocks are yet to be demonstrated.

Total resources for all plays in basin: .647 BBO, 2.322 TCFG, .115 BBNGL, 1.145 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Salawati-Bintuni, No. 11 COUNTRY Indonesia PLAY Salawati Pliocene Diapirs, No. 6
AREA OF BASIN (Mi^2) 56,000
VOLUME OF BASIN (Mi^3) 144,000 AREA OF PLAY (MMA) 1.53
ESTIMATE ORIGINAL RESERVES .415 BBO -- TCFG PLAY EST. ORIG. RESERVES -- BBO -- TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland and collision zone

DEFINITION AND AREA OF PLAY: Accumulations in Pliocene sandstones involved in diapir anticlines in the deeper, basinal part of the Salawati subbasin (area 6, fig. 69).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.100	.154	.200
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	.001	1.0	5.0
C. AVERAGE EFFECTIVE PAY (feet)	25	50	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	1	30	70
E. OIL RECOVERY (BBLS/AF)	100	160	300
F. GAS RECOVERY (MCF/AF)	700	900	1,800
G. NGL RECOVERY (BBLS/MMCFG)	8	50	100

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .004 BB, GAS .048 TCF, NGL .002 BB, OE .014 BBOE

REMARKS

A. From a measurement of traps in an unpublished map, there are approximately .154 million acres untested trap indicated.

B. Only one test of a diapir was dry hole and no further tests were made indicating probable low rate of future success, say 3 percent. No fill data; I assume 30 percent (world-average) indicating productive area of 1 percent.

C. Section must be mostly shale; sandstones would be thin; I estimate an average of about 50 ft.

D. The play is obviously in an overpressured shale deep where primary oil migration is inhibited. I estimate at least 70 percent gas.

E. Section mostly on shale; basin reservoirs probably poor, say 15 percent porosity.

F. Assuming same reservoirs and 8,000 ft depth but no overpressuring of reservoir for most likely case.

G. Average of Magoi and Wasian Fields

Limiting Factor: Sufficient reservoir

Total resources for all plays in basin: .647 BBO, 2.322 TCFG, .115 BBNGL, 1.145 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Arafura, No. 12 COUNTRY Indonesia PLAY Anticlines, No. 1
AREA OF BASIN (Mi^2) 50,000
VOLUME OF BASIN (Mi^3) 120,000 AREA OF PLAY (MMA) 11.5
ESTIMATE ORIGINAL RESERVES 0 BBO 0 TCFG PLAY EST. ORIG. RESERVES,
TECTONIC CLASSIFICATION OF BASIN: Foreland and collision zone 0 BBO 0 TCFG

DEFINITION AND AREA OF PLAY: Play combines two structural plays, drag folds in the northwestern area of basin (5.1 MMA) and compressional folds along northern edge of basin involving Mesozoic sandstones (6.4 MMA). Possible drape folds are included in play (figs. 71 and 72).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.300	.376	.500
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	3	4.5	15
C. AVERAGE EFFECTIVE PAY (feet)	50	200	250
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	10	30	90
E. OIL RECOVERY (BBLS/AF)	150	215	450
F. GAS RECOVERY (MCF/AF)	900	1,360	2,200
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .215 BB, GAS 3.22 TCF, NGL .036 BB, OE .782 BBOE

REMARKS

A. By analogy to the wrench-faulted Central Sumatra basin, I assume that drag-fold closures make up 5.5 percent of the drag-fold area of 5.1 MMA or 280,000 acres. Compressional folds - I estimate from an outcrop map (Visser and Hermes, 1962) that about 1.5 percent of compressional fold area (6.4 MMA) is effective trap, or about 96,000 acres. The percent of trap area tested is considered negligible.

B. Only two wildcats have been drilled in this play area and both were dry. However, because the traps are mainly folds, deemed more effective than fault or drape structures of the adjoining Australian Northwest Shelf (11 percent success as of 1982), I estimate a success rate of 15 percent and assume an average fill of 30 percent, indicating 4.5 percent of the trap area is productive.

C. Great thicknesses of Cretaceous sandstones are found in outcrops; I estimate a conservative average of 200 ft of pay.

D. An oil seep occurs at the west end of the play area. Discoveries on trend 100 miles to the east in equivalent sandstones are gas. The petroleum fill is assumed to be about 30 percent oil.

E. Assuming average reservoir parameters, it is estimated that the average oil recovery is about 300 barrels per acre-foot.

F. At estimated reservoir depths of 12,000 to 16,000 ft, the gas recovery is assumed to be about 1,900 MCFG.

G. In the absence of data, world-wide average figures are assumed.
Limiting Factor: Volume of source rock in this rather cool basin.
Total resources for all plays in basin: .350 BBO, 4.141 TCFG, .046 BBNGL, 1.089 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Arafura, No. 12 COUNTRY Indonesia PLAY Miocene Reefs, No. 2
AREA OF BASIN (Mi^2) 50,000 AREA OF PLAY (MMA) 20.0
VOLUME OF BASIN (Mi^3) 120,000 PLAY EST. ORIG. RESERVES, 0 BBO 0 TCFG
ESTIMATE ORIGINAL RESERVES 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland and Collision zone

DEFINITION AND AREA OF PLAY: Area of play is confined to Miocene subbasins where Miocene reefs are enveloped in Miocene shales. These subbasins are estimated to make up 60 percent of the Arafura basin, or about 20 million acres (fig. 71).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.200	.600	1.000
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1	2.5	5
C. AVERAGE EFFECTIVE PAY (feet)	50	83	150
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	10	30	90
E. OIL RECOVERY (BBLS/AF)	150	300	450
F. GAS RECOVERY (MCF/AF)	500	875	1,500
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .112 BB, GAS .763 TCF, NGL .008 BB, OE .247 BBOE

REMARKS

A. Estimate reefs are only half as prevalent as in the Salawati subbasin or about 3 percent of the play area, indicating an average acreage of 600,000 acres.

B. No reefs have been drilled; we estimate a success rate less than half of that of the Salawati subbasin (25 percent) or about 10 percent. By Salawati subbasin analogy, 25 percent fill is assumed indicating an average of 2.5 percent of the trap area will be productive.

C. On the basis that reefs are probably not as well developed, I estimate half the pay of the Salawati-Bintuli basin.

D. On the basis of discovery results on-strike, some 100 miles to the east in Papua, which tested only gas, we assume petroleum is 70 percent gas.

E. We judge that reefs are less developed and probably poorer reservoirs than in the Salawati-Bintuni basin; assuming average reservoir parameter, I estimate 300 barrels per acre-foot.

F. By analogy to the equally deep and equally cool Bintuni subbasin, but with about half the reservoir depth, I estimate a yield of 875 ft^3 per acre-foot.

G. World-wide average.

Limiting Factor: The presence of satisfactory reef development is yet to be demonstrated.

Total resources for all plays in basin: .350 BBO, 4.141 TCFG, .046 BBNGL, 1.089 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Arafura, No. 12 COUNTRY Indonesia PLAY Aru Hinge Area, No. 3
AREA OF BASIN (Mi^2) 50,000 AREA OF PLAY (MMA) 3.5
VOLUME OF BASIN (Mi^3) 120,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 0 BBO 0 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Foreland and Collision zone

DEFINITION AND AREA OF PLAY: The Aru hinge trends northward through Aru Island. The hinge structure is a densely step-faulted slope westward from the Arafura Platform into the Aru Trough. It has an approximate area of 3.5 million acres (Aru (Aru subbasin, fig. 71).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.035	.070	.200
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	.5	3	5
C. AVERAGE EFFECTIVE PAY (feet)	50	100	500
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	10	50	90
E. OIL RECOVERY (BBLS/AF)	150	215	500
F. GAS RECOVERY (MCF/AF)	800	1,500	3,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .023 BB, GAS .158 TCF, NGL .002 BB, OE .051 BBOE

REMARKS

A. From unpublished maps of the area, it appears that valid tilted fault-block closures make up about 2 percent of the play area.

B. The faulted closures do not appear effective. Five wildcats have been dry. Except for weak closure, other factors appear favorable, and a success rate of 10 percent is estimated. A 30 percent fill is assumed indicating 3 percent of trap area is productive.

C. The objective reservoirs are mainly the Kembelangan (Cretaceous) sandstones, which would have only half the thickness as supposed for the rest of the Arafura (200 ft) basin, being close to the pinchout of the formation.

D. Seals should not be as efficient in this faulted play so less gas is assumed than in the other parts of the basin; 50 percent oil is assumed.

E. Assuming average reservoirs and primary recovery.

F. Assuming average reservoir conditions, thermal gradient of 1.65°F per 100 ft, and average reservoir depth of 10,000 ft.

G. Assuming world-wide average.

Limiting Factor: Effectiveness of fault traps.

Total resources for all plays in basin: .350 BBO, 4.141 TCFG, .046 BBNGL, 1.089 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Waropen, No. 13 COUNTRY Indonesia PLAY Drag Folds, No. 1
AREA OF BASIN (Mi^2) 24,000 AREA OF PLAY (MMA) 15.36
VOLUME OF BASIN (Mi^3) 40,800 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 0 BBO 0 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Outer Arc

DEFINITION AND AREA OF PLAY: Petroleum accumulations in Pliocene sandstones in drag folds associated with east-west sinistral wrench faults, which transect the entire basin. Diapir folds are, because of data-lack, included in this play (fig. 74).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.300	.845	1.600
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	.5	2	4
C. AVERAGE EFFECTIVE PAY (feet)	40	100	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	10	20	40
E. OIL RECOVERY (BBLS/AF)	100	215	400
F. GAS RECOVERY (MCF/AF)	100	1,000	2,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	21

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .073 BB, GAS 1.352 TCF, NGL .015 BB, OE .314 BBOE

REMARKS

A. By analogy to the Central Sumatra basin where wrench faulting and associated drag folds dominate the structure, I estimate that drag-fold traps make up 5.5 percent of the play area or 845,000 acres.
B. Because of small volume of thermally mature source rock, a 20 percent average fill is estimated. No discoveries to date; given the relatively poor source, the poor reservoirs, and unknown, complex structure, I estimate a success rate of 10 percent, indicating only 2 percent of trap area productive.
C. Good quartz sandstones make up only a small percentage of the section, given the graywacke development and volcanic provenances. I estimate an average effective sandstone pay of 100 ft.
D. Shows and seeps are largely gas. The basin fill is mainly shale, which appears to be overpressured, inhibiting the primary migration of larger petroleum molecules. I estimate 80 percent gas.
E. Reservoirs appear to be poor to fair. Assuming 20 percent average porosity and average reservoir parameters, I estimate 215 BO/AF as an average.
F. Assuming the above reservoir, an average depth of 10,000 ft, a thermal gradient of 1.34°F per 100 ft.
G. World-wide average.

Limiting Factors: The apparent lack of sufficient source-rock volume.

Total resources for all plays in basin: .093 BBO, 1.49 TCFG, .017 BBNGL, .359 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Waropen, No. 13 COUNTRY Indonesia PLAY Drapes and Reefs, No. 2
AREA OF BASIN (Mi^2) 24,000 AREA OF PLAY (MMA) 1.6
VOLUME OF BASIN (Mi^3) 40,800 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 0 BBO 0 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Outer Arc

DEFINITION AND AREA OF PLAY: Petroleum accumulations in reefs or draped sandtones localized by topographic highs on the buried Paleogene island-arc surface. Play area is taken to be the shallow-basin area approximately along the northern coast (fig. 74).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.100	.288	.600
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	.5	1	4
C. AVERAGE EFFECTIVE PAY (feet)	50	80	300
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	10	40	40
E. OIL RECOVERY (BBLS/AF)	100	215	400
F. GAS RECOVERY (MCF/AF)	200	1,000	2,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	21

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .020 BB, GAS .138 TCF, NGL .002 BB, OE .045 BBOE

REMARKS

A. From an unpublished map, it appears that isolated topographic highs make up about 18 percent of the island-arc surface which, very approximately, is a shallow ridge along the present north coast of Irian Jaya of 1.6 million acres.

B. On the basis of the apparent lack of sufficient source and cover, petroleum fill is deemed to be only 20 percent. No discovery has been made. On the basis of poor reservoirs and migration distance from the depocenters where generation must take place, I estimate a discovery rate of only 5 percent.

C. Lack of data necessitates the lumping of carbonate and sandstone reservoirs. 735 ft of carbonate with three zones of porosity were found at O-1. Carbonate is missing from R-1, Niengo-1, and Mamberambo-1; Niengo-1 tested a 110 ft sandstone and R-1 a 22 ft sandstone. On the basis that half the highs may be carbonate capped, I estimate an average effective pay of 80 ft.

D. On the basis of a preponderance of gas shows and of thick overpressured shale, the basin is deemed gas-prone. However, the overpressure may not extend over all of this rather shallow play. I estimate 60 percent gas.

E. Assuming 20 percent porosity and average reservoir parameters, I estimate an average of 215 barrels will be recovered from an acre-foot.

F. Assuming the same reservoirs, a depth of 8,000 ft, and heat gradient of 1.34°F per 100 ft, an average recovery of about 1,000 MCFG/AF.

G. World-wide average.

Limiting Factor: The apparent lack of sufficient source rock.
Total resources for all plays in basin: .093 BBO, 1.49 TCFG, .017 BBNGL, .359 BBOE

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN South Makassar, No. 14* COUNTRY Indonesia PLAY Miocene drapes
AREA OF BASIN (Mi^2) 16,310 AREA OF PLAY (MMA) 10.4
VOLUME OF BASIN (Mi^3) 40,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 0 BBO 0 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Rift

DEFINITION AND AREA OF PLAY: Potential petroleum accumulation in Miocene and Pliocene sandstones draped over Lower Miocene tilted fault blocks. Play occupies entire basin (figs. 1, 76, and 77)

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.050	.260	1.000
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	0.5	4	10
C. AVERAGE EFFECTIVE PAY (feet)	35	50	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM-FILL (%)	5	15	50
E. OIL RECOVERY (BBLS/AF)	150	233	450
F. GAS RECOVERY (MCF/AF)	400	1,900	2,500
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .018 BB, GAS .840 TCF, NGL .009 BB, OE .041 BBOE

REMARKS

A. By analogy to the East Java Sea basin, about 2-1/2 percent of the play-area is assumed the most likely trap-area.

B. Assuming some traps and reservoirs are established, a 10 percent discovery rate is postulated. By analogy to the Kutei basin, the estimated trap area filled is 40 percent, giving a most likely figure of 4 percent as the amount of trap area productive.

C. In this deep basin, abyssal shales are expected to dominate with negligible reef development and minor sandstones around the perimeter. The most likely average effective pay is estimated to be 50 ft.

D. Percent of oil is deemed low in this largely shale basin; 15 percent is estimated (Kutei basin, 20 percent).

E. Analogous to Kutei basin.

F. Analogous to Kutei basin.

G. World-wide average estimate.

Limiting Factors: Postulated lack of reservoirs.

*Kartaadiputra (1982), and Situmorang (1982).

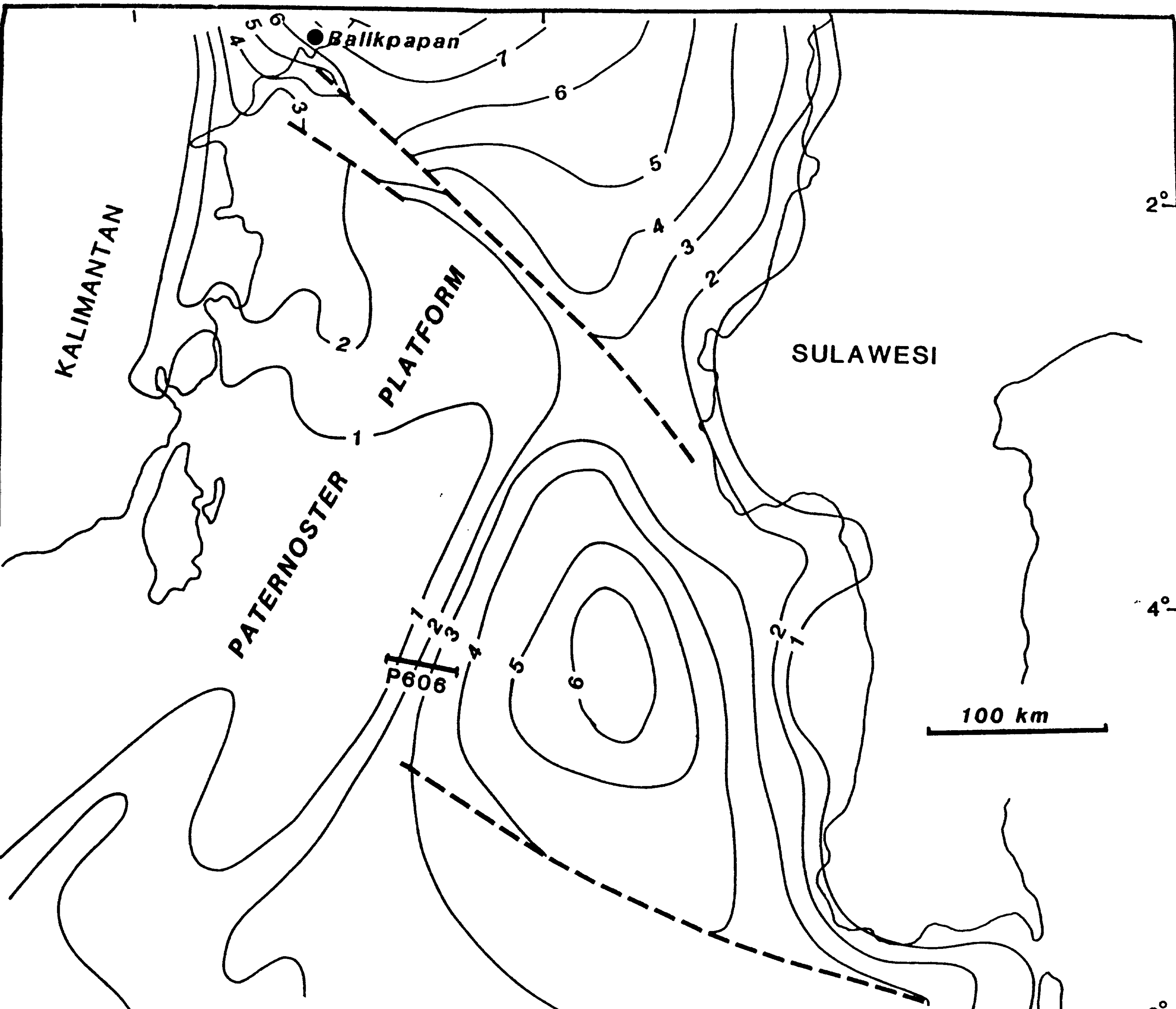
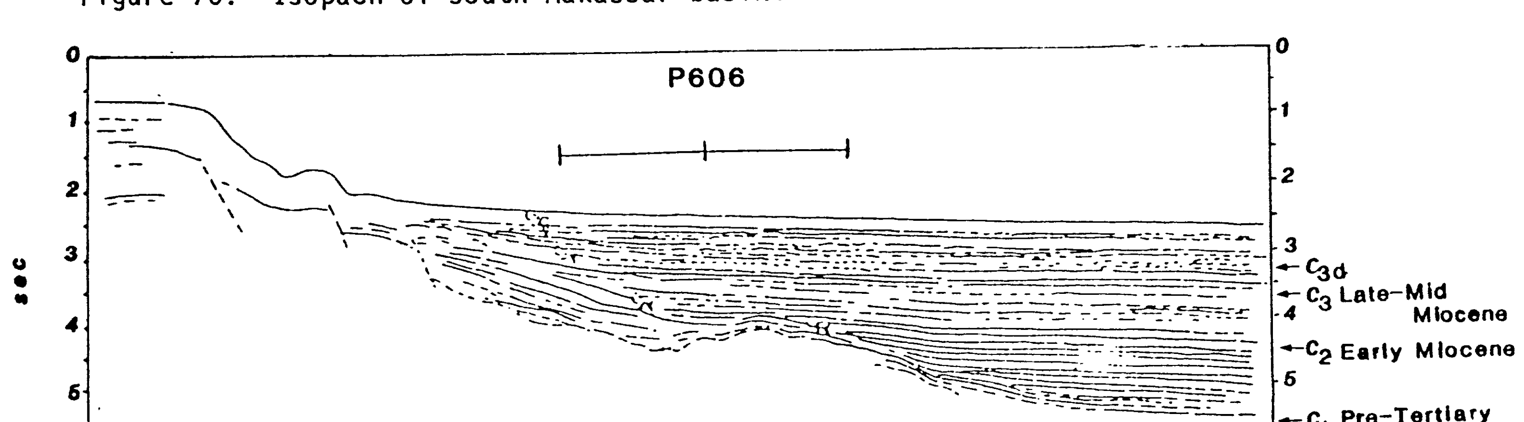


Figure 76.--Isopach of south Makassar basin.



gure 77.--West-east geologic section across west flank of south Makassar basin.

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Sumatra Outer Arc, #15* COUNTRY Indonesia PLAY Miocene Reefs, No. 1
AREA OF BASIN (Mi^2) 97,000 AREA OF PLAY (MMA) 15
VOLUME OF BASIN (Mi^3) 200,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 0 BBO 0 TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Fore Arc

DEFINITION AND AREA OF PLAY: Reef play would be limited to basin perimeter; estimate 25 percent or around 15 MMA. There may be a second play, i.e. sandstones, but the folded Paleogene are indurated and tectonized and the Neogene beds have little structure or porosity (figs. 1, 78, and 79).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.200	.900	2.000
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1.0	1.5	5.0
C. AVERAGE EFFECTIVE PAY (feet)	50	74	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	5	10	60
E. OIL RECOVERY (BBLS/AF)	100	200	400
F. GAS RECOVERY (MCF/AF)	200	500	1,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .020 BB, GAS .450 TCF, NGL .005 BB, OE .100 BBOE

REMARKS

A. Reef frequency and sizes deemed analogous to Salawati subbasin (i.e. 6 percent), giving an average trap area of .9 MMA.

B. One gas discovery from 21 wildcats = about 5 percent success (Muelabach-1, .7 MMCFCD). Fill estimated to be 30 percent, giving 1.5 percent untested trap productive (gas). This low percentage is supported by analogies to other fore-arc basins which have similar low thermal gradients, i.e. about 1.3°F per 100 ft.

C. Using Muelabach as an example, the average pay would be 74 ft.

D. Muelabach gas and other gas shows were dry gas. Some oil seeps occur onshore; I assume about 10 percent of petroleum mix is oil.

E. Assuming average to poor reservoir parameters, I estimate an average recovery of 200 barrels per acre-foot.

F. Assuming principal objective, middle Miocene reefs, at 4,000 ft, average thermal gradient of 1.3°F per 100 ft, and recovery factor of 80 percent.

G. Assume world-wide average.

Limiting Factor: Low thermal gradient (ave. 1.3°F/100 ft) puts top of mature source rock at about 13,000 ft (4 km), too deep to affect most Neogene rock but will affect some tectonized Paleogene. Poor sand reservoirs.

*Rose (1983).

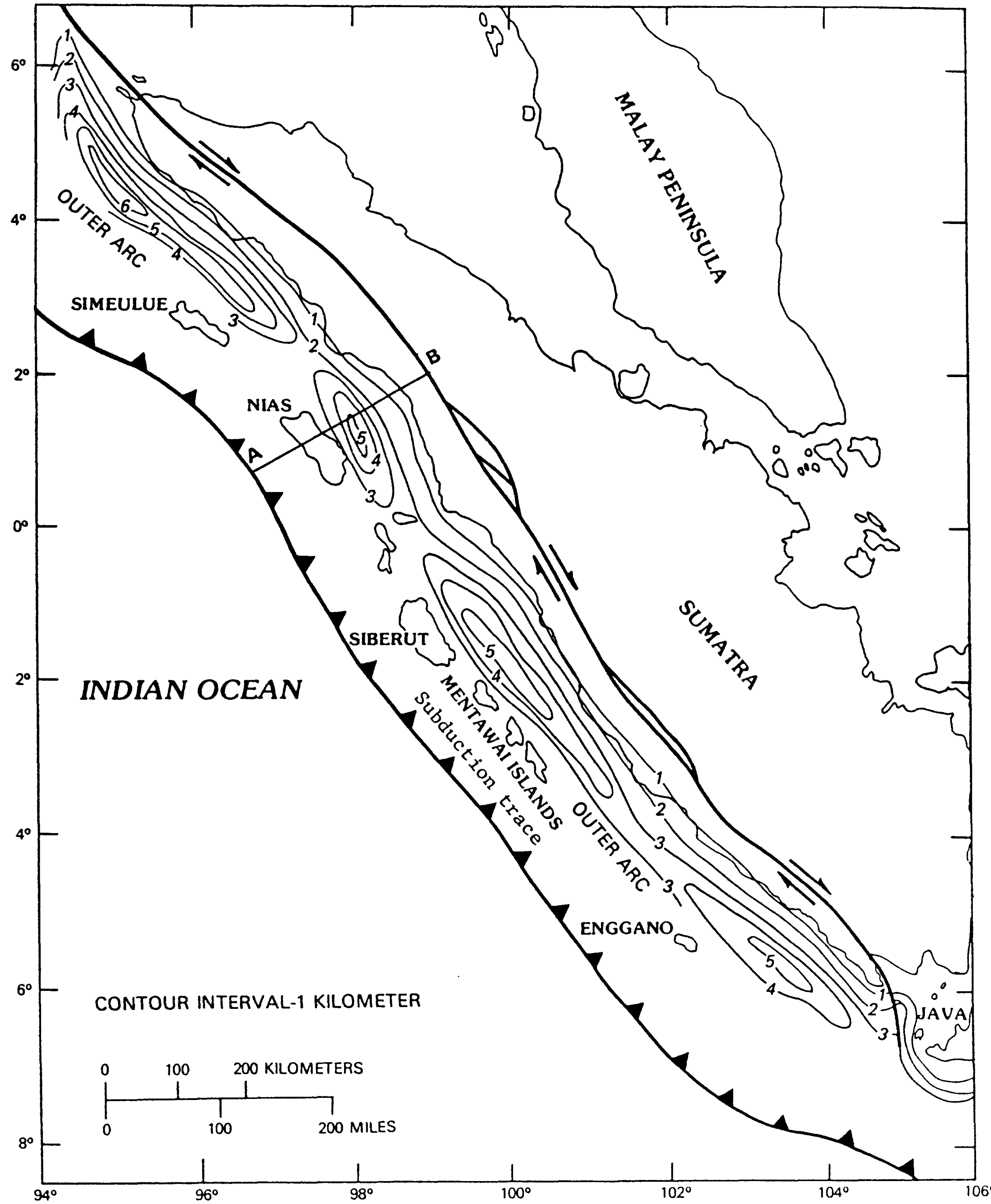


Figure 78.--Map showing tectonic elements and isopach of Neogene sediments, Sumatra Outer Arc basin. After Hamilton (1979).

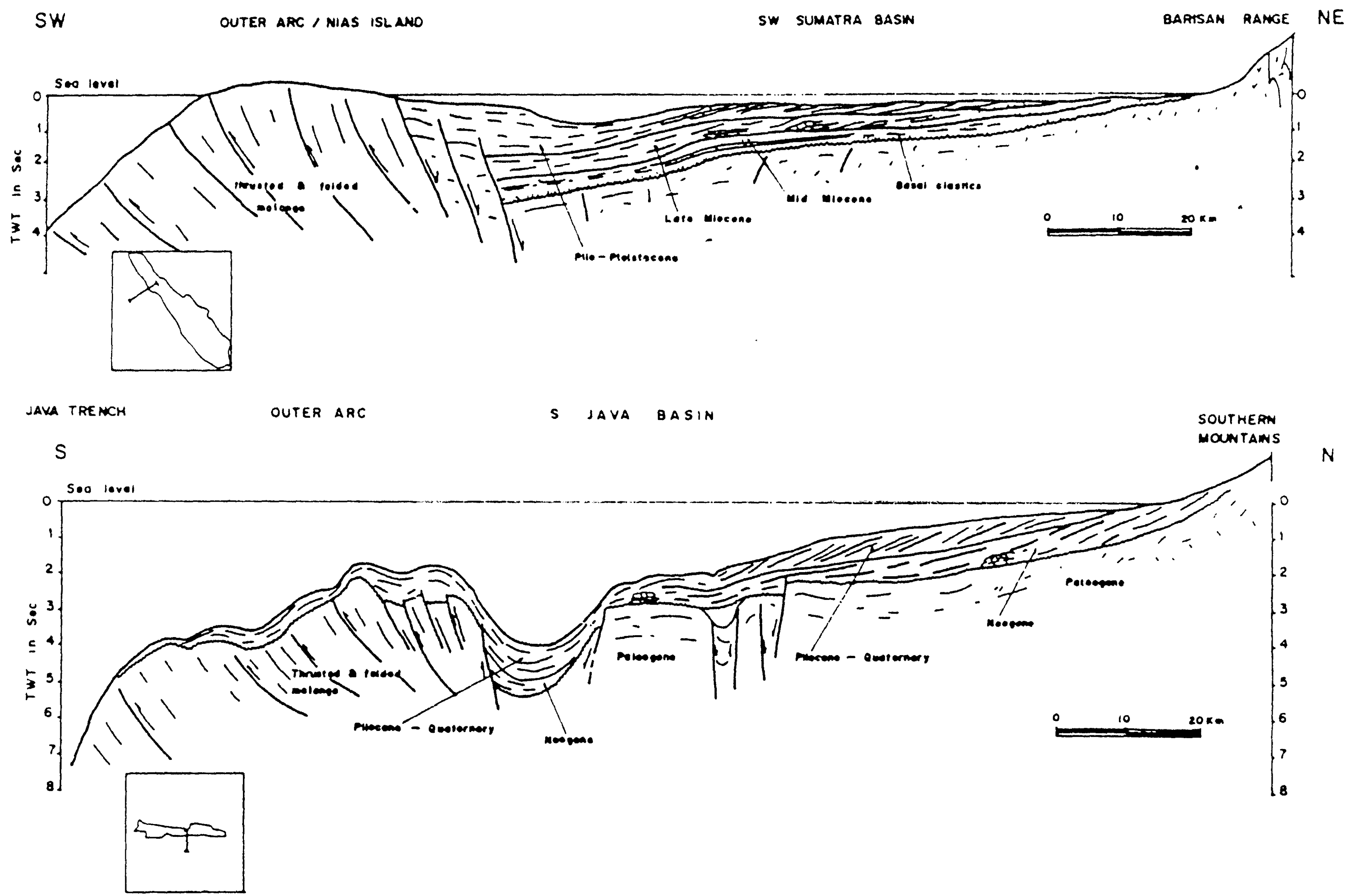


Figure 79.--Geologic cross-sections, A-A[1], across the Sumatra Outer Arc basin. After Kartaaduputra (1982).

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Java Outer Arc, No. 16* COUNTRY Indonesia PLAY Miocene Reefs, No. 1
AREA OF BASIN (Mi^2) 50,000 AREA OF PLAY (MMA) 8
VOLUME OF BASIN (Mi^3) 120,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES 0 BBO ______ TCFG 0 BBO 0 TCFG
TECTONIC CLASSIFICATION OF BASIN: Fore Arc

DEFINITION AND AREA OF PLAY: Reef play area would be on highs and perimeter of basin; estimate 25 percent of basin. Tertiary sandstones might be a second play, but the Paleogene appears too tectonized and volcanic, and the largely seismically opaque, Neogene lacking in trap structure; and so not considered (figs. 1, 79 and 80).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.100	.480	1.00
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	1.0	1.5	5.0
C. AVERAGE EFFECTIVE PAY (feet)	50	74	200
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	5	10	60
E. OIL RECOVERY (BBLS/AF)	100	200	400
F. GAS RECOVERY (MCF/AF)	200	500	1,000
G. NGL RECOVERY (BBLS/MMCFG)	8	11	20

PRODUCT OF MOST
LIKELY PROBABILITIES: OIL .011 BB, GAS .240 TCF, NGL .003 BB, OE .054 BBOE

REMARKS

A. By analogy to the Sumatra Outer Arc (and Salawati subbasin), 6 percent of play area is under trap.

B. By analogy to the Sumatra Outer Arc, untested trap area will be around 1.5 percent productive.

C. By analogy to the Sumatra Outer Arc, average effective pay around 74 ft.

D. By analogy to the Sumatra Outer Arc.

E. By analogy to the Sumatra Outer Arc.

F. About same average depth (4,000 ft) and thermal gradient (1.3°F per 100 ft) as the Sumatra Outer Arc.

G. World-wide average.

Limiting Factor: Low thermal gradient indicates that the oil-generating zone is below the Neogene in the largely tectonized melange dominated Paleogene sediments. Poor sand reservoirs.

*Bolliger and de Riuter (1975).

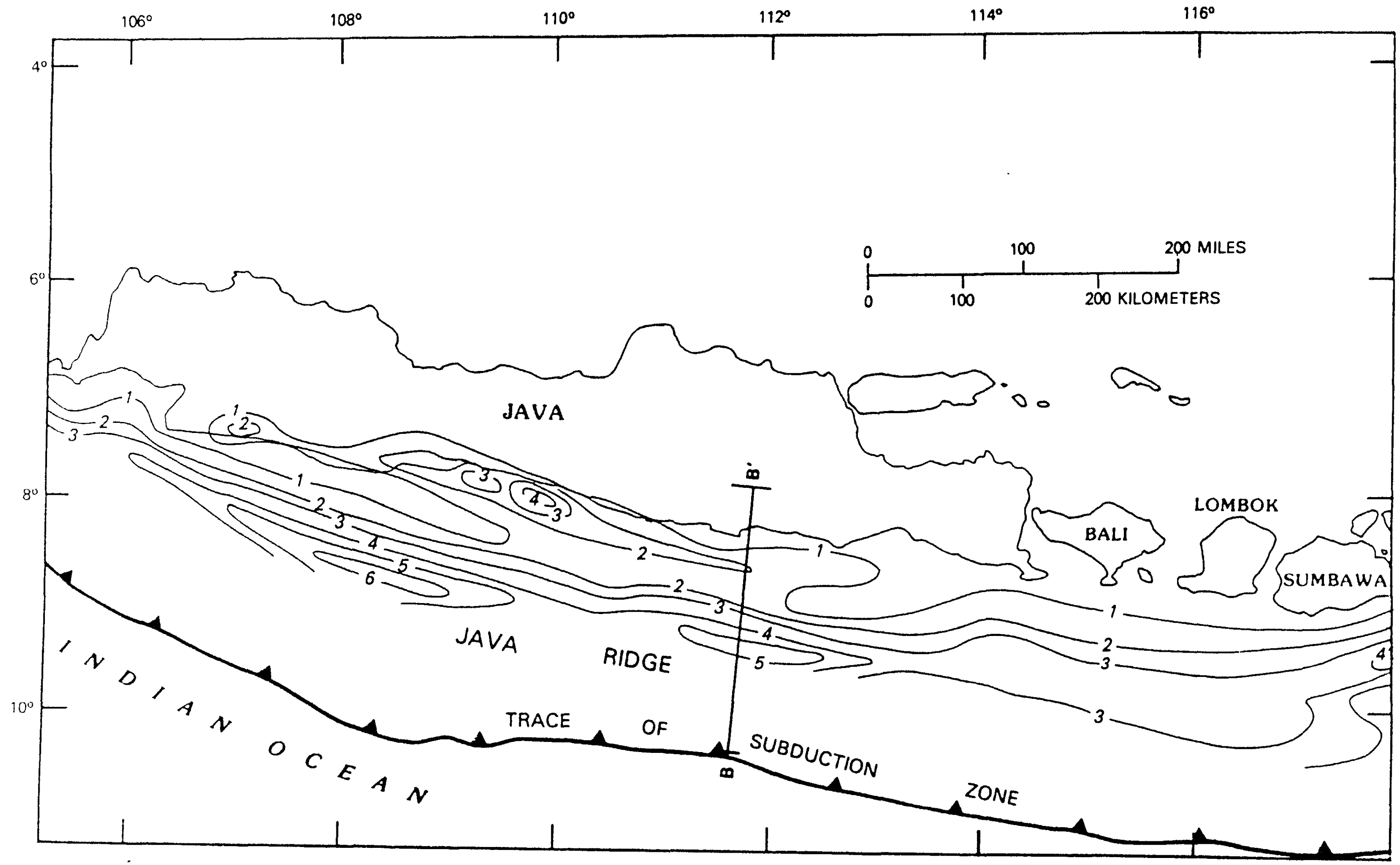


Figure 80.--Map showing tectonic elements and isopach of Neogene sediments, Java outer arc basin, contour interval 1 kilometer, after Hamilton (1979).

PLAY ANALYSIS SUMMARY OF UNDISCOVERED PETROLEUM

BASIN Bone-Senkang No. 17 COUNTRY Indonesia PLAY Carbonate Buildups, #1
AREA OF BASIN (Mi^2) 22,400 AREA OF PLAY (MMA) 3.6
VOLUME OF BASIN (Mi^3) 40,000 PLAY EST. ORIG. RESERVES,
ESTIMATE ORIGINAL RESERVES ____ BBO .75 TCFG(unproduced) ____ BBO .75 TCFG
TECTONIC CLASSIFICATION OF BASIN: Fore-Arc

DEFINITION AND AREA OF PLAY: Only appreciable reservoirs appear to be carbonate buildups. Area of play is assumed to be limited to periphery of basin or about one-fourth the basin area or approximately 3.6 million acres (fig. 1).

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 95%	MOST LIKELY	5%
A. UNTESTED TRAP AREA (MMA)	.10	.18	.50
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	3	7.5	15
C. AVERAGE EFFECTIVE PAY (feet)	50	200	700
D. PERCENT OIL VERSUS GAS IN PETROLEUM FILL (%)	2	4	10
E. OIL RECOVERY (BBLS/AF)	200	300	400
F. GAS RECOVERY (MCF/AF)	200	424	1,000
G. NGL RECOVERY (BBLS/MMCFG)	7	11	22

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .032 BB, GAS 1.10 TCF, NGL .012 BB, OE .227 BBOE

REMARKS

A. From an explored onshore part or subbasin (East Senkang, Grainge & Davies, 1983 map), it appears that 5 percent of that area is trap. Extrapolation over play-area indicates an untested trap area of .18 MMA.

B. Wildcat success rate to date is about 25 percent, average fill about 30 percent, indicating about 7.5 percent trap area productive.

C. Gross pay at wildcat K.B.-1 is shown as 75 m (230 ft), average net pay of Kampung Baru field reportedly 99 m (300 ft). I estimate 200 ft as average pay over play area.

D. Grainge and Davies indicate 4 percent oil or condensate, 96 percent gas in K.B. field. I take this as average for play.

E. Oil recovery on basis of 28 percent average porosity + average parameters.

F. Assume average depth of 700 m (2,300 ft) and thermal gradient of 1.4°F/100 ft.

G. World-wide average.

Limiting Factor: The volume of trap and reservoir is extrapolated into the largely unknown offshore area.

Conclusion: assessments of undiscovered recoverable petroleum

Resource estimates were made by consensus of a group of eight geologists of The World Energy Resources Program of the U.S. Geological Survey on the basis of a geologic review of the principal petroleum basins of Indonesia, as presented in this report, including the play analyses. These estimates were made of the undiscovered recoverable oil and gas in the four main groups of basins in Indonesia, i.e., Sumatra/Java, Kalimantan, Natuna, and Irian Jaya.

The following consensus estimates were made in ranges of three values, with a value for the mode (most likely), a low value with a 95-percent probability that the resource quantity will exceed it, and a high value with a 5-percent probability that the resource quantity will exceed it.

	Oil (billions of barrels)			Gas (trillions of cubic ft)		
	95%	ML	5%	95%	ML	5%
Sumatra-Java	1.5	3.3	5.9	8.2	17.2	32.9
Kalimantan	0.8	1.8	4.1	11.0	21.5	41.9
Natuna	0.4	1.1	2.8	11.0	25.9	64.4
Irian Jaya	0.7	2.2	5.8	5.1	14.8	35.0

These numbers are computer processed by using probabilistic methodology (Crovelli, 1981). The resulting curves show graphically the resource values associated with a full range of probabilities and determine the mean as well as other statistical parameters.

The cumulative probability curves for the undiscovered recoverable oil and gas resources are shown in figures 81 through 88, and aggregated for total Indonesia oil and gas in figures 89 and 90. The principal objective in making these curves is to find the mean quantity of undiscovered resources, a quantity which embodies estimates of the most likely quantity along with more remote probabilities for larger or smaller quantities, but particularly substantially of undiscovered larger quantities (sleepers) of undiscovered oil and gas.

The mean estimates of the four main groups of basins, as determined from the probability curves are summarized below:

	Oil (billions of barrels)	Gas (trillions of cubic ft)
Sumatra/Java	3.55	19.32
Kalimantan	2.21	24.63
Natuna	1.41	33.29
Irian Jaya	2.86	18.11

Figures 89 and 90 show the aggregation of the probability curves and accompanying statistical parameters for the undiscovered recoverable oil and gas resources of Indonesia. The aggregation assumes 75 percent dependence between the estimated probabilities, an assumption deemed proper to provide a proper statistical tie affecting all the aggregated parameters except the mean probability.

The mean estimates are the principal results of the study and, when aggregated, show that the undiscovered recoverable petroleum resources of Indonesia are 10 billion barrels of oil, and 95 trillion cubic ft of gas (not including 60 trillion cubic ft of discovered, but undeveloped, gas resources).

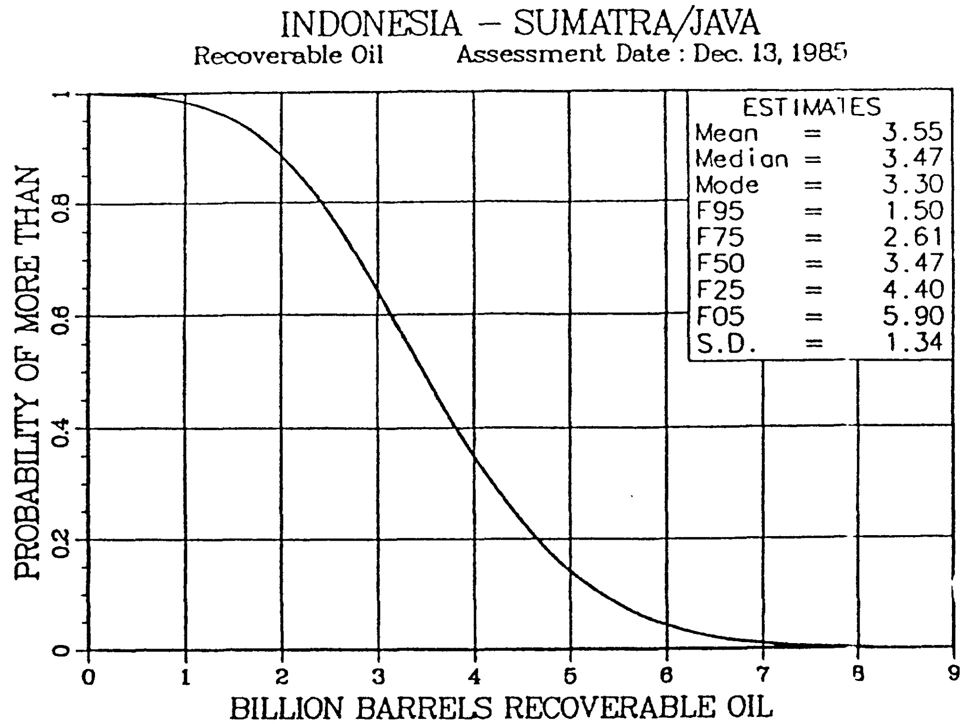


Figure 81.--Cumulative Probability Curve Sumatra/Java, recoverable oil

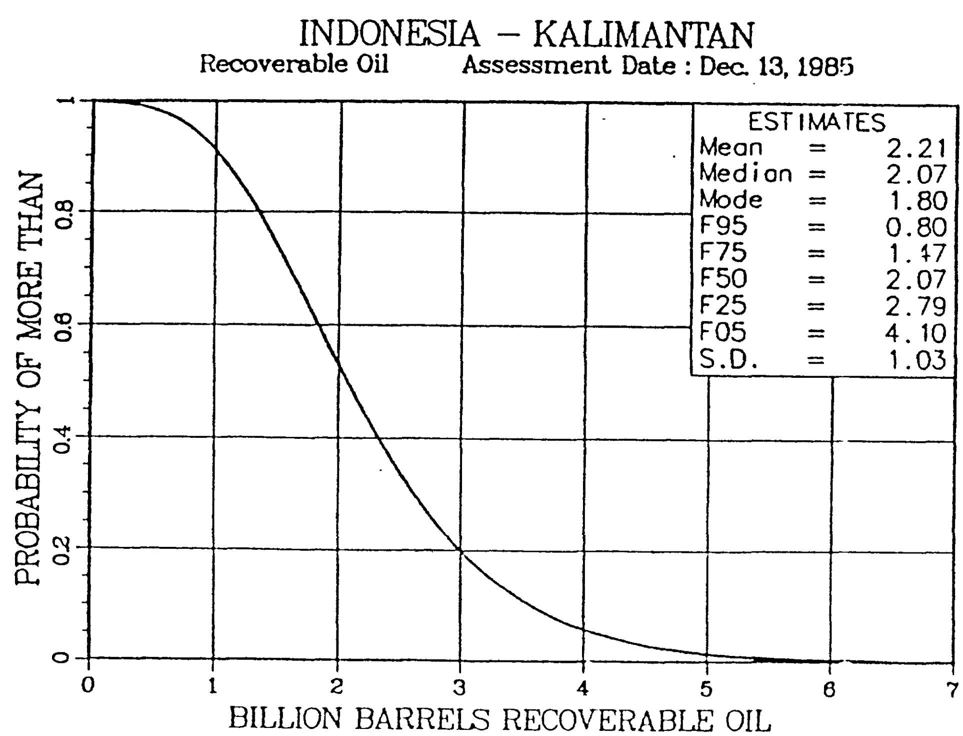


Figure 82.--Cumulative Probability Curve Kalimantan, recoverable oil

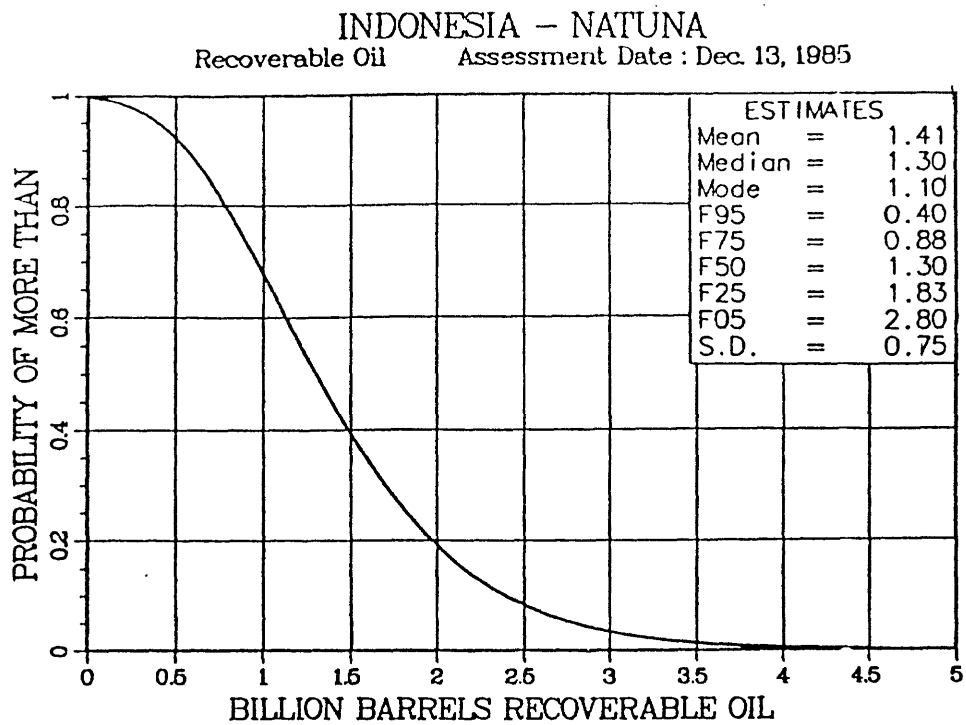


Figure 83.--Cumulative Probability Curve, Natuna, recoverable oil.

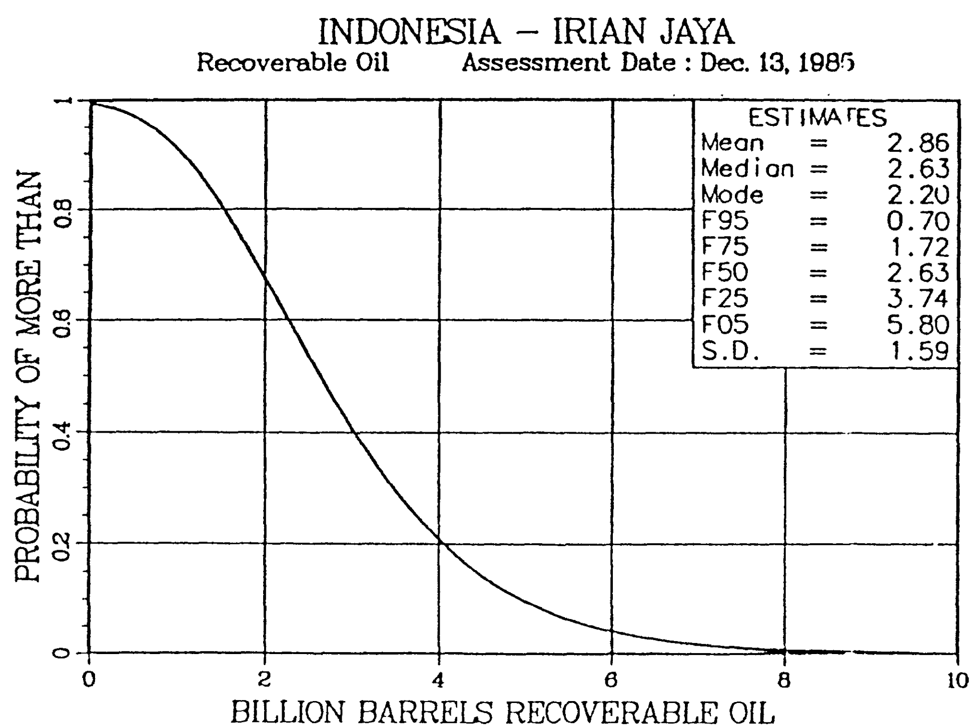


Figure 84.--Cumulative Probability Curve, Irian Jaya, recoverable oil.

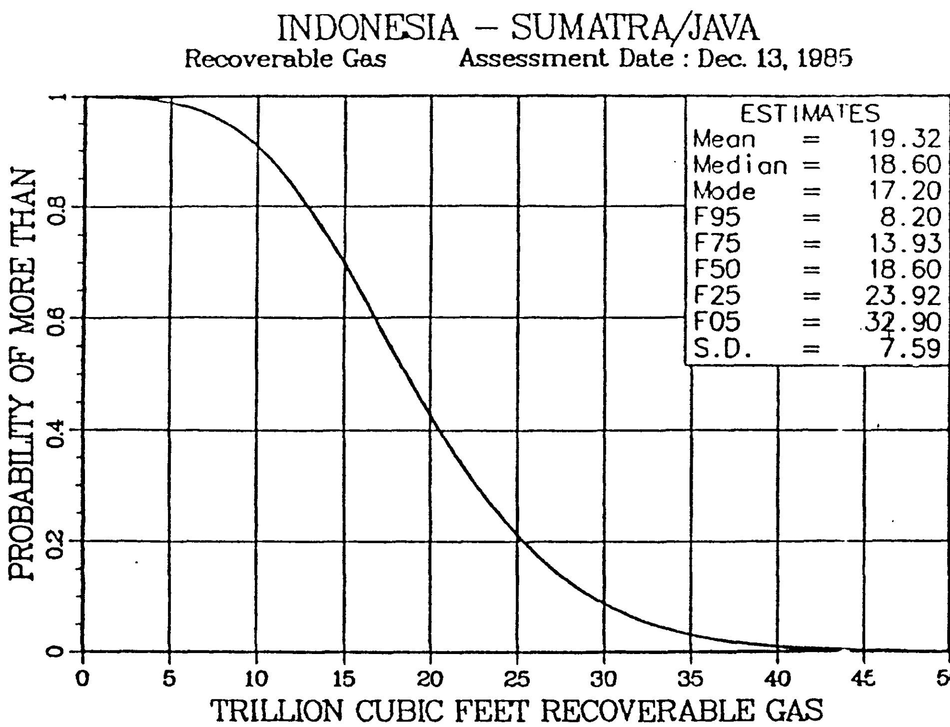


Figure 85.--Cumulative Probability Curve, Sumatra/Java, recoverable gas.

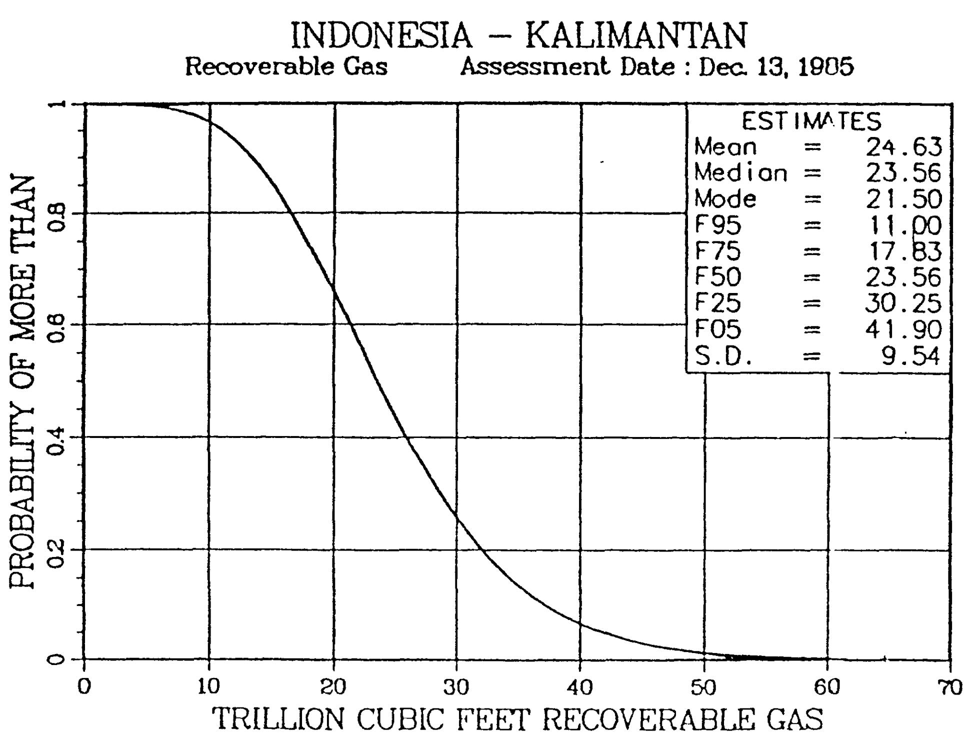


Figure 86.--Cumulative Probability Curve, Kalimantan, recoverable gas.

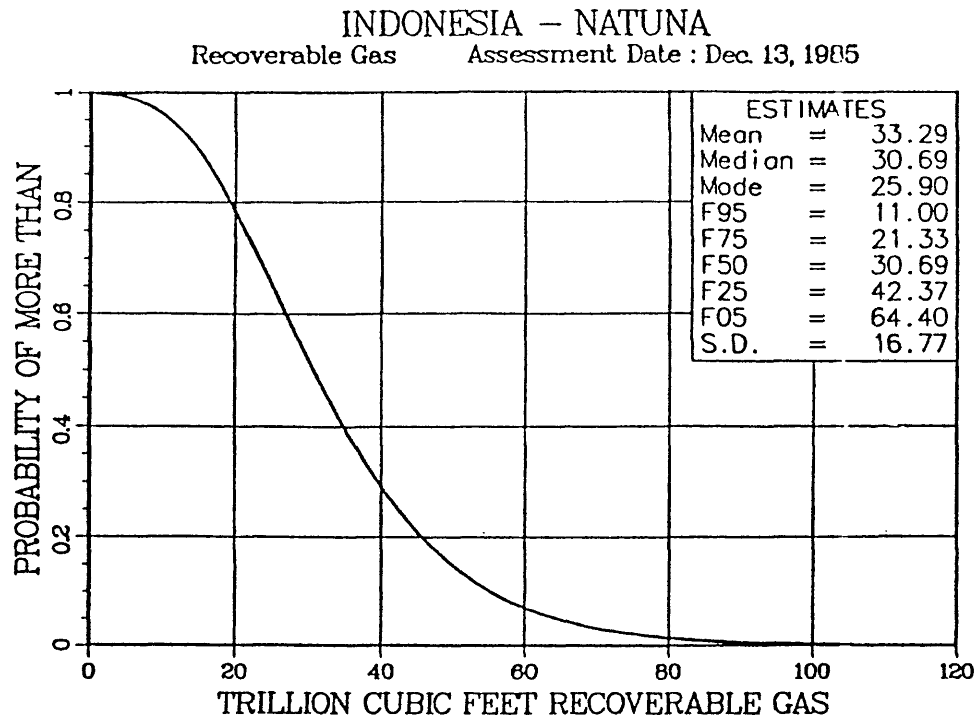


Figure 87.--Cumulative Probability Curve, Natuna, recoverable gas.

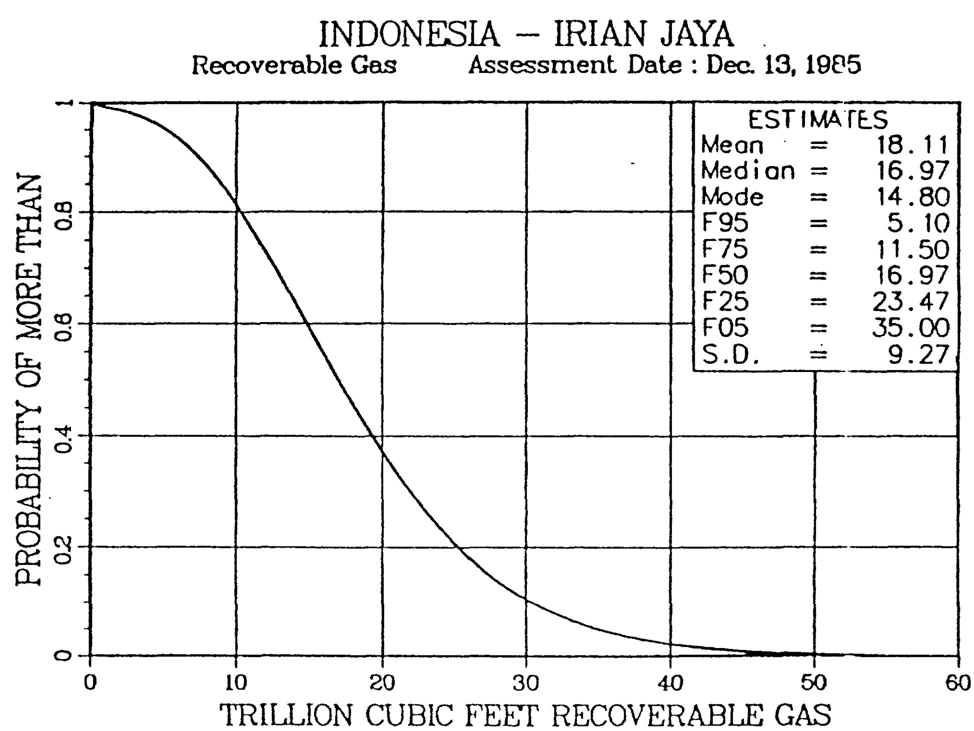


Figure 88.--Cumulative Probability Curve, Irian Jaya, recoverable gas.

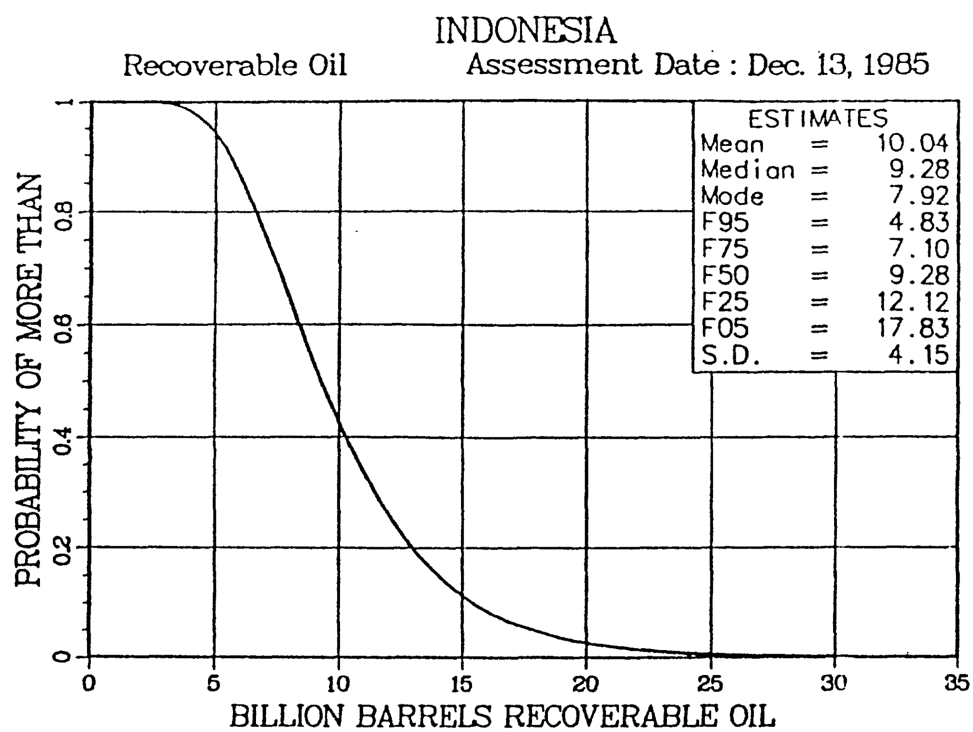


Figure 89.--Cumulative Probability Curve, recoverable oil.

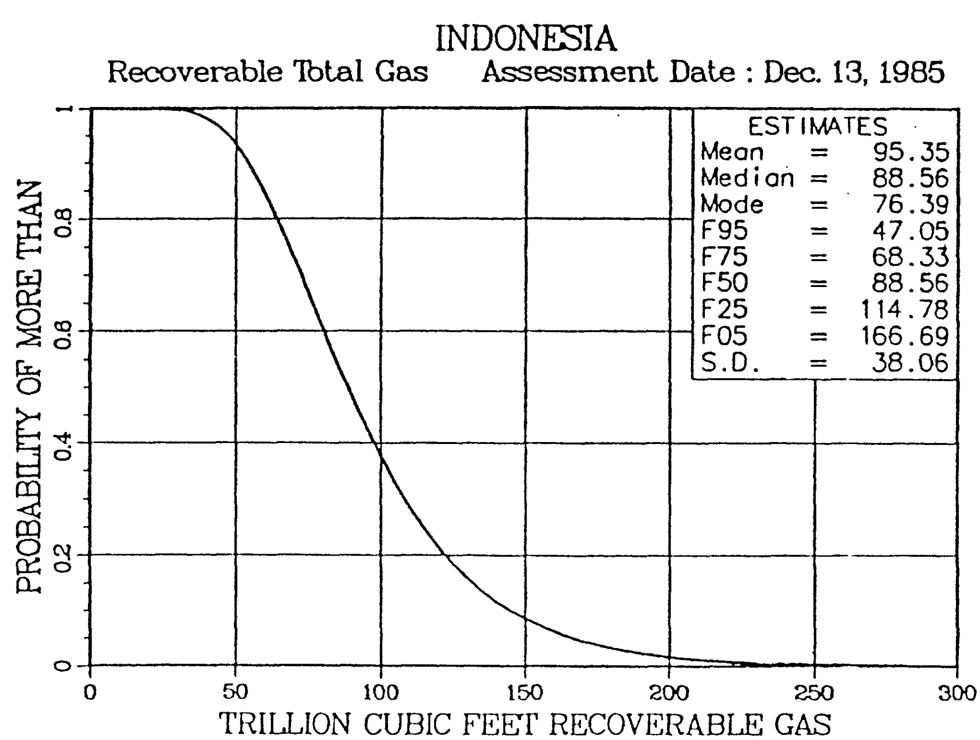


Figure 90.--Cumulative Probability Curve, recoverable total gas.

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