History of hydrocarbon generation in the Tembungo field, offshore northwest Sabah

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Abstract: The Tembungo field in the Sabah Basin produces oil from upper Miocene turbidite reservoirs. The oils, possessing low sulphur and wax contents and API gravities of 38–40°, were derived from marginal marine source rocks subject to significant land plant input. The history of hydrocarbon generation in the Tembungo area including burial, fluid pressure and fluid-flow, thermal history, hydrocarbon generation and migration has been studied using a two-dimensional finite difference basin modelling approach.

Backstripping exercises suggest that high sedimentation rates occurred during middle to late Miocene. The Tembungo structure itself began to grow in late Miocene (7.2 Ma), with an accelerated growth rate in early Pliocene. A constant basement heat flow of 55 mWm^{-2} was determined for the area. The faults are known to be sealing, with very low associated permeabilities. The presence of barrier faults contributed to the development of overpressure in the area. The contribution of hydrocarbon generation to the overpressure is considered less significant.

Maturity reconstruction based on kinetic models indicates that hydrocarbon generation began approximately 9.0 Ma and oil began to be trapped in the Tembungo structure in late Miocene to early Pliocene. These oils were most likely sourced from middle Miocene sediments. Sensitivity analysis of transient state versus steady state pressure calibration reveals different histories of hydrocarbon generation and migration.

INTRODUCTION

The Tembungo field, described by many authors (Whittle and Short, 1977; Ismail, 1992; ONGC-PRI, 1992), is located offshore northwest Sabah (Fig. 1) and was the first producing oilfield in the offshore Sabah region. The field, discovered by EPMI in 1971, was recently (1986) relinquished to PETRONAS. The lower part of the upper Miocene turbidites forms the main reservoir in this field.

The Tembungo anticlinal structure is dissected by normal faults into three major blocks, i.e. Western, Central and Eastern, which can be further subdivided into several sub-blocks. The western block contains oil with a thin gas cap whereas the central block is oil bearing without any gas cap. The eastern block contains only gas (Fig. 2).

The source rocks for the hydrocarbons have been postulated by several authors to be upper Miocene turbidite sequences in a more mature downdip location (Whittle and Short, 1977; Ismail, 1992; ONGC-PRI, 1991). Recent investigations from biomarker analysis have shown that the middle Miocene sequence is more likely to be the source of the hydrocarbons in the area (Abdul Jalil and Mohammad Jamaal, 1992; Woodroof and Carr, 1992; Azlina *et al.*, 1993).

The objectives of this study were to provide an understanding for the source of the oil in the Tembungo field, as well as to determine the relative timings of hydrocarbon generation and structure formation, and to determine migration pathways for the hydrocarbons. This study utilized a commercial basin modelling programme (Temispack) to reconstruct geological and thermal history of the basin in order to quantitatively predict the generation, migration and accumulation of hydrocarbons.

BASIN MODELLING

Geological cross-sections of the Tembungo field were modelled using Temispack 2D basin modelling programme. Detailed descriptions of this programme and its applications can be found elsewhere (Ungerer *et al.*, 1986; Ungerer *et al.*, 1990; Forbes *et al.*, 1991; Burrus *et al.*, 1992a, b). The cross-sections were constructed from interpreted seismic lines which extend from the synclinal areas around the anticlinal structure and pass through the Tembungo-7, Tembungo-2, Tembungo-5, Tembungo-1 and Tembungo-6 wells (Fig. 3). Interpreted reflectors of major unconformities (DRU, LIU, UIU, SRU, Horizon III,

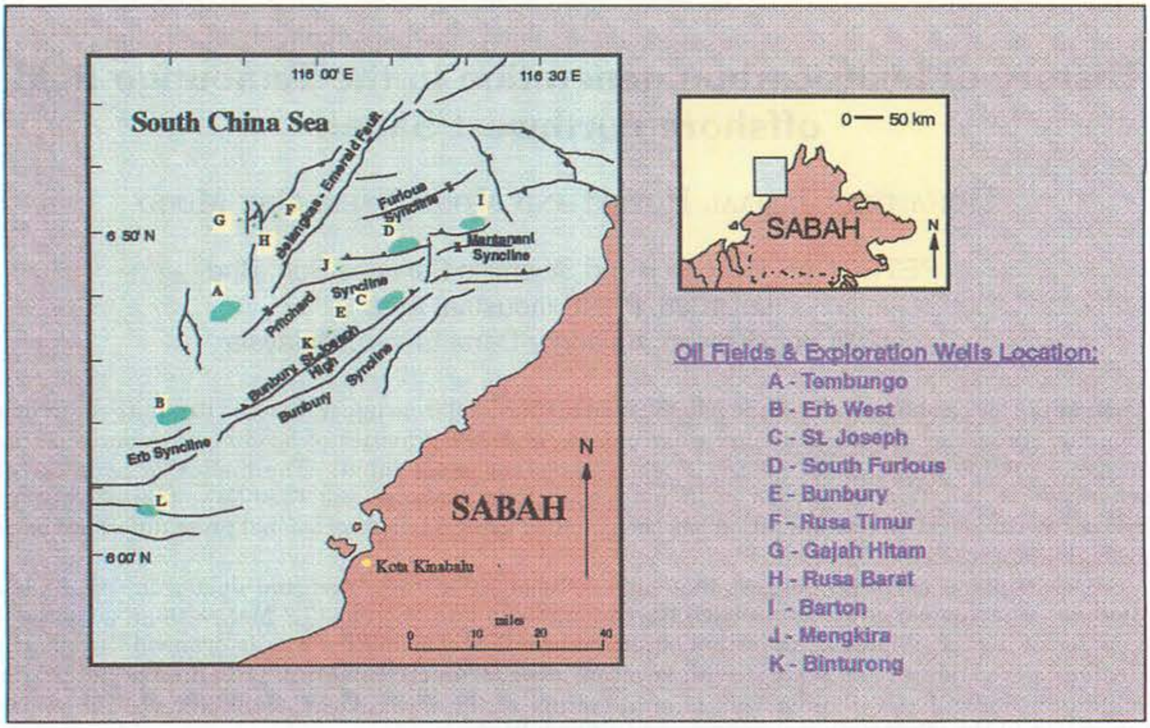

Figure 1. Tembungo field and location of surrounding exploration wells and oilfields in Northwest Sabah basin.

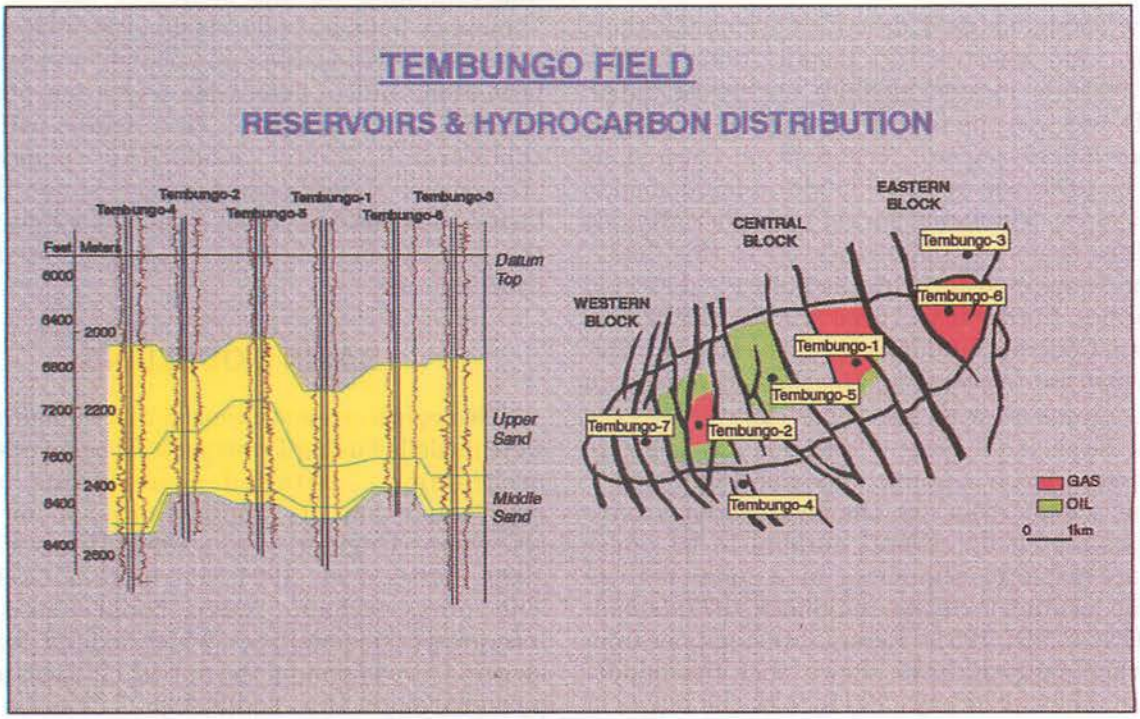

Figure 2. Structure map of Tembungo field showing hydrocarbon distribution.

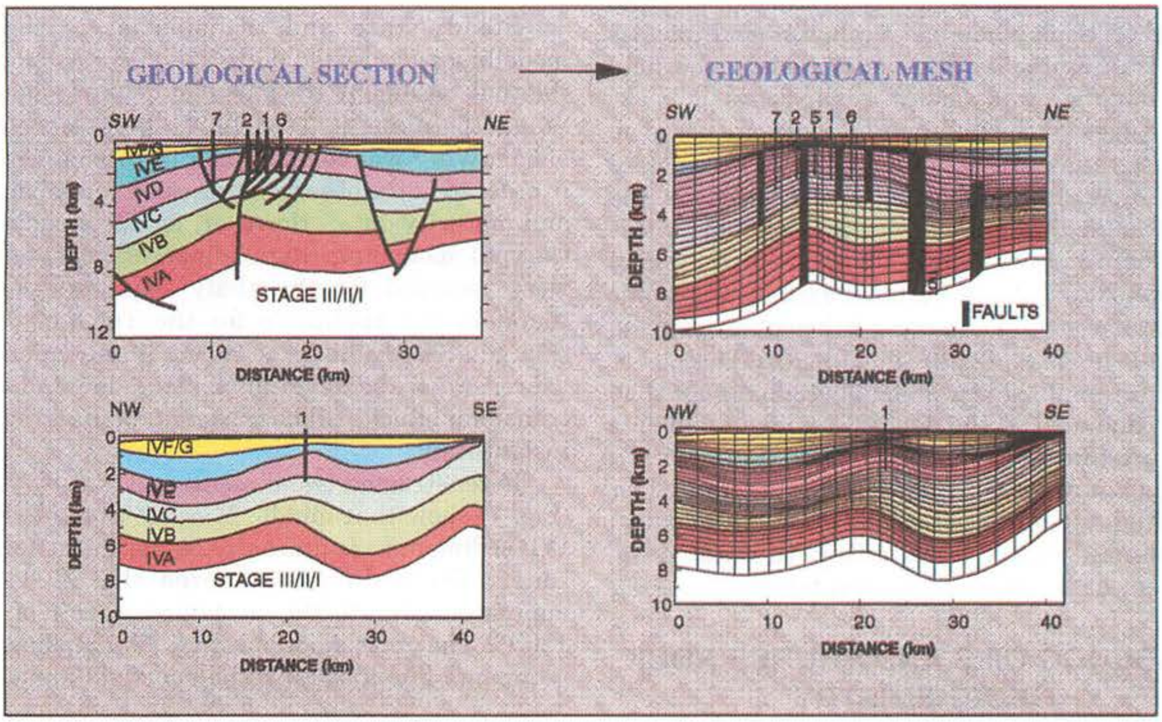

Figure 3. Geological and modelled mesh section of Tembungo section.

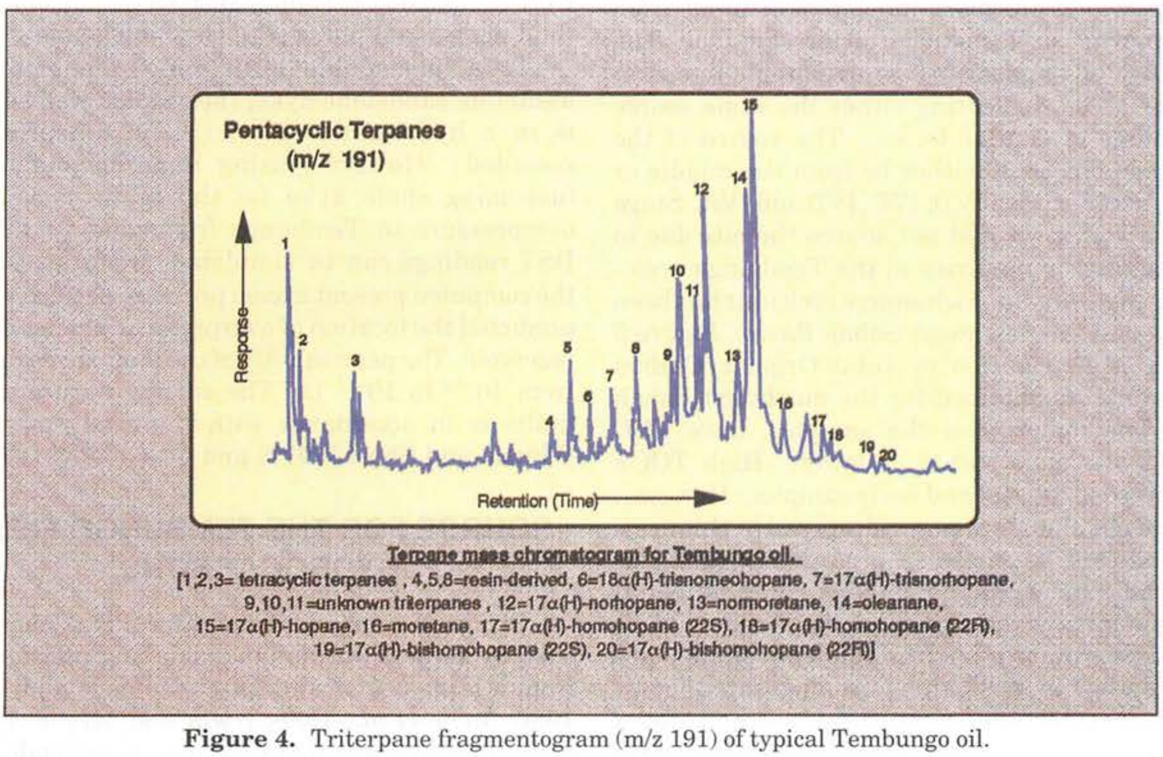

Figure 4. Triterpane fragmentogram (m/z 191) of typical Tembungo oil.

Horizon II, Horizon I) were used as isochron markers on the section. The sections were transformed into gridded sections made up of columns and rows as shown in Figure 3. The faults cutting the field were simplified into vertical shear zones.

The ages for the different horizons are based on biostratigraphic studies of the wells. Where no age information is available, ages are based on the stratigraphic time scale commonly adopted for this area (Johnson *et al.*, 1987). With the exception of the lower Stage IVD limestone, each stratigraphic layer was assigned a specific lithology by varying the sand/shale ratio with the aid of well logs. For deeper layers, lithologies were based on published reports and also on the depositional environments which are thought to have prevailed (Levell, 1987; Tan and Lamy, 1990). Additional data required for modelling include eustatic history, lithological parameters, source rock units, thermal data, basement data and hydrocarbon types.

TEMBUNGO OILS AND SOURCE ROCK GEOCHEMISTRY

The Tembungo oils are paraffinic, low in sulphur and are moderately waxy. The oils are sourced from land-plant derived organic matter (Abdul Jalil *et al.*, 1991; Azlina *et al.*, 1993). GCMS analysis shows the oils contain typical land-plant indicators such as and bicadinanes, and a lack of tricyclic terpanes, gammacerane and C_{34} and C_{35} extended hopanes which are more indicative of input from distal marine or lacustrine facies (Fig. 4). The Tembungo oils appear to be correlatable to oils in adjacent areas, indicating either the same source or a source of similar facies. The source of the Tembungo oils could either be from the middle or upper Miocene Stage IVD, IVC, IVB and IVA. Stage IVE and younger could not source the oils due to their thermal immaturity in the Tembungo area.

No single organic-rich source rock unit has been identified in the northwest Sabah Basin. Figure 5 shows the distribution of Total Organic Carbon (TOC) contents obtained for the northwest Sabah area. The majority of the samples, have TOC contents of about 3 wt.% or lower. High TOC's were recorded for coal and coaly samples. However, coals are not abundant nor widespread in this area. No significant variation in organic richness was observed between different depositional environments as the organic matter seems to be well disseminated. Although the shales are relatively low in TOC, this is compensated for by the considerable thickness of middle and upper Miocene shales, and the close association with interbedded sandy layers, which facilitate primary migration.

THERMAL AND MATURATION HISTORY

Steady-state and transient-state thermal modelling were tested on the section. Assuming a thermal basement thickness of 20 km below the Stage III sediments, a constant subcrustal heatflow of 55 mWm^{-2} was computed for the Tembungo area in order to fit the observed present-day temperature and maturity data. However, for the steady-state thermal modelling, high temperature anomalies were recorded for the shaly sequences, and is therefore not applicable for the Tembungo area (Fig. 6). Steady-state modelling is only applicable to areas where sedimentation rate is low and where transient effects, like sediment blanketing, are insignificant.

Reconstructed two-dimensional maturity plots (Fig. 7) show that middle Miocene Stage IVA and IVB sediments are presently in the gas generation zone. The sediments entered the oil window approximately 10 Ma, at temperatures of 100–120°C. The upper Miocene stage IVC and base IVD sediments are mature in the synclinal areas.

SEALING FAULTS AND OVERPRESSURE DEVELOPMENT

In order to reproduce the pressures observed in the well, the permeability of the faults must be tuned to match the observed pressure data. Both lateral and vertical permeabilities of the fault zones were assigned to permit or restrict displacement of fluid across and parallel to the fault planes.

In a 'permeable fault zone' scenario, i.e. assuming sandstone dyke, the studied well section is in a hydrostatic state, i.e. no overpressure recorded. However, using impermeable faults (assuming shale dyke for the fault zones), the overpressure in Tembungo from mudweight and DST readings can be simulated. Figure 8 shows the computed present excess pressure pattern which predicted the location of overpressured zones at the reservoir. The permeability of the fault zones ranges from 10^{-12} to 10^{-17} D. The sealing nature of the faults is in accordance with the study made by Whittle and Short (1977) and ONGC-PRI (1991).

SOURCE FOR THE TEMBUNGO FIELD HYDROCARBONS

Principal component analysis (PCA) has been used by several workers in extracting information from a large chemical dataset (Telnaes and Dahl, 1986; Mello *et al.*, 1988; Irwin and Meyer, 1990). Forty rock extracts and nine oils from Tembungo, Barton, South Furious and St. Joseph fields and Rusa Timur, Rusa Barat and Mengkira wells were

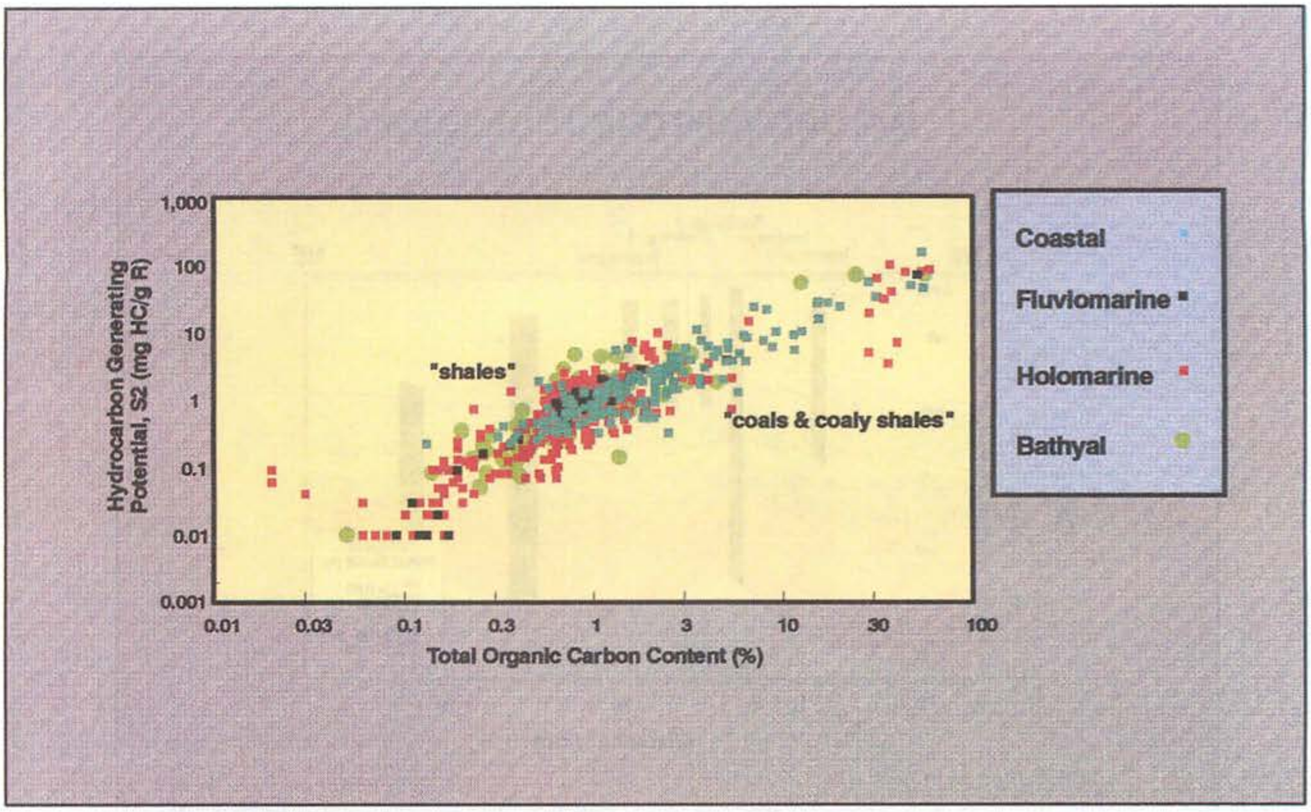

Figure 5. Correlation of Total Organic Carbon (TOC) content and Hydrocarbon Generating Potential (S2) from shales and coals.

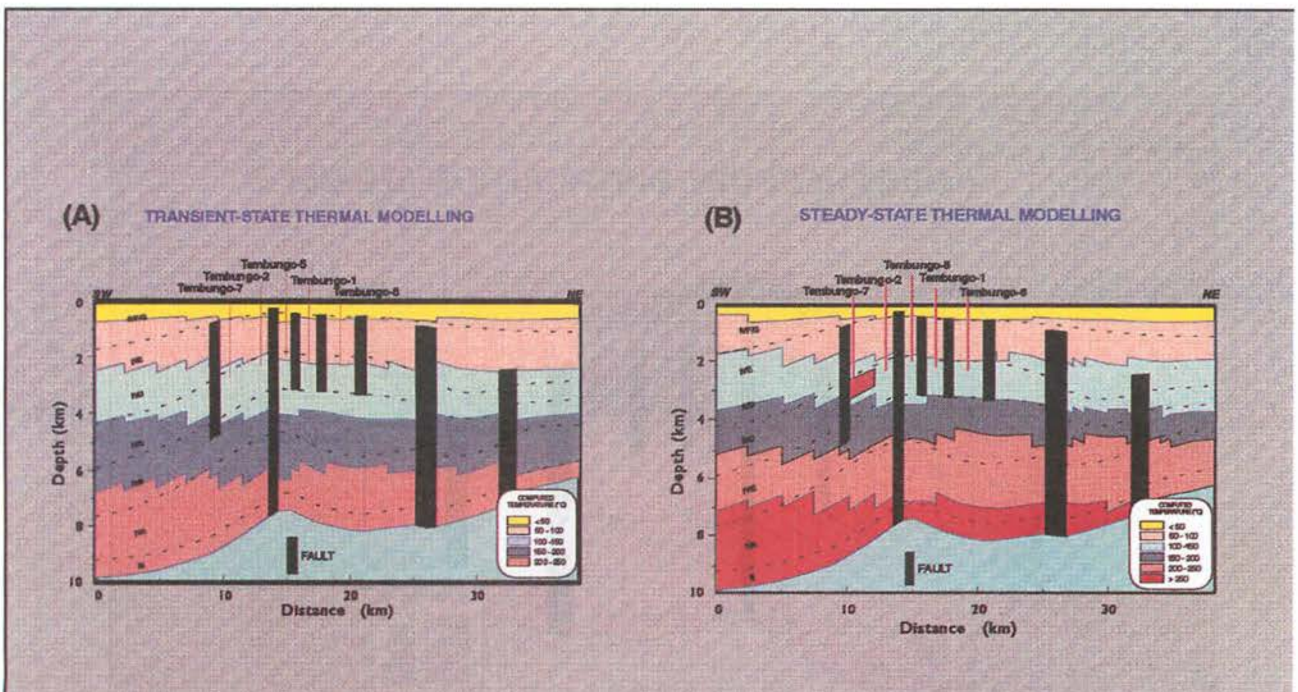

Figure 6. Computed temperature distribution at present using (A) transient-state, versus (B) steady-state.

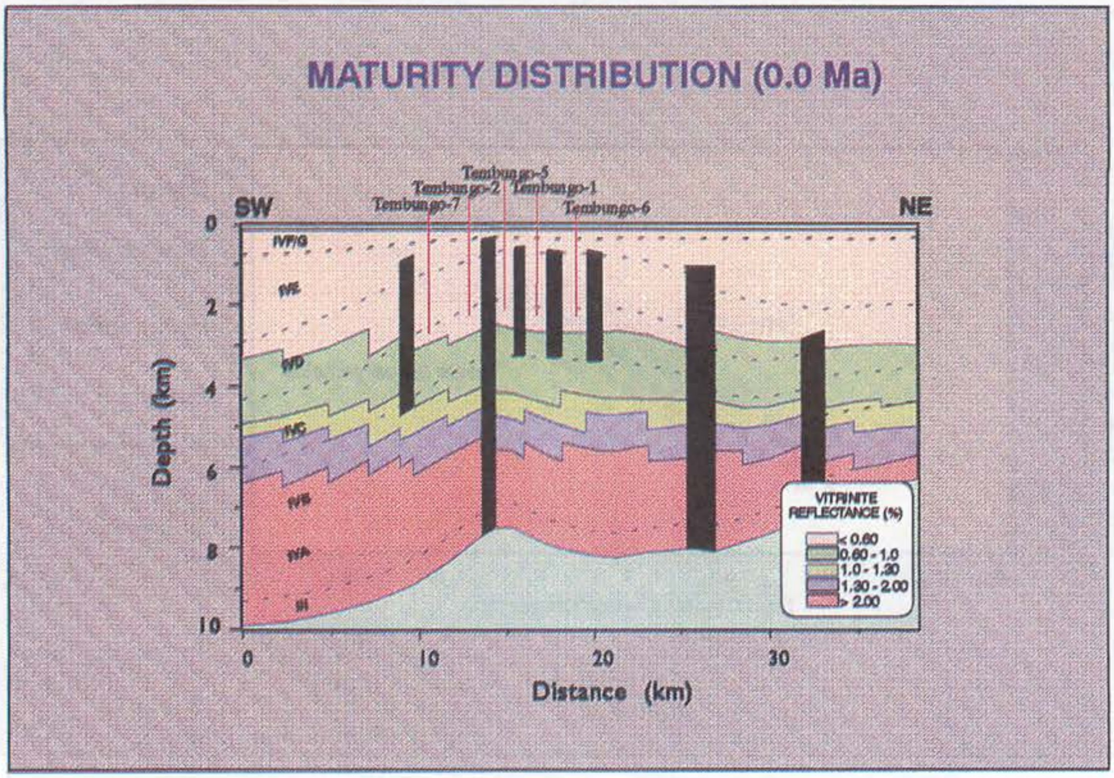

Figure 7. Computed maturity distribution (vitrinite reflectance) at present time.

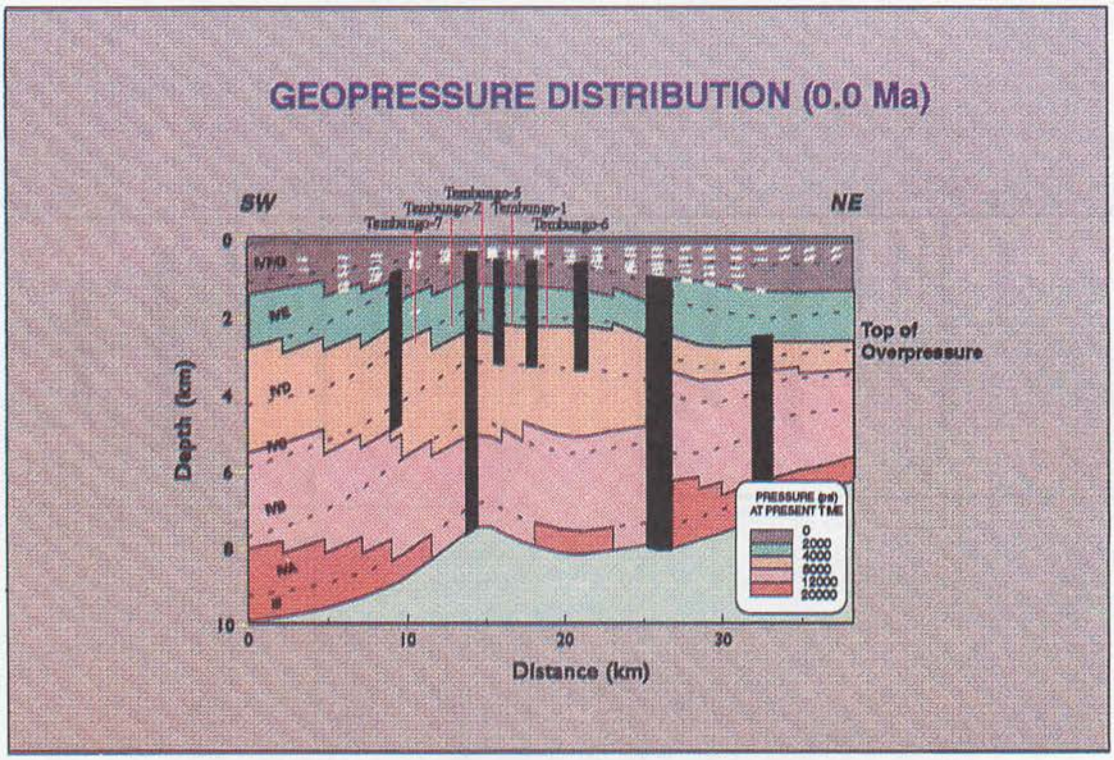

Figure 8. Computed excess pressure distribution at present.

correlated based on triterpane distributions using the multivariate statistical analysis programme SIRIUS of Kvalheim and Karstang (1987).

The results suggest that the rock extracts group by stratigraphic units and palaeodepositional environments (Fig. 9). The oils, however, were grouped in a single grouping suggesting they were derived from a similar source (same source or sources having similar organic facies). The slight variation is probably due to variation in kerogen assemblages, maturity and/or migration. The PCA analysis shows that Stage IVA and IVB (single datum) sediments are most similar to the oils, that is correlatable. This suggests that Stage IVA and IVB are the most likely source rock candidates for the oils in the area. This is contrary to the findings by others who suggest intraformational shales within the IVD turbidites acted as the source rock (Whittle and Short, 1977; Ismail, 1992; ONGC-PRI, 1991). The intraformational shales were observed to contain significant amounts of carbonaceous material.

To test the source rock hypothesis for the Tembungo oils, maturity modelling was carried out using different possible source rock intervals: (1) upper Miocene (Base of Stage IVD and/or Stage IVC) and (2) middle Miocene (Stage IVA and/or Stage IVB). The source rock intervals were modelled using measured kinetic data (Fig. 10) with varying hydrocarbon generating potentials.

In the cases of base Stage IVD and combined Stage IVC and IVD source rocks, even using a high hydrocarbon generating potential of 10 mg HC/g rock, sediments of oil window maturity are volumetrically insufficient to generate enough hydrocarbons to fill the Tembungo structure (Fig. 11). However, for Stage IVA or IVB, the simulations in Figure 12 and 13 show that these thick sediments can generate sufficient amounts of hydrocarbons for the Tembungo reservoirs (assuming even a low hydrocarbon generating potential of 2 and 3 mg HC/g rock for Stage IVA and IVB, respectively). This suggests that Stage IVA and possibly Stage IVB are the most likely sources for the oils in the Tembungo field. Using a hydrocarbon density of 500 kgm^{-3} to simulate oil migration, the model successfully predicted the filling of the central and western block. Furthermore, no oil was emplaced in the eastern block by the model (see Fig. 12).

TIMING OF GENERATION

During the forward backstripping process, growth of the Tembungo structure was observed to begin in Late Miocene (7.2 Ma). High sedimentation rate was recorded during this period. Accelerated growth of the Tembungo structure started in early Pliocene. Modelling has indicated that oil generation from base of Stage IVA started in late Miocene (9 Ma) and the hydrocarbons began to be expelled about 1 Ma later. Figure 14 shows the computed transformation ratio for the base of Stage IVA sediments. High transformation rate or maturation of the source rock is attributed to the high sedimentation rate during this period.

MIGRATION PATHWAYS

The main concern regarding Stage IVA as the main source is related to migration of the generated hydrocarbons to the present trap in lower Stage IVD, the problem being the intervening thick Stage IVB and IVC shales. Such a thick shale sequence will inhibit vertical migration and hence act as a seal. However, intense faulting and fracturing observed in the Tembungo structure provides vertical migration conduits for oils generated from deeper middle Miocene source rocks. Hydrocarbon volumes generated by Stage IVA in the western syncline are large enough to account for the known accumulations in Tembungo.

Oils began to be trapped in the Tembungo structure during late Miocene to early Pliocene. The central fault block, e.g. Tembungo-5, began filling as early as 6 Ma, earlier than the western fault block, e.g. Tembungo-6 and 7 (Fig. 15).

To simulate gas migration, a hydrocarbon density of 250 kgm^{-3} was used. Figure 16 shows the model currently predicts the observed gas accumulation in the three blocks of the Tembungo field. The observed lack of gas cap in the central block is attributed to gas escaping through the faulted zone as gas chimneys can be readily seen on seismic profiles over Tembungo.

The modelling results indicate that the distribution of oil and gas in the Tembungo fault blocks are largely dependent upon the thickness of matured sediments and the influence of faults between the blocks. Other possible factors affecting hydrocarbon distribution may be source facies variation of the middle Miocene sediments, or phase separation occurring during migration and/or in the reservoirs. These hypotheses are not tested.

CONCLUSIONS

The main objective of this study was to understand the origin of hydrocarbons in the Tembungo field. This was achieved by reconstructing the history of hydrocarbon generation using numerical basin modelling. In this study, the middle Miocene Stage IVA, and possibly Stage IVB, is the best candidate for sourcing hydrocarbons for the Tembungo field. Stage IVC

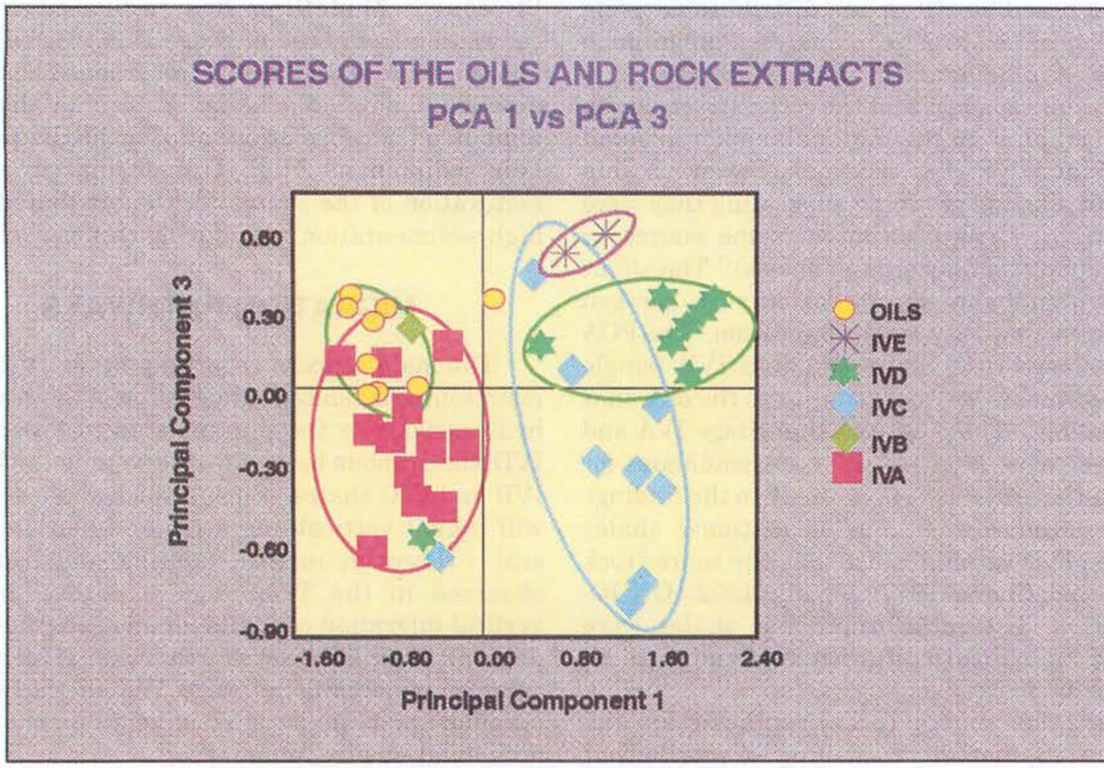

Figure 9. Scores of the oils and extracts on principal component 1 versus the scores on principal component 3.

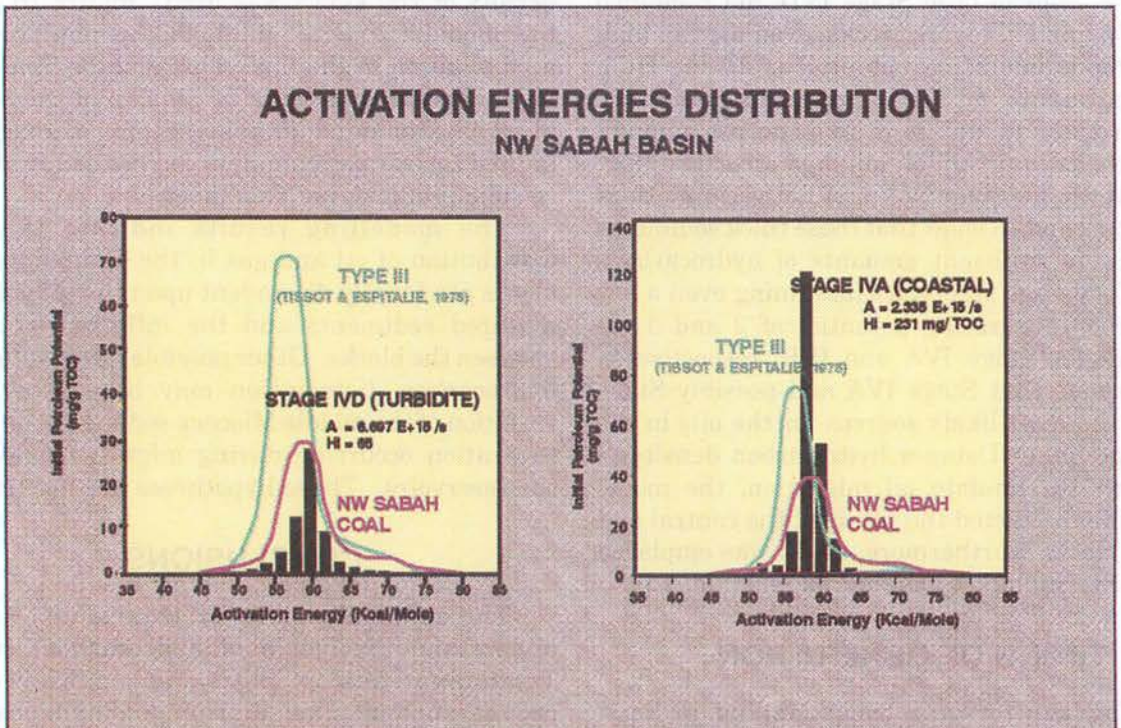

Figure 10. Distribution of activation energies for Stage IVA and Stage IVD.

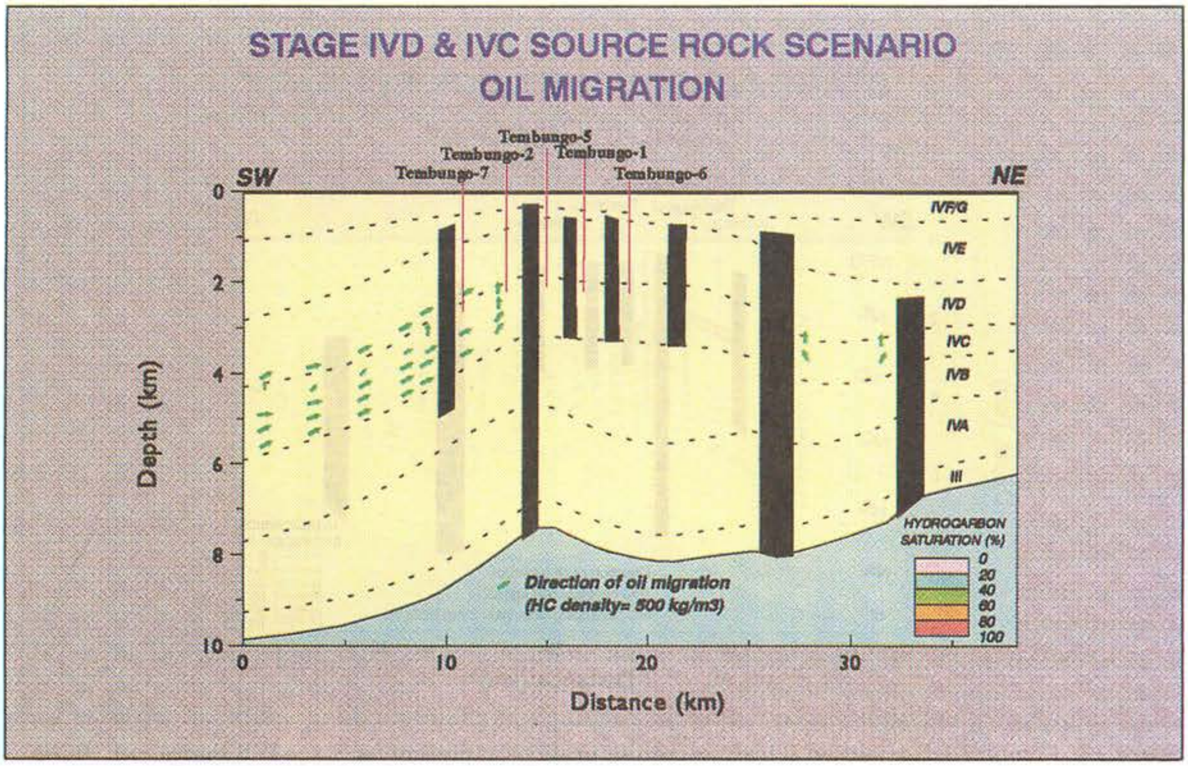

Figure 11. Computed distribution of hydrocarbon saturations at present for Stage IVC and lower Stage IVD source rocks (Initial hydrocarbon generating potential of 7 mg HC/g rock and HC density of 500 kg/m^3).

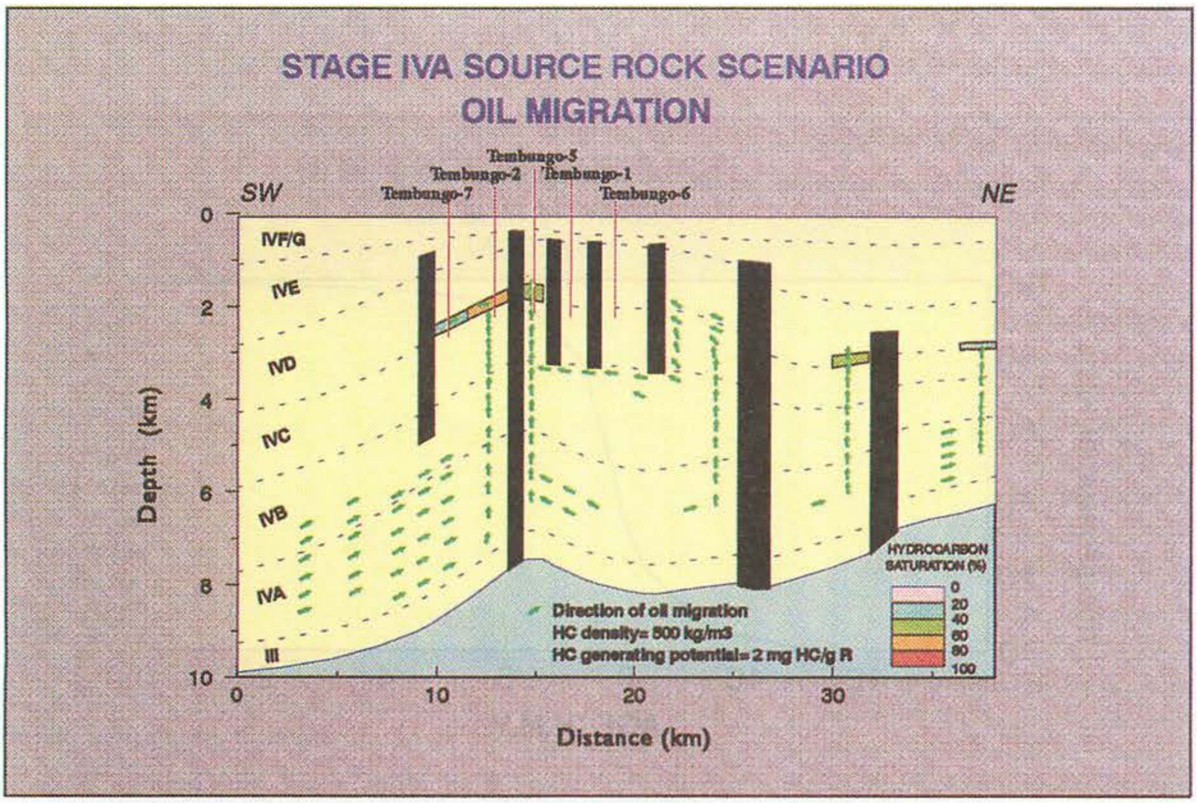

Figure 12. Computed distribution of hydrocarbon saturations at present for Stage IVA source rock (Initial hydrocarbon generating potential of 2 mg HC/g rock and HC density of 500 kg/m^3).

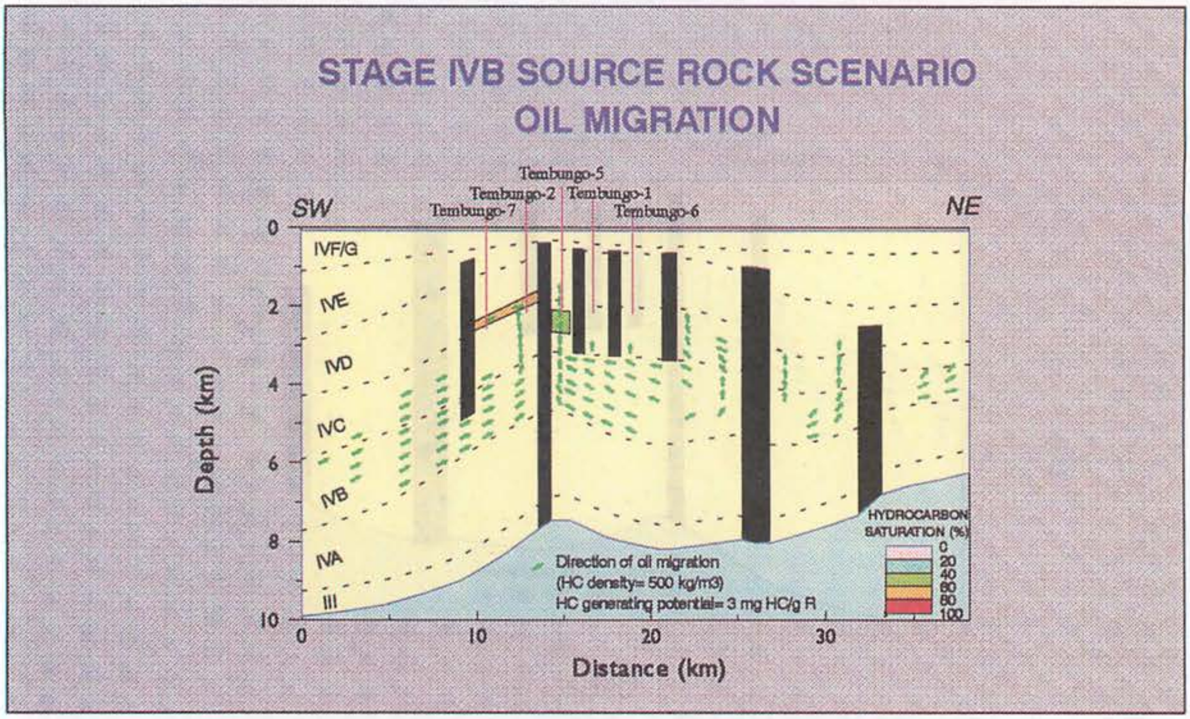

Figure 13. Computed distribution of hydrocarbon saturations at present for Stage IVB source rock (Initial hydrocarbon generating potential of 3 mg HC/g rock and HC density of 500 kg/m^3).

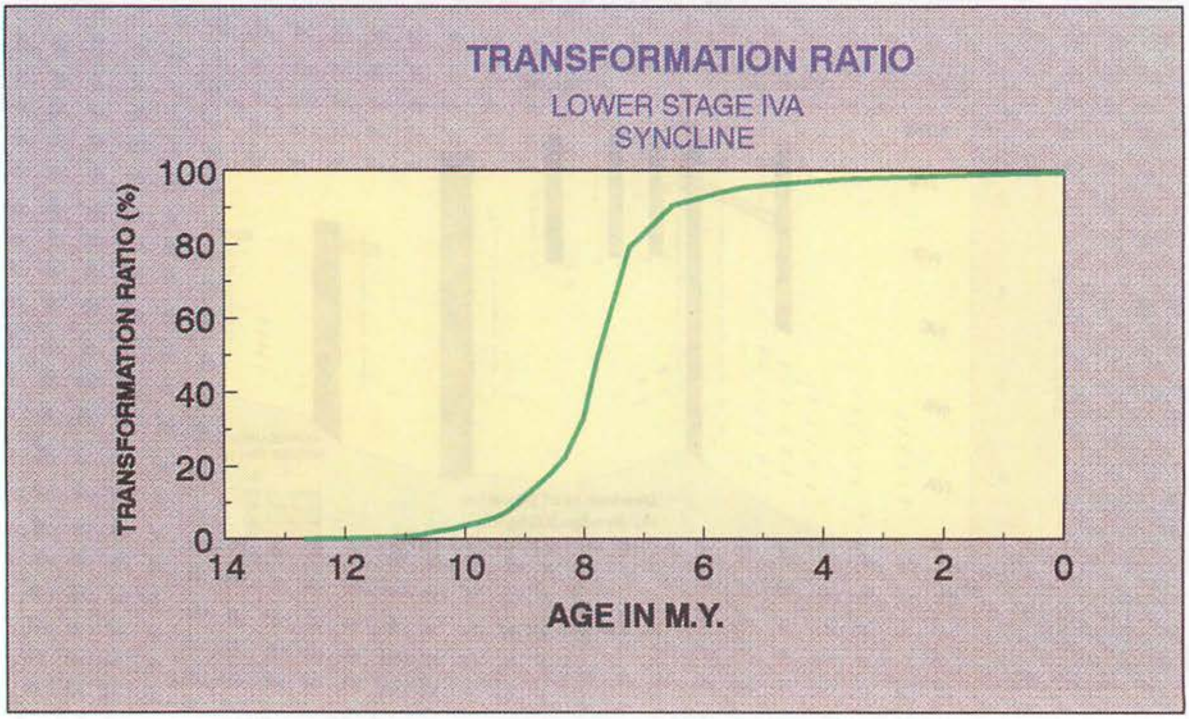

Figure 14. Computed transformation ratio for base Stage IVA.

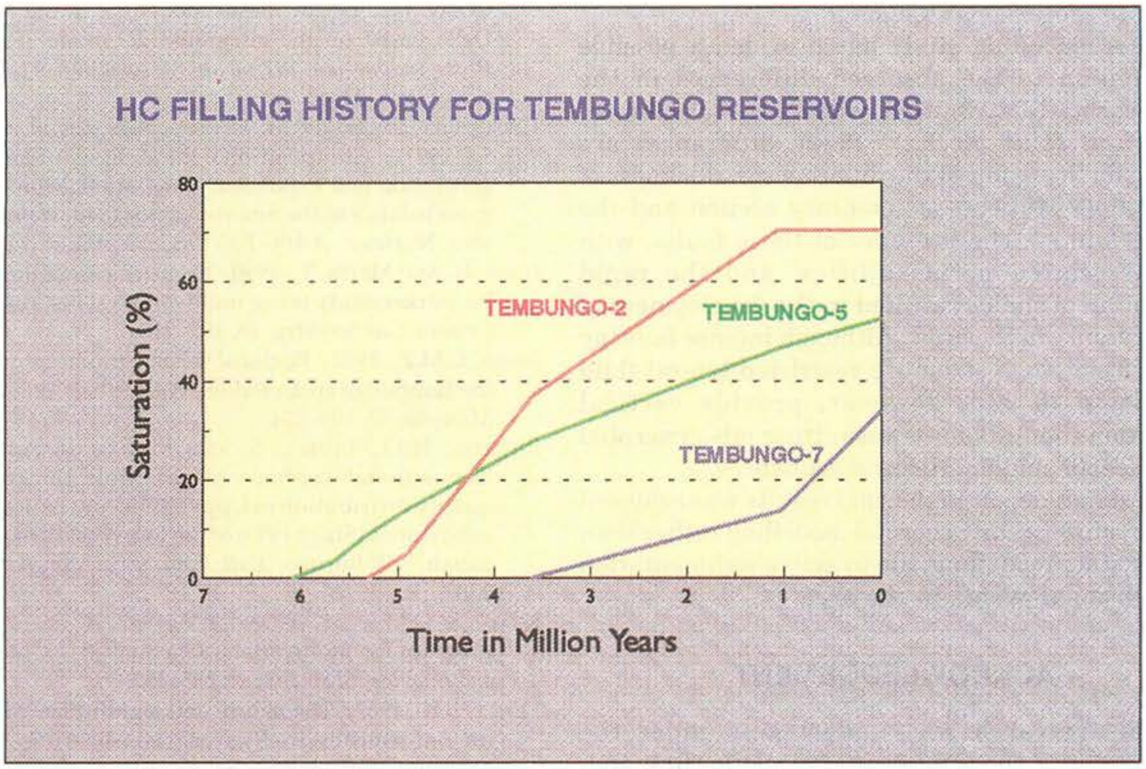

Figure 15. Computed filling histories for Tembungo reservoirs.

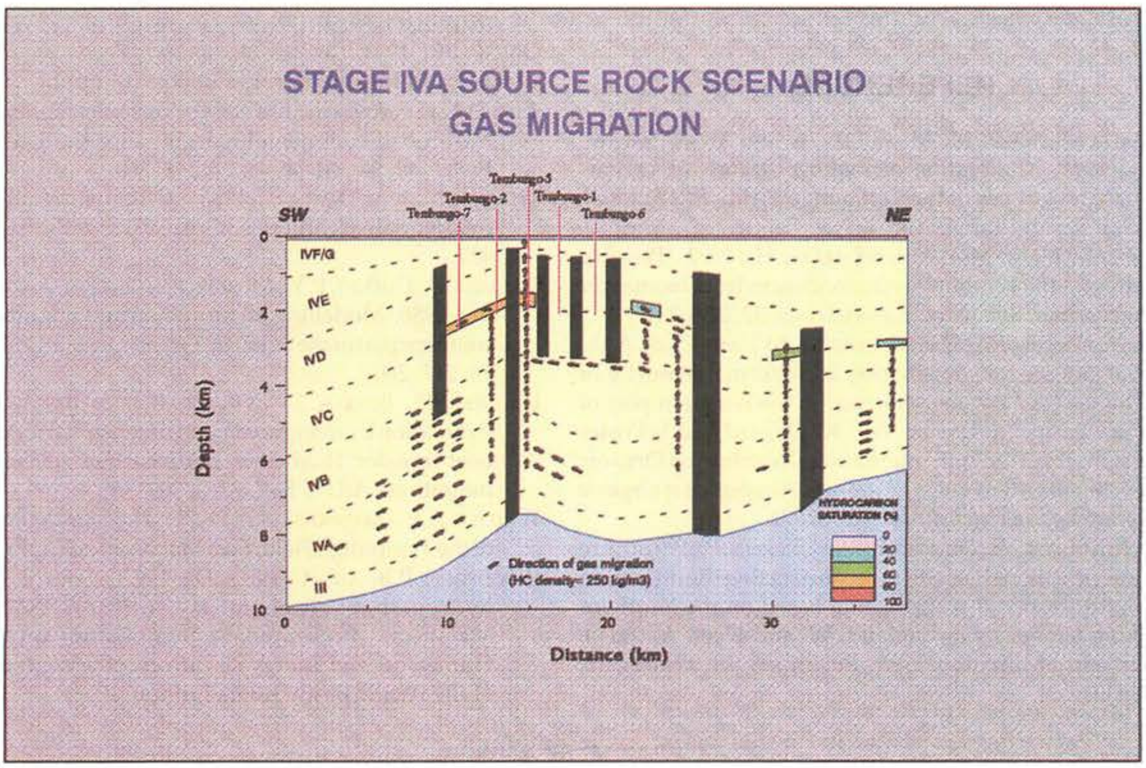

Figure 16. Computed distribution of hydrocarbon saturations at present for Stage IVA source rock (as in Fig. 12) with HC density of 250 kg/m³ to simulate gas phase.

and Stage IVD sediments do not contribute greatly to the hydrocarbons in place.

This modelling study has provided a possible explanation to the observed differences in the hydrocarbon distribution within the Tembungo structural fault blocks. These differences are primarily the result of the difference in thickness of the middle Miocene sedimentary section and the role of faults. The presence of these faults, with low associated permeabilities, and the rapid deposition of shales resulted in the development of overpressure in the area. Although intense faulting of the Tembungo structure restricted lateral fluid migration, it did, however, provide vertical migration conduits for transmitting oils generated from deeper middle Miocene sequences.

Best agreement in thermal results was achieved using transient state thermal modelling rather than steady state modelling due to active sedimentation and erosional events in the area.

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