# Petroleum systems of the Northern Malay Basin

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**Abstract:** The Northern Malay Basin petroleum province, offshore Peninsular Malaysia, comprises a central/basinal gas-rich area, flanked on both sides and to the south by mixed oil/gas zones. Non-associated gas fields in the central zone (Cakerawala to Bujang Trend) are found mainly in groups D and E reservoirs, in anticlinal traps formed by basin inversion during late Miocene times. This distribution may be biased by the depth of well penetrations in the basin centre due to the onset of overpressure. Oil occurs in faulted traps along the Western Hinge Fault Zone (Kapal to Beranang Trend), and is especially abundant on the NE ramp margin (Bunga Pakma-Raya Trend) where a separate kitchen may be present. Oil geochemistry reveals three main types of source rocks for the oils: lower coastal plain, fluvial marine and lacustrine source rocks. Most of the oils and condensates in the basin centre and on the Western Hinge Fault Zone are lower coastal plain oils, indicating charge from the basin centre. Lacustrine oils are restricted to the Bunga Pakma-Raya Trend on the NE flank, indicating charge from the basin centre as well as input from a small sub-basin to the northeast. Marine influence was found in oils from the most central position in the basin (Cakerawala-Bumi area). Vitrinite reflectance and basin modelling indicate that hydrocarbons were generated from source rocks within two main stratigraphic intervals: Group H and Group I, which are presently in the peak oil generation and gas generation stages, respectively. The basin-centre gas fields are charged from directly underneath, i.e. from the Group I kitchen, and from the post-mature shales in the older units (e.g. groups J and K). Vertical migration, assisted by deep-seated faults, is the dominant process in the basin centre. The enormous volume of thermogenic gas generated at the basin centre appears to have largely flushed out much of Group H oil that might have filled the D and E reservoirs initially. As a result, oil is more likely to have re-migrated and be trapped along the faulted basin margins, such as in the Western Hinge Fault Zone, away from the basin-centre gas kitchen. Limited oil accumulations may still exist in the basin centre where gas flushing is less effective. Oil could also be present below the regional overpressure seal (Group F) in the basin centre. The gases in the Northern Malay Basin contain varying amounts of $CO_2$. High $CO_2$ concentrations (>50 mol%) are typical of reservoirs in groups I and older and are mainly derived from inorganic sources. Low $CO_2$ concentrations (<6 mol%) are more typical of the reservoirs in groups D and E, and are derived from organic sources (thermal degradation of kerogen). The inorganic $CO_2$ distribution appears to be governed by proximity to deep-seated faults that act as conduits for fluid migration.

## INTRODUCTION

The Malay Basin, located offshore east of Peninsular Malaysia, is considered to be in a mature stage of exploration. Oil exploration in the basin started in the late 1960s. By 2003, there had been over 150 oil and gas discoveries, about a quarter of which are already in production (Figure 1). Much of the oil production, between 370,000 and 400,000 barrels of oil per day, comes from the southeastern part of the basin. Gas is produced from fields in the central and northwestern parts of the basin. These fields occur on large anticlinal trends along the basin axis. Many were discovered during the 60s and 70s based on 2D seismic. During the 90s, important discoveries were made, especially on the northeastern flank of the basin, through the use of higher quality seismic and a better understanding of the petroleum systems.

A more detailed knowledge of the petroleum systems is now needed in order to find the smaller and subtle plays. Hence, a regional study of the petroleum systems in the northern Malay Basin was carried out jointly by Petronas Research and CS Mutiara Petroleum in 2003. The objective was to improve our regional understanding of the petroleum systems and assess the remaining prospectivity of the northern Malay Basin. This paper summarizes the results of that study. The petroleum systems of the area were identified based on a comprehensive review of geological and geochemical data from more than 30 key wells. Since then CS Mutiara, as operator in blocks PM301 and PM301 in the study area, has been drilling actively, with very encouraging successes in finding major gas accumulations, particularly within the Gajah-Ular-Pilong trend (Figure 1).

## STRUCTURAL & STRATIGRAPHIC FRAMEWORK

The Malay Basin is about 500 km long and more than 200 km wide (Figure 2). It consists of two parts: a southern part with a NW-SE structural trend and a northern part with northerly-trending structures. The latter are more akin to those of the Pattani Basin, in the Gulf of Thailand. A major basement saddle, extending from Bintang to Bergading, separates the main NW-trending main Malay Basin from a smaller north-trending sub-basin in the Malaysia-Thai Joint Development Area (JDA). Sediment thickness is more than 12 km in the basin centre.

The tectonic setting and structure of the Malay Basin have been described by Khalid Ngah *et al*. (1996), Tjia & Liew (1996), and Madon *et al*. (1999). The Malay Basin

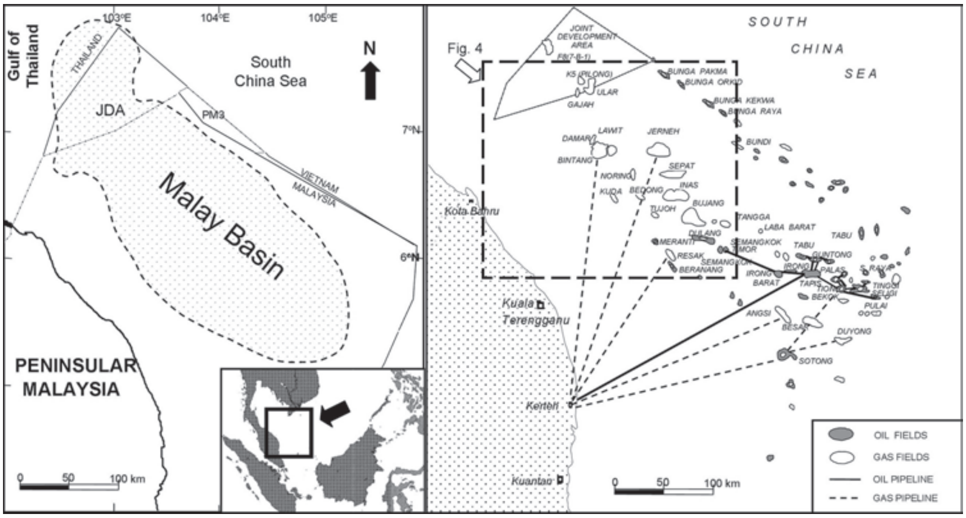


**Figure 1.** Location of the Malay Basin in SE Asia (left, and inset) and the distribution of oil and gas fields.

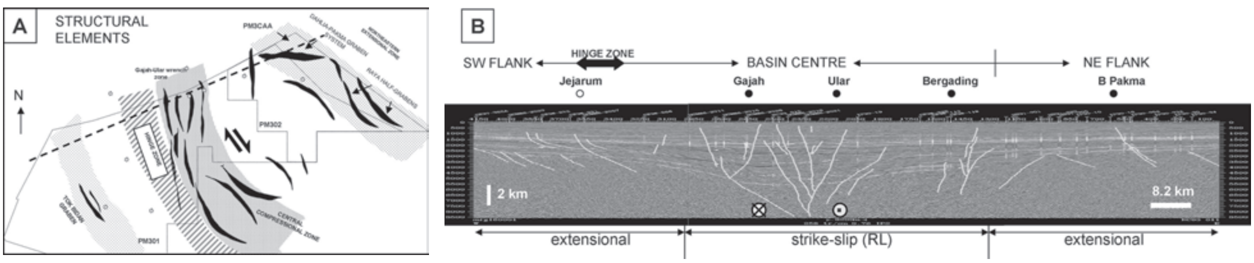


**Figure 2.** Structural framework of the Northern Malay Basin. (A) Main structural elements. (B) Interpreted regional seismic section showing the dominant structural styles. Gas is trapped mostly in the central zone of strike-slip fault-related structures. Note the vertical, deep-seated basement at the centre. Oil is trapped in fault-dip closures associated with normal faults along the basin margins.

evolved by transtensional shear and crustal extension during the early Tertiary, probably in response to extrusion of Malaya and Indochina continental blocks brought about by the indentation of India into Eurasia (Tapponnier *et al.*, 1982). Extension occurred during the ?late Eocene-Oligocene to earliest Miocene, forming the synrift half-grabens, now seen only on the basin flanks (e.g. Tok Bidan area on the West Flank, and Raya-Kekwa area on the East Flank). The “steer’s head” geometry of the basin is typical of a rift-sag basin formed by crustal extension. Madon (1997a) analysed the subsidence and thermal histories of the basin using a uniform lithospheric stretching model and reported a maximum stretching factor (b) of 2.3.

A summary of the stratigraphy of the basin is shown in Figure 3. The stratigraphic subdivision follows the well-established alphabetical nomenclature, based on seismic stratigraphy and further refinements by biostratigraphy. Like many extensional/rift basins, the structural history of the Malay Basin may be described in terms of a synrift phase and a post-rift phase. The actual timing of basin initiation uncertain, but a late Eocene extension is possible, as suggested by other authors (Khalid Ngah *et al.*, 1996, Tjia & Liew, 1996). Eocene extension has been documented in many rift basins of Thailand (e.g. Polachan *et al.*, 1991). The synrift (?Eocene-Oligocene) was when there were active faulting and extension, whereas the post-rift (early Miocene and later) was when extensional faulting had ceased and the basin continued to subside under the load of the sediment and the cooling lithosphere. This thermally-induced subsidence is still going on at the present-day. The post-rift thermal subsidence produced a broad sagging of the basin, which was interrupted by a major phase of basin inversion during early to middle Miocene (Tjia, 1994). The inversion caused the re-activation of the Malay Basin axial shear zone, from left-lateral to right-lateral during the middle Miocene (Madon, 1997b).

Basin inversion (probably episodically) started during late Group I times (late early Miocene) and seems to have continued well into the Pliocene. In the southern part of the Malay Basin, the inversion had resulted in a regional uplift and tilting of the basin towards the northwest, which formed a major erosional unconformity at the base of Group B. Using biostratigraphy, we have been able to date the unconformity relatively accurately at 7 Ma (Figure 3). The right-lateral shearing also caused the development of tight, *en echelon* anticlines and reverse faults, which characterize many oil fields in the southern part of the basin.

The study area in the Northern Malay Basin may be subdivided into three parts: Basin Centre, West Flank, and East Flank (Figure 2B). A basin-margin fault zone, the Western Hinge Fault Zone (WHFZ) separates the West Flank from the Basin Centre. The WHF forms a complex faulted basin margin, particularly in the PM303 block from Kuda southwards to Resak. A seismic section across the

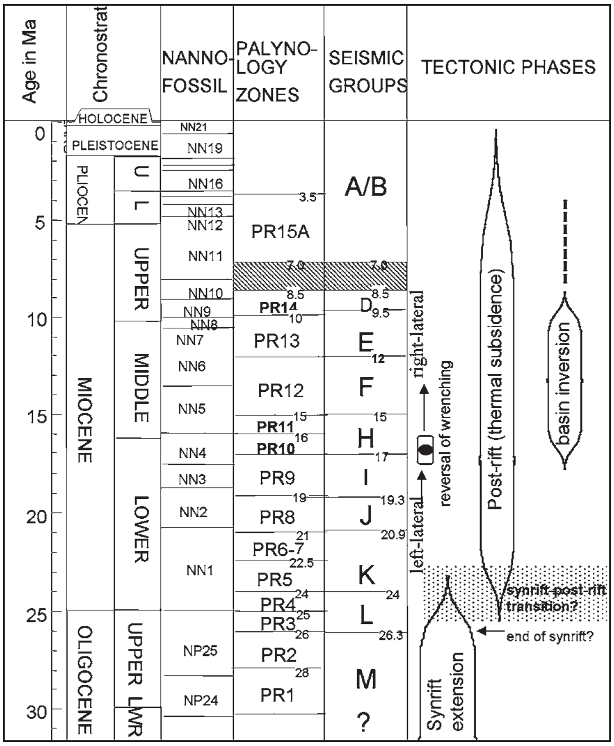


**Figure 3.** Stratigraphic zonation scheme for the Northern Malay Basin used in the study, and its relationship to the main tectonic phases and biozones.

study area in Figure 2B shows the main structural elements and deformation styles that characterize blocks PM301-302. The basin centre has a thick Tertiary section and is characterized by steeply dipping faults that originate in the basement. The faults are linked at depth, which may indicate a strike-slip origin. The upper part of the section is characterized by fault-dip anticlinal closures that make up many of the gas discoveries in the Northern Malay Basin. Gajah and Ular are examples of such structures (Figure 4).

The basin flanks are relatively gently dipping towards the centre, with a few major normal faults and half-grabens. Both flanks have a system of half-grabens; e.g. the Tok Bidan graben on the West Flank and the Bunga Raya, Bunga Orkid, and Bunga Pakma grabens on the East Flank. These half-grabens are the product of the synrift extension phase, just like the half-grabens in the centre of the basin, but because they occur on the flanks, they were not subject to as much thermal subsidence as the ones in the centre of the basin. The basinward margin is marked by the WHFZ, described by Liew (1994). This is a zone of intense faulting that affected much of the stratigraphy, from pre-Tertiary basement up to Group A/B, as a result of reactivation of major basin-bounding basement faults.

## HYDROCARBON DISTRIBUTION

Figure 4 shows the hydrocarbon occurrences in the study area. Most of the oil and gas fields and discoveries are in groups E, D and B reservoirs. The largest accumulations occur mostly in the basin axial trend, from the large cluster of fields in the JDA (Cakerawala, Bumi, Suriya, etc.) southwards to Bujang and Tangga. Non-associated gas fields in the central zone (Cakerawala to Bujang Trend) occur mainly in the groups D and E sandstone reservoirs in the inversion anticlines. From Dulang southwards, the structures tend to be more oil-prone. Data are lacking in the undrilled area between Ular and Jerneh. The hydrocarbon distribution shown in Figure 4 may be biased by the shallow depth of well penetrations in the basin centre due to the onset of overpressure. Oil may be present in the overpressured zone beneath the gas fields.

On the south-western flank of the basin, the three wells drilled were all dry. Northwards into the JDA, oil and gas have been found in the Samudra and Senja discoveries, which suggest that this type of play is prospective. The main risk is trap integrity, due to fault seal failure or inefficient top seal (by thinning of major shale units). Oil occurs in faulted traps along the Western Hinge Fault Zone, in the Kapal- Beranang Trend.

On the eastern flank and into PM3CAA block, there are mixed oil/gas discoveries but less desirable success in Bunga Dahlia-1 and Bunga Teratai-1. The Bunga Pakma-Raya trend is oil-bearing with minor gas zones. Generally, gas occurs in the upper layers (groups H, I and J) while the oil tend to occur in the deeper reservoirs (groups J and K).

## OIL FAMILIES

The liquid hydrocarbons in the study area range from very light condensate or condensate-like liquids to waxy oils. Their geochemistry indicates three main source rock types for the oils: lower coastal plain, fluvial marine and lacustrine. The geochemical characteristics that define these oil families are shown in Table 1. Mixtures of liquid hydrocarbons with terrigenous, marine and lacustrine characteristics are also common.

Figure 5 maps out these oil families. Most of the oils and condensates that occur in the basin centre and along the Western Hinge Fault Zone are lower coastal plain oils. They are probably charged from source rocks in the basin centre. Lacustrine oils are restricted to the Bunga Pakma-Raya Trend on the NE flank, and are believed to have been charged from half-grabens to the northeast of the study area. Marine indicators are also found in oils from Cakerawala-Bumi area, which is in a relatively central/basinal position.

## SOURCE ROCKS

The geochemical data and basin modelling results indicate that groups H and I are the two most effective source rock intervals. Their present-day depth of burial, maturity, and source-rock quality contribute to their effectiveness. Figure 6 shows the distribution of oil and gas fields in relation to the present-day maturities of groups

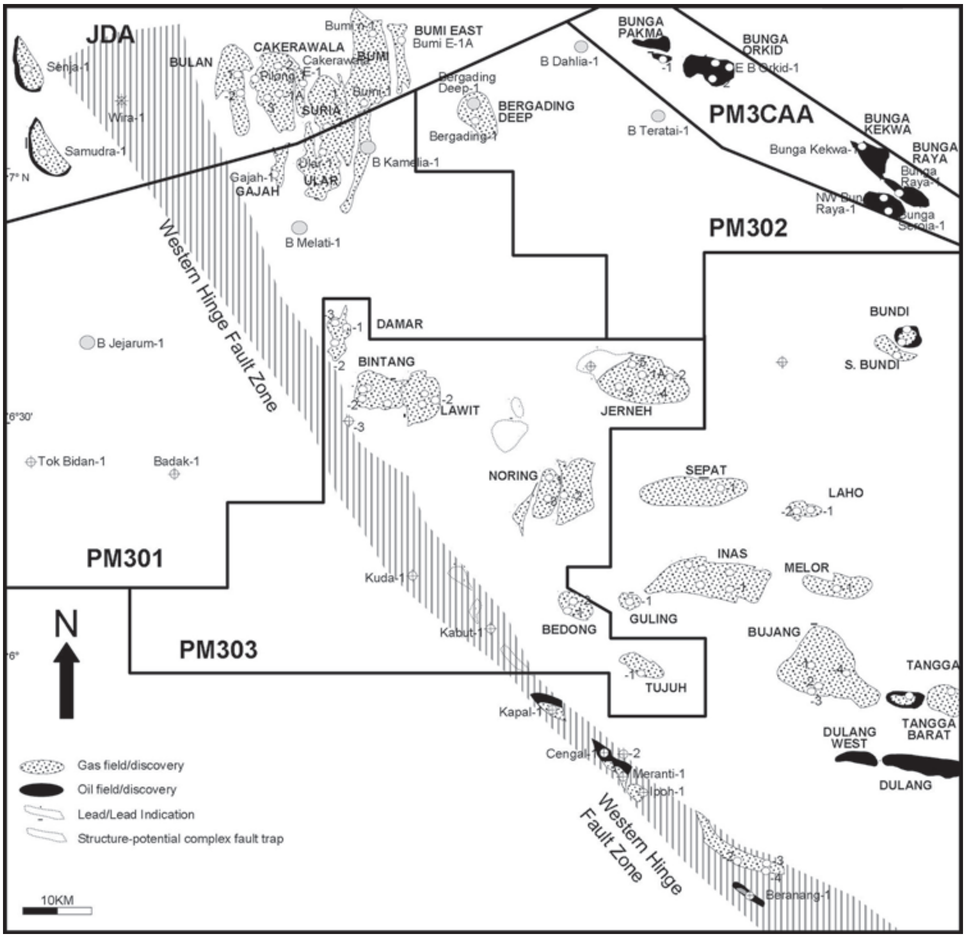


**Figure 4.** Oil and gas fields in the Northern/Central Malay basin, showing the main oil trends on the basin flanks and gas-prone structures in the central zone. Location of area is shown in Figure 1.

**Table 1:** Characteristics of oil families in the Northern Malay Basin.

| Biomarker Characteristic | Fluvial Marine | Lower Coastal Plain | Fluvial Lacustrine |
|---|---|---|---|
| higher plant biomarkers | low | low | very low |
| Tm/Ts ratio | moderate | moderate | low |
| Pr/Ph | high/very high | moderate | moderately high to high |
| Pr/nC17 | moderately high | low to moderately high | low |
| diahopane | low | moderate | high abundance of C29Ts and C30 diahopanes |
| tricyclics | present | low tricyclics, but abundant C24 tetracyclics | present |
| diasteranes | high | low to moderate | high |
| sterane | C27, C29 dominant | C29 dominant, swamped by bicadinanes | C27 dominant |
| others | | some oils are waxy and solid at room temperature | presence of gammacerane |

H and I. The maturity windows of groups H and I define the effective source rock kitchens that provide the charge to the oil and gas fields. The timing of generation and expulsion of hydrocarbons from these source rocks were determined by basin modelling (Figure 7). The results show that oil expulsion from Group H source rocks started around 5 Ma ago, and is still progressing. Oil expulsion from Group I source rocks started around 11 Ma ago, but by 5 Ma ago only gas was being expelled. Many structures in the basin centre were formed late (mainly during the last 4-5 Ma), and are able to trap only gas generated from the Group I source rocks. Source rocks older than Group I could also contribute to the gas. The Group K shale, for example, is a known oil source in the southern part of the basin.

As shown in Figure 6A, the distribution of gas fields are closely associated with an axial zone of gas-generating, highly mature source rocks in Group I. The basin-centre gas fields are evidently charged from beneath, directly from the Group I kitchen and from the post-mature shales in the older units (e.g. groups J and K). The high maturities of the hydrocarbon gases (>0.9% equivalent vitrinite reflectance or VRe) support this interpretation.

Many gas fields, e.g. Gajah, Ular, Bergading, and the JDA fields, lie close to deep-seated basement faults. These faults may have acted as conduits for the migration of hydrocarbons, particularly gases from the deep source. Vertical migration seems to have been the dominant process in the basin centre. A large amount of thermogenic gas generated at the basin centre, probably including that

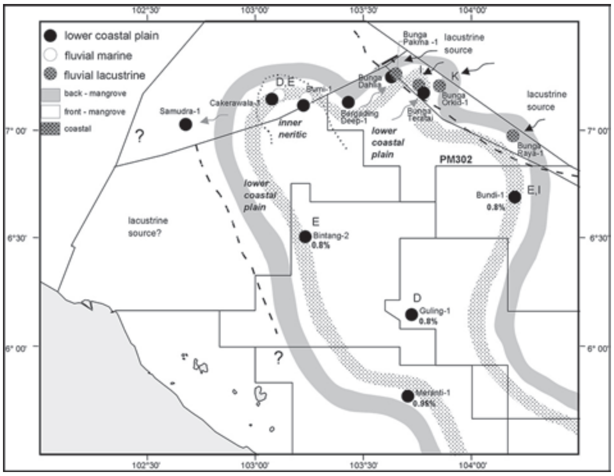


**Figure 5.** Distribution of the main oil families based on the depositional environment of the source rocks. Most oils in the basin centre are lower coastal plain oils, while some oils in the central-most position have marine influence. Lacustrine oils are restricted to the NE flank. Circles represent main oil families. Shaded lines represent coastal facies belts based on paleogeographic reconstruction from micropaleontology.

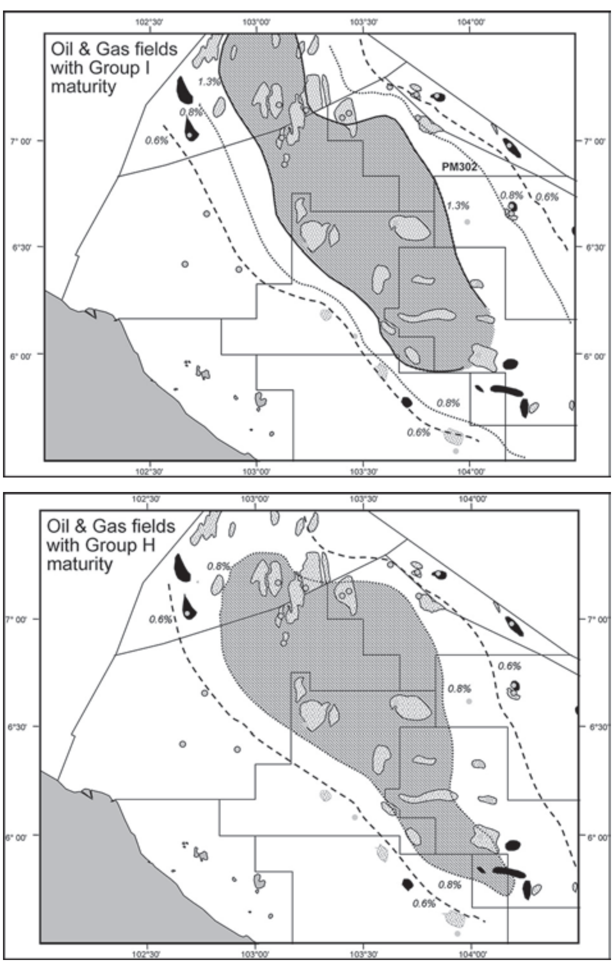


**Figure 6.** Map of oil and gas fields with overlay of (A) Group I maturity (B) Group H maturity. Note the close correspondence of oil fields with the Group I oil window. WFHZ- Western Hinge Fault Zone. Contour values are in % VRo.

generated from Group H source rocks, appears to have flushed out much of the oil that might have filled the D and E reservoirs initially. Limited oil accumulations may still exist in the basin centre where gas flushing is less effective. Oil could also be present below the regional overpressure seal (Group F) in the basin centre.

As a result of gas flushing, oil is more likely to have re-migrated and been trapped along the faulted basin margins, such as in the Western Hinge Fault Zone, away from the basin-centre gas kitchen. Besides generating gas, Group I is also actively generating oil along the basin margins. Thus, Group I oil is likely to be contributing to the liquids found along the Western Hinge Fault Zone between Samudra and Damar, and on the NE ramp margin between Dahlia and Bundi.

Figure 6B shows the oil and gas fields with Group H maturity window. Although the gas fields are directly above the oil-generating Group H kitchen, there is very little evidence for occurrence of oil in the overlying structures. The small amounts of oil in structures such as Samudra on the western margin and Bundi on the eastern margin could well have been charged by the Group H source rocks. The general absence of oil in the gas fields was probably the result of subsequent flushing by gases that had migrated vertically from source rocks deep in the basin centre.

In addition to the group H and I source rock kitchens, the geochemistry of oils in the Bunga Raya, Pakma and Orkid wells indicate the presence of a distinct source rock kitchen to the east of the PM3CAA area (indicated in Figure 5). The source rock is evidently lacustrine in nature, and probably occurs in the synrift half-graben systems, which are partly seen in the PM3CAA area. Lacustrine source rocks are expected to be present in the Oligocene/ Early Miocene groups K, L, M, and pre-group M (the early synrift sequence)

Gases found in the study area are primarily thermogenic in origin, generated from gas-prone kerogen at very mature stages (VRe 1-2%) deep in the basin centre (Figure 8). Based on isotopic and compositional data, M Jamaal Hoesni and Abolins (2000) described these gases as dry thermogenic gases derived from a mainly coaly pre-cursor at high maturity levels. The basin centre traps are mostly anticlinal/faulted structures in much shallower and younger reservoirs. Structuration was relatively late in the basin history, probably beginning from around latest Miocene to early Pliocene, during the inversion event. Hence, the gas charge must have taken place relatively recently, during the late Pliocene to present. The basin modelling results indicate that the source rocks from Group I down to M in the basin centre have generated and, are presently generating, gas. Hence, all these source rocks could have charged the shallow reservoirs/structures in groups E, D and B in the basin centre structures. It is likely, though, that the most significant contribution comes from Group I shales and coals because these are presently well into the gas-generating window (VRe 1.3-2.0%).

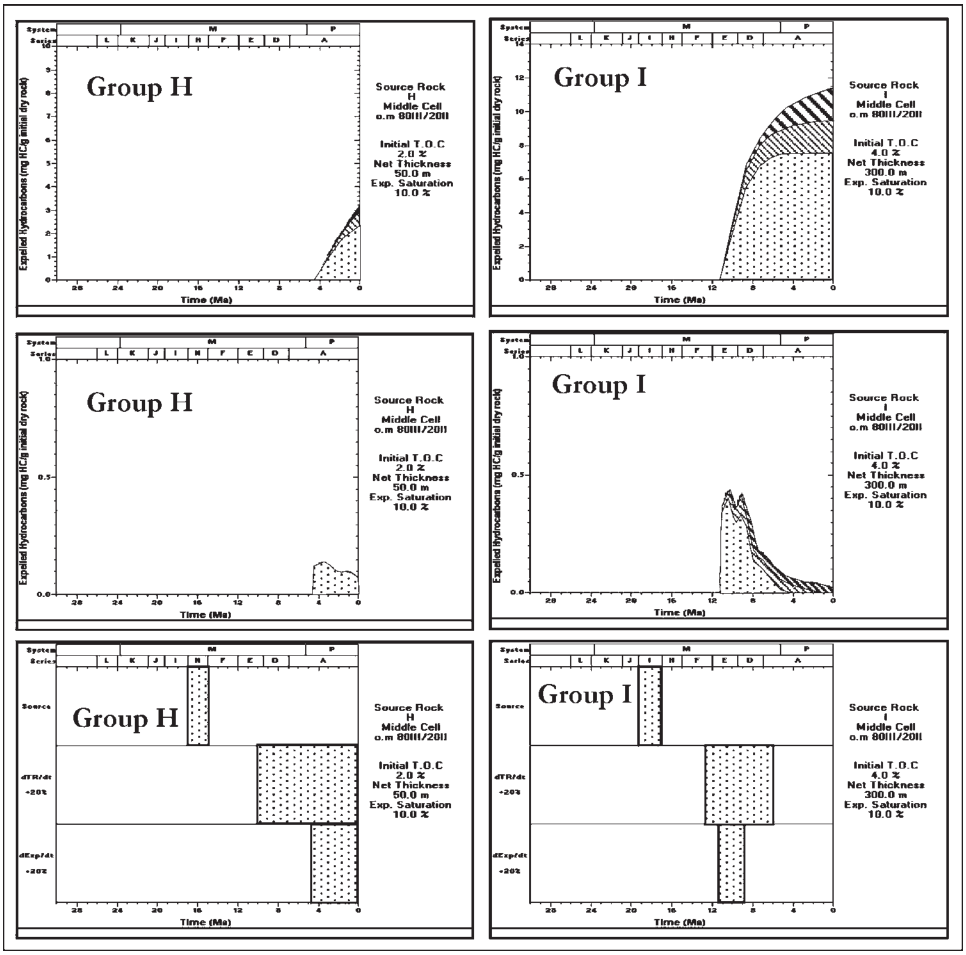


**Figure 7.** Source rock history from basin modelling. Left column: Group H, Right column: Group I. Top chart: cumulative hydrocarbon generation, middle: hydrocarbon composition with time, bottom: summary of source rock deposition, generation and expulsion.

## $CO_2$ DISTRIBUTION

The gases in the Northern Malay Basin contain varying amounts of $CO_2$. Figure 9 shows a map of the $CO_2$ concentrations in the study area. Areas with relatively high $CO_2$ concentrations in the basin centre are associated with large gas fields. Generally, there are high concentrations of $CO_2$ in the Cakerawala-Ular-Gajah trend southwestwards to Inas. Many of these structures are compressional anticlines underlain by deep-seated basement faults. This strongly suggests that the high levels of $CO_2$ were derived from deep sources and that the deep-seated basement faults had acted as conduits for the migration of $CO_2$-rich gases, along with the hydrocarbon gases. Waples *et al*. (2000) and M. Jamaal Hoesni and Abolins (2000) gave geochemical evidence that supports the inorganic (basement) origin of $CO_2$ in the basin.

Some general observations can be made regarding the $CO_2$ distribution. High $CO_2$ concentrations (>50 mol%) are typical of reservoirs in groups I and older and are mainly derived from inorganic sources. Low $CO_2$ concentrations (<6 mol%) are more typical of the reservoirs in groups D and E and are derived from organic sources (thermal degradation of kerogen). The inorganic $CO_2$ distribution appears to be governed by proximity to deep-seated faults that act as conduits for fluid migration. High $CO_2$ concentrations in older rock units (Group I down to M) could be derived from carbonate rocks in the pre-Tertiary basement. Organic $CO_2$ is an early by-product of thermal maturation of kerogen, and always occur in small amounts, especially when the source rock contains significant amount of coaly kerogen.

## PETROLEUM SYSTEMS

Based on this study, we identified two main petroleum systems:

- Group I Petroleum System.
- Group H Petroleum System.

The Group I Petroleum System (Figure 10A) comprises a source rock pod defined by the Group I maturity window. For the most part, Group I Petroleum System is a mainly gas system. Some oil may be generated from Group I source rocks that are within the peak oil window, around the central gas source rock pod on the basin margins. This oil could be charging the basin-margin plays as well, along with the Group H oil. The effective trap formation and migration of gas from the Group I source shales occurred at around 3.5 Ma ago. The group E and D sands are believed to be charged from Group I source rocks which reached gas generation phase by the time the anticlinal traps were formed.

The major reservoirs for the Group I system are the sands in the shallower units, especially Group E and Group D, and also some in Group H. Vertical migration of hydrocarbons is the dominant mechanism for charging the relatively shallow reservoirs since the Group I source rocks are structurally deeper everywhere in the basin (generally greater than 2000 m deeper). Sub-vertical, basement-linked faults acted as conduits for hydrocarbon migration, especially gases. These gases are also likely to migrate laterally into stratigraphically equivalent formations on the flanks, but risk major losses during migration.

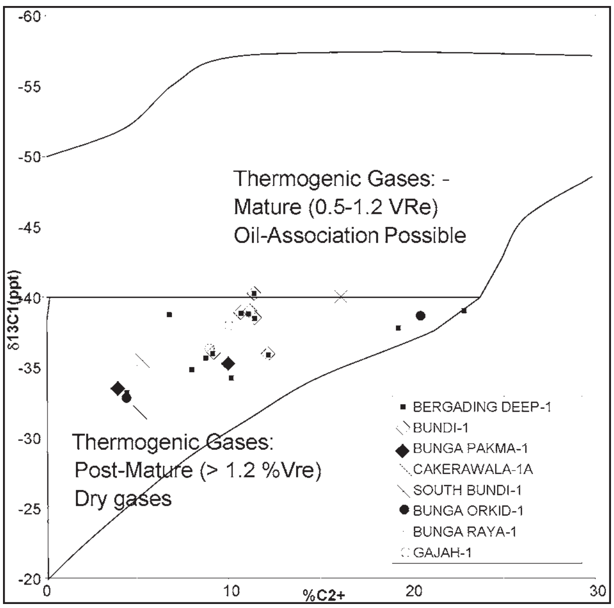


**Figure 8.** Plot of total C2+ hydrocarbon vs. stable carbon isotope of methane from Northern Malay Basin.

Group E reservoir sands are predominantly fluvial channel deposits formed in a lower coastal plain setting during a time of lowest relative sea level and greatest expansion of the coastal plain basinwards. Group D reservoir sands are mainly offshore, subtidal sand bars at the centre of the basin and more proximal (coastal plain setting) towards the flanks.

Seal rocks are provided by intraformational shales within and overlying groups E, D and the F regional seal. Wrench-related compressional anticlines and fault-associated structural closures are proven effective traps in the basin centre, having formed prior to gas generation in the Group I source shale.

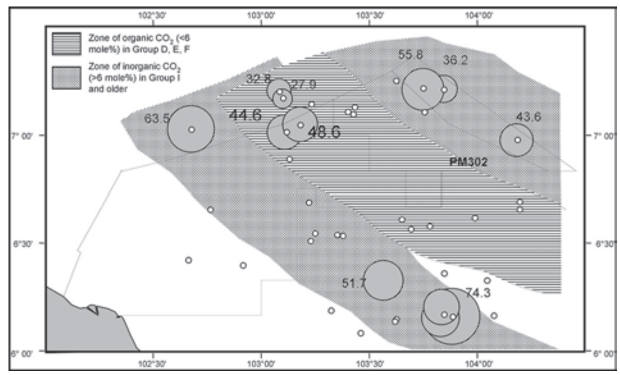


**Figure 9.** $CO_2$ concentrations in the Northern Malay Basin (values in mol%, larger circles represent higher concentrations). $CO_2$ types are inorganic and organic. Most high concentrations in the outer zones are from inorganic sources (basement, carbonates). Shallower reservoirs (groups D, E and F) in the basin centre tend to have organic $CO_2$.

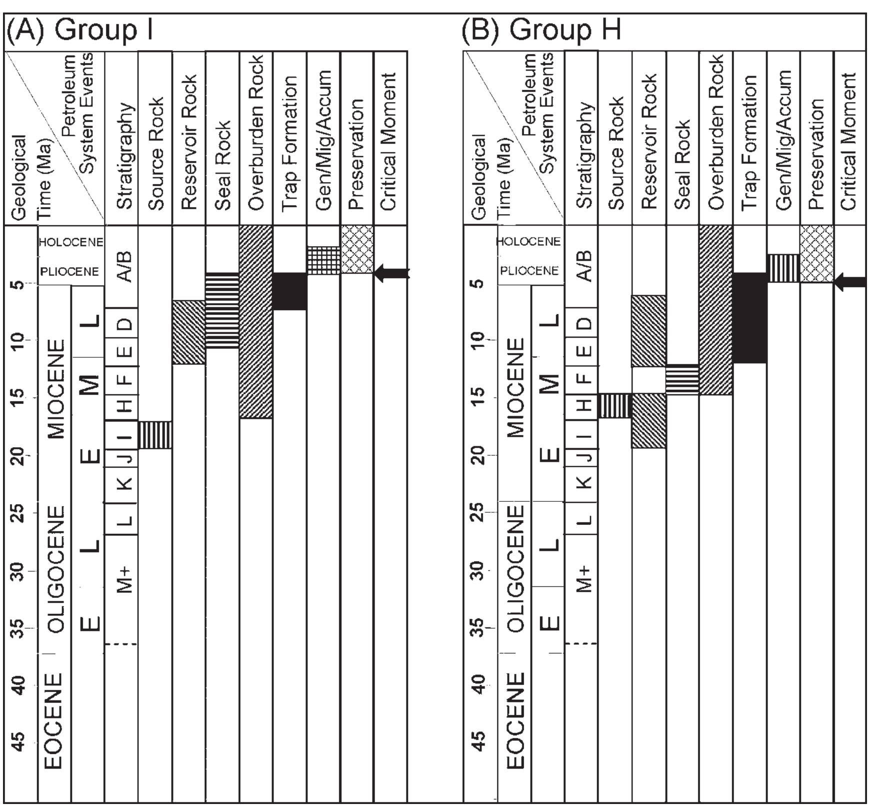


**Figure 10.** Petroleum systems of the Northern Malay Basin, illustrated as petroleum systems events chart *ala* Magoon & Dow (1994). (A) Group I Petroleum System (basin centre play). (B) Group H Petroleum System (mainly basin margin play).

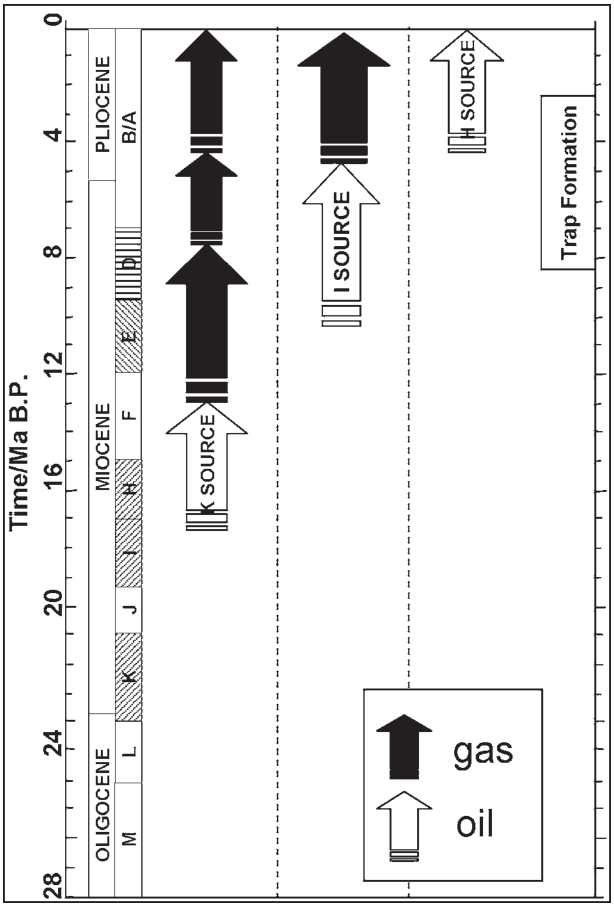


**Figure 11.** Summary of the maturation/expulsion histories of three main source rock units (K, I, H), based on basin modelling results. The timing of trap formation refers to the anticlinal traps in the basin centre, earlier in the south than in the north. Basin centre traps in groups D & E form late (~4 Ma), and are likely to be filled by the oil from Group H and gas from Group I and older source rocks.

Group H Petroleum System (Figure 10B) derives its hydrocarbons from the Group H source rock, which is at present in peak oil generation stage at the basin centre (Figure 11.7B). The location of the Group H oil kitchen indicates that the potential traps in groups D, E and B overlying it should be filled with oil. A major risk for Group H system is that the Group I source is currently in the gas generation window, and it is very likely that the group H oil will be flushed out by the incoming gas. Group H oil is more likely to be preserved on the basin margins where it may migrate laterally via carrier beds. Hence, the main reservoirs for the Group H petroleum system would be in the fault-related traps at the basin margins. Some of these structures are proven to be hydrocarbon-bearing, e.g. Meranti, Resak and Beranang fields (see Figures. 1, 4).

## CONCLUSIONS

Figure 11 shows a summary of the expulsion histories of the Group I and H source rocks for a hypothetical location in the basin centre. Group I source started oil expulsion by 11 Ma and dry thermogenic gas by 5 Ma. Thus, most traps in the basin centre are likely to trap gas since they formed very late, during the basin inversion phase, from about 8 to 3 Ma ago. Any oil from the group I source, and indeed from Group H source, would have been flushed out by the incoming gas, not just from the I shales but from the K shales and deeper sources (Figure 11). Group H source starts to expel oil only during the last 5 Ma, and provides a potential charge to the basin margin plays. Similarly, group I source would be less mature and probably also in peak oil window at the margins, which would also contribute to the oil prospectivity of the basin margin plays.

The petroleum systems in the Northern Malay Basin comprise the Group I gas source, which provides the charge to the main group D and E reservoir in the basin centre. Both the Group I and H sources provide oil charge to basin-centre structures as well as those on the flanks. Group I and older source rocks are actively producing gas, which tend to migrate up the sub-vertical faults directly into the reservoirs in the shallow section.

Figure 12 shows the key features of the petroleum systems in the Northern Malay Basin. The basin is typified by a deep sag in the middle, underlain by synrift extensional half-grabens. Half-grabens also developed on both flanks, as exemplified by the Tok Bidan and Raya half-grabens in the west and east, respectively. Some of these half-grabens have more than 4000 m of total synrift sediment fill and, under suitable thermal conditions, can be a lacustrine source-rock kitchen. This appears to be the case for the northeastern flank, which had provided a source for the lacustrine oils for the oil and gas fields there.

In the basin centre, the oil generation window is between about 3000 and 4500 m deoth, below which gas becomes more dominant. The effective source rocks are in groups H and I which are in peak oil and wet gas windows, respectively, in the basin centre. Deeper still in the basin centre is the Group K shale, which is believed to be the main source rock in the southern Malay Basin, but here is probably in the post-mature stage and generating only dry gas. Modelling suggests that these older source rocks also contribute to the dry gas in the fields above.

Hydrocarbon occurrences so far indicate that very little of Group H oil is being trapped in the shallow groups D and E reservoirs above the regional overpressure seal at Group F level. There are two possible reasons: 1) The group H oil had indeed migrated up the faults into the shallow reservoirs above the overpressure seal, but was subsequently flushed out by gases coming out from the deeper source rocks (Group I and older). 2) The H oil is retained within the overpressured zone, while the gases, being more mobile, had preferentially migrated up the faults to fill the shallow reservoirs. Where carrier beds are available, the Group H oil could migrate laterally towards the flanks and fill up the traps at the basin margins. This may explain the oil occurrences in the basin margin structures such as Dahlia and Bundi (on the eastern flank)

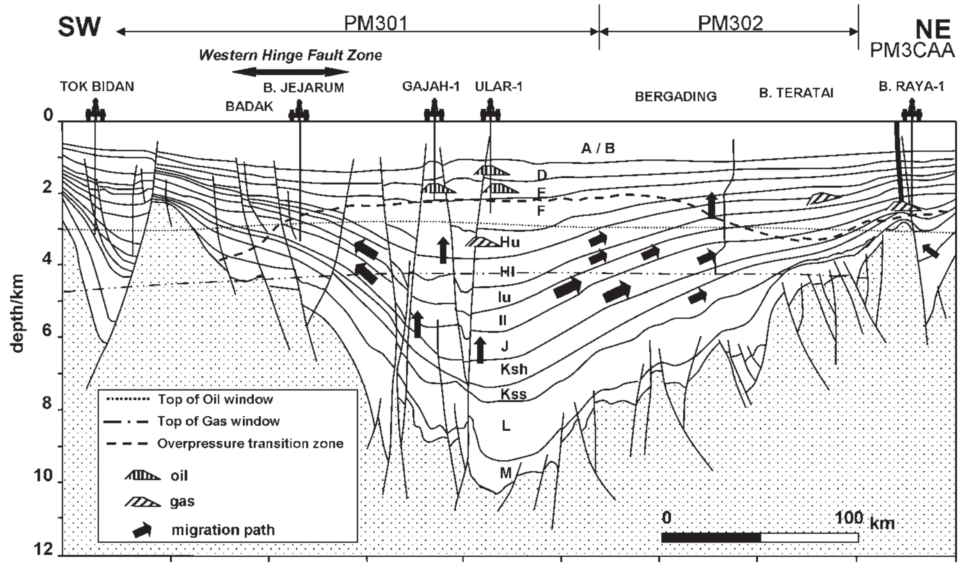


**Figure 12.** Schematic cross section of the Northern Malay Basin, depicting the main elements of the petroleum system. The figure shows two main systems, Group I and Group H sources, providing charge to structures above, e.g. Gajah and Ular, and laterally, e.g. Teratai. Besides the I source, Group K and deeper are also contributing to the gas via vertical migration up the basement-attached faults. Lateral migration up the flanks along carrier beds is also possible, but its effectiveness may be controlled by the presence of large sealing faults.

and probably the Cengal and Resak structures on the Western Hinge Fault Zone.

Figure 12 also shows the importance of faults as conduits for hydrocarbon migration. In particular, the deep basement-attached faults at the centre of the basin are believed to be the main conduits for gases from the Group I and older source rocks migrating into the shallower reservoirs. The major fault east of Bergading also acted as a partial barrier to the flow of hydrocarbons towards the NE flank, and is also a partial overpressure seal (Madon, 2005). As indicated by the basin modelling results, the basinal overpressure cell is presently dissipating, and partial release of gas is therefore occurring at the basin margin faults. This has allowed high-maturity gases, including $CO_2$, to migrate laterally onto the flanks and fill up some of the structures there.

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