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Stratigraphic and lateral variations of source rock attributes of the Pematang Formation, Central Sumatra

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Abstract: The Pematang Formation of the Central Sumatra basin has been shown to be the primary, if not the sole, source for the basin's 10⁺ billion barrels of recoverable oil. This lacustrine unit, which is restricted to a series of Paleogene half-grabens, typifies the variability present in many rift source rock systems.

Differences in organic facies (i.e., level of organic enrichment, kerogen composition, bitumen and product character) occur both stratigraphically and laterally as a result of a series of complex interactions. The stratigraphic controls on organic facies within the Pematang appear to be: (1) the changing relationship between subsidence and sedimentation; (2) long-term climate trends influencing both lake level and regional vegetation patterns; and (3) the evolution of the lake basin's nutrient pool. These controls result in an increase in the level of organic enrichment and oil-proneness toward the top of the unit. Superimposed on this pattern are changes in organic matter content (carbon content) and character (palynofacies, biomarker and isotopic compositions) caused by short-term climatic oscillations. Lateral controls on organic facies can be examined at two different scales — basinal and sub-basinal. Basinal variations can be related to: (1) different relative subsidence rates among the various sub-basins; and (2) variations in lake water chemistry as a result of the nature of the paleodrainage basin. On a sub-basinal scale organic facies appear to be controlled by: (1) hydrodynamic processes and basin circulation; and (2) variations in water depth. These lateral variations are manifested in the level of organic enrichment, the relative proportions of oil- and gas-prone kerogen, and variations in oil composition.

INTRODUCTION

The Central Sumatra basin (Fig. 1) formed as a consequence of back arc extension during the Middle to Late Eocene (Eubank and Makki, 1981; Daly *et al.*, 1991). The basin itself has been subdivided into a series of sub-basins covering approximately 103,000 km^2. Individual sub-basins may exceed 265 kilometers in length (Moulds, 1989). The hydrocarbon prospectiveness of each of these individual sub-basins appears to vary with respect to both the volume and type (oil vs. gas). In part, this difference in prospectiveness appears to be a consequence of differences in such factors as sub-basin depth and rate of subsidence which has affected depositional conditions within the troughs.

The objective of this paper is to examine the detailed geochemical characteristics of what appears, through the process of elimination, to be the region's most promising oil source rock, the Pematang Formation (Brown Shale Member or the Kelesa Formation) and its product oils. In addition, this work will attempt to determine the causes for any observed variability within the geochemical attributes of the source rock and oils.

The basin's sedimentary fill has been described by de Coster (1974) and Koning and Darmono (1984). It ranges in age from Eocene through the Recent. Maximum sediment thicknesses typically are ~3 km, with sediment thicknesses occasionally approaching 4.5 km within individual sub-basins. In terms of general depositional settings, the basal sediments were deposited within a fluvial setting grading upward into a shallow water lacustrine setting, a deep water lacustrine environment, with the nonmarine sequence being capped by a shallow lake fill sequence. This nonmarine sequence is covered by a series of largely marine sands and shales.

Source rock candidates

The Central Sumatra basin contains approximately 50% of Indonesia's known recoverable reserves. Over 90% of these known 10⁺ billion barrels of petroleum are present in fields containing at least 100 million barrels (Root *et al.*, 1987). The origin for this oil has been the topic of much speculation. Four possible source rocks have been suggested for the central Sumatran reserves. These include the shales of the Petani, Telisa (Wongsosantiko, 1976) and Pematang (Williams *et al.*, 1985) Formations and the coals of the Sihapas Group (MacGregor and McKenzie, 1986). A review of the available geochemical data, however, suggest that only the Brown Shale of the Pematang Formation actually represents a viable petroleum source (Table 1). The geochemical attributes of the three eliminated candidates are summarized below in order to provide support for the single dominant Pematang source.

The Petani Formation is middle Miocene to Pleistocene in age. The sediments represent a regressional sequence, grading from open marine to brackish water to nonmarine conditions (Mertosono and Nayoan, 1974). The organic carbon and pyrolysis data indicate some limited hydrocarbon source rock potential. Organic carbon contents may exceed 6 wt.%, however, the total pyrolysis yields (S_1+S_2) are less than 8 mg HC/g rock. As is typical of many regressional sequences

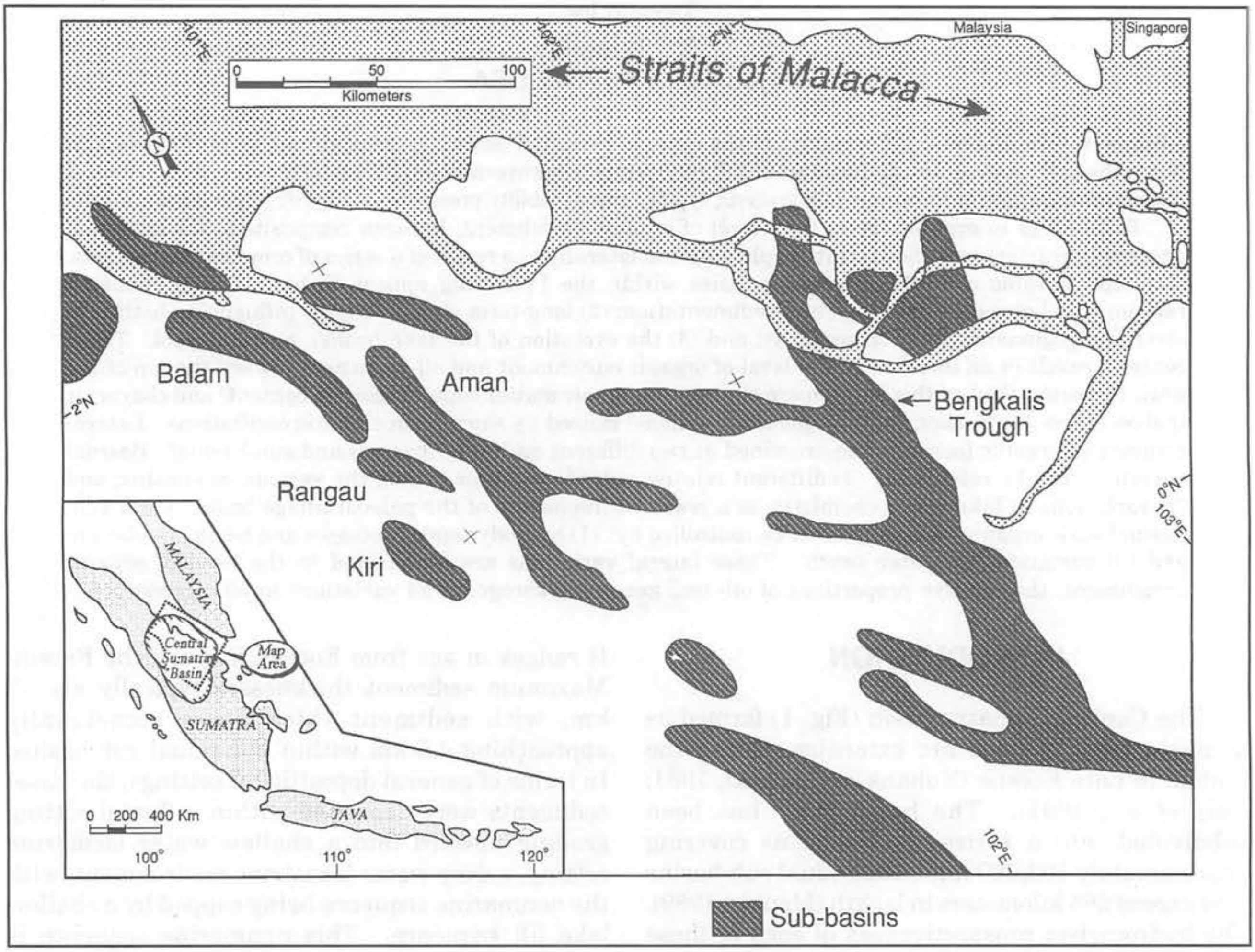

Figure 1. Regional index map. Primary focus of this study were the Aman, Balam, Kiri and Rangau sub-basins.

Table 1. Summary of organic geochemical attributes of Central Sumatra rock units.

Formation	Organic Carbon (wt. %)	Generation Potential (mg HC/g rock)	Kerogen Type	Thermal Maturity
Petani Fm.	< 6	< 8	II–III	Immature
Telisa Fm.	~ 1	< 4	III	Marginally mature
Sihapas Gp. Coals	< 80	100–350	III	Marginally mature
Pematang Fm.	Can exceed 15	can exceed 10	I–II	Marginally mature to overmature

(c.f., Pasley *et al.*, 1993), the organic matter is predominantly type III and gas-prone. It should be further noted that, even if there was limited oil potential present within these sediments they are thermally immature (i.e., pre-generative). Calculated vitrinite reflectance values are typically less than 0.4%. This is a consequence of the Petani's shallow depth of burial, typically less than 760 meters.

The Telisa Formation which is early-to-middle Miocene in age consists largely of marine shales. These shales typically contain about 1.0 wt.% organic carbon and have pyrolysis yields less than 3 mg HC/g rock, with an occasional sample yielding slightly greater than 4 mg HC/g rock. The kerogen appears largely gas-prone (type III), with some samples containing a mixture of type II–III organic matter. Thermal maturation modeling results suggests that portions of the Telisa may be within the oil-window (Sundararaman *et al.*, 1988). However, as a consequence of its typically shallow depth of burial, less than 1,250 meters, much of the section displays vitrinite reflectance values less than 0.55% and is immature to marginally mature. These data suggest that the Telisa shales may be a minor contributor of liquid hydrocarbons but could not explain the volumes of hydrocarbons observed.

The Sihapas Group coals may contain as much as 80 wt.% TOC, with total pyrolysis yields of between 100 and 350 mg HC/g rock (MacGregor and McKenzie, 1986). These coals are also reported to have hydrogen indices of ~300 mg HC/TOC which have been interpreted by some to suggest some limited oil potential. Pyrolysis-gas chromatography of these coals also produces a chromatogram with a significant heavy-end contribution. However, Katz (1983) has shown that elevated hydrogen indices are common among many gas-prone, vitrinite-rich coals and that the elevated values may be an artifact of the analytical method and not an indication of oil potential. It has also been noted that the products expelled by coals under natural and pyrolytic conditions may differ. Heavy hydrocarbons are retained under natural conditions while they are released during pyrolysis as a result of kerogen relaxation (Monthioux and Landais, 1987). Furthermore, attempts at oil-source rock correlation with these central Sumatran coals has been less than completely successful (MacGregor and McKenzie, 1986). Significant differences are observed among the steranes when coal extracts and oils are compared, with lesser differences also noticeable among the triterpanes.

The Brown Shale Member of the Pematang Formation was deposited in a series of lake-filled sub-basins, with each sub-basin being at least temporarily hydrologically isolated. The lacustrine nature of the unit has made age assignment problematic. Diagnostic fossils are lacking and palynologic data are inconclusive (Williams *et al.*, 1985). Based on stratigraphic position the Pematang is considered Paleogene in age. Although the unit was originally considered to be largely Eocene, it is now believed to extend into the Oligocene.

The Pematang Formation is known only in the subsurface, where it may obtain thickness in excess of 1,800 meters (Williams *et al.*, 1985), the oil-prone Brown Shale Member may reach thicknesses in excess of 580 meters. Stratigraphically equivalent lacustrine rocks, which also display oil source rock characteristics, are present in the Ombilin basin to the southwest of the study area (Koning and Aulia, 1984).

Within the Brown Shale itself, Longley *et al.* (1990) have demonstrated the presence of three "lacustrine" facies; a lake margin facies, a "shallow" lake facies, and a "deep" lake facies. There is clear stratigraphic cycling between these lithofacies indicating temporal changes in depositional conditions during Brown Shale-time associated, at least in part, with climate changes. The lake margin facies displays clear evidence of subaerial exposure, pedogenesis (soil formation), and the presence of rootlets. No significant source rock potential has been attributed to this facies. The "deep" lake facies consists of mottled or finely laminated brown and dark gray mudstones, with only rare indications of bioturbation. There is evidence for subaqueous dewatering within this facies. Although there is no clear evidence for water depth, a "deep" water assignment was made based largely on the palynofacies which suggests deposition removed from the shoreline. The "shallow" lake facies consists of red-brown laminated mixed carbonate and terrigenous mudstones. The "shallow" water assignment is based on the abundance of mat-forming as opposed to planktonic algal material and the presence of an increase in the abundance of chemical deposits. Both the "shallow" and "deep" facies are reported to display oil source rock potential. The relative abundance of these three facies is dependent on basinal position.

PEMATANG FORMATION SOURCE ROCK ATTRIBUTES

Various organic geochemical attributes from the noncoaly facies of the Pematang Formation from the Aman, Balam, Kiri, and Rangau sub-basins are summarized in Table 2. These attributes are discussed in detail in the following sections.

Table 2. Summary of source rock characteristics of Pematang Formation.

	Minimum	Maximum	Mean
Organic Carbon (wt. %)	0.21	23.25	3.7
Total generation potential (mg HC/g rock)	0.13	123.94	25.3
Atomic H/C ratio	0.84	1.49	
Kerogen $\delta^{13}C$ (‰)	−26.8	−17.1	
Pristane/Phytane	1.07	10.25	
Whole-Bitumen $\delta^{13}C$ (‰)	−28.8	−22.5	

Organic enrichment and generation potential

Organic carbon content and generation potential determine whether a rock contains sufficient quantities of labile organic matter for hydrocarbon generation and expulsion to occur. Nearly 200 organic carbon determinations were made on samples from several wells from four of the sub-basins. The total organic carbon (TOC) contents of these samples ranged from 0.21 to 23.25 wt.% (Fig. 2), with a mean value of ~3.7 wt.%. Slightly more than three quarters of the samples were found to contain greater than 1.0 wt.% TOC. A further analysis of these data reveals that many of the more organically depleted samples actually represent the analysis of sandstone and siltstone samples rather than shales. An analysis of a single well profile within the Pematang further reveals that the lowest levels of organic enrichment are in the basal portion of the sequence (Fig. 3).

A comparison of data sets from the different sub-basins suggests that there are some clear differences in the level of organic enrichment. For example, Katz and Kelley (1987) have reported an average organic carbon content of 4.40 and 2.99 wt.% for the Pematang of the Aman and Balam sub-basins, respectively. Significantly lower levels of organic enrichment than in either the Aman or Balam sub-basins were observed in the Rangau sub-basin (Williams *et al.*, 1985). Although this may, at least in part, be the result of a more advanced level of thermal maturity, Katz and Kelley (1987) have concluded that much of this difference appears to be associated with the nature of the depositional system.

The total pyrolytic yields (S_1+S_2; free + generatable hydrocarbons) of those samples with a minimum of 1.0 wt.% TOC ranged from 0.13 to 123.94 mg HC/g rock (Fig. 4), with a mean yield of 25.3 mg HC/g rock. Approximately 95% of the pyrolyzed samples yielded above-average quantities of hydrocarbons (i.e., > 2.5 mg HC/g rock; Bissada, 1982), with nearly 80% of the samples having total generation potentials consistent with good or excellent hydrocarbon source rocks (i.e., > 6 mg HC/g rock; Tissot and Welte, 1984). As with organic carbon, there is a tendency for increasing generation potentials upward in the stratigraphic sequence. However, the more elevated hydrocarbon yields begin stratigraphically higher in the Brown Shale than does the elevated levels of organic enrichment.

Geographically there appears to be slightly higher generation potentials in the Aman sub-basin compared to the Balam sub-basin. This difference in yield is greater than would be expected simply from the differences in level of organic enrichment, and must, therefore, be the result of differences in the nature of the organic matter preserved in both sub-basins.

Kerogen composition and character

Kerogen composition controls the nature of the hydrocarbons generated after achieving the appropriate levels of thermal maturity. Kerogen character can be determined through several different analytical approaches providing information on oil- vs. gas-proneness, as well as the degree of waxiness. Oil- and gas-proneness is typically determined through an assessment of the relative enrichment of organic hydrogen and oxygen. This may be accomplished through the calculation of the pyrolysis hydrogen ("S_2"/TOC) and oxygen ("S_3"/TOC) indices. These indices display a great deal of variability among the samples (Fig. 5). Some of the material is closely aligned with the type I reference curve. However, much of the material displays an affinity for the type II and III reference curves. Thus the "Rock-Eval" data suggests that both oil- and gas-prone organic matter is present.

An analysis of the data set further reveals that the samples displaying the more elevated oxygen indices are associated with the organically leaner samples. The elevated oxygen indices may be the result of either mineral matrix contributions of CO_2 or the consequence of poorer preservation of the organic matter in the leaner samples.

An alternative method to assess the oil- vs. gas-proneness of a sample is through the elemental analysis of isolated kerogens. This method of organic matter characterization is not sensitive to mineral matrix effects as is the "Rock-Eval" method (Katz, 1983). The atomic H/C and O/C ratios (Fig. 6) display the same magnitude of variability as the hydrogen and oxygen indices, with the H/C ratios

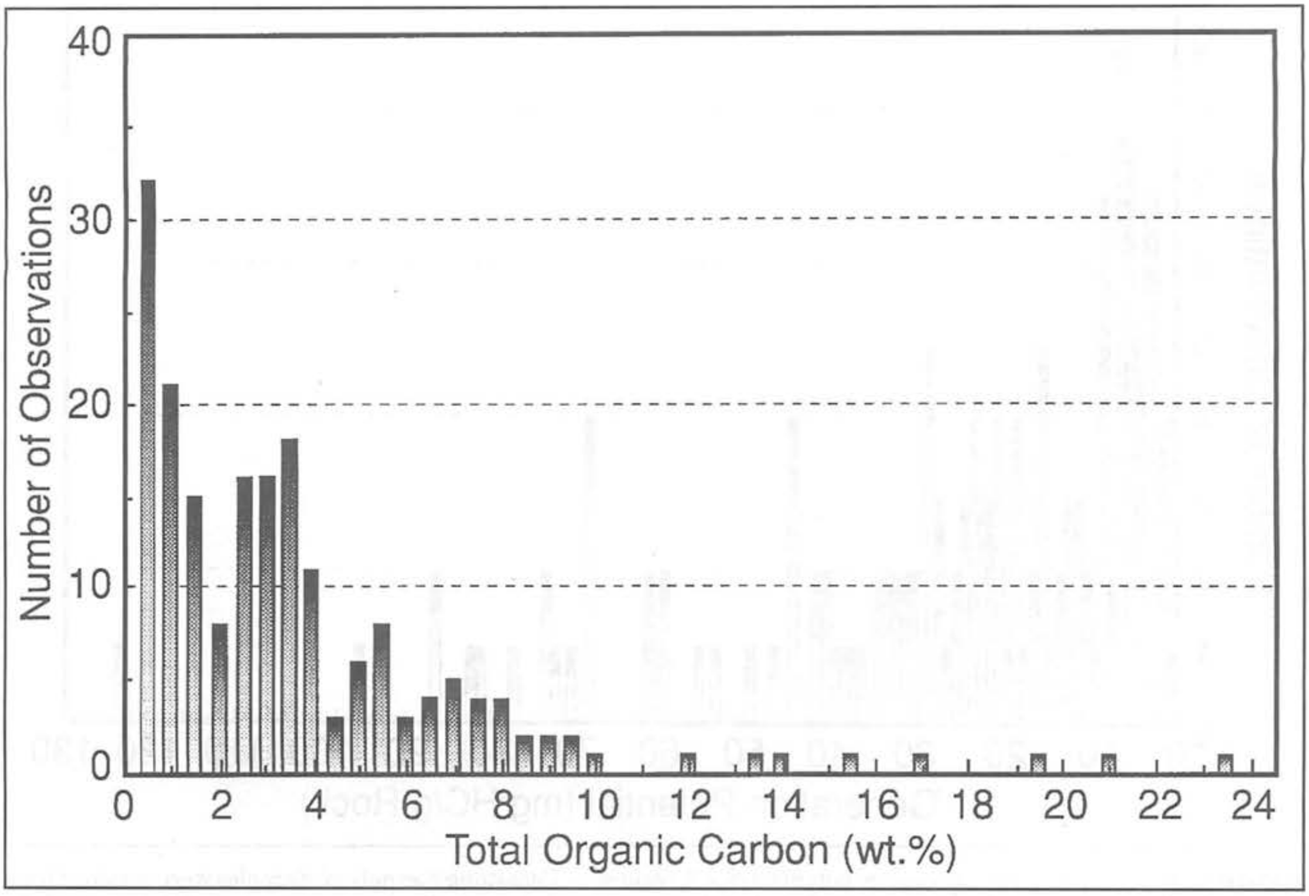

Figure 2. Histogram of organic carbon determinations — Pematang Formation. Samples were obtained from the Aman, Balam, Kiri, and Rangau sub-basins.

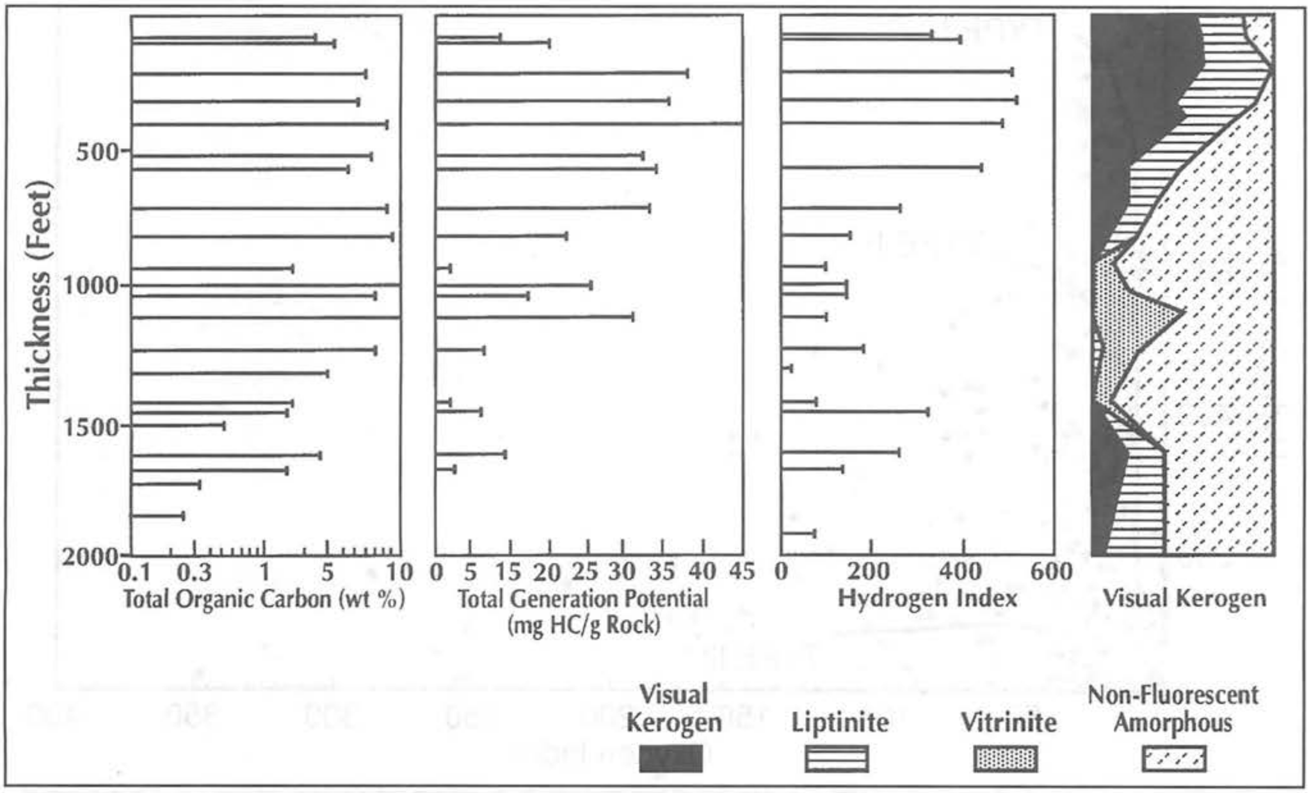

Figure 3. Geochemical log from a well located in the central portion of the Balam sub-basin. This log represents the geochemical variability of the Pematang Formation.

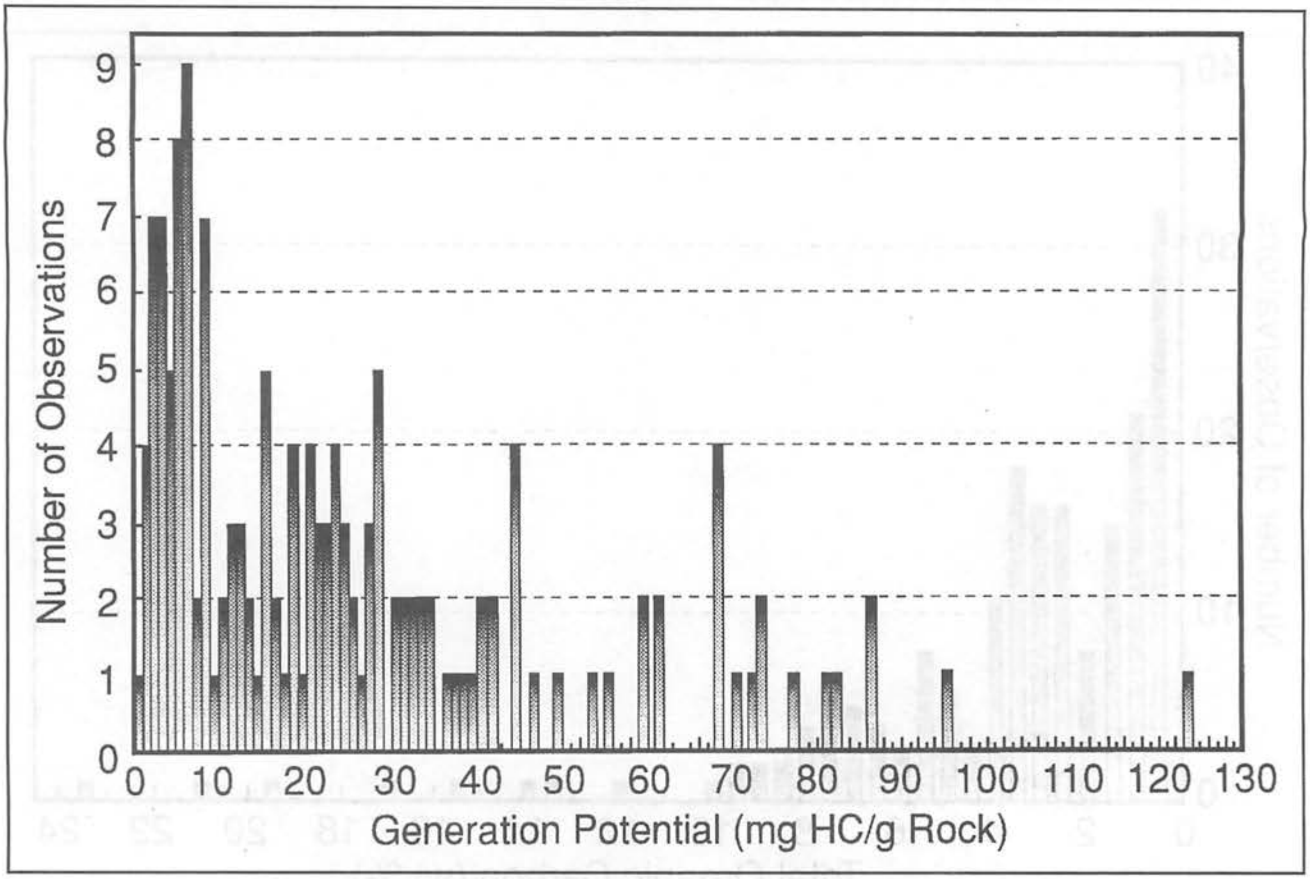

Figure 4. Histogram of total generation potential (S_1+S_2) values — Pematang Formation. Samples were obtained from the Aman, Balam, Kiri and Rangau sub-basins. Pyrolysis was limited to samples containing at least 1.0 wt.% TOC.

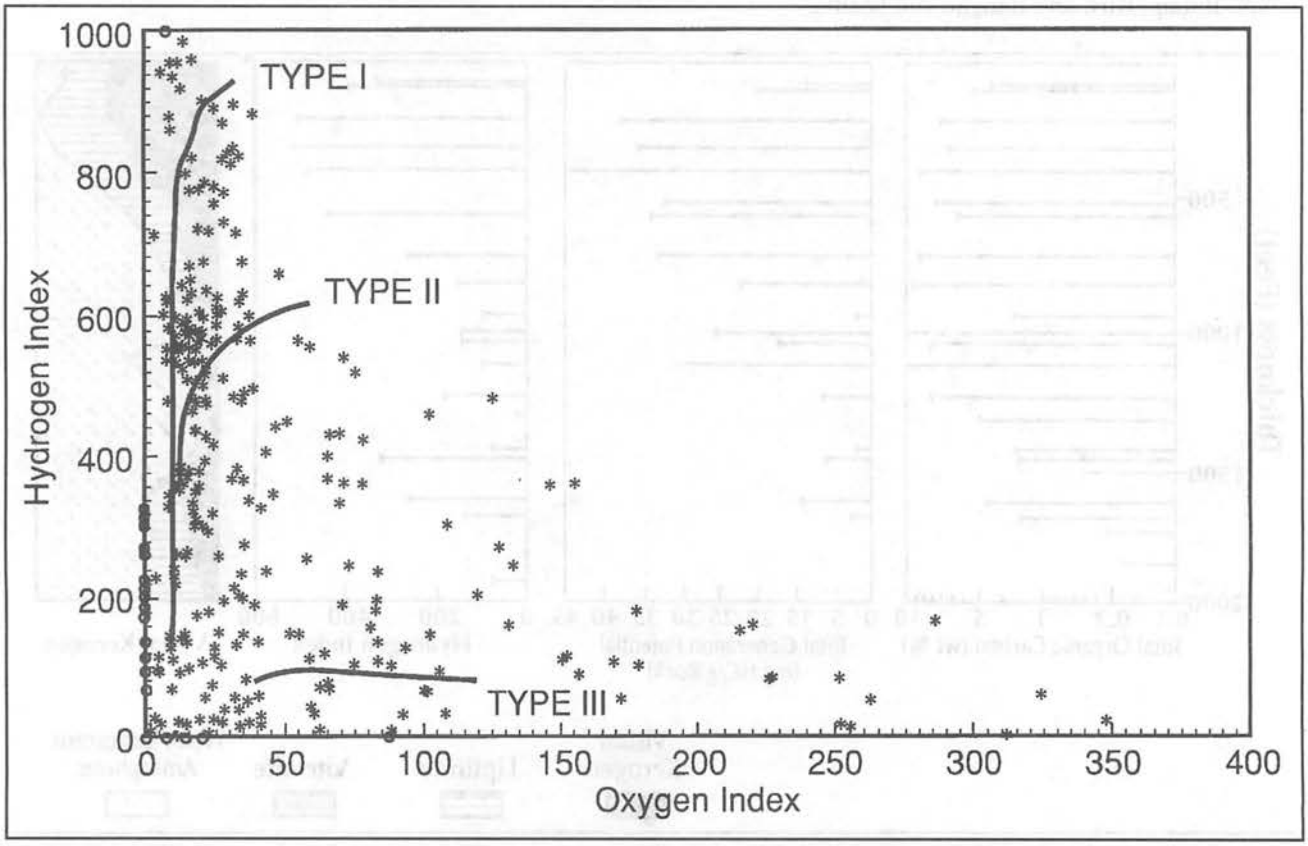

Figure 5. Modified van Krevelen-type diagram based on "Rock-Eval" pyrolysis of "whole-rock" Pematang Formation samples from the Aman, Balam, Kiri and Rangau sub-basins. The lower hydrogen index values (< 100 mg HC/g TOC) are largely associated with the Rangau sub-basin as a result of a more advanced level of thermal maturity. Pyrolysis was limited to samples containing at least 1.0 wt.% TOC.

ranging from 0.84 to 1.49.

Visual kerogen analysis also reveals that some samples are dominated by oil-prone organic matter, while others are dominated by gas-prone organic matter. The oil-prone organic matter is dominated by fluorescent amorphous material, exinites, and algal debris, with subordinate amounts of nonfluorescent amorphous material. The algal material in some of the oil-prone samples is dominated by mat-forming algal remains, while in others planktonic algae including *Botryococcus braunii* and *Pediastrium sp.* dominate (Williams *et al.*, 1985; Longley *et al.*, 1990). The gas-prone samples are dominated by nonfluorescent amorphous material with subordinate amounts of algal material and vitrinite.

Although "Rock-Eval," elemental and visual kerogen analysis provide qualitative information on the oil- vs. gas-proneness they do not provide detailed information on the nature of the products. Such information can, with some limitations, be obtained through the use of pyrolysis-gas chromatography. Pyrolytically generated hydrocarbons in the organically enriched samples are dominated by a series of normal alkane-alkene doublets; aromatics are only minor components (Fig. 7). The longer chain hydrocarbons nC_{22}+ are important contributors to the total pyrolysate. Such a chromatographic fingerprint is typical of an alginite or an algal-derived source (Larter and Douglas, 1980). A less developed, but similar pattern is also obtained when organic-poor samples are pyrolyzed. This similarity suggests that the gas-prone character (i.e., nonfluorescent organic matter and low organic hydrogen content) of these sediments is a result of poor organic matter preservation (i.e., oxidation). The nature of the pyrolysis-gas chromatograms suggests that upon achieving the appropriate levels of thermal maturity these sediments would produce a high wax crude oil.

The carbon isotopic composition of the isolated kerogens is also quite variable. The $\delta^{13}C$ values range from –26.8 to –17.1‰ relative to PDB (Fig. 8). The carbon isotopic composition of these kerogens is generally heavier than that observed in

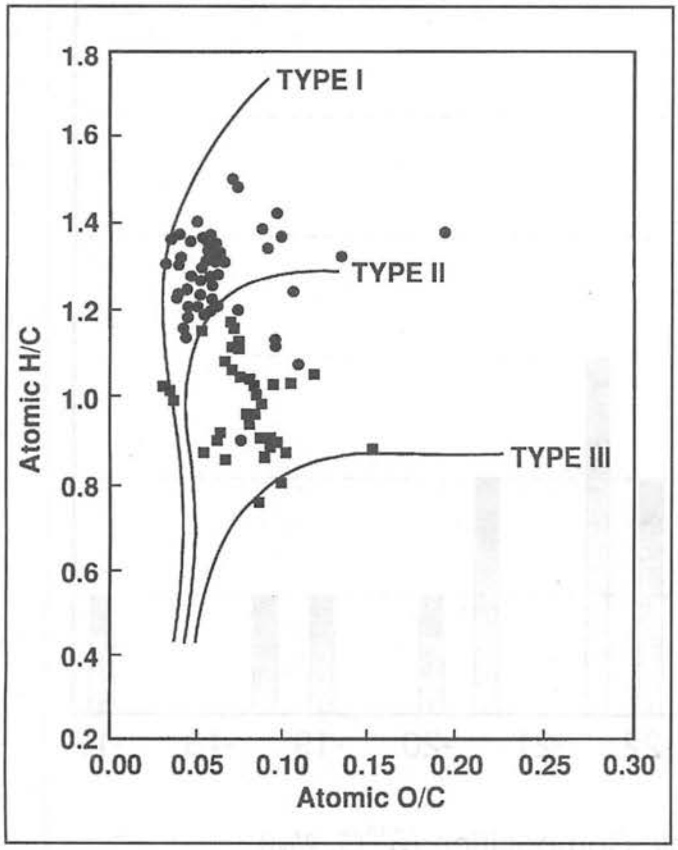

Figure 6. Van Krevelen-type diagram based on the elemental analysis of isolated kerogens (● upper Brown Shale; ■ lower Brown Shale) from the Aman and Balam sub-basins.

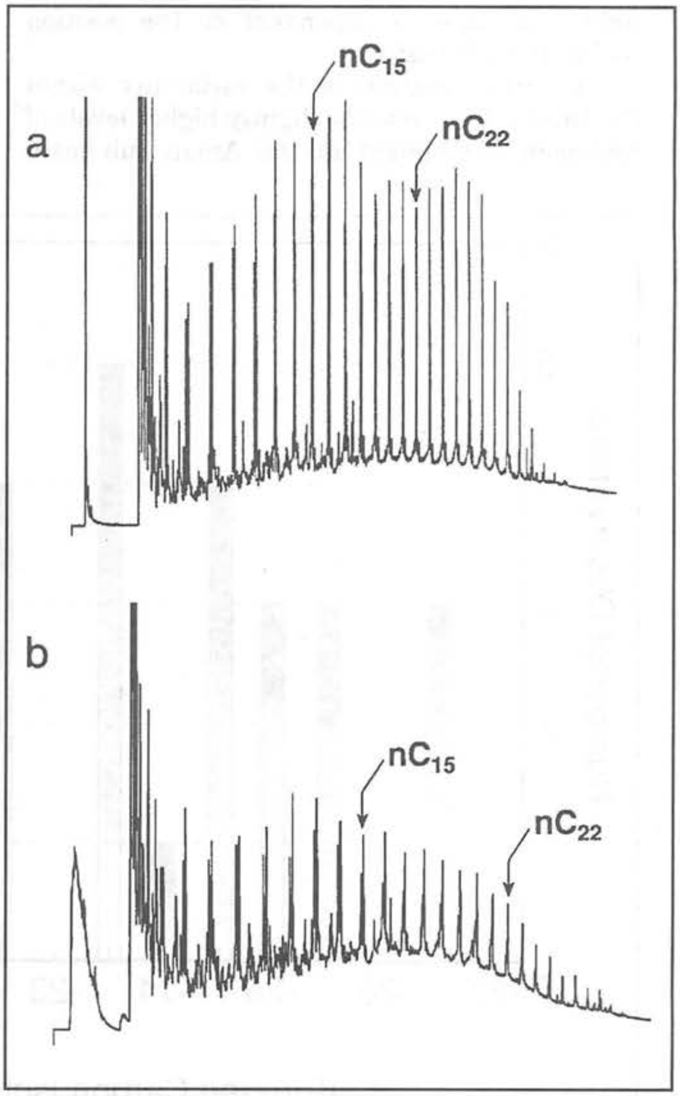

Figure 7. Representative pyrolysis-gas chromatograms (a- organic-rich sample; b- organic-poor sample). The nC_{15} and nC_{22} doublets are labeled as points of reference.

other Tertiary lacustrine source rock systems such as the Green River Formation (Collister and Hayes, 1991; Dean and Anders, 1991). In fact, these values are comparable to those observed in many Tertiary-age marine kerogens.

An analysis of the stratigraphic relationships among these data reveal that the more hydrogen-enriched, oil-prone material is largely limited to the upper portion of the Brown Shale. The lower Brown Shale is dominated by more gas-prone organic matter (Figs. 3 and 6). Longley *et al.* (1990) further noted that oil-prone Brown Shale can be further differentiated into a "shallow" water facies dominated by fragments of mat forming algae; and a "deep" water facies dominated by planktonic algal remains. Maceral analysis of both facies suggests that approximately 75% of the kerogen is oil-prone. A third lake-margin gas-prone facies was identified within the primarily oil-prone sequence. The dominance of an individual facies is dependent on the position within the sub-basin.

A further analysis of the variability within the Brown Shale reveals slightly higher levels of hydrogen enrichment in the Aman sub-basin compared to the Balam sub-basin (Katz and Kelley, 1987). Even more gas-prone kerogen was observed in the Brown Shale within the Rangau basin (Williams *et al.*, 1985). These differences are principally the result of variations in the level of primary productivity, organic preservation or both, with more favorable conditions for oil source rock development having existed within the Aman sub-basin. The level of thermal maturity and the generation and expulsion of hydrocarbons may also play a role in establishing some of this variability.

Bitumen composition and character

The abundance and character of the extractable fraction is dependent on both the nature of the source rock and its level of thermal maturity. Total extractable yields were highly variable ranging upward to ~26,400 ppm by weight. The extractable hydrocarbon yields are generally consistent with the pyrolytic S_1 yields. The bulk bitumen composition was also variable and dependent on the level of thermal maturity. At lower levels of thermal maturity the samples were dominated by nonhydrocarbons. The proportion of hydrocarbons, largely saturated hydrocarbons, increases with

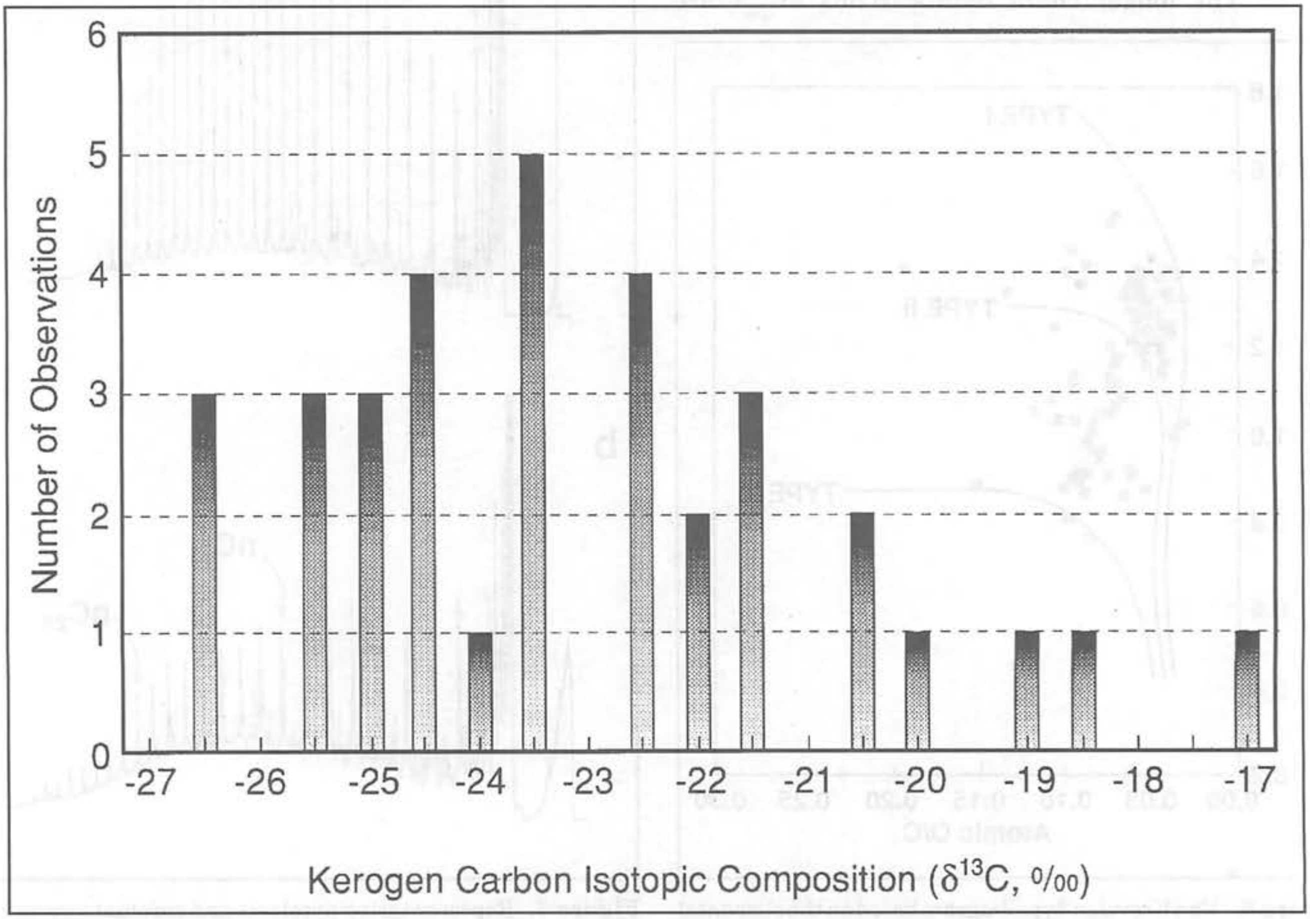

Figure 8. Histogram of carbon isotopic composition of isolated kerogens — Pematang Formation. Samples were obtained from the Aman, Balam and Kiri sub-basins.

increasing maturity. A number of the samples display anomalously high hydrocarbon contents (> 70% saturated + aromatic hydrocarbons). These samples are believed to have been contaminated by migrating hydrocarbons.

Gas chromatography of the saturated hydrocarbon fraction typically reveals an abundance of waxy ($n\mathrm{C}_{22}$+) components (Fig. 9). An abundance of long-chain *n*-alkanes has been attributed to higher plant waxes (Lijmbach, 1975) and/or certain freshwater algae (Gelpi *et al.*, 1970). Additionally, a few samples appear to be depleted in light hydrocarbons (Fig. 9c). It is possible that this light-end loss is a consequence of preferential losses during expulsion (Leythaeuser and Poelchau, 1991).

Pristane/phytane ratios were found to range from 1.07 to 10.25, with most values being greater than 2. Such elevated values are commonly, but not exclusively, associated with nonmarine depositional settings (Powell and McKirdy, 1975).

An examination of the available biomarker information reveals the presence of low concentrations of steranes. Sterane/hopane ratios are less than 0.1. Such ratios are commonly associated with lacustrine settings (Mello *et al.*, 1988). Some of the samples contain 4-methylsteranes. These compounds are believed to be derived from freshwater algae typical of many lacustrine settings (Volkman, 1988), as well as from dinoflagellates (Goodwin *et al.*, 1988).

Although the steranes are present in only low concentrations, an analysis of the m/z 217 ion chromatograms reveals significant variability in the normal sterane composition. The $\mathrm{C}_{27}/\mathrm{C}_{29}$ ratios range from ~0.1 to ~2.2. A further analysis of the m/z 217 ion chromatogram reveals that diasteranes account for between 12 and 47% of the identified components, with most values between 20 and 40%.

The m/z 191 ion chromatograms reveal generally low to moderate concentrations of tricyclics. Tricyclics account for typically less than 10% of the m/z 191 ion chromatogram, although individual samples may exhibit values as high as 26%. Relatively high concentrations of oleanane are also present in some of the extracted bitumens (Longley *et al.*, 1990). Oleanane is considered an indicator of angiosperm input (Ekweozor and Udo, 1988). Gammacerane is also present in several of the samples. The presence of gammacerane in only some of the samples suggests that there may have been differences in the salinity during Brown Shale deposition. However, the concentrations of gammacerane do not appear to be indicative of a hypersaline setting. The samples also generally display low Tm/Ts (17α-22,29,30-trisnorhopane/18α-22-29-30-trisnorneohopane) ratios with values typically less than 1.0, although significantly higher

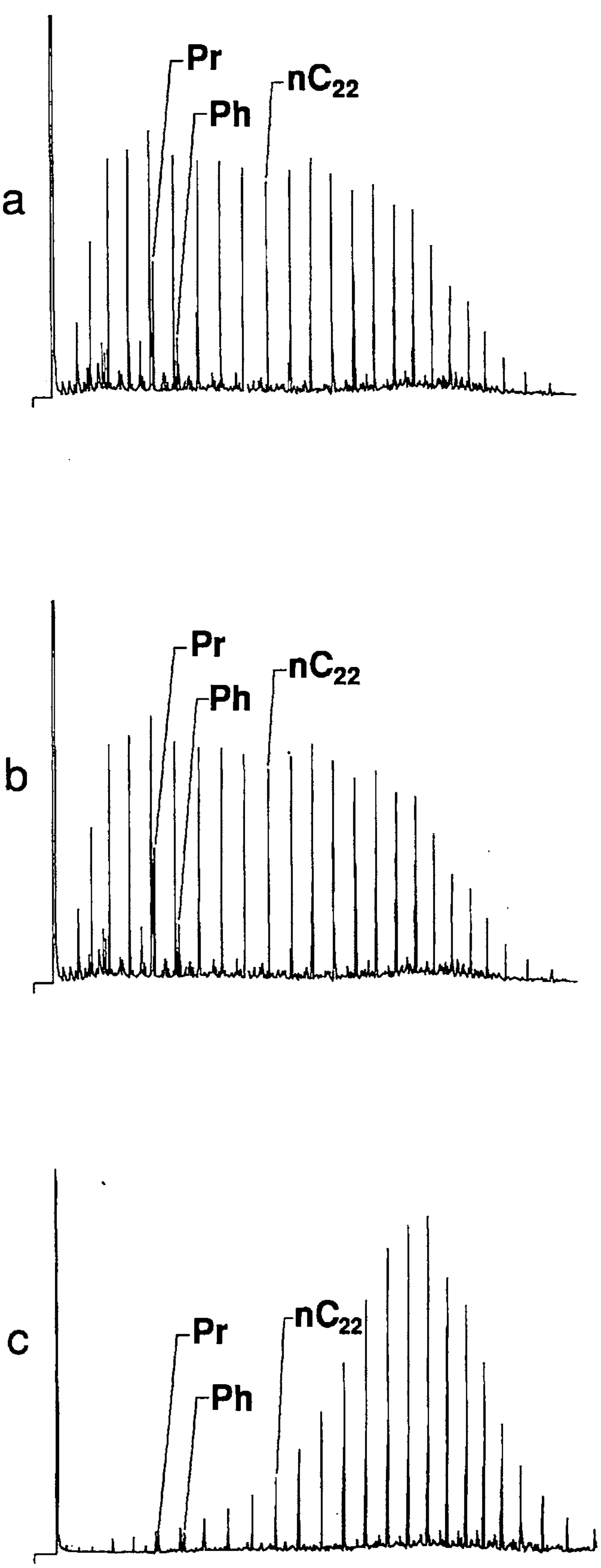

Figure 9. Representative C_{15}+ saturated hydrocarbon fraction gas chromatograms of extracts. Key *n*-alkanes and isoprenoids are marked for reference.

values have been observed. This ratio is influenced by both thermal maturity and organic facies.

Another important biomarker compound in some of the extracts is the isoprenoid, botryococcane. Botryococcane is derived from the green alga *Botryococcus braunii* (Moldowan and Seifert, 1980). However, it should be noted that the absence of botryococcane in an extract or oil does not confirm the absence of the alga from the depositional system. Studies on algal cultures have revealed that botryococcene, the unsaturated form of botryococcane, is present in the alga only during the resting stage and that normal alkanes dominate during the growth stage (Wake and Hillen, 1981).

Whole-bitumen carbon isotope data reveal a range of more than 6, ranging from at least –28.8 to –22.4‰ relative to PDB (Fig. 10). This range in isotope composition is similar to that observed among the kerogen samples. An examination of the relationship between the saturated and aromatic hydrocarbon isotopic compositions (Fig. 11) suggests a predominantly algal origin for the organic matter. Only a few of the extracts appear to have a largely higher plant origin.

Insufficient data are available to characterize the geographic variability of the extract. Sufficient data are, however, available to suggest some general temporal or stratigraphic trends. For example, there appears to be greater variability in bitumen character within the lower portion of the Brown Shale than in the upper Brown Shale. However, even the upper Brown Shale displays some variability in extract composition. For example, there appears to be a general increase upward in the C_{27}/C_{29} normal sterane ratio (Katz and Mertani, 1989).

Furthermore, as with the kerogen, Longley *et al.* (1990) noted that the bitumen character displays a regular systematic pattern related to water depth. Deeper water facies tend to display higher pristane/phytane ratios, high relative concentrations of oleanane and lower C_{30} 4-methylsterane content. The shallower water facies displays somewhat lower pristane/phytane ratios (<3.0), relative high concentrations of C_{28}–C_{30} 4-methylsteranes, and low concentrations of oleanane. Botyrococcane and gammacerane have been identified in the shallow water facies.

OIL COMPOSITION AND CHARACTER

The chemical and physical properties of oils are a direct response to the nature of the precursor material, the generation process, and post-generation alteration processes. Brown Shale-derived oils display a wide-range of physical properties as a result of various alteration processes, including biodegradation. For example, API gravities range from 16.5 to 47.0°, with pour points ranging from 40 to 115°F. These variations in physical character are a reflection of variations in gross chemical composition, i.e., the relative abundance of saturated and aromatic hydrocarbons and nonhydrocarbon components. Saturated hydrocarbon content ranges from ~40 to greater than 90% (Fig. 12), with saturate/aromatic hydrocarbon ratios typically being greater than 3. Unaltered oils are classified as paraffinic, with low sulfur contents (< 0.2 wt.%).

Although some chemical properties reflect post-generation processes, there are other chemical characteristics which can largely be attributed to the nature of the precursor (i.e., chemical composition of the source rock). These inherited characteristics include their carbon isotopic composition and the distribution and abundance of various biomarker compounds.

Saturated hydrocarbon gas chromatography of non-biodegraded oils reveals an abundance of long-chain *n*-alkanes or waxes (Fig. 13). This is commonly manifested by elevated nC_{27}/nC_{17} ratios (> 0.5). Nondegraded oils typically display a bimodal or broad *n*-alkane distribution. Where a bimodal pattern is present the second mode commonly occurs at nC_{27} (Fig. 14). The CPI (carbon preference index) values are slightly greater than 1 (1.03–1.07). Pristane/phytane ratios are typically greater than 2, but range from 0.69 to 10.65. Such characteristics are typical of oils derived from nonmarine sources, perhaps with the exception of the low pristane/phytane ratios. Biodegraded oils, such as Duri, display low *n*-paraffin abundances (Fig. 13).

As with the kerogen and whole-bitumen data, the whole-oil carbon isotopic composition displays considerable variability, ranging from ~–29 to ~–22‰ relative to PDB. Many of the values are isotopically heavier than those typically reported for nonmarine or lacustrine oils. This range is also greater than that commonly attributed to a suite of oils derived from a single source.

The relationship between the carbon isotopic compositions of the saturated and aromatic hydrocarbons appears similar to that previously described for the bitumens. The oils do, however, exhibit a greater range, with saturated and aromatic hydrocarbon fractions being as much as 2‰ lighter in the oils than in the bitumens (Fig. 11). This increase in the degree of fractionation is to be expected as a consequence of cracking. The relationship between the carbon isotopic composition of the saturated and aromatic hydrocarbons suggest a predominantly algal source for the oil. Only a single oil appears to have been derived from largely terrestrial organic matter.

An analysis of the biomarker data reveals some common properties among the oils. For example, the m/z 191 ion chromatograms reveal generally low concentrations of tricyclic compounds, typically less than 15% (Robinson and Kamal, 1988). These oils also display low sterane/hopane ratios (~0.2), Tm/Ts ratios of less than 0.5, and significant concentrations of gammacerane. Oleanane is also ubiquitous, although its abundance does vary significantly. The oils also contain 4-methylsteranes in varying proportions.

These data also reveal that there are significant differences within the biomarker compositions among the various oils. For example, there are significant differences in the normal sterane compositions. In most oils C_{29} steranes dominate over C_{27} steranes. There are, however, some oils including the S.E. Balam and Kayuara in which they are present in near equal proportions. Variability is also observed in the monoaromatic sterane distributions (Moldowan *et al.*, 1985). The relative abundance of C_{31} homohopanes also appears to differentiate some of the oils. Oils such as Damar display elevated relative concentration of C_{31} homohopanes compared to most of the region's oils. Furthermore, botryococcane is present in only a limited number of the sampled oils including Minas and Duri oils.

A detailed analysis of the oil data, including the biomarker and carbon isotopic compositions, reveals that multiple oil families exist within the basin (Seifert and Moldowan, 1980; Katz and Mertani, 1987; Robinson and Kamal, 1988). Seifert and Moldowan (1980) note that within the Caltex acreage, at least four primary oil families can be differentiated (Table 3). These families appear to be geographically restricted with each family representing hydrocarbon charging from a single sub-basin (Fig. 15). It is therefore, probable that with the inclusion of additional sub-basins there would be the potential for additional families.

LONG-TERM AND SHORT TERM INFLUENCES ON SOURCE ROCK POTENTIAL

The combined data sets clearly reveal that variations in source rock potential and character occur both stratigraphically and geographically. Stratigraphic variations occur both as a result of changes in long-term trends and as a consequence of high frequency changes in the depositional setting. Long-term factors include changes in the relationship between sedimentation and subsidence rates (basin development patterns), long-term

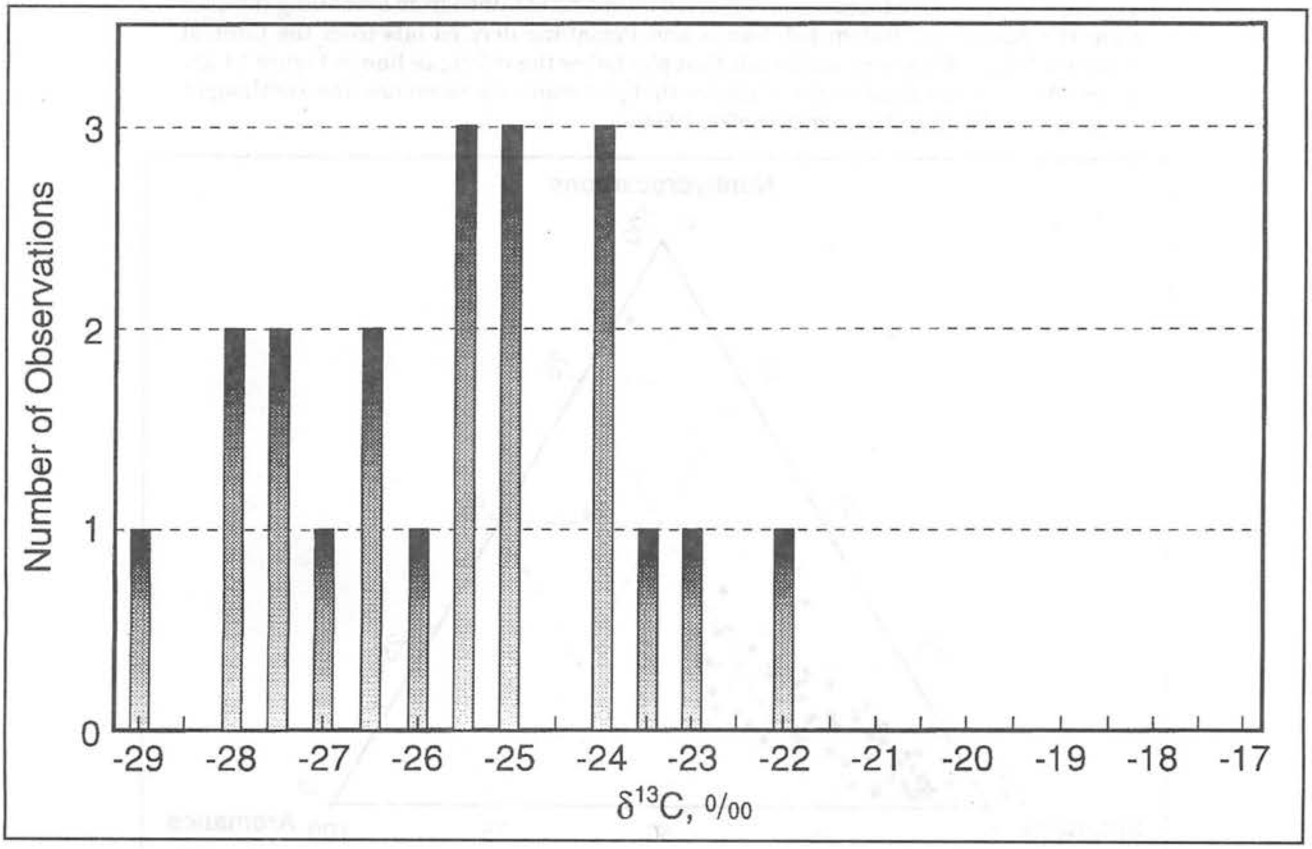

Figure 10. Histogram of carbon isotopic composition of extracted whole-bitumens — Pematang Formation. Samples were obtained from the Aman and Balam sub-basins.

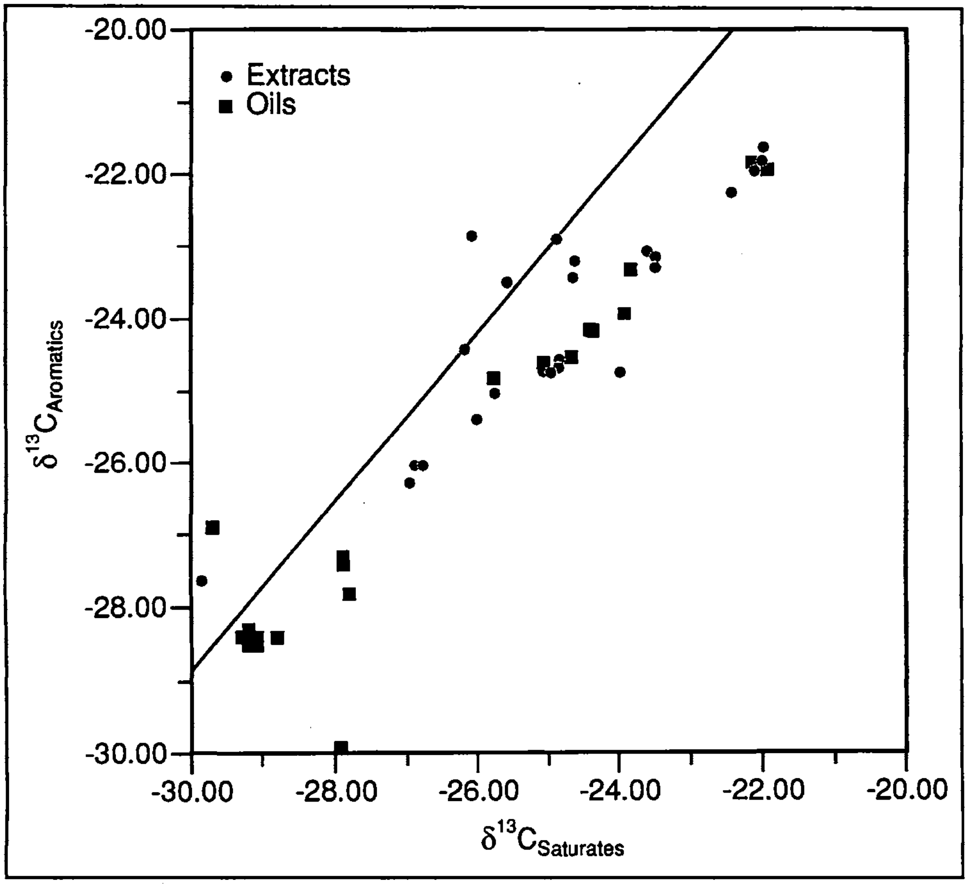

Figure 11. Relationship between the carbon isotopic composition of the saturated and aromatic hydrocarbon fractions of extracted bitumens obtained from Pematang samples from the Aman and Balam sub-basins and Pematang derived oils from the Central Sumatra basin. Bitumens and/or oils that plot below the reference line in Figure 11 are believed to have an algal origin. Samples that plot above the reference line are thought to have some higher plant input (Sofer, 1984).

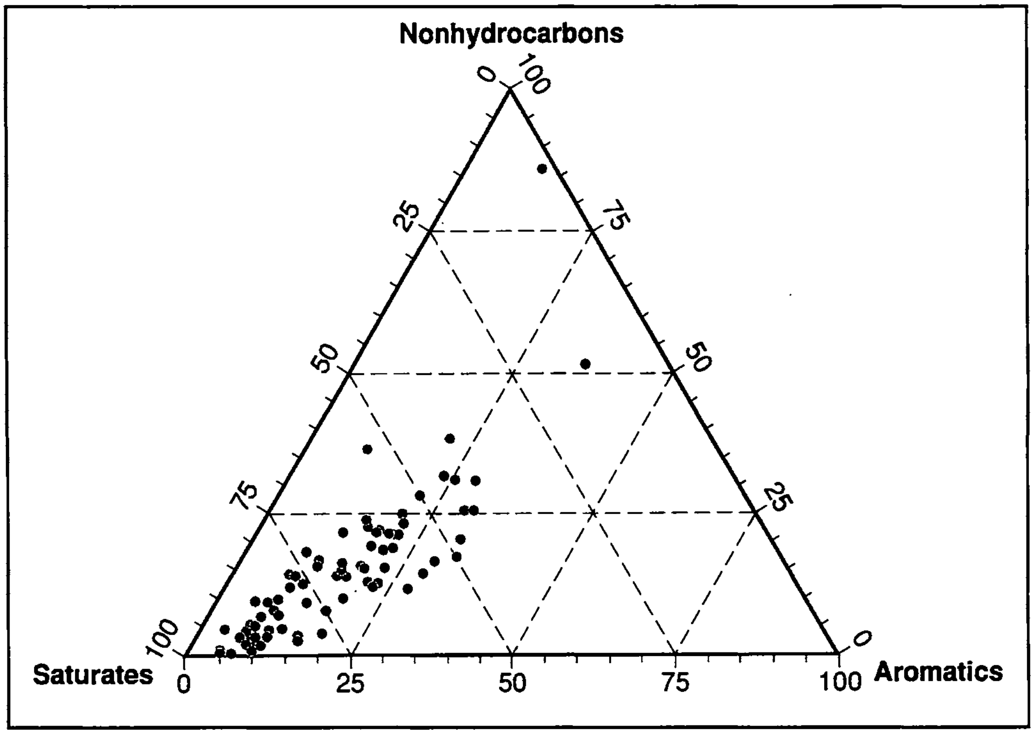

Figure 12. Ternary diagram representing bulk oil composition.

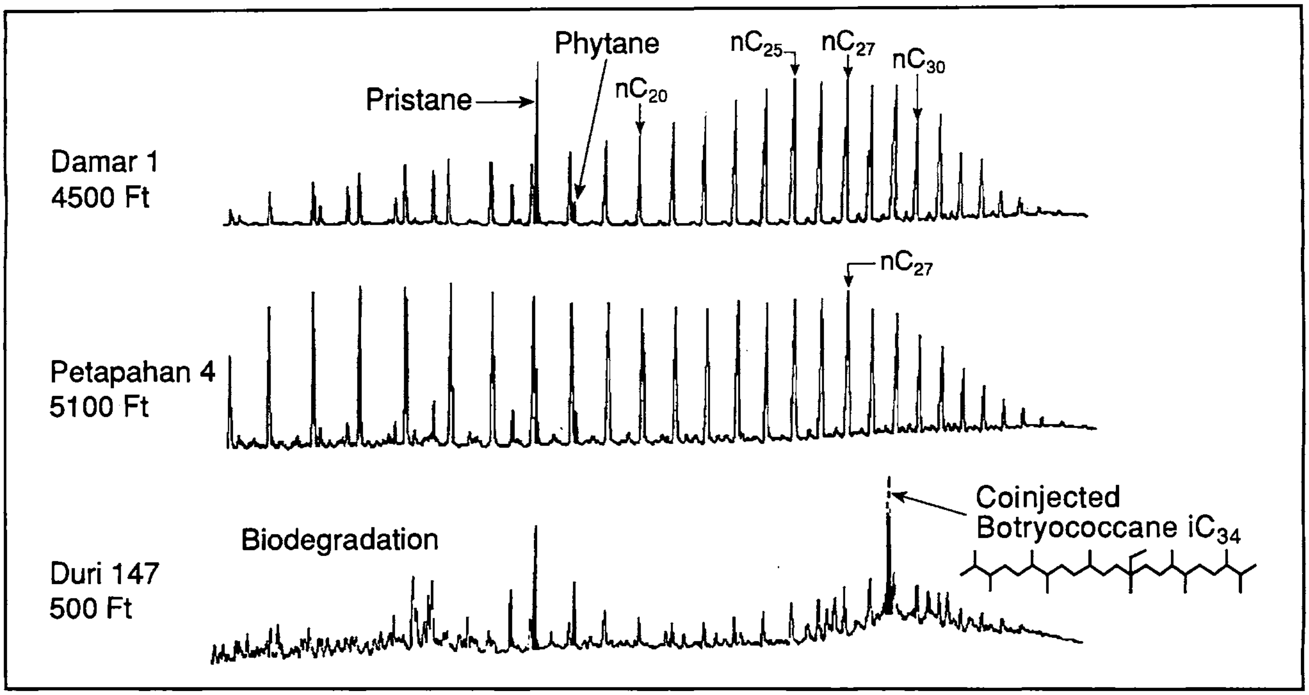

Figure 13. Representative saturated hydrocarbon fraction gas chromatograms of oils. Key *n*-alkanes and isoprenoids are marked for reference.

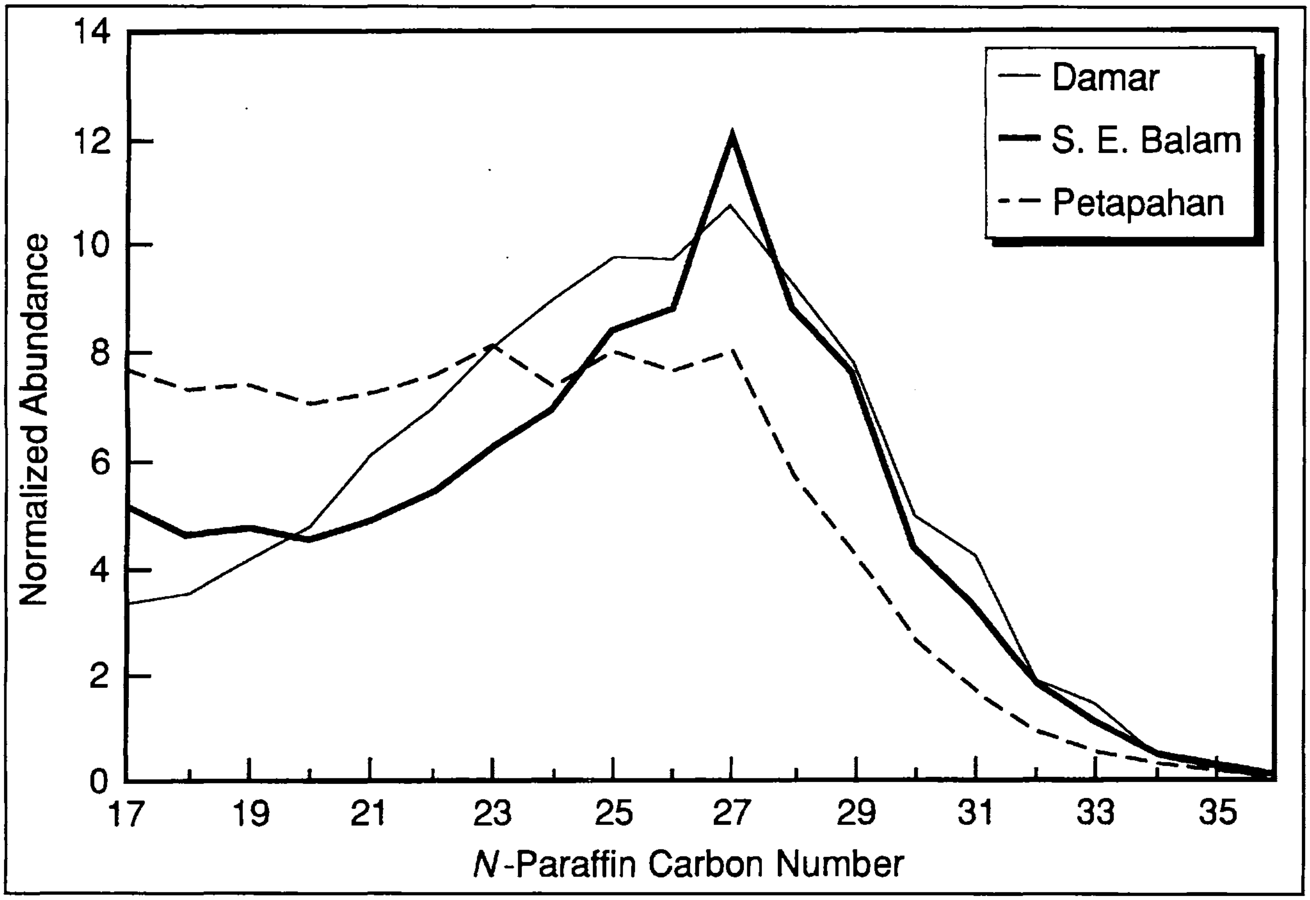

Figure 14. Normalized oil *n*-alkane distributions.

climate trends and vegetation changes, and the maturing of the lacustrine nutrient pool.

Influence of subsidence history

The effects of basin development on the stratigraphic positioning of lacustrine, rift source rocks were described by Watson *et al.* (1987) and Lambiase (1990). They suggest that the relationship between sedimentation and subsidence rates define three phases of rift development, each of which has different potential for source rock development. The initial phase of development is characterized by a series of minor faults displaced over a wide area, resulting in only minor subsidence. Fluvial sedimentation dominates during this period. If lakes are present they would be broad and shallow. This is equivalent to the Lower Red Beds of the Central Sumatra basin. Such conditions would not be favorable for source rock development.

The second phase of development begins with the formation of a major boundary fault. This, in turn, results in an increase in the relative subsidence rate and the potential for deep lake development. This phase of basin development typically occurs between 5 and 15 million years following initial rifting and is the primary period for oil-prone source rock development. This phase of development is coincident with Brown Shale

Table 3. Genetic classification of Central Sumatra oils.

Oil Family	$\delta^{13}C$	Botryococcane	Normal Steranes	C_{31} Homohopanes
Family I (Damar)	~ −28.4	ND	$C_{29}>C_{27}$	+++
Family II (S.E. Balam)	~ −22.1	ND	$C_{27}>>C_{29}$	+
Family III (Suram)	~ −28.6	ND	$C_{29}>C_{27}$	+
Family IV (Minas)	~ −25.0	+	$C_{29}>C_{27}$	+

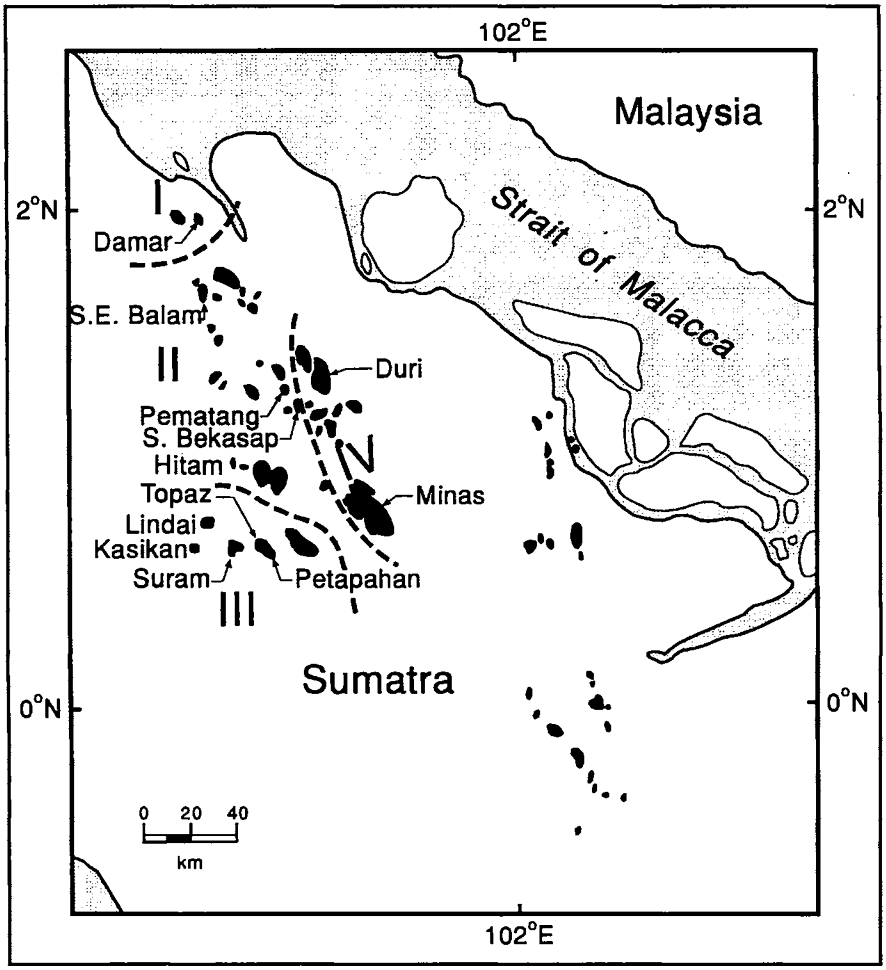

Figure 15. Geographic distribution of oil families (after Seifert and Moldowan, 1980).

deposition.

During the third phase of basin development, the rate of extension decreases as does the subsidence rate. This decrease in subsidence results in the shallowing of any lakes present through sedimentary influx. This results in the termination of oil source rock development as a consequence of both the decrease in organic preservation potential through lake basin shallowing and dilution of organic matter as a consequence of sedimentary influx. Within the Central Sumatra basin this unit is represented by the lake fill sequence.

Influence of climate

Although basin development processes are generic, climatic influences are regionally specific. Paleoclimatic modeling results suggest that only changes in the hydrologic cycle may have an influence on the stratigraphic distribution of potential source rocks within the region (Katz, 1991). Other climatic factors such as temperature, storm tracks and wind patterns, although not constant, do appear favorable for lacustrine source rock development throughout the Eocene and early Oligocene. The hydrologic cycle appears to have undergone an increase in seasonality upward in the sequence, so that by the early Oligocene "wet" and "dry" seasons are present. Although seasonality does not preclude source rock development it may result in significant seasonal changes in lake level. Such seasonality would increase the volumetric importance of marginal lacustrine facies, particularly along the hinge zone margin thus reducing the extent of potential oil-prone facies.

The inferred climatic change could also result in the modification of the type of allochthonous material which may be supplied to the lake. The decrease in rainfall could result in a change from tropical rain forest to more savanna-like conditions. Such a change would reduce the availability supply of vitrinitic material and increase the potential supply of exinitic material.

Influence of nutrient availability

There is at least one additional long-term factor which appears to influence the potential for lacustrine source rock development, namely, the maturing of the nutrient pool. Dean (1981) suggested that lacustrine productivity is largely controlled by the recycling of nutrients except in immature systems which have not yet established an internal nutrient pool. This implies that potentially higher levels of productivity would be associated with the Pematang lakes during upper Brown Shale deposition than during the deposition of the lower Brown Shale. Not only would the lower levels of productivity during lower Brown Shale deposition result in a reduction in the amount of available algal material but would also reduce its potential for preservation. Organic preservation is enhanced in systems displaying high biological oxygen demand, which is, in part, the result of the decomposition of organic matter.

Influence of water depth

Short-term variability or rapid cycling of both lithofacies and organic facies within the largely oil-prone portion of the Brown Shale was demonstrated by Longley *et al.* (1990). They present detailed results for a thirty foot cored interval which reveals a dominance by "shallow" lake facies (60%) with the presence of lesser amounts of both "deep" lake (25%) and lake margin (15%) facies. These facies changes imply significant changes in lake level, on the order of at least several tens of meters over periods of a few thousand years. These changes appear to be largely tied to climatic (i.e., Milankovitch) forcing factors. These climatic changes are manifested as changes in the hydrologic cycle, resulting in the rise and fall of lake level. It has been noted that even in tropical settings there are significant changes in lake level (Street and Grove, 1979). Finney and Johnson (1991) suggest that Lake Malawi may have experienced lake level changes of 150 meters, while Scholz and Rosendahl (1988) have implied that changes in Lake Tanganyika may have approached 350 meters.

It should also be noted that the potential for very elevated levels of productivity may exist during these low lake stands. This is a consequence of the reintroduction of a large nutrient pool from the hypolimnion back into the photic zone. These potentially hypotrophic levels of productivity may be able to partially compensate for the decrease in preservation potential which results from the shallowing of the lake and the associated reduction in stratification potential. Such conditions appear to be the case currently in Lake Victoria.

Influence of water chemistry

Geographic variability is also multi causal with each sub-basin being influenced independently by such factors as the nature of the drainage system, the influence of subsurface spring discharges, and variations in subsidence rate. In addition, within an individual sub-basin the character and abundance of organic matter is influenced position.

The nature of the drainage system, including the type of country rock, and the relative importance of subsurface hydrothermal springs and riverine input, can influence lake water chemistry. Lake water chemistry, in turn, has a direct impact on the nature of the biomass within an individual lake basin. Such differences have been well documented in modern east African rift lakes (Serruya and Pollingher, 1983). Differences in the nature of the algal biomass would have a direct effect on hydrocarbon character influencing both the *n*-paraffin and biomarker composition (Gelpi *et al.*, 1970).

Influence of water column stability

Differences among the individual sub-basins in the quality and quantity of organic matter may be a reflection of water column stability (or stratification) and water depth. Katz (1988) noted that within the modern east African rift lakes the most oil-prone organic matter was present in Lake Edward. In Lake Edward high primary productivity is maintained by the annual recycling of nutrients from the hypolimnion and high organic preservation potential because of the dominance of anoxic conditions throughout much of the year. Following the annual overturn of the water column, anoxic conditions are quickly reestablished because of the availability of organic matter. In lakes such as Lake Edward or Ranau Lamongan (Indonesia) an anoxic hypolimnion can be reestablished in a matter of weeks (Green *et al.*, 1976). The ability to recycle a large portion of the nutrient pool and to reestablish a stable water column is a consequence of the moderate water depths associated with these lakes.

Slightly poorer source quality material was observed in the deeper Lakes Tanganyika and Kivu, where although preservation potential is high, productivity levels are somewhat reduced compared to that of Lake Edward because of the lower rates of nutrient recycling (i.e., much of the nutrient load is maintained within the hypolimnion) to the photic zone. The depth of the water column largely precludes the efficient recycling of the majority of the nutrient pool associated with the hypolimnion with there being only partial erosion of the hypolimnion.

The poorest source quality material and the lowest concentrations of organic matter were found in Lake Albert where organic preservation potential is low even though productivity is elevated. Organic matter preservation potential is reduced in Lake Albert because of its shallow nature and its frequent water column overturn. Therefore, based on the observed central Sumatra data set it may be inferred that the Aman, Balam, and Rangau sub-basins were comparable to Lakes Edward, Tanganyika and Albert, respectively.

As noted above differences in water depth among sub-basins may influence productivity and preservation by influencing water column stratification. Variations in water depth are at least, in part, the result of differing relationships between subsidence and sedimentation. The greater the subsidence rate compared to sedimentation rate the high the probability there is for deep lake development. When sedimentation and subsidence rates are in-balance there is elevated potential for swamp rather than lake development. Under such conditions there is a greater likelihood for coal deposition. This explains the more coaly nature of the Kiri sub-basin compared to the Aman or Balam sub-basins (Williams *et al.*, 1985; Katz, 1991). Under circumstances where sedimentation rates exceed subsidence rates lake bodies fill, and available organic matter not only tends to be more oxidized, because of the shallower nature of the lake, but the available organic matter also becomes more diluted by clastic influx. Such conditions may explain both the lower levels of enrichment and poor quality of the organic matter in the Rangau sub-basin.

Influence of basin hydrodynamics

Within any individual sub-basin the nature and abundance of the preserved organic matter also varies. This is a consequence of local variations in productivity and preservation, the availability of allochthonous organic matter, as well as hydrodynamic effects. There is a tendency for higher concentrations and better quality organic matter to be located away from the sub-basin margins (Demaison and Moore, 1980). This is a consequence of both enhanced preservation potential away from the higher energy settings of the margin and a reduction in the amount of allochthonous, gas-prone material.

Huc (1990) proposed that redistribution processes within a rift lake are a major influence on organic matter distribution. Organic matter would be continuously winnowed from high energy settings with final deposition in the lowest energy environments. Within half-graben settings, these processes would result in the asymmetric distribution of oil source rock material. Conditions would be less favorable on the hinge-zone margin than along the border fault margin, as a consequence of preservation potential and hydrodynamic redistribution of organic matter.

IMPLICATIONS

These variations in geochemical attributes raise several questions concerning their interpretation. For example, is a given sample suite representative of the unit being examined? If not, does it over-estimate or under-estimate the unit's generation potential? Or, does it suggest a more gas-prone or oil-prone character than would be supported if accurately sampled? If the samples do not accurately represent the unit under examination, what does their analysis provide? Are there sub-basins which should display similar, better or poorer source rock potential? Or, are there regions within a sub-basin which display more or less favorable charge potential?

A calculation of the liquid hydrocarbon charge potential based on the integration of measured total generation potentials and kerogen compositions in the Brown Shale suggest a range of more than three orders of magnitude assuming the same maturation history. At peak hydrocarbon generation the minimum liquid hydrocarbon yield is ~0.3 x 10^6 bbl/km^3. This contrasts with the maximum case for liquid hydrocarbon generation from the Brown Shale of ~1,200 x 10^6 bbl/km^3 and a mean case of 180 x 10^6 bbl/km^3. Assuming these data were from a frontier rather than a mature exploratory province, such differences in calculated yield would alter the economic assessment of the region. Clearly such geochemical information cannot accurately be interpreted outside of their geologic context. The geologic framework establishes the representativeness of the sample suite and permits a meaningful extrapolation of properties beyond the limits of the sample population.

In addition, the variability observed both in the oils derived from a single source rock and within the source rock itself also raises doubts as to whether some oil-oil and oil-source rock correlations are valid or simply fortuitous. The available data suggest that there is a high probability that oils derived from a single source from a single sub-basin will display some degree of genetic similarity and a valid correlation will be drawn. However, the probability of establishing a correlation of oils derived from the same stratigraphic unit deposited in different sub-basins is much lower. The probability is even further reduced if source rock deposition occurred within a different structural/depositional basin altogether. Thus commonality of stratigraphic name does not insure the presence of uniform depositional setting or organic facies and thus genetic similarity of produced hydrocarbons.

The stratigraphic variability observed within a source rock sequence may further complicate oil-source rock correlations. Even if the oils and source rock samples were obtained from a single sub-basin, many attempts to correlate oils to individual source rock samples often do not take into consideration either the facies variability within the sequence or the fact that oils actually represent an integrated product of hydrocarbon generation from each of the different oil-prone intervals within the source unit. Although these differences may be amplified in lacustrine systems there is also evidence for high frequency variability within marine source rock intervals (Katz *et al.*, 1993). Therefore, oils within the Central Sumatra basin would represent an integrated product of both "shallow" and "deep" lacustrine, oil-prone horizons, each contributing their biomarker and isotopic signatures to the oils. The importance of each would be dependent on the nature of the sub-basins depositional character. Thus valid correlations can only be established when composite samples representative of the entire generative sequence are available.

CONCLUSIONS

The results of this study permit one to draw conclusions that are both global as well as those that are regionally specific. Those of a regional nature are:

- The Pematang Formation and its stratigraphic equivalents are the source for the oils of Central Sumatra. Of all the potential source rock candidates it is the only unit which contains sufficient quantities of the appropriate type of organic matter at the appropriate level of thermal maturity to explain the quantities of liquid hydrocarbons available.
- Stratigraphic and geographic variability occurs at several different levels. The geochemical characteristics of the source rock were influenced by differences in the relative subsidence and sedimentation rates, the changing climate, and the maturing of the nutrient pool. It has also been inferred that there were differences in water chemistry among the different Pematang lakes which resulted in different algal populations and different oil chemistries.
- Best oil source rock development occurred within mature lakes of moderate water depth. Optimum conditions for productivity and preservation occurred well after basin initiation.
- Variability in oils is greater than commonly attributed to a single source. Significant differences in isotope and biomarker chemistry permit the differentiation of the oils derived from a single source into discrete families. Each family appears to be geographically restricted and associated with a sub-basin.

The conclusions of a more global or general nature are:

- Geochemical data can only accurately be interpreted in a geologic framework. An understanding of the significance of a geochemical data set can only be obtained when the geologic setting is known. An understanding of the geologic/depositional setting should be used to establish the sampling program.

- Improper sampling can result in an inaccurate assessment of hydrocarbon potential. The lack of an appropriate sampling program can result in either the over-estimation or under-estimation of a region's resource potential by several orders of magnitude.
- Oil-source rock correlations may only be fortuitous. Most published correlations do not take into consideration either the stratigraphic variability of the source rock or differences which may be associated with depositional conditions of individual sub-basins.

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