

## CHAPTER 6

### GEOCHEMICAL ANALYSIS AND PETROLEUM SOURCE ROCK FACIES

#### 6.1 INTRODUCTION

In general, there are six principal considerations that explain the presence or absence of petroleum in a given subsurface situation. These include 1) reservoirs, 2) traps, 3) abundance of organic matter (TOC), 4) organic matter type, 5) maturation, and 6) migration. Two of these are geological phenomena (1 and 2) and the rest are geochemical phenomena (3, 4, 5, 6). A deficiency in one of these may cause a lack in discovery.

The present study is intended to integrate details of source rock and the generative potential of the sequences present. Source rock potential for hydrocarbons is dependent on the type and quantity of the organic matters, whereas, the generative potential for hydrocarbons is controlled by the extent of thermal evolution of the organic matter. Hence, items 3, 4, and 5 of the above list are the subject of this chapter.

In order to meet the objective, a total of 28 samples, gathered at regular intervals from the Mae Sot Formation, were geochemically analysed (Tables 6.1, and 6.2). The data were critically examined, elaborated and presented as diagrams and logs. Using the results of the analysis, the organic matter type, abundance and the maturity status of the sediments is clearly defined. Moreover, an attempt has been made to explain the distribution and characteristics of potential source rocks along the vertical section.

#### 6.2 GEOCHEMICAL METHODS

A wide range of organic geochemical techniques are used for oil source rock studies. Some of these are chemical and others are organic petrolo-

Table 6.1 Rock-Eval Pyrolysis and TOC contents (after D.E.D., 1987).

Sample Depth (ft)	TOC (wt %)	Tmax (C)	Production index (OPI)	Potential yield (S1+S2)	Hydrogen Index
1680-1720	2.35	434	0.19	0.03	129
1780-1820	1.06	423	0.15	0.91	86
1880-1920	0.69	426	0.23	0.85	123
1980-2020	0.62	424	0.13	0.76	123
2080-2120	1.22	426	0.08	1.84	151
2180-2220	1.57	425	0.08	3.03	193
2280-2320	1.16	427	0.07	2.26	195
2380-2420	1.12	427	0.06	1.55	138
2480-2520	0.55	422	0.08	0.72	131
2580-2620	0.71	429	0.11	1.19	168
2680-2720	0.62	429	0.1	0.94	152
2800-2840	1.61	428	0.09	4.08	253
2900-2940	1.36	427	0.11	2.29	168
3000-3040	1.26	425	0.15	2.11	167
3100-3140	1.01	427	0.11	1.37	136
3200-3240	1.97	430	0.08	3.87	196
3300-3340	1.47	428	0.1	2.91	198
3400-3440	1.91	432	0.1	4.67	245
3500-3540	2.41	437	0.06	9.71	403
3700-3740	1.99	437	0.09	4.77	260
3800-3840	1.8	433	0.16	3.75	208
3900-3940	2.02	436	0.14	5.46	270
4000-4040	1.96	434	0.09	5.29	270
4100-4140	1.75	436	0.14	4.48	256
4200-4240	1.85	436	0.11	4.6	249
4300-4340	1.72	434	0.11	3.85	224
4400-4440	1.87	439	0.09	4.32	231
4460-4500	1.8	437	0.11	4.29	238

Table 6.2 Solvent extraction data (after D.E.D., 1987).

Sample Depth (ft)	Total Extract (ppm)	Total Extract (mg/g TOC)
1680-1720	171	7
3900-3940	2598	129

gical methods. Rock-Eval pyrolysis method (as far as the chemical aspect is concerned) is currently used for rapidly identifying and characterising source rocks. This method is almost always performed together with the determination of the total organic content (TOC). The principles underlying these methods are briefly explained in the following section.

#### 6.2.1 Rock-Eval pyrolysis/TOC Method

Rock-Eval pyrolysis is a method of programmed temperature heating that can be used to characterize organic matter in fine grained rocks. A number of compounds are generated during pyrolysis (Figure 6.1) and are sensed by flame ionization detector. The quantity of hydrocarbons volatilised and expelled during isothermal heating at 300°C is determined from the area of the first analytical peak (S1). The quantities of hydrocarbons and CO<sub>2</sub> expelled during heating from 300° to 600°C are determined from the areas of the second and third peaks (S2 and S3, respectively). The pyrolysis temperature corresponding to the maximum of S2 is called the temperature of maximum pyrolytic yield (T<sub>max</sub>).

TOC is easy to measure. The source sample in question is crushed, leached with acid to remove any carbonate carbon and then burned in a stream of oxygen so that the non carbonate carbon is converted to CO<sub>2</sub> or CO. This is usually done in Leco furnace with a carbon determinator attachment that allows the total amount of oxidized carbon to be measured.

From these measured values, several useful parameters are calculated. Hydrogen index (HI) is the normalized S2 value, expressed as mg HC/g TOC which allows the types of organic matter to be estimated. Oxygen index (OI)

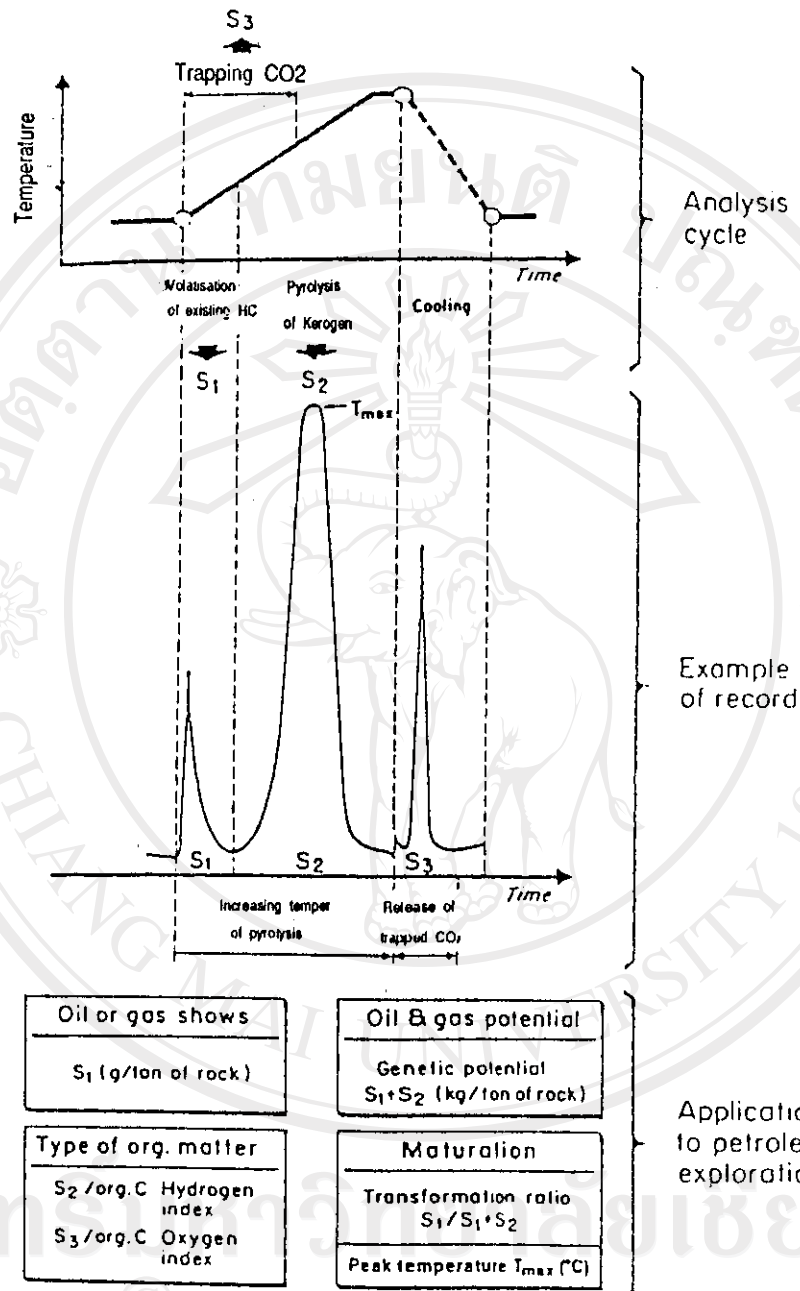


Figure 6.1 Cycle of analysis and example of record by the pyrolysis method and its application to the petroleum industry (after Tissot and Welte, 1984)

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is the normalized S3 value (S3/TOC) expressed in mg CO<sub>2</sub>/g TOC. Production index (PI) or transformation ratio [PI = S1/(S1 + S2)] indicates the level of thermal maturation and also the presence of epigenetic hydrocarbons.

A crossplot of the hydrogen index and Tmax values is useful for determining the type of organic matter. End members of kerogen types have been defined (Tissot and Welte, 1984) based on the hydrogen index and oxygen index values during maturation. Type I kerogen is primarily derived from fresh-water algal materials but is not present in the samples analyzed for this study. Type III kerogen (huminite) is derived from allochthonous terrestrial organic material such as coaly and higher plant detritus and has higher gas potential than Types I and II kerogens. Type II kerogen is composed of autochthonous organic matter (algal and planktonic remains and some terrestrial debris of marine and lacustrine origin). There is a wide range of mixing between Types II and III kerogens. Type II kerogen is considered to be a good source for oil and gas. Type IV kerogen is derived from oxidized and recycled organic matter, and has little or no hydrocarbon potential.

In the interpretation of the Rock-Eval pyrolysis/TOC data certain guidelines after Beicip (1988) were used.

### 6.3 GEOCHEMICAL ANALYSIS (RESULTS AND DISCUSSION)

Generally, the recognition and characterization of a petroleum source bed essentially involves the determination of 1) abundance; 2) type; 3) level of thermal maturation of the organic matter and; 4) the petroleum

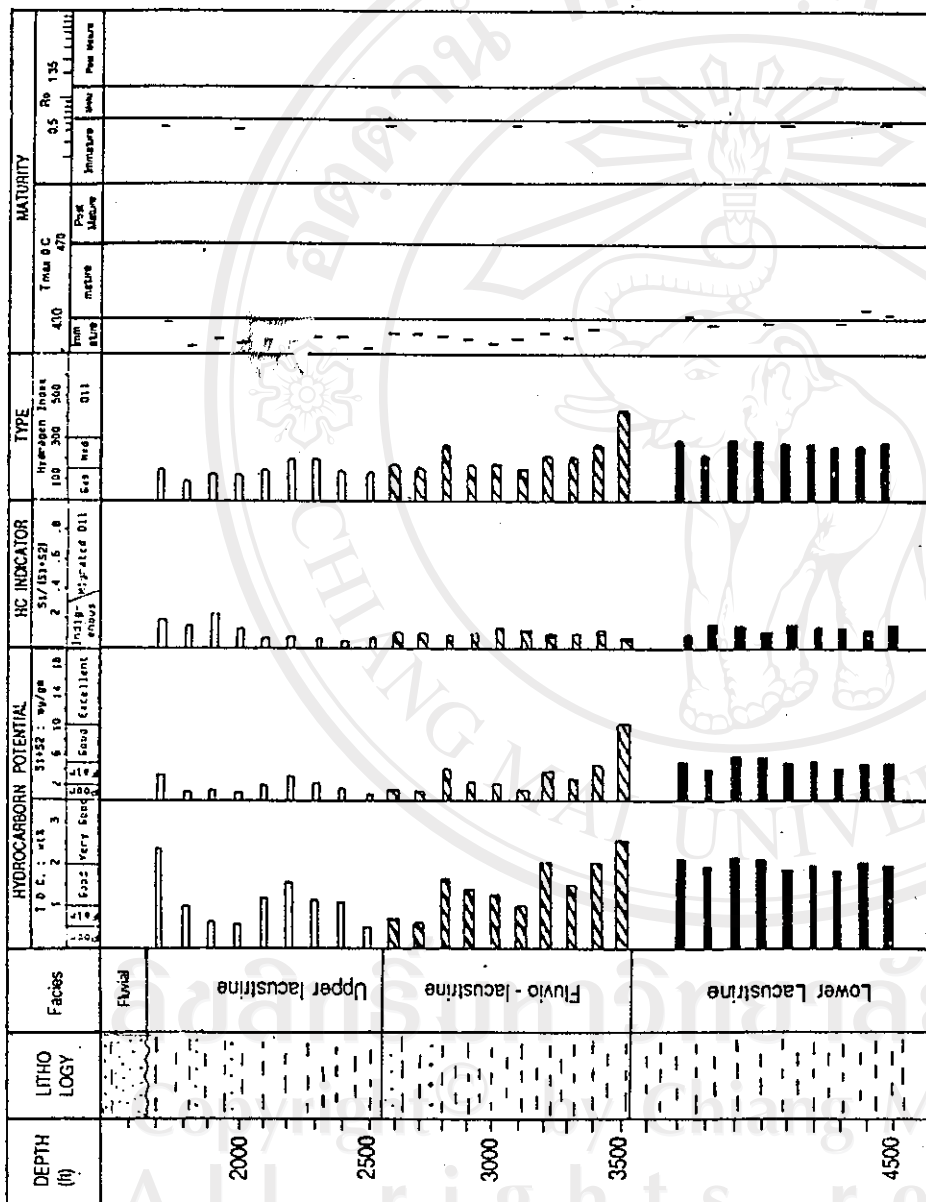
potential of the source rocks. Here, the type, abundance, and the maturity status of the organic matter is discussed and possible interpretations are also included.

### 6.3.1 Abundance of organic matter

Organic matter content is measured by the amount of organic carbon content (TOC) present in sediments. Total organic carbon (TOC) is, however, a crude index of source rock potential. Organic carbon may be recycled from older sediments, possessing little capacity for further release of liquids. Well documented oil source beds fall into a range of TOC content between 1 and 20 % by weight (Demaison and Moore, 1980). A commonly accepted minimal TOC value for potential source rocks is 0.4 percent (Tissot and Welte, 1984); generally values greater than one percent are preferable. A broad category of source rock quality by TOC values is given by North (1985).

All the samples analyzed for this study have total organic carbon values (TOC) greater than the critical limit cited by Tissot and Welte (1978, 1984). Of 28 drill cutting samples, 23 had TOC values greater than one percent, and only 5 samples had values between 0.5-1.0 %. The TOC values range from 0.62 to 2.4 %, with an average value of about 1.48 %. These values would rate the samples as having average to high (fair to good) source rock quality. The most organic rich intervals (with the highest TOC values upto 2.4 %) are confined within the lower part of the fluvio-lacustrine (Unit 2) and lower lacustrine (Unit 1) facies. Average TOC values increase from 1.15 % (upper lacustrine facies) through 1.43 % (fluvio-lacustrine facies) to 1.86 % (lower lacustrine facies) (Figure 6.2).





Upper lacustrine shale  
 Fluvio-lacustrine shale  
 Lower lacustrine shale

TOC = Total organic carbon  
 Tmax = Temperature of Maximum S2  
 S1 + S2 = Potential yield  
 Ro = Mean vitrinite reflectance  
 Hydrogen index = (S2 / TOC X 100)  
 S1 / (S1 + S2) = PRODUCTION INDEX

Figure 6.2 Geochemical log of Oil Well IF 30 03S

The distribution of TOC values (i.e. lower values at the top and relatively higher values at the bottom) is primarily accounted for

- 1) clastic dilution from sediment source areas.
- 2) post depositional biodegradation of the organic matter in sufficiently oxygenated water (eg. upper lacustrine facies).
- 3) larger input of aquatic organic matter (Type II) deposited in a reducing environment (as is the case in the lower lacustrine facies) than terrestrial debris (upper lacustrine facies).

In summary, sufficient organic matter appears to have been preserved throughout much of the section (or within at least some intervals) to quantify the samples as potential sources for hydrocarbons.

#### 6.3.2 Organic matter type

The type of organic matter (kerogen) deposited and preserved in sedimentary rocks subsequently influences the amount and composition of hydrocarbons that can be generated from the rock (Tissot and Welte, 1984; Hunt, 1979). Hence, distinction between the various types is essential for the proper source rock appraisal. Organic matter type, in this study, was defined using HI/Tmax crossplot and Rock-Eval pyrolysis based hydrogen index. From the position of the samples on the HI/Tmax diagram (Figure 6.3), they could be classified as type II and III kerogens.

The pyrolysis data clearly show that kerogen type varies along the vertical profile. Kerogen types trend from predominantly Type III at the top (upper lacustrine facies) to mainly Type II kerogen at the bottom (lower part of the fluvio-lacustrine and lower lacustrine facies). Such a



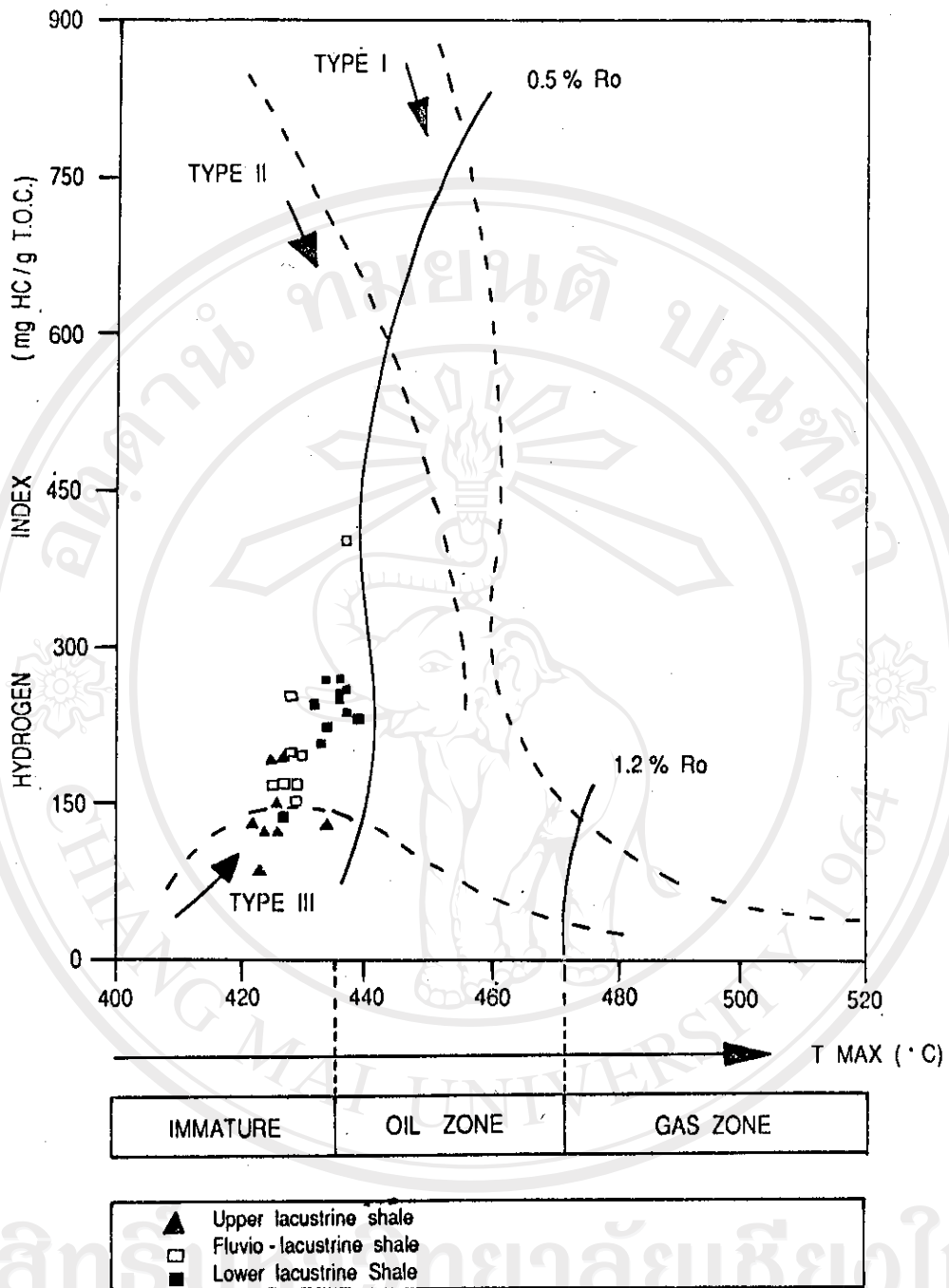


Figure 6.3 Hydrogen index / Tmax diagram (Organic matter type and thermal maturity)

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trend in kerogen type may reflect differential input of aquatic (Type II) and terrestrial (Type III) organic matter and could also be related to the depositional pattern. According to Demaison and Moore (1980), anoxic conditions are critical for the enhanced preservation of aquatic organic matter (as is the case for the lower lacustrine facies) that are the precursors of the oil prone Type II kerogen. Conversely, the presence of Type III kerogen (upper lacustrine facies) appears to have resulted from the transport of terrestrial organic matter into the lake, where oxic water column prevented the deposition of aquatic organic matter. Such conditions lead to comparatively enhanced preservation of the more resistant terrestrial organic matter (Type III) whereas the aquatic organic matter input is preferentially biodegraded. This assumption is also substantiated by the organic petrological studies (Section 4.4.3). For instance, some shaly layers within the lower part of the section contain abundant alginite which is a clear evidence of increased algal organic matter input.

The organic matter type was also assessed using Rock-Eval hydrogen index. Values range from 86-403 mg HC/g TOC, averaging to approximately 200 mg HC/g TOC. Average HI values tend to increase with depth. The average value for the upper lacustrine facies is 141 mg HC/g TOC; the fluvio-lacustrine facies - 208.6 mg HC/g TOC; and the lower lacustrine facies - 245 mg HC/g TOC. These values indicate medium to high source rock potential. Higher values were again recorded from the lower part of the fluvio-lacustrine and lower lacustrine facies. The variation in hydrogen index within the formation may represent variations in source rock quality.

To sum up, two sources could have contributed to the organic matter contained in the shales - 1) terrestrial (autochthonous) organic debris (Type III) 2) aquatic (allochthonous) organic material (Type II). Type II kerogen contains a mixture of amorphous and herbaceous organic matter or alternatively some alginite and higher plant exinites : sporinite, resinite and cutinite (in coal petrographic terminology). Type III kerogen is derived from humic organic matter (coaly and woody materials) and roughly corresponds to the vitrinite group (Stach, 1985). The downhole variations in organic matter probably reflect slight differences in the depositional environment, the degree of organic matter preservation, proximity to organic matter source etc.

From the above discussions, it is readily apparent that there is an increase towards better source rock potential from top to bottom. This trend is very easy to visualize when hydrogen indices and TOC values are crossplotted (Figure 6.4). Source rock potential seems to have increased from lower left to upper right of this diagram, owing to high HI and TOC values.

### 6.3.3 Level of thermal maturity

The primary purpose of kerogen maturation studies is to determine whether or not petroleum has been generated in source beds as to be preserved in reservoirs. Two approaches of maturation measurements were applied in this study : Rock-Eval parameters and vitrinite reflectance measurements. The maturation parameters derived from Rock-Eval pyrolysis analysis are

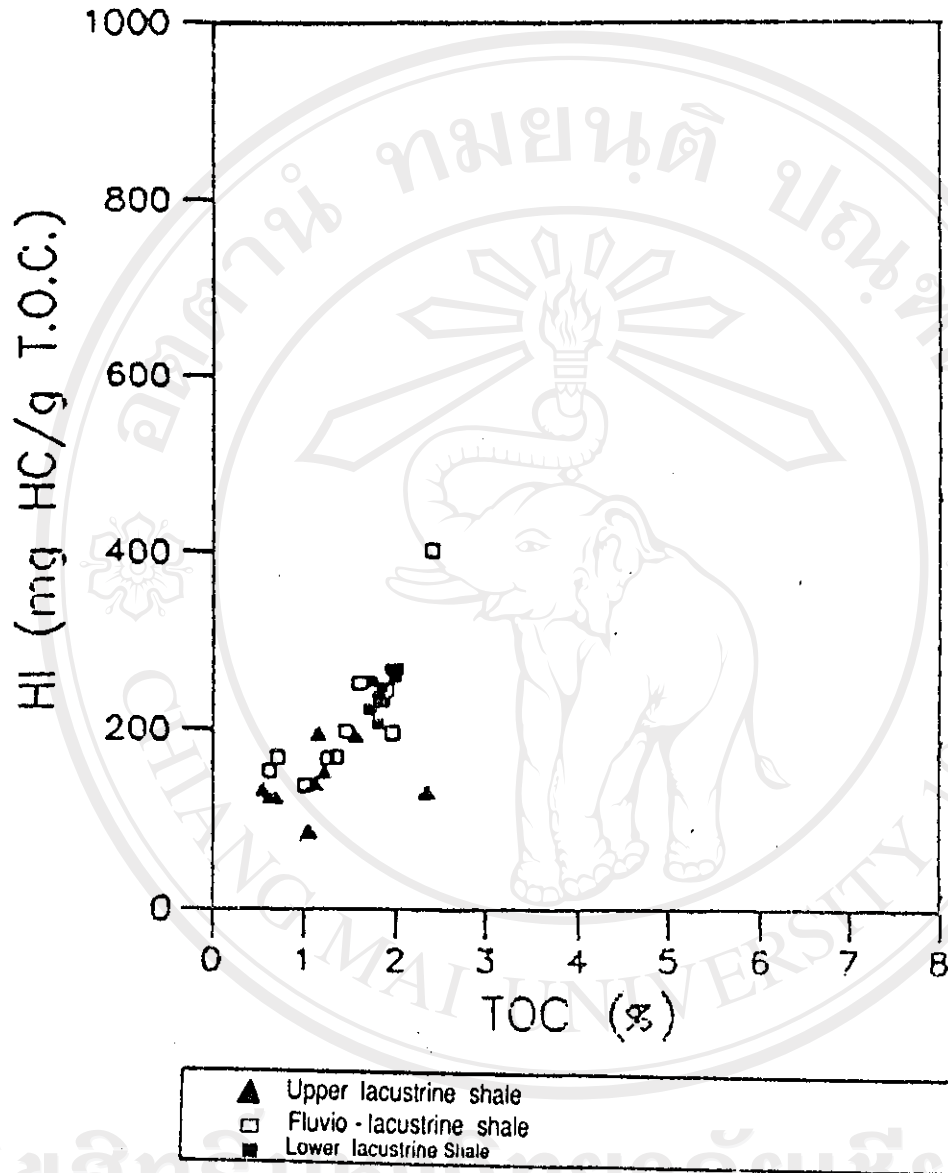


Figure 6.4 HI vs. TOC diagram showing increased source rock potential from lower left to upper right of the plot for the shale samples from Oil Well IF 30 03S

1) the  $T_{max}$  value, representing the temperature of maximum evolution of hydrocarbons during pyrolysis, and

2) the production index (PI) or transformation ratio,  $(S_1/S_1 + S_2)$  which is the proportion of free hydrocarbons ( $S_1$ ) released during thermal extraction and pyrolysis ( $S_1 + S_2$ ).

Both  $T_{max}$  and PI values increase as hydrocarbons are cracked from the kerogen during maturation.

Generally, source rocks are mature and generate oil at temperature ranges of  $435^{\circ}$  to  $460^{\circ}\text{C}$ . PI values of 0.1 and 0.4 mark the entrance and exit from the oil window (Tissot and Welte, 1984). The relationships between the various parameters of maturity and the corresponding zones of petroleum generation and destruction are illustrated in Figure 6.5.

Estimations based on  $T_{max}$  values ranging between  $422^{\circ}$ - $439^{\circ}\text{C}$  (this study) indicate the immature to marginally mature state of the samples.  $T_{max}$  values greater than  $435^{\circ}\text{C}$  (corresponding to the onset of oil generation) were exclusively noted from the lower lacustrine facies. Rock-Eval pyrolysis  $T_{max}$  based interpretation was cross checked using the vitrinite reflectance ( $R_o$  %) measurements. Vitrinite reflectance values vary between 0.39 and 0.48 % suggesting that the probable source rocks fail to reach what is conventionally stated to be the oil generation threshold ( $R_o = 0.5$  %). Thus the maturity profile is unclear. Two reasons could account for the inconsistency observed between  $T_{max}$  and  $R_o$  values :

1) the presence of alginite or bitumen can significantly lower vitrinite reflectance values (Cook and Ranasinghe, 1990).

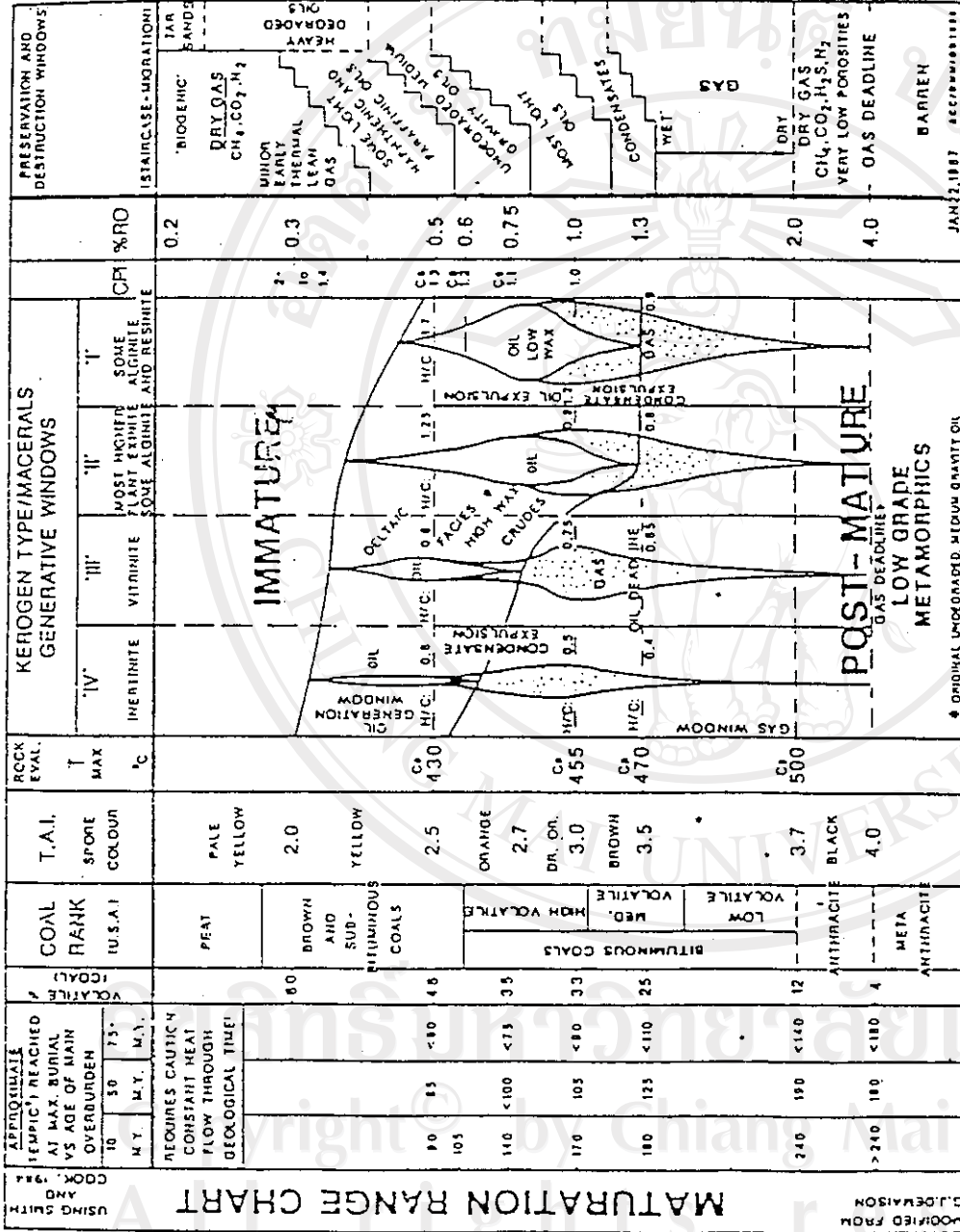


Figure 6.5 Maturational range chart indicating oil and gas windows, for the major macerals and kerogen types (after Cook and Ranasinghe, 1990)



2) Tmax values could be affected by what is termed as the mineral matrix effect (Peters, 1986; Cook and Ranasinghe, 1990).

Extrapolation of the vitrinite reflectance based maturity profile (Figure 6.2), suggests that the universally accepted Ro value (0.5 %) corresponding to the onset of oil generation can be attained at a depth of approximately 5400 ft.

Unlike Tmax and vitrinite reflectance measurements, the production index or transformation ratio is independent of organic matter type (Tissot and Welte, 1978, P.453) and should give a better maturation trend. This parameter ranges from 0.05 to 0.26 (Table 6.1) indicating the samples are immature to marginally mature.

#### 6.3.4 Petroleum (Genetic) potential

A semiquantitative evaluation of the petroleum potential can be achieved by using pyrolysis data i.e. the potential yield (S1 + S2). The quantity S1 represents the fraction of the original genetic potential which has been effectively transformed into hydrocarbons. The quantity S2 represents the other fraction of the genetic potential (the residual potential which has not been used to generate hydrocarbons).

Potential yield values of the analyzed samples vary between 0.72-9.71. Following Beicip's (1988) subdivision of petroleum potential using potential yield  $PY = (S1 + S2)$ , values for nine of these samples fall between 0.5-2.00, for 16 samples between 2.01-5.00 and 3 samples have values greater than 5, rating the source rocks as having poor, fair and good genetic potential, respectively. Relatively higher values varying between

3.75-5.46 from the lower lacustrine facies indicate higher petroleum potential. Values upto 9.71 from some discrete layers in the lowermost part of the fluvio-lacustrine facies still suggest a much higher source potential.

Extract chemistry (Table 6.2) can be used as a measure of source potential and the level of maturation (Cook and Ranasinghe, 1990). Source potential is usually assessed in relation to the amount of extract yielded and in particular, the proportion of the yield which comprises of hydrocarbons.

The source potential of a sample is generally assessed on the basis of a plot of the extracted hydrocarbon (in ppm) against the total organic carbon in the sample. It can be noted that the sample from the upper lacustrine facies is either lean-barren shale or have little or no source quality. The lower lacustrine shale sample, on the other hand, shows very good and/or excellent source quality (Figures 6.6 and 6.7).

#### 6.4 PETROLEUM SOURCE ROCK FACIES

The presence of an adequate volume of source rock facies is critical to the ultimate productivity of a sedimentary basin. Hence, the prediction, recognition and delineation of petroleum source units are primary tasks in basin evaluation and subsequent exploration.

A potential source rock as Barker (1980) defines it is a unit of rock that has the capacity to generate oil or gas but has not yet done so because of insufficient thermal maturation. Active source rocks in addition

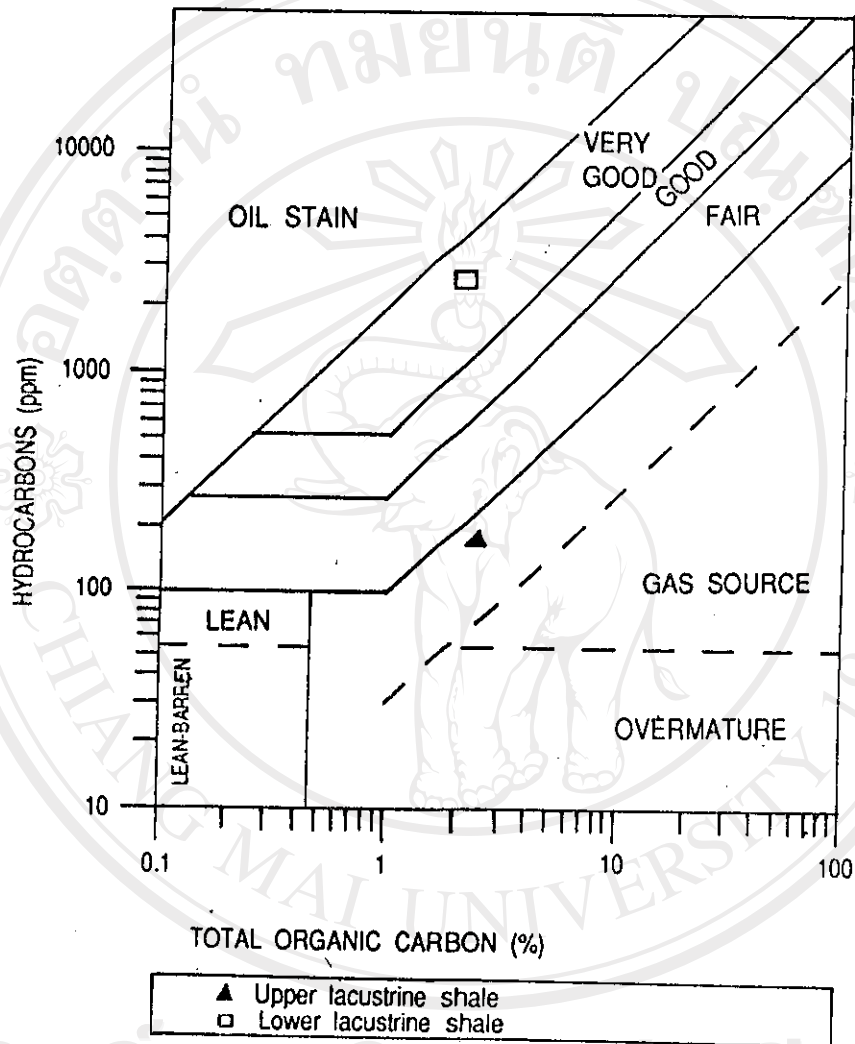


Figure 6.6 Source rock quality (potential) from the upper and lower lacustrine shales. Classification of source rock quality is after Cook and Ranasinghe (1990).

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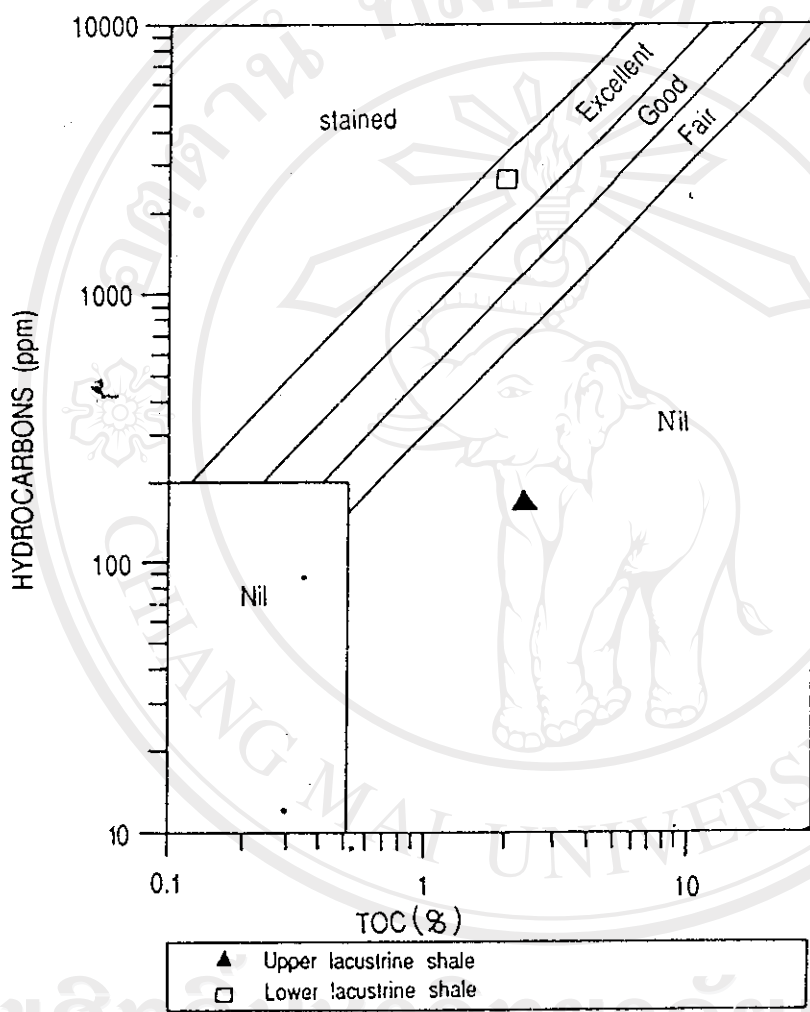


Figure 6.7 Source rock quality based on TOC content and extractable hydrocarbon yields of two samples from Oil Well IF 30 03S. Classification of source rock quality is after Powell (1978).

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to their initial enrichment of organic matter, have been subjected to sufficient burial and consequently thermal maturation to generate oil or gas.

In general, the evaluation of source rock facies must provide answers to the following questions :

- 1) does the rock have sufficient organic matter ?
- 2) is the organic matter of the appropriate type ?
- 3) has this organic matter generated petroleum ?
- 4) has the generated petroleum migrated out ?

As discussed above, the types of organic matter found in the shales and their state of preservation appears to have been associated with the depositional conditions and patterns. Hence, the facies and depositional environments interpreted (Section 3.3); the organic matter type as well as abundance, and the maturation level of the samples which are already defined here can be combined to give a clear picture about the characteristics and distribution of the source rocks :

- 1) The shales of the upper lacustrine facies have average to high (fair to good) organic carbon contents but the potential of the rocks to generate liquid hydrocarbons, as demonstrated by Rock-Eval pyrolysis, is extremely poor. These rocks contain Type III, gas prone, kerogen. Vitrinite reflectance measurements and pyrolysis based Tmax values indicate an immature state of the sediments. Relatively lower HI values and the extremely low hydrocarbon potential may reflect deposition in a shallow

oxygenated environment. Most of the sediments of this section are, therefore, considered to be non-source rocks (cf. Figures 6.6 and 6.7) or at most sources for gas.

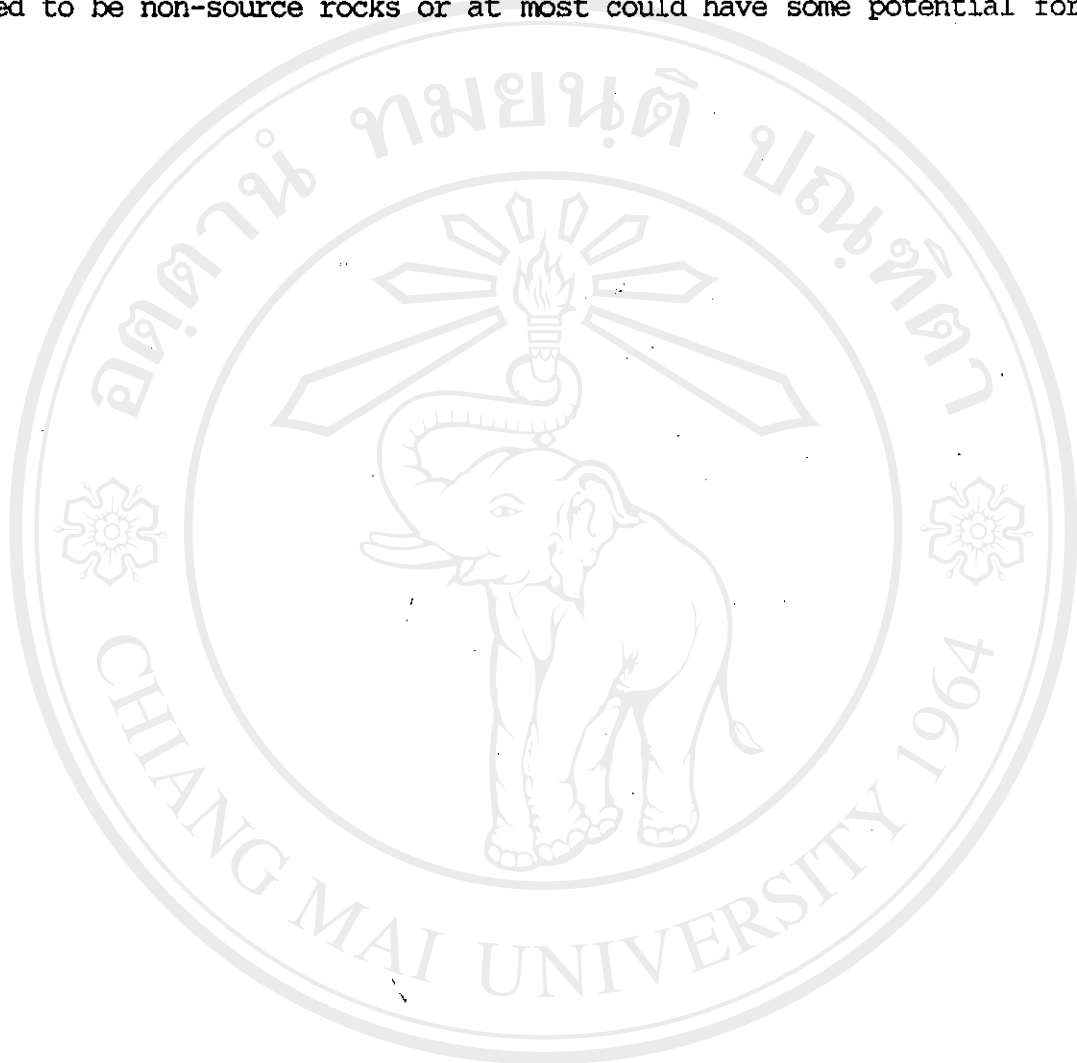
2) The lower lacustrine shale samples have generally high to very high (good to very good) organic carbon content, predominantly Type II kerogen, relatively higher hydrogen index values and therefore good hydrocarbon source potential (fair to good). However, the organic matter has not reached the expected level of maturity,  $R_o = 0.5 \%$  - corresponding to the oil generation threshold. Although there were no fully mature source rocks, the deeper samples were very close to the point where oil generation becomes significant. More mature sections and liquid hydrocarbon generation in laterally equivalent facies is possible. Therefore, by definition, shales of this section are considered to be potential source rocks.

Source rocks are known to generate some naphthenic and paraffinic oils in the maturation range of 0.4-0.55 %  $R_o$  (Figure 6.5). With much restriction, it is probable that this part of the section could have done so (?), although the generated hydrocarbon may not be significant. Shales of this section are marginally mature.

3) Samples from the lower part of the fluvio-lacustrine facies have sufficient organic matter (high-very high TOC values) and predominantly Type II kerogen and therefore good hydrocarbon potential (fair to good). Vitrinite reflectance and  $T_{max}$  values are too low indicating the immature state of the kerogen, hence liquid hydrocarbon generation is not possible. The sediments of this part of the section are also regarded as potential source rocks. Samples from the upper part have similar geochemical charac-



teristics to those of the upper lacustrine samples. Thus, they are considered to be non-source rocks or at most could have some potential for gas.



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