CHAPTER V

PETROLEUM SOURCE POTENTIAL

In the search for petroleum, petroleum geologists put great emphasis on the location of a proper structure, the presence of suitable reservoir permeability and porosity, and some type of cap rock. When all of these conditions were present but no oil or gas was found. It has been statistically determined that 60% of dry holes drilled thoughout the world are the result of lack of source rock. Rocks that generate petroleum are "potential source rocks" and can be classed as "source rocks" after commercial quantity of petroleum have migrated out of them. To reduce exploration risk of drilling dry holes, evaluation the petroleum-generative potentials of prospective source rocks appears to be the basic problem in petroleum exploration.

It now is generally accepted that petroleum is generated from organic matter which were accumulated into sediments during deposition. The analysis of organic matter in sedimentary rock is therefore critical to interpreting their petroleum generation potential. The objectives of this chapter are to assess the hydrocarbon potential of prospective source unit within the Wichian Buri sub-basin.

Geochemical Analysis

In order to identify the petroleum source rocks, rock cutting and sidewall core samples were collected from the unpublished, Wichian Buri-3, Si Thep-1 and Bo Rang-1 wells and geochemical analyzed for organic carbon content, kerogen type, and level of maturity of a source rock; total organic carbon, Rock-Eval pyrolysis, vitrinite reflectance, and visual kerogen description were also carried out by Core Laboratories International.

The first requirement in the recognition of a petroleum source unit is the determination of quantity of organic matter or organic richness. Two useful measurements related to quantity of organic matter are the total organic carbon (TOC) and generation potential ($S_1 + S_2$). Total organic carbon (TOC) provides an initial screen to identify possible source units. Further analysis may be limited to those horizons with above-average levels of enrichment (TOC>1.0%). Samples meeting this criterion should be examined for generative capacity. Those rocks yielding above-average total hydrocarbon generation potentials (S1+S2 > 2.5 mg HC/g rock) are considered the potential source rocks. Rocks yielding less amount may be either non-source (containing large quentities of sedimentary inert material) or post-mature.

The second step is to establish the principal hydrocarbon products of the source unit. The term KEROGEN has been defined as all the disseminated matter of sedimentary rocks insoluble in organic solvents. It is capable of generating hydrocarbons on heating. Kerogen is classified as type I, II, and III, depending on its elemental composition and its evaluation path on a van Krevelon diagram (Tissot and Welte, 1978). The kerogen type I, II, and III are really mixtures, with Type I generally comparable to algal-amorphous categories. It is a very good oil source. Type II is a mixture of amorphous and herbaceous organic material. It is a good oil source. Type III again is a mixture, but now of woody (vitrinite) and coaly (inertinite) material. It is a poor oil source, but can be a good gas source. The other organic matter classification system and relationship between these different classification systems are shown in Table 5.1. The determination of the type of kerogen uses pyrolysis indices (hydrogen index vs. oxygen index; hydrogen index vs. Tmax) and visual description of kerogen.

Table 5.1 Classification of organic matter in sedimentary rocks (Hunt, 1979).

	SAPROPELIC			HUMIC	
KEROGEN (by transmitted light)	Algal	Amorphous	Herbaceous	Woody	Coaly (Inertinite)
COAL MACERALS	Liptinite (Exinite)			Vitrinite	Inertinite
(by reflected light)	Alginite	Amorphous	Sporinite Cutinite Resinite	Telinite Collinite	Fusinite Micrinite Sclerotinite
KEROGEN (by evolutionary pathway)	Types I, II		Type II	Type III	Type III
H/C	1.7–0.3		1.4–0.3	1.0–0.3	0.45–0.3
O/C	0.1–0.02		0.2–0.02	0.4–0.02	0.3–0.02
ORGANIC SOURCE	Marine and lacustrine		Terrestrial	Terrestrial	Terrestrial and recycled
FOSSIL FUELS	Predominately oil Oil shales, boghead and cannel coals		Oil and gas	Predominately gas Humic coals	No oil, trace of gas

The third component in the identification of the source rocks is the thermal maturity. As source rock continues to get more and more deeply buried, it is subjected to a number of processes such as pressure increase, temperature increase, compaction and expulsion of water. Petroleum geochemists apply a general term to all these processes as THERMAL MATURATION. By definition, thermally immature systems are pre-generative; mature systems are presently in the "oil-window" and would presently be generating hydrocarbons if a source were present; and post-mature sequences have undergone intense organic diagenesis and are no longer capable of generating and/or preserving heavy hydrocarbons. The level of thermal maturation of the source rocks is an important parameter in the evaluation of the petroleum potential of a sedimentary basin. It can be estimated by a variety of methods. Some of those are used for interpreting thermal maturation of the Wichian Buri sub-basin such as visual analysis (SCI), vitrinite reflectance, and pyrolysis indices (Tmax, transformation). The relationship between these indices and the zones of hydrocarbon generation and preservation is present in Table 5.2.

1. Organic Richness and Generation Potential

In the unpublished, Wichian Buri-3, and Si Thep-1 wells, the organic richness and generation potential for each formations have been shown in Figure 5.1 and 5.2 and Table 5.3.

In general, the organic richness of sediments in the Wichian Buri sub-basin is considered good to very good, with about 80% of the samples show TOC values of greater than 1% and 65% show TOC of 1-5%. The highest TOC value is up to 10.2% at the unpublished well. Samples containing no organic carbon are none. The pyrolysis potential yields also indicate good to very good potential to generate hydrocarbons in organic-rich samples.

Table 5.2 Correlation of chemical and visual maturity indices (Bissada, 1983).

HYDROCARBON GENERATION ZONE	VITRINITE REFLECTANCE (R_o,%)	THERMAL ALTERATION INDEX	TIME TEMPERATURE INDEX	TRANSFORMATION RATIO	T_{max} (°C)
IMMATURE (BIOGENIC DRY GAS)					
	0.55	2.5	2	0.1	427
INITIAL OIL GENERATION (NO EFFECTIVE EXPULSION)					
	0.68	2.7	7	0.2	440
PEAK OIL GENERATION AND RELEASE					
	1.28	3.2	560	0.4	460
HEAVY HYDROCARBON DEGRADATION (WET GAS & CONDENSATE)					
	2.00	3.7	10,000	?	470
INTENSE ORGANIC METAMORPHISM (THERMAL DRY GAS)					

Figure 5.1 Plots of total organic carbon versus depth for each well.

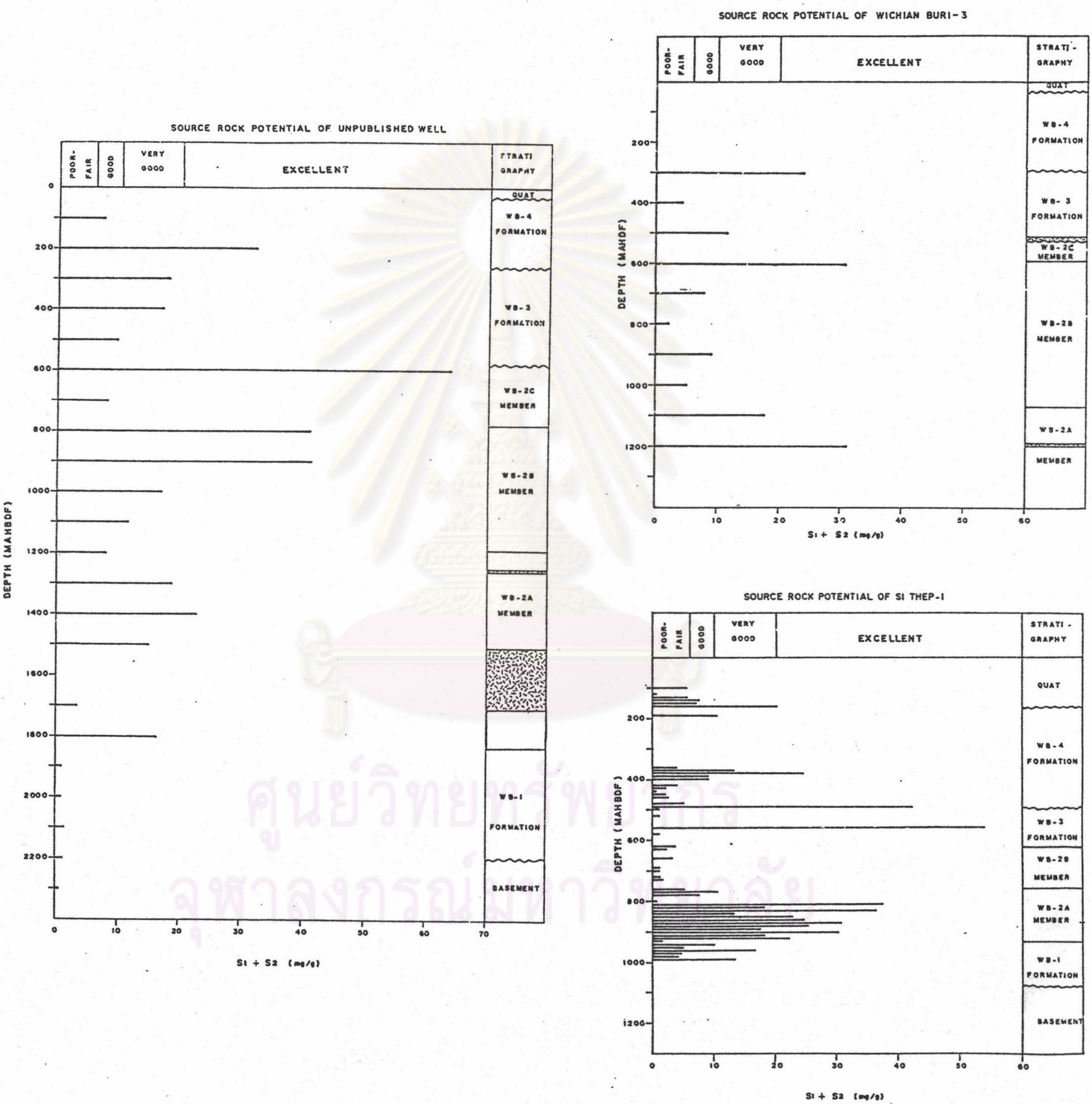

Figure 5.2 Plots of hydrocarbon generation potential versus depth for each well.

Table 5.3 A summary of organic richness and generation potential for the unpublished, Wichian Buri-3, and Si Thep-1 wells.

Well	Formation/ Member	TOC (%wt) Average	S1+S2(mg/g) Average
Unpublished	WB-1	1.23	0.71
	WB-2A	4.18	18.38
	WB-2B	4.26	23.6
	WB-2C	(10.2,1.6)[a]	(64.58,8.11)[a]
	WB-3	2.80	15.00
	WB-4	3.75	19.75
Wichian Buri-3	WB-2A	4.30	24.25
	WB-2B	1.57	5.88
	WB-2C	6.10[b]	31.30[b]
	WB-3	2.80	13.20
	WB-4	0.14	none
Si Thep-1	WB-1	1.79	8.66
	WB-2A	3.28	21.27
	WB-2B	0.81	1.76
	WB-3	1.85	12.11
	WB-4	2.20	10.64

a - only two samples

b - only one sample

These high measures of organic richness and generation potential indicate that significant oil and gas generation can be expected from the very good quality source rock material present within the interval penetrated at peak thermal maturity.

Area of high organic richness and generation potential mostly presents in the WB-2 Formation, that contains large quantities of Miocene lacustrine claystones, especially in the lower part, the WB-2A Member which contains significant thick lacustrine claystone. The WB-2A Member sediments contain 4.18, 4.30, and 3.28 % average TOC contents and 18.38, 24.25, and 21.27 mg HC/g rock average S_1+S_2 for the unpublished, Wichian Buri-3, and Si Thep wells in respectively, indicating the presence of very good source rock potential.

For the lacustrine claystone in the WB-4 Formation is less organic rich than the WB-2 Formation, and they have poor organic richness (< 0.5 %) and have no generation potential where the Wichian Buri-3 well penetrated. Therefore, the lacustrine WB-2 Formation sediments compare favorable in thickness and potential with demonstrated petroleum source rocks.

2. <u>Type of Organic Matter</u>

Type of organic matter was determined by using Hydrogen Index / Oxygen Index (Figure 5.3), Hydrogen Index / Tmax cross plots (Figure 5.4), and visual kerogen composition data (Figure 5.5). It confirms that liptinite, Type I/II oil prone kerogens in the form of alginite, cutinite, sporinite, resinite, and liptodetrinite forms the dominant kerogen component (35-80 %) in the organic rich samples, with subordinate quantities of vitrinite, Type III gas prone kerogen and inertinite, non-hydrocarbon prone matter.

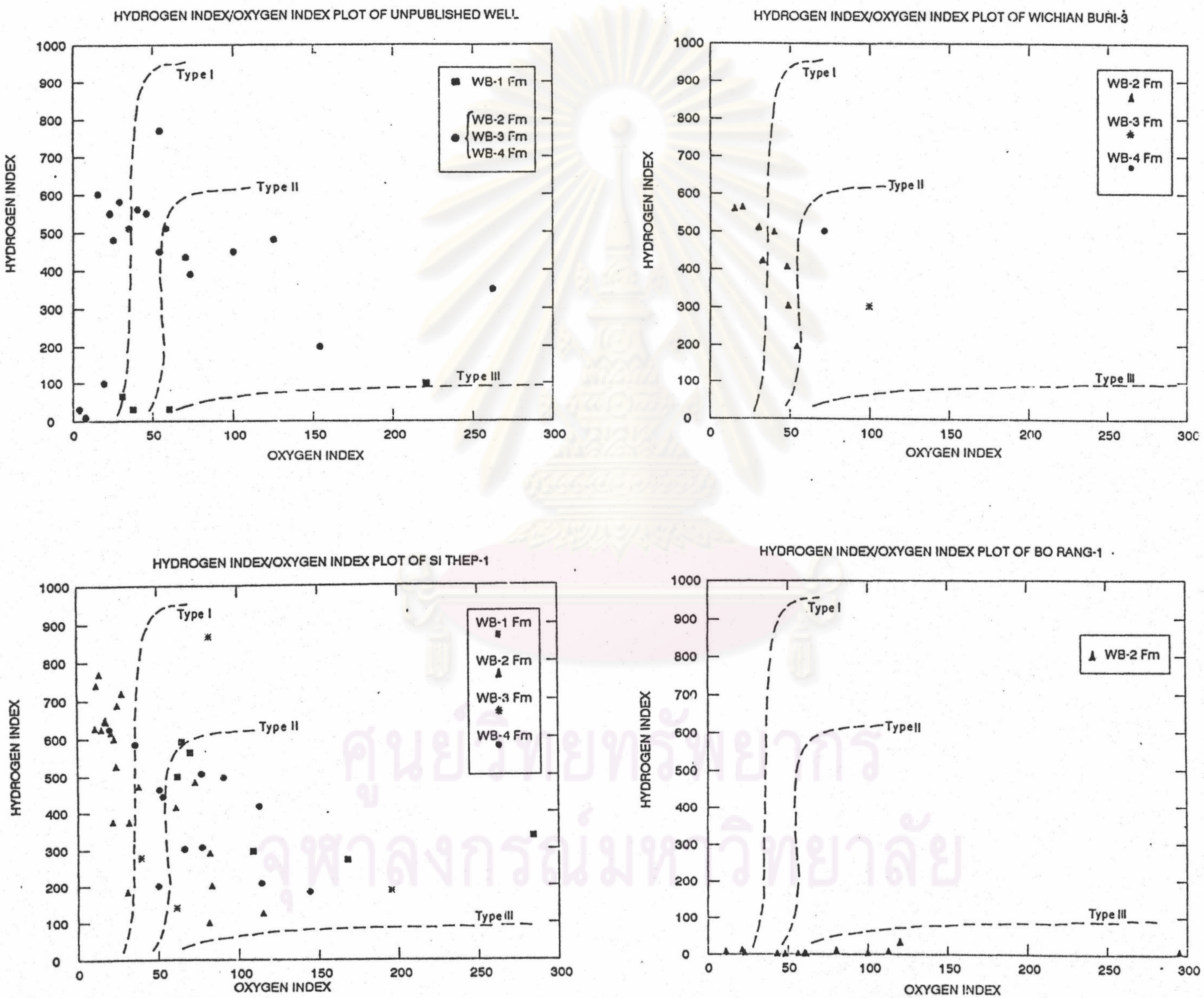

Figure 5.3 Plots of hydrogen index versus oxygen index for each well.

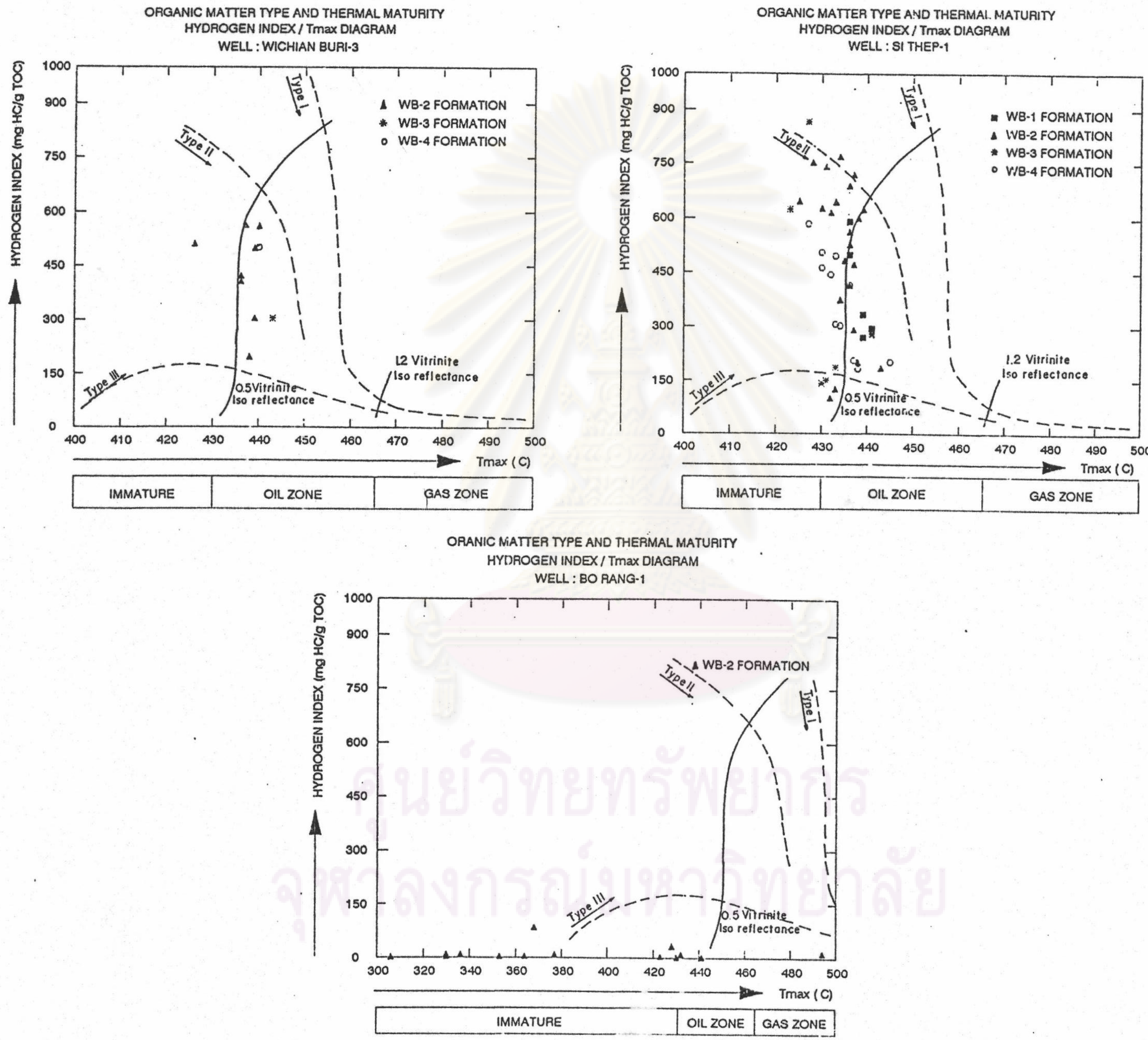

Figure 5.4 Plots of hydrogen index versus Tmax for each well.

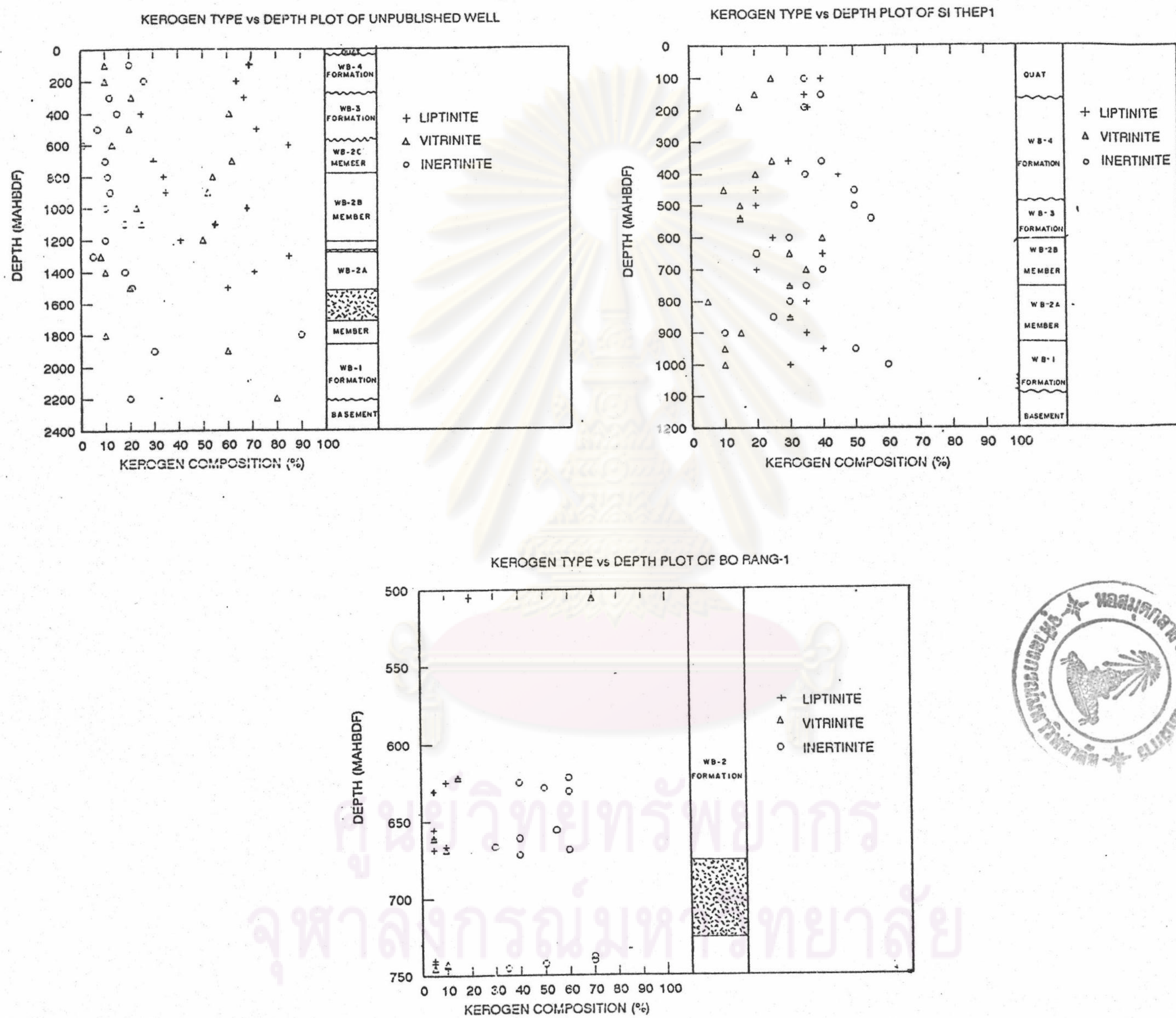

Figure 5.5 Plots of maceral composition versus depth for each well.

Comparison of kerogen component data from the unpublished and Si Thep-1 wells found that kerogen in the latter represents a more proportion of inertinite than the former. For the Bo Rang-1 well, in contrast from the others, inertinite non-hydrocarbon prone matter constitutes 55-70% of the maceral composition. However, the evidence of the presence of gas and igneous intrusion indicated on logs between 675-725 m. suggest that the organic matter may have originally been oil or gas prone kerogens, and may have generated hydrocarbons shortly after igneous intrusions and these hydrocarbons may have migrated away to accumulate at reservoirs. After the kerogen material subjected to extremely thermal effect, it would have been thermally degraded to poor quality non-hydrocarbon prone matter. Note that, data from the unpublished well, the Oligocene sediments of the WB-1 Formation which have a fair organic carbon content, are dominated by Type III kerogen with little potential for hydrocarbon generation.

Biostratigraphic data served to suggest that Type I and II kerogens is non-marine origin and derived from the fresh water *Botryoccocus* and *Pediastrum* algae. For vitrinite and inertinite macerals identified in the biostratigraphic study confirm an input of terrestrial higher plant matter.

In summary, kerogen assemblages are of mixed algal/ terrestrial depositional facies, where a mixture of algal matter and terrestrial higher plant material has been deposited in a fluvio-lacustrine environment. From the more proportion of inertinite in the Si Thep-1 well, indicates that sedimentation in the southern part of the Wichian Buri sub-basin deposited in the shallower condition and recieved higher fluvial influence when compared to the central part of the basin where the unpublished well located. The above data when combined with high hydrogen index (400-750) demonstrate that even under idealized conditions of maturation there is probably limited potential for generation of liquid hydrocarbons. So, significant oil generation is to be expected from the very good quality organic material present in the lacustrine sequence of the WB-2 Formation at peak thermal maturity.

3. Thermal Maturity

The correlation of SCI against Thermal Alteration Index (TAI) given on the SCI versus depth plot in the report was made by direct comparison of Staplin's standard slides with SCI standard slides (Figure 5.6).

The spore colour maturity profiles of the Wichian Buri-3 and Si Thep-1 wells where SCI values generally between 1 and 3 imply thermal immaturity, indicates that the entire well section is immature for hydrocarbon generation. However, igneous intrusions, if present, could increase the maturity of all or part of the well section, altering the maturity profile. In fact, the presence of igneous intrusions is noted in the stratigraphy of all wells, especially the Bo Rang-1 well where significantly thick intrusive rocks were observed and SCI values indicate high maturities with SCI between 5 and 6.

Vitrinite reflectance(Ro) profiles from the wells show that vitrinite reflectance increases regularly with increasing stratigraphic depth (Figure 5.7). From the Si Thep-1 well, vitrinite reflectance values range from 0.32 % to 0.4 %, and indicate the well section to be thermally immature for hydrocarbon generation. And as such, no significant generation has yet occurred from the WB-2 Formation within this well section. For the unpublished well, vitrinite reflectance values are also too low for hydrocarbon generation (Ro<0.5), except that values below 1400 m. are complex due to the presence of intrusives between 1510 m. and 1710 m., which increased the overlying and underlying vitrinite reflectance values. A maximum reflectance of 8.23% was measured in a sample immediately overlying the intrusive and below the sill,

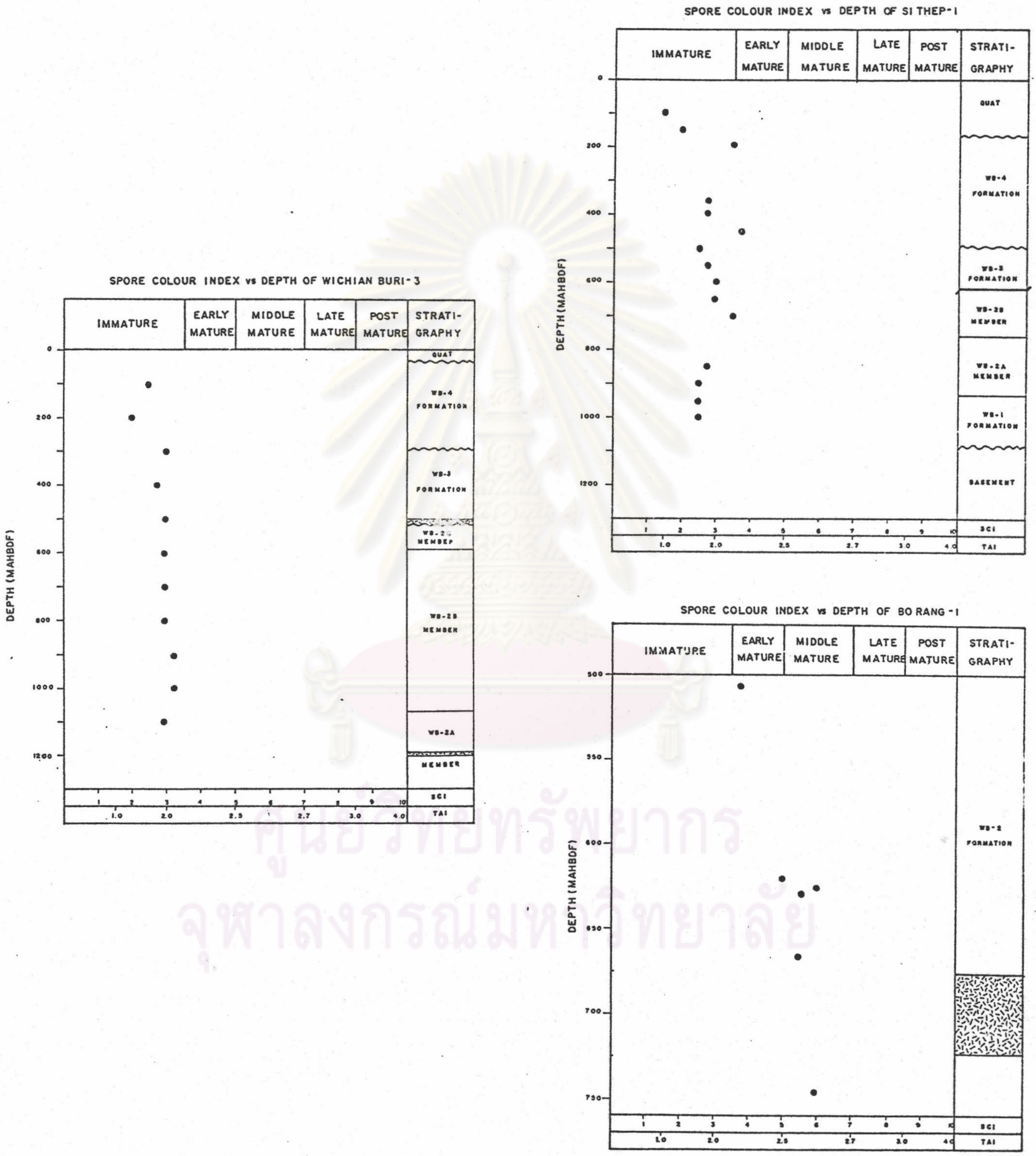

Figure 5.6 Plots of spore colour index versus depth for each well.

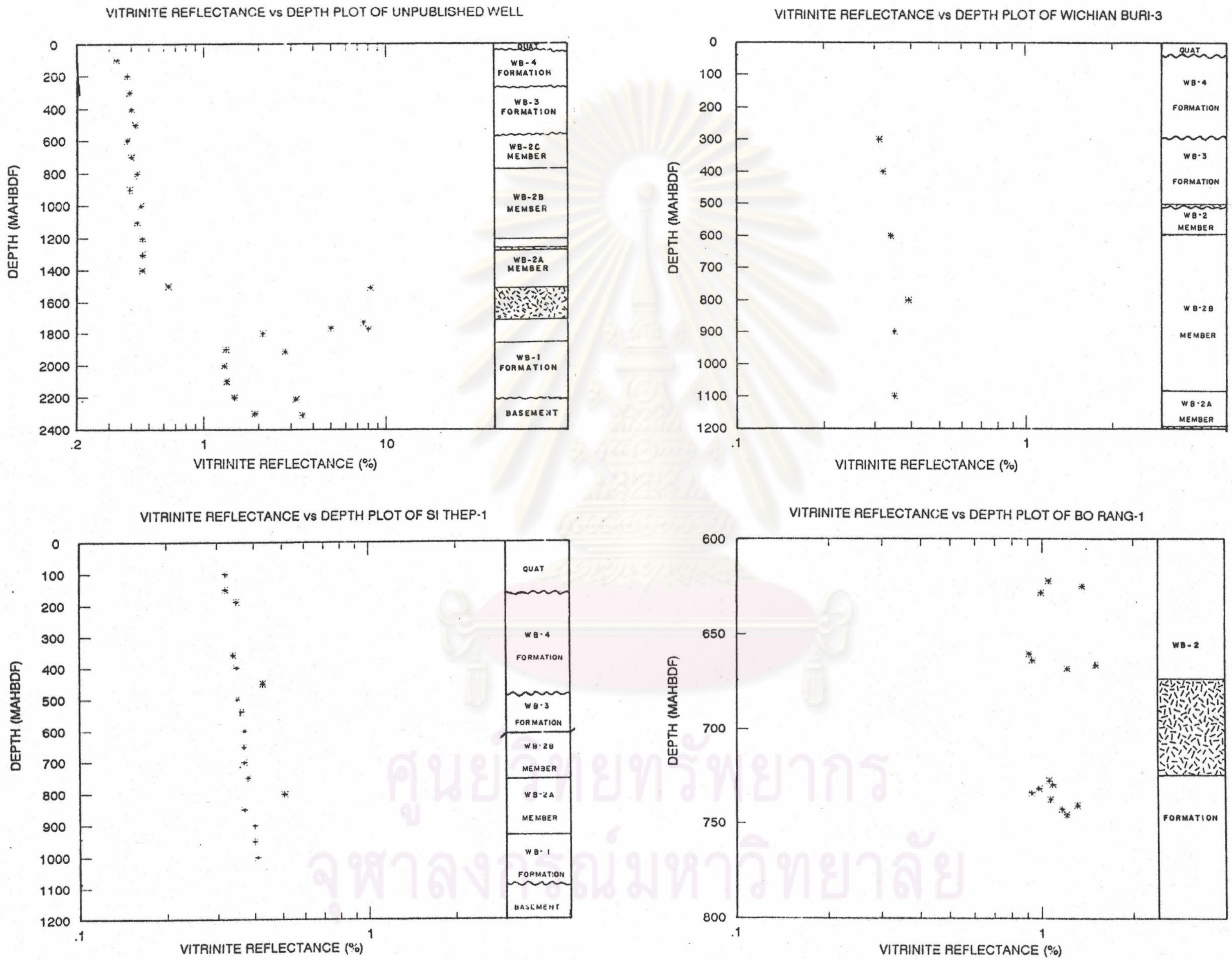

Figure 5.7 Plots of vitrinite reflectance versus depth for each well.

show a progressive decrease with distance from the sill. These values imply that Lower Miocene source material present is mature to post-mature for hydrocarbon generation. For the offset of vitrinite reflectance values within the WB-1 Formation, changing in kerogen type from liptinite-rich lacustrine sequence of the WB-2 Formation to vitrinite-rich fluvial sequence of the WB-1 Formation seems to the most likely explanation for this.

From Figure 5.7, vitrinite reflectance values define a clear trend within the Miocene sequence for the unpublished, Wichian Buri-3, and Si Thep-1 wells. Because the kerogens are Type I/II, and the top of oil window occurs at Ro = 0.7 for a Type I kerogen, 0.5 for Type II kerogen and 0.6 for Type III kerogen (Tissot and Welte, 1978). For convenice, depth of top oil window was calculated using the HP calculator displaced the construction of linear profile as shown in Table 5.4. Because the source rocks in Tertiary sedimentary basins of Thailand were mostly of lacustrine origin and have high sulfur contents. So, the depth at Ro = 0.7 is considered to be the most accurate position for the top of oil window. From Table 5.4, in the unpublished well, mature sections lie above and below the igneous intrusive, the source rocks would start generating oil at approximately 1453 m. and towards the contact of the igneous body is late- to post-mature for oil generation, the end of oil generation is at approximately 1945 m. Mostly mature sections lie below the intrusive within the bottom part of the WB-2A Member or the upper part of the WB-1 Formation.

From the above mentioned, the Early/Middle Miocene intrusives have had a significant effect on the surrounding claystones; resulting of the maturation levels. Also the Bo Rang-1 well, where large igneous intrusions have intruded. Vitrinite reflectance values range from 0.78% Ro to 1.50% Ro above the intrusion between 621.8 m. and 671.5 m. implying that all source material present is well within the oil window and towards the contact of the igneous body is late- to post- mature for oil

Table 5.4 A summary of top of oil window are calculated from vitrinite reflectance and Tmax profiles.

Well	**Ro**	**Depth (m)**	**Tmax (^{o}C)**	**Depth (m)**
Unpublished	0.7	1453 , 1945	435	1300 , 1399
	0.5	1445 , 1972	440	1362 , 2066
	0.6	1449 , 1958		
Si Thep-1	0.7	2560	435	828
	0.5	1576	440	937
	0.6	2109		

generation. Below the intrusion measured reflectance values range from 0.93% Ro to 1.21% Ro, again indicating middle- to late- thermal maturity for oil generation. Vitrinite reflectance profiles above and below the intrusion show no significant decrease in reflectance with distance from the contact. This implies that the thermal effect above and below the igneous intrusion is extensive, since it has placed source rocks within tens of meters distance from the igneous contact well within the oil window.

From vitrinite reflectance profile at the Si Thep-1 well, when calculated, defines the top of oil window approximately 2560 m. This depth should be the true depth that source rock in the Wichian Buri sub-basin started to generate oil in the stituent of no igneous affect.

The level of source rock maturity determined by vitrinite reflectance is in close agreement with the degree of maturation obtained by Tmax. In general, source rocks are mature and will generate oil at a Tmax range of 435^{o} to 460 ^{o}C. But the algal component of the kerogens of the Wichian Buri sub-basin is likely to increase the level of maturation required for generation to Tmax = 440 ^{o}C.

Plots of Tmax vs depth show Tmax values increase regularly with depth in all wells and show a scatter of values through the Tertiary sequence, but a trend can be defined within the Lower Miocene sequence (Figure 5.8). Using the HP calculator displaces the construction of linear profile, the onset of oil generate at Tmax = 435 ^{o}C and 440 ^{o}C are summarized in Table 5.4. For the unpublished well, boundaries of mature section at Tmax = 440 ^{o}C lie between 1362 m. and 2066 m. which are close to the depths derived from vitrinite reflectance data. However, the top of oil window derived from Tmax for the Si Thep-1 well is much different from the depth derived from vitrinite reflectance data. It can be noticed that Tmax values sometimes were

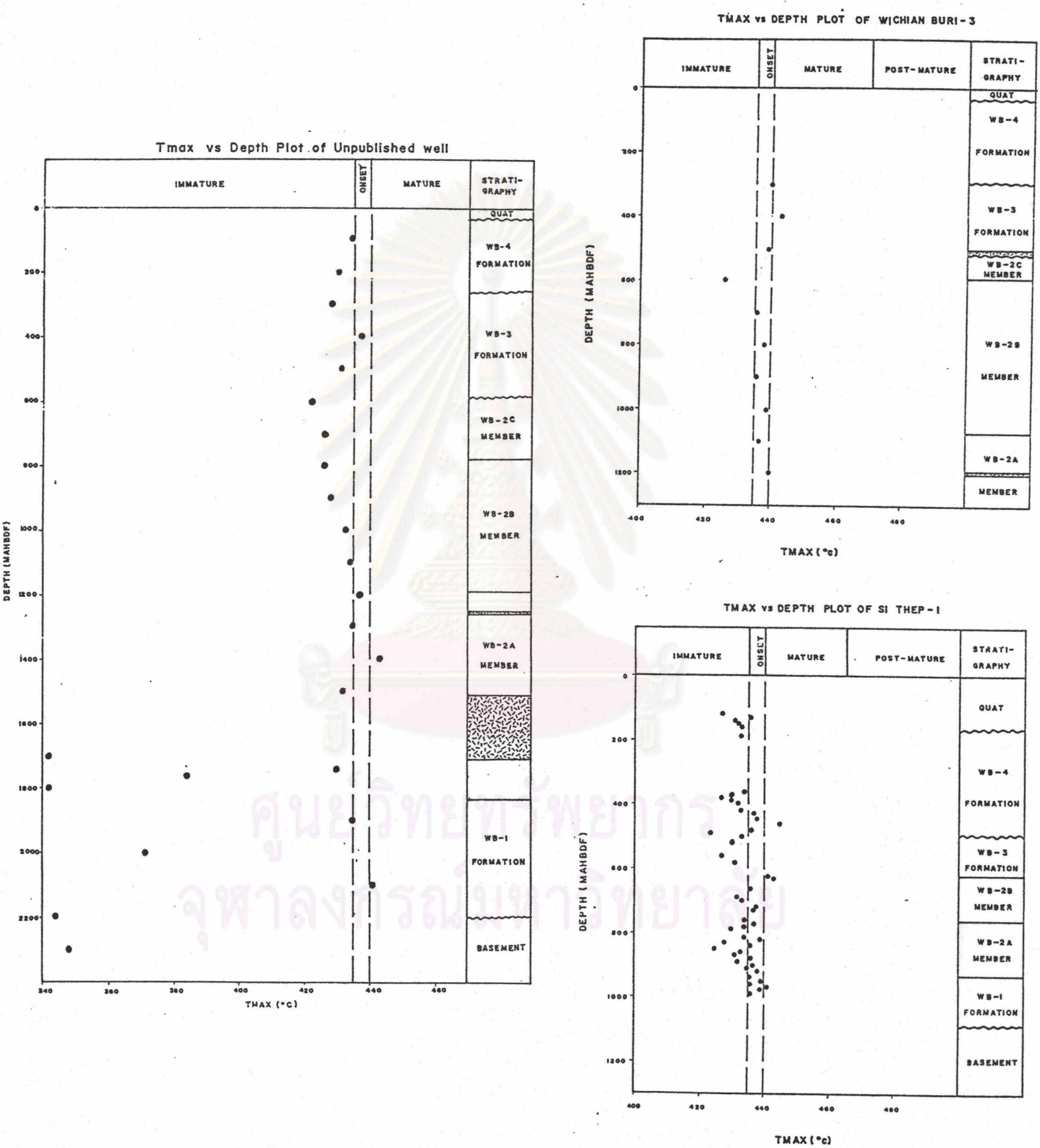

Figure 5.8 Plots of Tmax versus depth for each well.

found to be unreliable. Leckie et al., 1988 suggested that this may be that Tmax is a bulk parameter measured on the total organic fraction in the sample, whereas vitrinite reflectance values are measured on selected particles within the organic fraction.

The another plot which is commonly used is plots of Hydrogen Index vs Tmax (Figure 5.4). Tmax values for the Si Thep-1 well vary from 425°C to 443°C, indicating that the source material are immature to marginally mature. Tmax values those have been measured higher than expected oil window (435-440 °C), are possible the error data. Because other maturation indicators such as spore colouration, vitrinite reflectance, and transformation ratios confirm thermal immaturity of source material. For the Bo Rang-1 well, almost Tmax values are considered to be anomalous because these values were measured on the samples with S_2 peaks less than 0.2 mg HC/g rock, no accurate maturity estimates can be made using Tmax values measured on such these samples (Peters, 1986). Only the sample at 621.8 m. yielded a Tmax value of 494 °C, which is in agreement with other maturation indicators implying late thermal maturity.

The plots of transformation ratio (KTR), (S_1/S_1+S_2) also support the entire well section of the Wichian Buri-3 and Si Thep-1 wells to be immature for hydrocarbon generation due to KTR values less than 0.1. While, a plot of the transformation ratio from the unpublished well provides the most evidence of maturation associated with the intrusions (Figure 5.9). The KTR exhibits very little variation within the Miocene sequence, but is offset abruptly between 1400 m. and 1500 m. to values exceeding 0.4, indicating that the Lower Miocene claystones are post-mature for hydrocarbon generation; samples below the sill exhibit similar degrees of maturation. For the Bo Rang-1 well, the plot of transformation ratio also provides the evidence of maturation associated with the igneous intrusion.

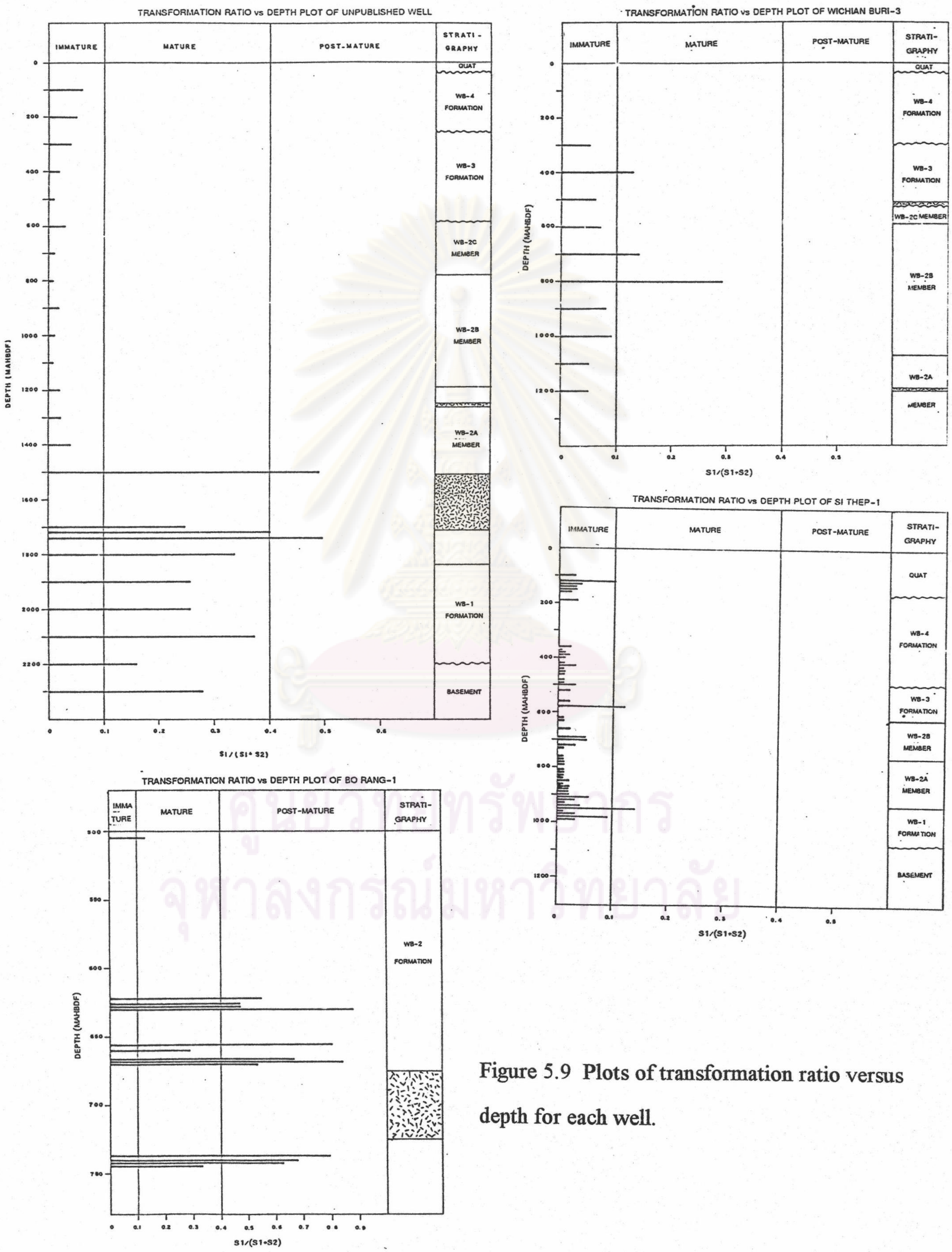

Figure 5.9 Plots of transformation ratio versus depth for each well.

Source Rock Volumetrics

Pyrolysis is the main analytical approach used to estimate the source rock volumetrics. The volume of hydrocarbon generated per unit of source rock can be obtained from pyrolysis data such as: total generation potential or total yield (S_1+S_2 in mg HC/g Rock or kg HC/tonne Rock)

Within maturation, the amount of the pyrolysate in the S_2 (generatable hydrocarbon) peak will fall, to be compensated by an increase in the S_1 (free hydrocarbon) peak. In close system, $S_1 + S_2$ is constant. However, if some hydrocarbon has migrated out (been expelled) of the source rock, S_1 will be depleted and if hydrocarbon has migrated in, S_1 will be enhanced. To calculate the amount of expelled oil, we can estimate from:

Expelled Oil = Total original yield ($S_1' + S_2'$) - Total final yield ($S_1 + S_2$)

The amount of oil that can be generated in the source rocks represented by the total original yield, can be obtain from pyrolysis data of immature(pre-expulsion) source rocks within the WB-2A Member of the Si Thep-1 well. For the final yield are available from pyrolysis data of mature source rocks of the unpublished well.

The original (immature) values are: $S_1' + S_2' = 21.27$ kg/tonne

And the final (mature) values are : $S_1 + S_2 = 18.38$ kg/tonne

Thus the rock has lost (expelled) 2.89 kg/tonne of hydrocarbon during burial from the immature to the mature stage. It can be express in terms of an "Expulsion Effciently" (ie; the fraction lost during burial through the oil window), which is defined as:

EE = (Total original yield - Total final yield) / Total original yield

= 0.14

The Expulsion Efficiency is about 0.14 or 14%.

The oil potential is expressed in units of kg'oil' / tonne rock. This unit must be convert to more appropiate volumetric units of cu.m.'oil' / cu.km. rock.

Where: 1 kg of oil has density = 0.88

1 tonne of rock has density = 2.3

Thus to convert kg/tonne to cu.m./cu.m.

multiply by (density of rock/density of oil)/1000 = 0.00261

A more useful volumetric unit is cu.m. 'oil' / cu.km. rock

where the multiplier is 2.61×10^6

From a source rock has an oil potential of 2.89 kg oil / tonne rock. The volumetric yield will then be:

$$2.89 \times 2.61 \times 10^6 = 7.54 \times 10^6 \text{ cu.m. oil / cu.km. rock}$$

This yield suggests that at least 7.54×10^6 cu.m. of oil have been generated and expelled from the source rocks occupy 1 cu.km.

Geothermal Gradient

The geothermal gradient of each well was estimated using the bottom-hole temperatures obtained from wire-line logs. Unfortunately, the temperatures recorded during logging operations, usually much lower than the true formation temperature. These low temperatures result due to the circulation of drilling mud that cools the formation as it is drilled. In order to correct the bottom-hole temperature approaching the true formation temperature, the Horner temperature plot can be used in this way under the basic that after the circulation stops, the bottom-hole temperature will rise until the mud and the formation were in thermal equilibrium. This will generally take some time. The equation of the Horner technique is;

TF = TL + K log (t1+t2)/t2

TF = True formation temperature

TL = Bottom-hole log temperature at time t2 (Maxinum record temperature)

t1 = Bottom-hole circulation time after drilling stopped and before the mud pump were shut off and the bit pulled.

t2 = Time interval between cessation of circulation and the measuring of TL

K = 1

To calculate TF, a semi-logarithmic grid is used. In x-axis, (t1+t2) / t2 is plotted on logarithmic scale. In y-axis, TL is plotted on a linear scale. The plotted points allow a line to be drawn (Figure 5.10). TF is read as the intersection of the line with the y-axis, for x=1.

For convenience, the TF was calculated using the HP-42S displace the construction of the Horner plot as shown in Table 5.5 a, b, c, d, e, f.

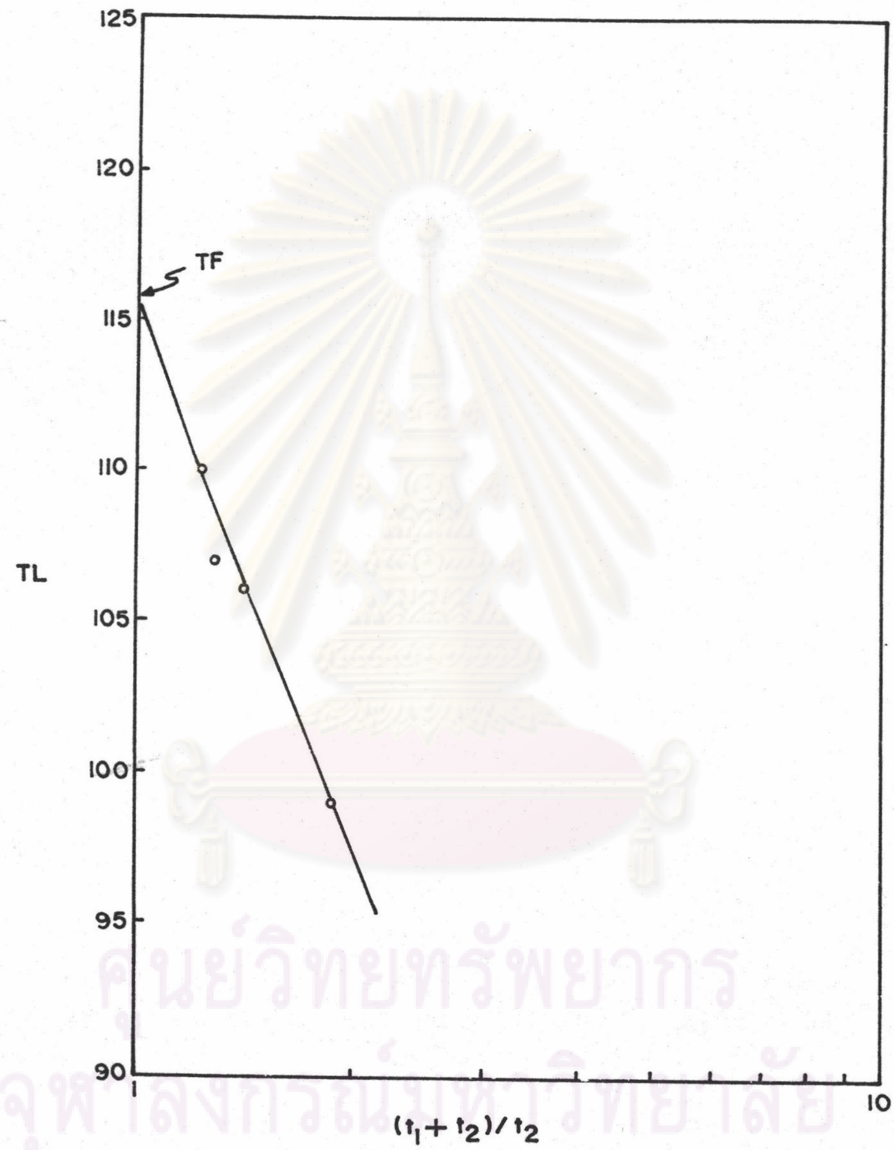

Figure 5.10 Example of Horner temperature graph for an idealized well.

Table 5.5a A summary of the calculation for geothermal gradient using the bottom-hole temperature of the unpublished well.

Well name UNPUBLISHED

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (°C)
DLL-MSFL-GR	444.5	1	6:10	1.1622	44.0
SHDT-GR	444.0	1	17:15	1.0580	41.0
SHDT PLAYBACK	444.0	1	16:35	1.0603	44.0

TF = 46 °C @ 444.17 m

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (°C)
LDL-CNL-GR-SP	1522.5	1	11:10	1.0896	76.0
CYBERDIP	1521.0	1	18:20	1.0357	88.0

TF = 83 °C @ 1521.75 m

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (°C)
DLL-SLS-MSFL-GR	2290.0	1	6:00	1.1667	77.5
LDL-CNL-GR-SP	2293.0	1	9:30	1.1053	85.5
SHDT-GR	2293.0	1	14:00	1.0714	91.0

TF = 102 °C @ 2292 m

Geothermal gradient = 3.3 °C/100m

Table 5.5b A summary of the calculation for geothermal gradient using the bottom-hole temperature of the Wichian Buri-2 well.

Well name W ICHIAN BURI-2

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^oC)
DLL-SLS-CA-GR	401	1	2:51	1.400	41

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^oC)
CHECK SHOT	1241	1	19:50	1.050	71.1
SHDT-GR	1245	1	15:21	1.066	71.1

TF = 71.1 ^oC @ 1243m

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^oC)
DLL-MSFL-SLS-GR	1256	1	5:42	1.185	63.3
LDL-CNL-GR	1258	1	11:00	1.090	68.3

TF = 73.46 ^oC @ 1257m

Geothermal gradient = 3.7 ^oC/100m

Table 5.5c A summary of the calculation for geothermal gradient using the bottom-hole temperature of the Wichian Buri-3 well.

Well name WICHIAN BURI-3

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^{o}C)
DLL-SLS-CAL-GR	395.5	1	3:07	1.326	41.7

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^{o}C)
RFT-HP-GR	960	1	10:09	1.099	65.1

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^{o}C)
CHECK SHOT	1168	1	13:45	1.074	71.7
SIDEWALL CORES	1170	1	17:15	1.058	71.7
ML-GR	1174.5	1	10:52	1.095	70.0

TF = 74.87 ^{o}C @ 1170.83m

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^{o}C)
FMS-GR	1183	1	16:27	1.061	72.2
DLL-MSFL-SLS-GR	1185	1	5:20	1.192	64.4
LDL-CNL-GR	1186	1	10:52	1.095	70.0

TF = 76.12 ^{o}C @ 1184.67m

Geothermal gradient = 4.2 ^{o}C/100m

Table 5.5d A summary of the calculation for geothermal gradient using the bottom-hole temperature of the Khao Leng-1 well.

Well name KHAO LENG-1

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^oC)
CBL-VDL-GR-CCL	595	1	5:42	1.185	55.5
BHC-CAL-GR	600	1	4:30	1.232	55.5

TF = 55.5 ^oC @ 597.5m

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^oC)
DLL-AS-MSFL	901.5	1	6:56	1.152	61.0
FMS-GR	905.5	1	16:31	1.061	64.0
LDL-CNL-NGS	905.5	1	10:42	1.096	63.0
CHECK SHOT	906.5	1	20:15	1.050	68.0

TF = 69.25 ^oC @ 904.75m

Geothermal gradient = 4.7 ^oC/100m

Table 5.5e A summary of the calculation for geothermal gradient using the bottom-hole temperature of the Si Thep-1 well.

Well name SI THEP-1

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^oC)
DLL-LSS-GR-SP	395	1	3:00	1.333	46.7

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^oC)
DLL-AS-MSFL-GR	986	1	5:15	1.194	68.9
LDL-CNL-GR	986	1	24:00	1.042	77.7
FMS-GR	986	1	13:00	1.077	80.0

TF = 82.84 ^oC @ 986m

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^oC)
DLL-AS-MSFL-GR	1305	1	6:26	1.159	81.1
LDL-CNL	1305	1	15:15	1.066	92.2

TF = 100.68 ^oC @ 1305m

Geothermal gradient = 5.7 ^oC/100m

Table 5.5f A summary of the calculation for geothermal gradient using the bottom-hole temperature of the Bo Rang-1 well.

Well name BO RANG-1

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^{o}C)
DLL-LSS-MSFL-GR	499	1	10:45	1.096	49

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^{o}C)
LSS-CAL-GR-SP	992.5	1	5:30	1.189	61
LDL-CNL-GR	924.0	1	9:45	1.106	63

TF = 65.78 ^{o}C @ 993.25m

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^{o}C)
CHECK SHOT	1504	1	17:30	1.058	82

Log name	Depth logger (m)	t1 (hr)	t2 (hr)	(t1+t2)/t2	TL (^{o}C)
DLL-LSS-GR-SP	1641.5	1	7:35	1.136	80

Geothermal gradient = 3.4 ^{o}C/100m

Geothermal gradients within the Wichian Buri sub-basin range from 3.3 $^{o}C/100m$ to 5.7 $^{o}C/100m$. The lowest gradient was measured in the central basin and reflects the thickness of Tertiary sediment. Gradients increase toward the basin margins with a basin average of 4.1 $^{o}C/100m$. It appears to have higher than an average normal geothermal gradient (3 $^{o}C/100m$). This may be reflected to the igneous intrusives

The average geothermal gradient can be used combine with other parameters for determining source rock maturity in relatively unexplored area by Pigott (1985) 's equations.

$$T = 164.4 - 19.39 \ln t \qquad (1)$$

T = Threshold temperature in ^{o}C

t = Sediment age in 10^{6} years

and
$$D_{oc} = 100((T - Ts) / (dT / dZ)) \qquad (2)$$

D_{oc} = Depth in meters for the oil ceiling

T_s = Mean surface temperature

dT/dZ = Geothermal gradient in $^{o}C/100m$

Using the equation 1 and 2, the Wichian Buri sub-basin where the potential source rocks buried in Early Miocene (approximately 24 x 10^{6} years), the surface temperature averages 31 ^{o}C and the geothermal gradient averages 4.1 $^{o}C/100m$, gives a depth to the oil ceiling of approximately1850 m.

Source Rock Potential

Generally, most of the sediments in the Wichian Buri sub-basin are good quality source rock material. The best source rocks were analyzed to be the Miocene lacustrine claystones in the WB-2 Formation, especially in the lower part, the WB-2A Member which contains significant thick lacustrine claystones, rich in organic content and with high source potential. The source material contain Type I/II kerogens, with Type I kerogen better occurring in the deeper garben areas. Biostratigraphic data confirm that much of the organic component of the sediments comprises of a mixed fresh water algal/terrestrial source are favorable for oil generation at peak thermal maturation.

Potential source rocks in the WB-2 Formation are immature over much of the basin. However, maturity indicators such as spore colouration, vitrinite reflectance and transformation ratio confirm thermal maturation of the source rocks adjacent to the Miocene intrusives. Present-day geothermal gradients within the basin have been calculated, range from 3.3-5.7 ^{o}C/100m with average of 4.1 ^{o}C/100m. Consideration of this value suggests that the source rocks lie below 1850m, have an opportunity to generate hydrocarbons. In conclusion, mostly the source rocks in the Wichian Buri sub-basin are immature and are mature to post-mature where they are affected by igneous intrusions and in the deep part of the basin where intrusives are not present.