

5) The Khon Kaen–Ubon area, gas are reported found in both Permo-Carboniferous and Triassic Pre-Khorat reservoir. Some seismic stratigraphy underlain the Khorat Group which does not show a characteristic of Permo-Carboniferous sequence is thought to be a Devonian strata. Further more, reprocessing of old seismic sections are recommended, since it is proved by the Phu Wiang-1 well where the unclear and unidentified section below the Triassic Pre-Khorat rocks turned out to be thrust Permian section.

2.7 Petroleum prospect in Permian basin play

These Permian basin plays contain Saraburi Group of rocks, consisting of upper clastic, Pha Nok Khao, and lower clastic formations. The upper clastics or Lam Pao formation (Hua Na Kham formation), represent the top section and the lower clastics or Si That, represent the bottom section, with Pha Nok Khao or Permian carbonate rock, contained in between.

Permian play types may lie beneath either Triassic semi-graben basins or Khorat Group, or with thin layers of Huai Hin Lat Group in between. Actually, Nam Phong and Sinphuhorm gas field represent Permian basin play. Department of Mineral Fuels (2007) summarized that the play types consist of the following.

2.7.1 Permian carbonate fault-reactivated anticlines

The anticlinal play type resulted from fault lines in Pha Nok Khao formation that moved further away. Formerly normal faults of Permian age, these became reverse faults with the collision during Indosinian Orogeny I and II of Western Myanmar, Shan Thai, and Himalayan Orogeny. These Permian carbonate fault-reactivated anticlinal play types tend to have reverse fault lines, or virtual thrust lines,

as major fault lines. One finds Huai Hin Lat Group, and thin Triassic Group overlying Saraburi Group, with Pha Nok Khao formation (Permian carbonate rock) or Si That formation being moderately thin.

2.7.2 Permian basin inversions and reactivated fault-anticlines

The anticlinal play type resulted from the inversions and reactivated faults of Permian basins with Saraburi Group deposited in them. These play types is not as prominent as the Permian carbonate fault-reactivated anticlines.

2.7.3 Permian reverse fault relate folds/Khorat flats

The Saraburi Group play type is related to reverse fault or thrust fault, causing folding before the Khorat Group were laid down, after which these faults were in place, thereby not causing the folding of the Khorat Group or some insignificant folding, while the Saraburi Group contained numerous folding.

2.7.4 Tertiary reverse fault-related folds

The anticlinal play type resulted from reverse faults that occurred after the Khorat Group had been laid down. These faults, which could have been Tertiary age, caused anticlines on the faults. In contrast to other play types, major thrust faults cut through the Khorat Group.

2.7.5 Shallow Permian/Permo-Carboniferous anticlines

The anticlinal play type occurred after the Khorat Group had been laid down as relatively thin layers compared with other play type. Underneath the Khorat Group, one could find the Saraburi Group or older rocks at fairly shallow depths.

2.7.6 Thick Permian carbonate rocks

The play type relies on very thick the Saraburi Group in a series of anticlines and synclines beneath the Khorat Group with few fault lines cutting across.

The bottom section of the Saraburi Group is not well defined. One could roughly predict that the play type underlie the Phu Phan Anticlinorium range with several prospects.

2.7.7 Permian reefal build-up

The reefal build-up play type of the Saraburi Group is cut across by faults. Nevertheless, the faults seemed to stop even when experiencing Indosinian Orogeny I and II due to the collision of Western Myanmar with Shan Thai or Himalayan Orogeny. As a result, the overlying the Khorat Group remains relatively flat with hardly any folding.

2.8 Exploration history in the Chonnabot prospect

This prospect is located in the east of the N-S fold belt. It formed as the N-S trending fold parallel to the Loei-Phetchabun fold belt. There are two seismic series run across and two wells (Chonnabot-1 well and Phu Wiang-1 well) drilled in this area.

2.8.1 Seismic interpretation of Permian carbonate fault-reactivated anticlines play type

In genrallly, the folding in the Khorat Plateau is as a result of basin inversion and reactivated faults. It is not controlled by pre-existing structure. The Chonnabot prospect shown anticline not related basin inversion structural style.

Two seismic series (Chantong, W., 2005) present in this prospect that (1) seismic profile line 86 (Figure 2.6 to 2.7), and (2) seismic series consist of seismic profile lines 27, 90, 29, 30, and 88 (Figure 2.8).

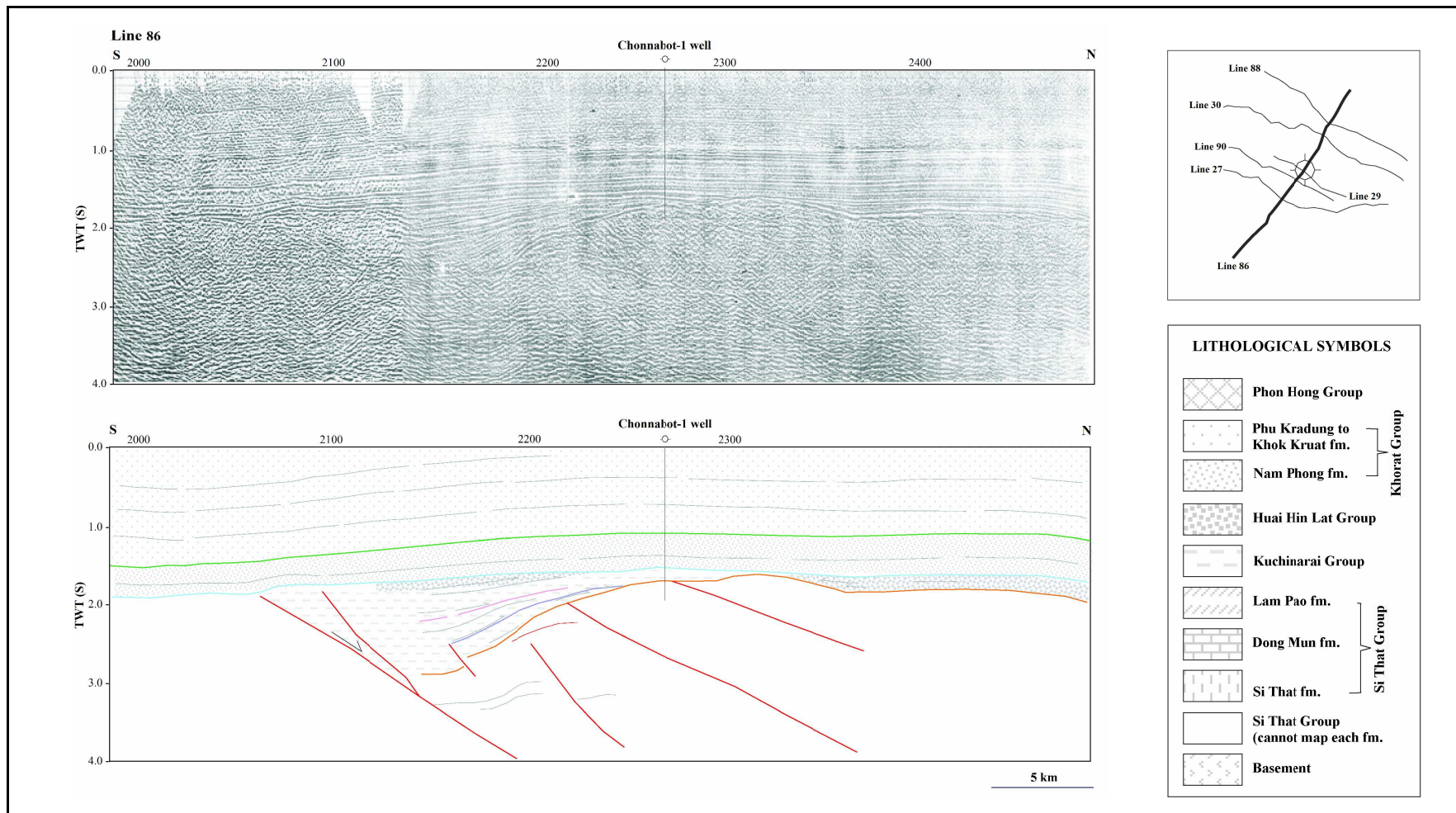


Figure 2.6 Seismic profile line 86 in the Chonnabot prospect (Modified from Chontong, W., 2005).

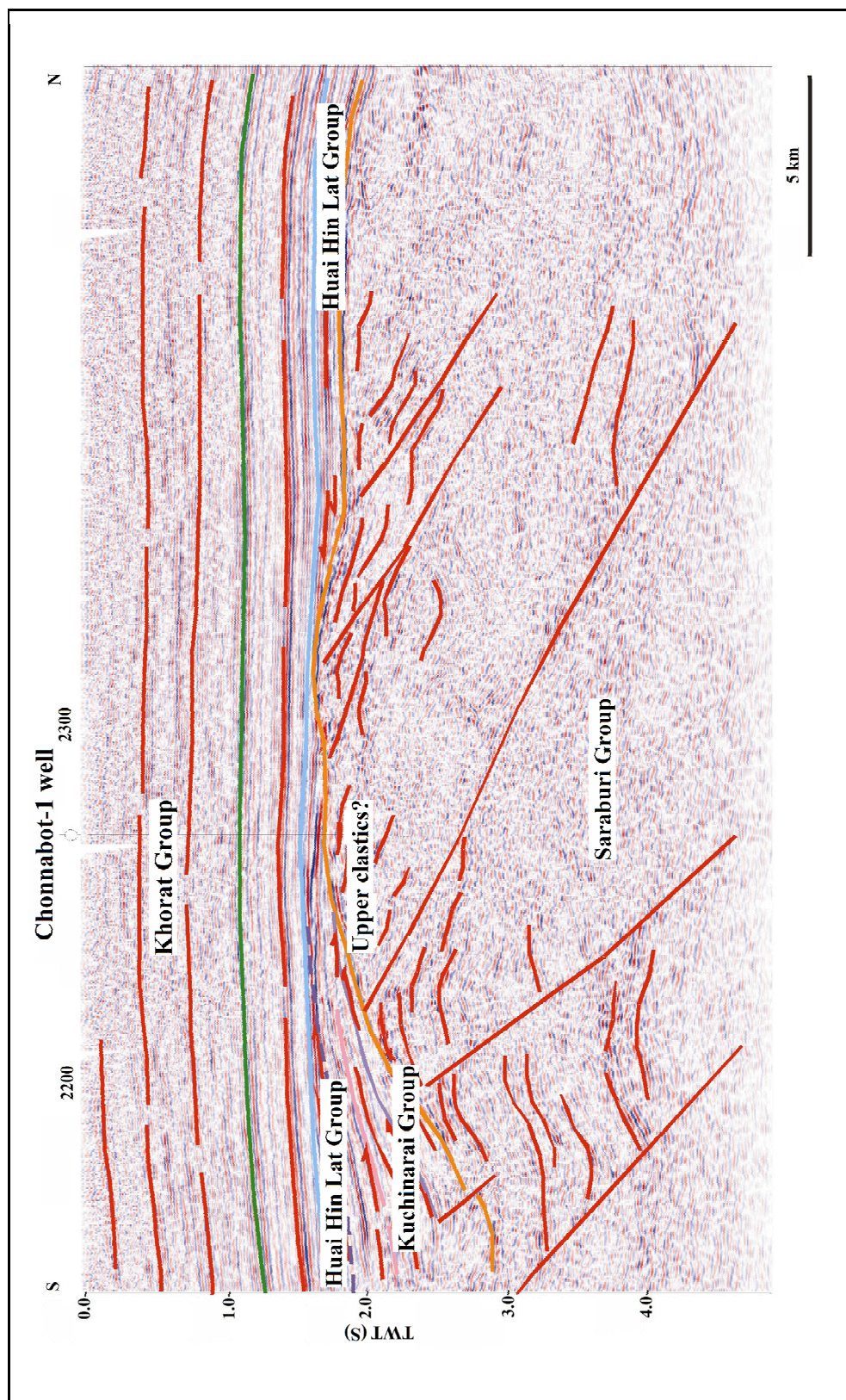


Figure 2.7 Cross-section of Chonnabot prospect from seismic profile line 86 (Modified from Chontong, W., 2007).

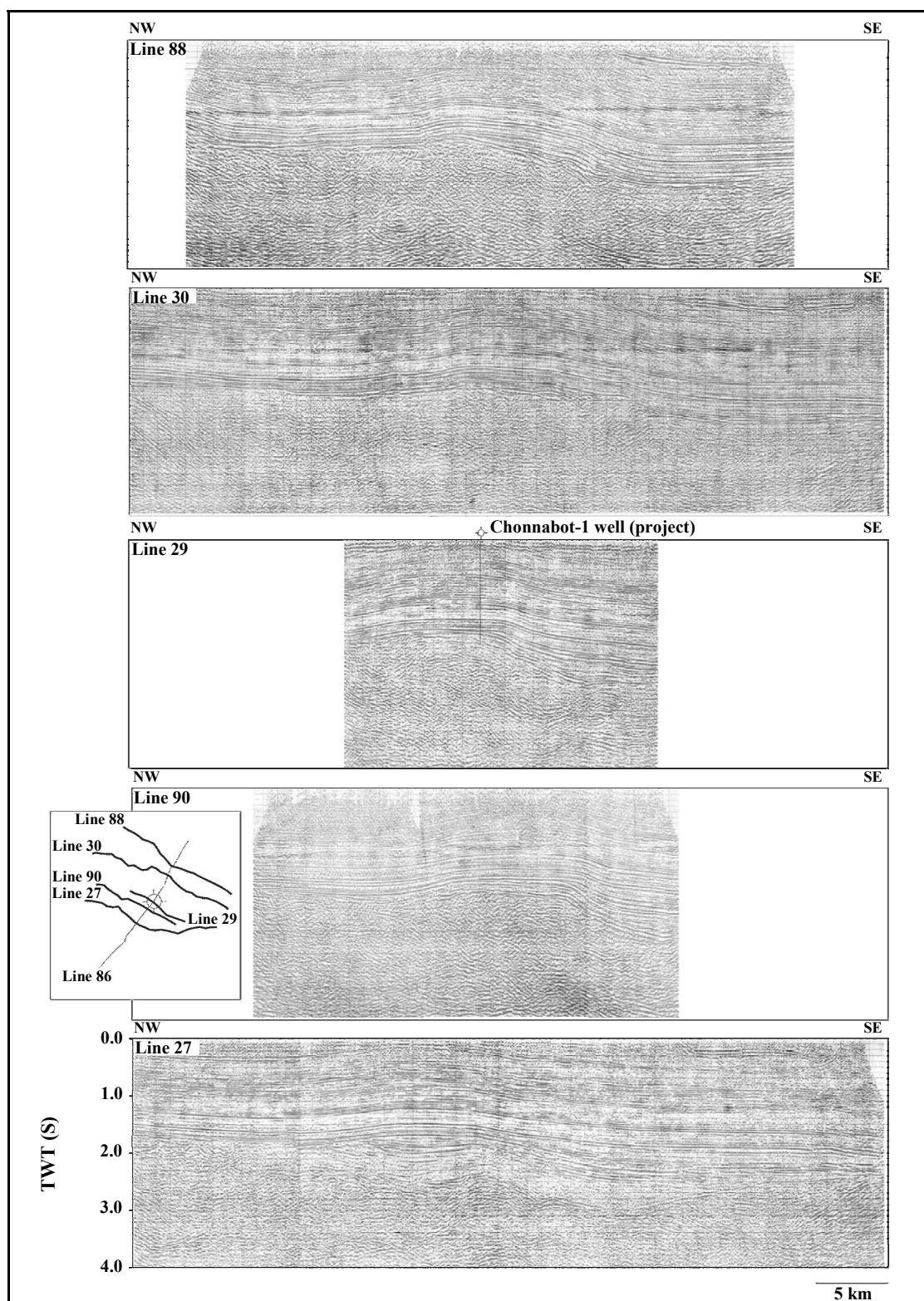
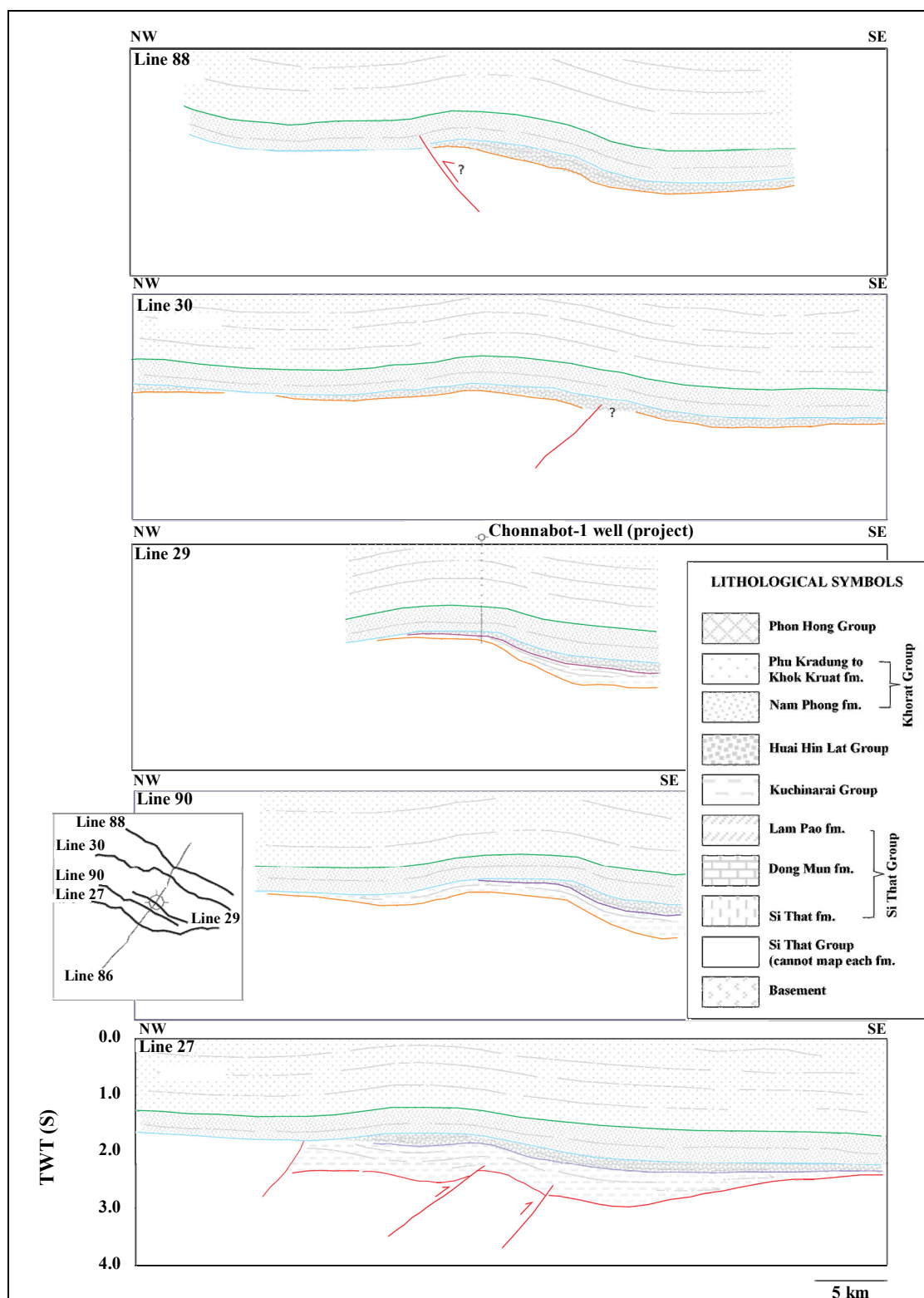


Figure 2.8 Seismic series of profile line 27, 90, 29, 30, and 88 in the Chonnabot prospect (Modified from Chontong, W., 2005).



The seismic profile line 86 run from S to N (Figure 2.6 to 2.7), which run parallel the fold trend as present on the surface shows the Triassic half graben is controlled by the N dipping normal fault and underneath the undeformed the Khorat Group. The Kuchinarai Group filled in the half graben and pinches out at the north. The Huai Hin Lat Group deposited over the half graben and the Si That Group. It also shows the onlap termination with the basement.

The seismic series consists of seismic profiles run from NW to SE (Figure 2.8), display wavelength fold of the Khorat Group. There is no main fault interpreted across the profiles. They are presented as the Khorat, Huai Hin Lat, Kuchinarai Groups, and basement. The series do not show the Triassic half graben but the boundary of the half graben tied to the S-N seismic profile line 86.

2.8.2 Drilling history of Chonnabot prospect

Chonnabot-1 well

Booth (1998) concluded that the drilling report of Chonnabot-1 well that drilled in 1982 by Esso exploration and production Khorat Inc. The Chonnabot-1 well encountered significant overpressure at relatively shallow depth. Although seismic interpreters observed possible gas indicators in the Khorat Group, the degree of overpressure was not anticipated. Between 786 to 893 meter, the background gas levels increased and the mud weight was raised from 9.6 to 10.6 ppg. A gas kick was taken at 1,425 meter (Phu Kradung formation), whilst drilling with 10.8 ppg mud, and killed by raising the mud weight to 13.6 ppg. An RFT was taken over these sandstones, but they proved to be very tight. After setting the $9\frac{5}{8}$ inches casing at 3,054 meter (lower Nam Phong formation), the mud weight was reduced to 10.2 ppg. A gas kick was taken from 1.50 meter thick sandstone at 3,263 meter (above the

Indosinian II unconformity) which was killed with 18.8 ppg mud. Drilling continued through under formation (Kuchinarai Group) with significant gas shows, until at 3,601 meter sudden mud loss occurred and a significant gas kick was taken. After the well was brought under control it was felt that a loss-gain situation had resulted and, with further drilling impossible, the well abandoned.

Phu Wiang-1 well

Booth (1998) concluded that the drilling report of Phu Wiang-1 well that drilled in 1998 by Amerada Hess exploration (Thailand) Co.,Ltd. This was a redrill of Esso's Chonnabot-1 well, which had to be abandoned because of mechanical problems and excessive overpressure, that lead to an inability to control mud losses and contain a gas kick.

Phu Wiang-1 well was drilled only 300 meter NW of Chonnabot-1, primarily for safety reasons. It was recognized that the entire section from the middle Phu Kradung formation downwards was highly overpressured and that the lower portions would have to be drilled with mud weights in excess of 19 ppg in order to control the gas charged sandstones in the lower Nam Phong formation and Kuchinarai Group, which had caused most of Esso's problems. However, there was a considerable risk that this high mud weight may have caused the lost circulation problems that lead to the abandonment of Chonnabot-1 well by being highly overpressured on entering the Phu Nok Khao reservoir. Therefore, a casing string had to be set as close as possible to the Indosinian I unconformity to seal off these high pressure formations and allow the mud weight to be dropped before entering the prognosed reservoir section.

The well encountered the same stratigraphy as Chonnabot-1 well down to the Indosinian I unconformity, which it penetrated at 6,001 meter. It also encountered the same gas charged sandstones in the overlying section. However, the Permian section proved to be a sequence of open marine sandstones, shales, siltstones, and limestones. It had been prognosed that this section would be imbricated by thrusting of Indosinian I age, which proved to be the case, however, an FMIS log clearly shows that it has also been tightly folded. This lithological assemblage continued until TD at 4,024 meter.

The mud weight had been dropped to 16.50 ppg to enter the Permian section, however, with continued drilling it had to be raised to 17.50 ppg to control connection and trip gas level. The original play concept had been based on a low porosity-permeability platform carbonate section, with productivity enhanced by karstification of the interval just below the Indosinian I unconformity and fractures associated with the numerous thrust planes observed on seismic lines. Although logging indicated that the sandstones and limestones encountered were very low in porosity and permeability the ubiquitous gas shows meant that the drilling was continued to intersect a prominent seismic reflector, thought to be a major thrust plane, which it was hoped would be surrounded by fractures. At 3,917 meter a 36% gas peak was recorded, requiring the mud weight to be raised and the gas circulated out of the mud system. Between 3,939 meter and 3,965 meter the level of gas increased with at least 16 major spikes between 15 and 40%. This zone coincided with the predicted depth of the major thrust plane and it was assumed that the gas peaks were being derived from an open fracture system.

2.9 Subsurface structural map of the Permian play

The subsurface structural maps are generated from the seismic interpretation and geological surface data. It composed time structural contour map and isochore map.

2.9.1 Time structural contour map

The time contour map of top Dong Mun/Pha Nok Khao formation is interpreted by Chontong, W. (2005) that shown in Figure 2.9 and top Permian carbonate formation is interpreted by Kozar, Crandall, and Hall (1992) that shown in Figure 2.10. The Permian carbonate rock is the target reservoir rock for hydrocarbon development within the Khorat Plateau. Consequently, this section interprets the subsurface distribution and structure of this unit, complied onto this map. The boundary of top carbonate rock cannot be traced in the area due to poor seismic data. However, there are presented two trends: (1) the western part is SW-NE trend and (2) the eastern part is NW-SE trend which represent the Pha Nok Khao and Dong Mun formation respectively.

2.9.2 Isochore map

The Si That Group isochore map is represented by Chontong, W. (2005) that that shown in Figure 2.11. The Permian rock in the area is divided into two groups: (1) the Saraburi Group and (2) the Si That Group. In the western part, the base Saraburi Group cannot be mapped because the seismic profiles quality is poor data. Only the Si That Group can be mapped as shown in Figure 6.9. The Si That Group is found in the central of the area. The thickness of the Si That Group is different from place to place.

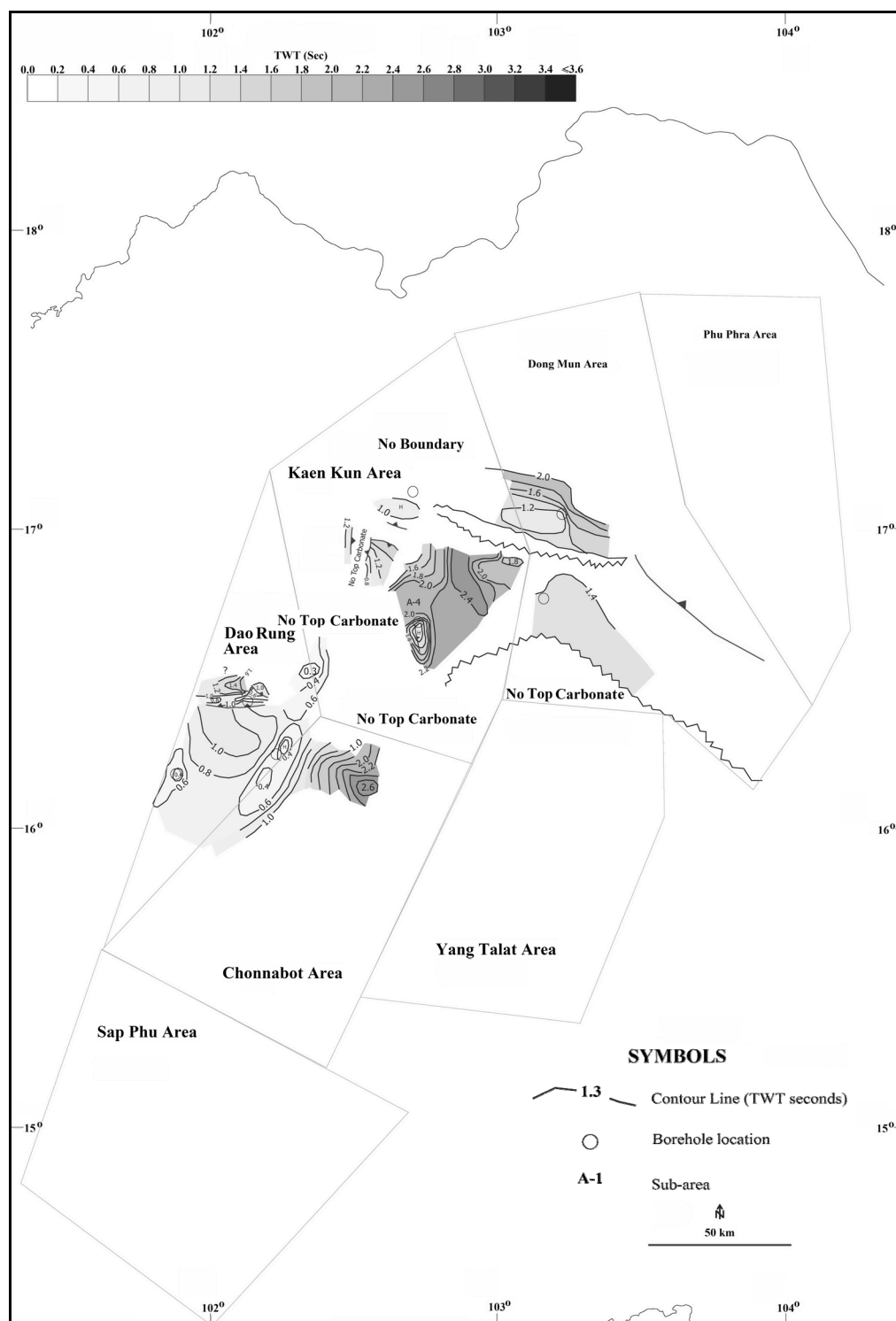


Figure 2.9 Time structural contour map of top Dong Mun/Pha Nok Khao formations in the Khorat Plateau, Thailand (Modified from Chontong, W., 2005).

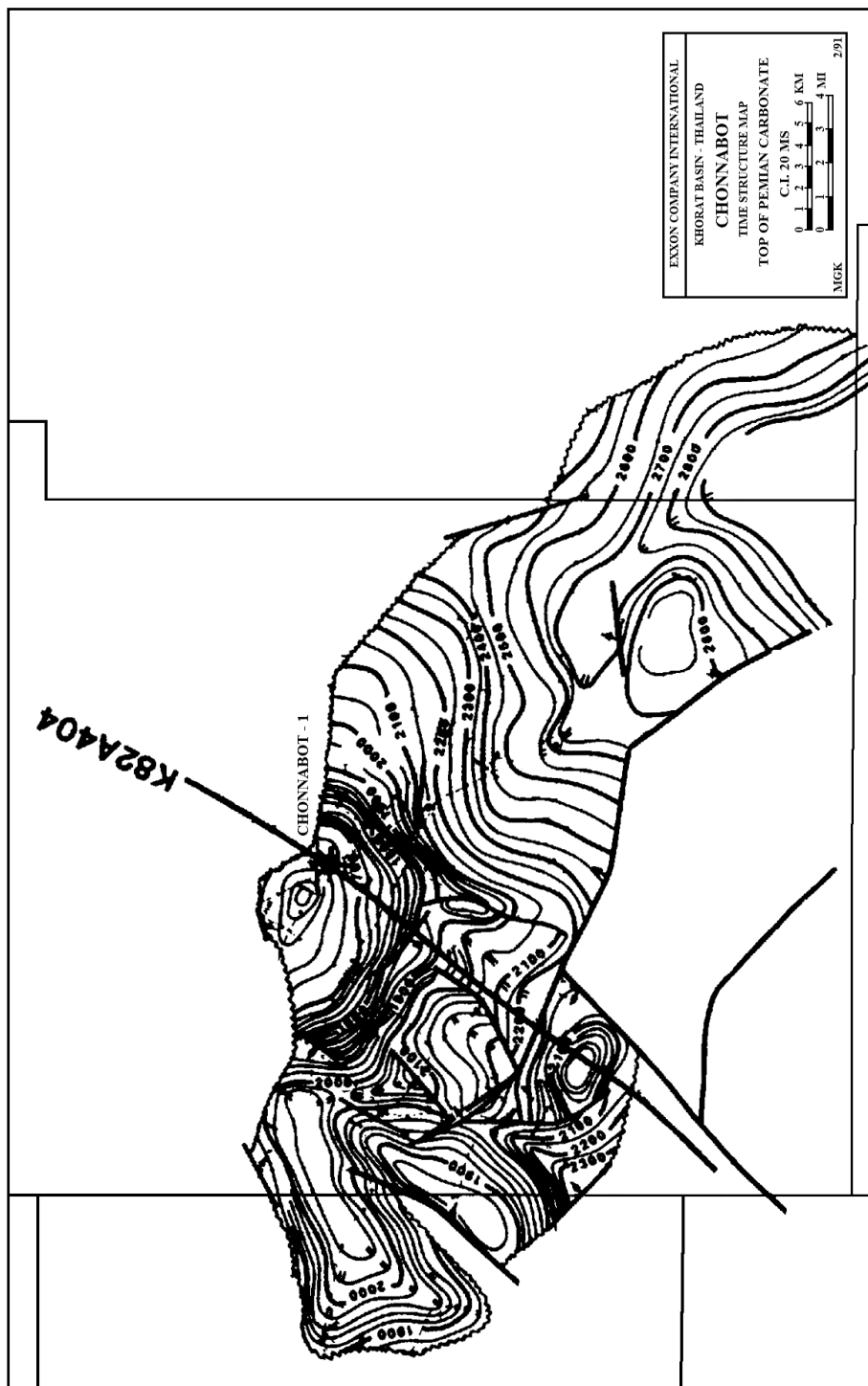


Figure 2.10 Time structural contour map of top Permian carbonate in the Chonnabot prospect, Khorat Plateau, Thailand (Modified from Kozar, Crandall, and Hall, 1992).

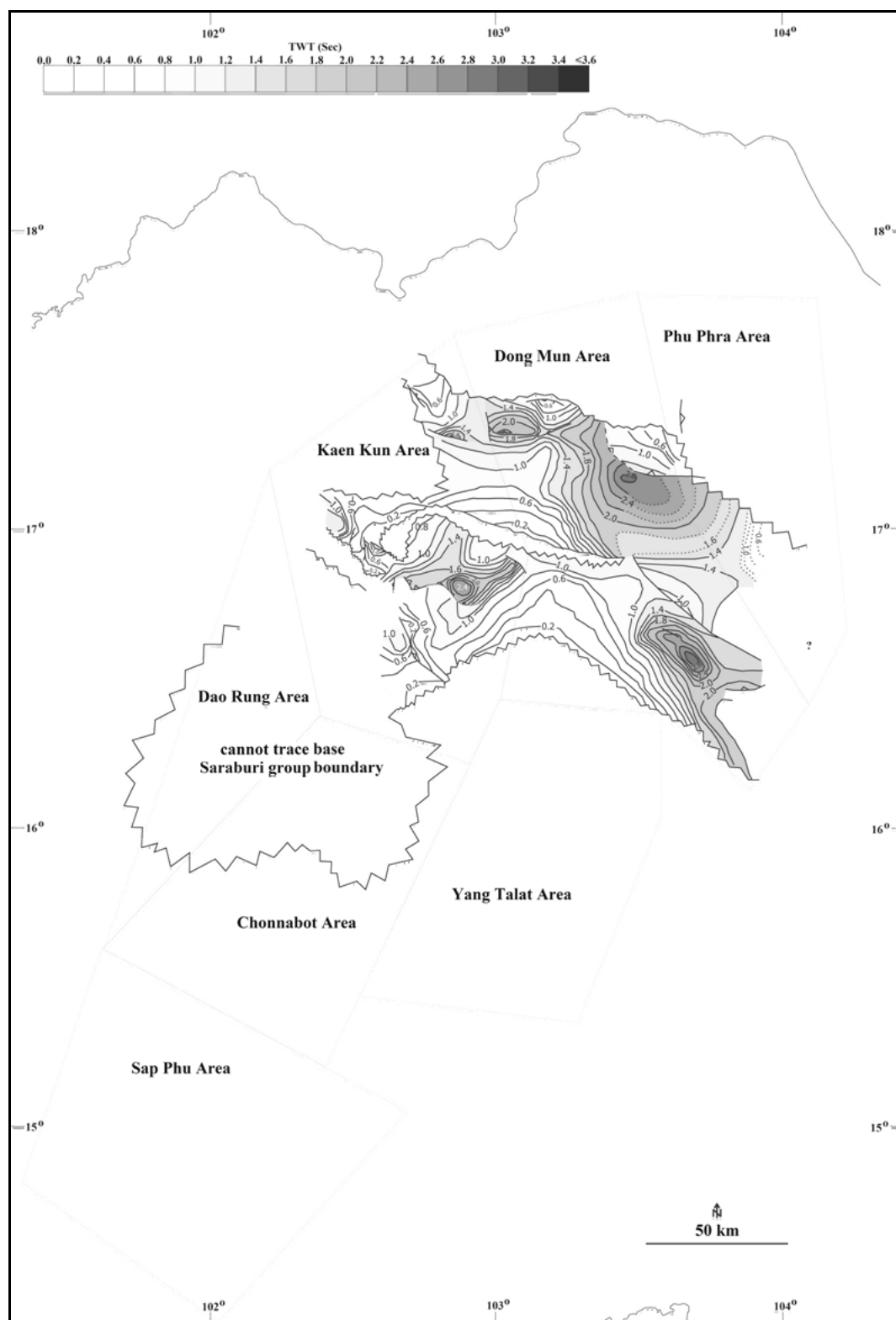


Figure 2.11 Isochore map of the Saraburi/Si That Group in the Khorat Plateau, Thailand (Modified from Chontong, W., 2005).

2.10 Petroleum geochemistry evaluation of Permian carbonates rock

The study is reviewed and determined the result of geochemical analyses that performed on cutting samples from Phu Lop-1 well (Latitude 17°11'48''N. Longitude 103°34'04''E.) and Dao Ruang-1 well (Latitude 16°27'20''N. Longitude 102°10'42''E.). It is based on the basis of source rock characterisation and source rock maturity evaluation.

2.10.1 Source rock characterisation

Total organic carbon (TOC) analysis measures the organic richness of a rock in weight organic carbon. Organic richness is the first requirement for an oil or gas source rock. The analysis is also used as a technique to determine which samples merit more detailed analysis. The overall efficiency of converting organic carbon in the source rock for different lithologies are shown in Table 2.1.

Table 2.1 The classification of organic richness by total organic carbon in percent by weight (after Thongboonruang, C., 2008).

Clastic Rock (Shale)	Carbonate Rock (Limestone)	Classification of Quality
0.0-0.5	0.00-0.01	Poor
0.5-1.0	0.01-0.25	Fair
1.0-2.0	0.25-0.50	Good
2.0-4.0	0.50-1.00	Very good
>4.0	>1.00	Excellent

This scale refers to rating of organic richness and not source potential. Type of organic matter at give concentration determines source potential.

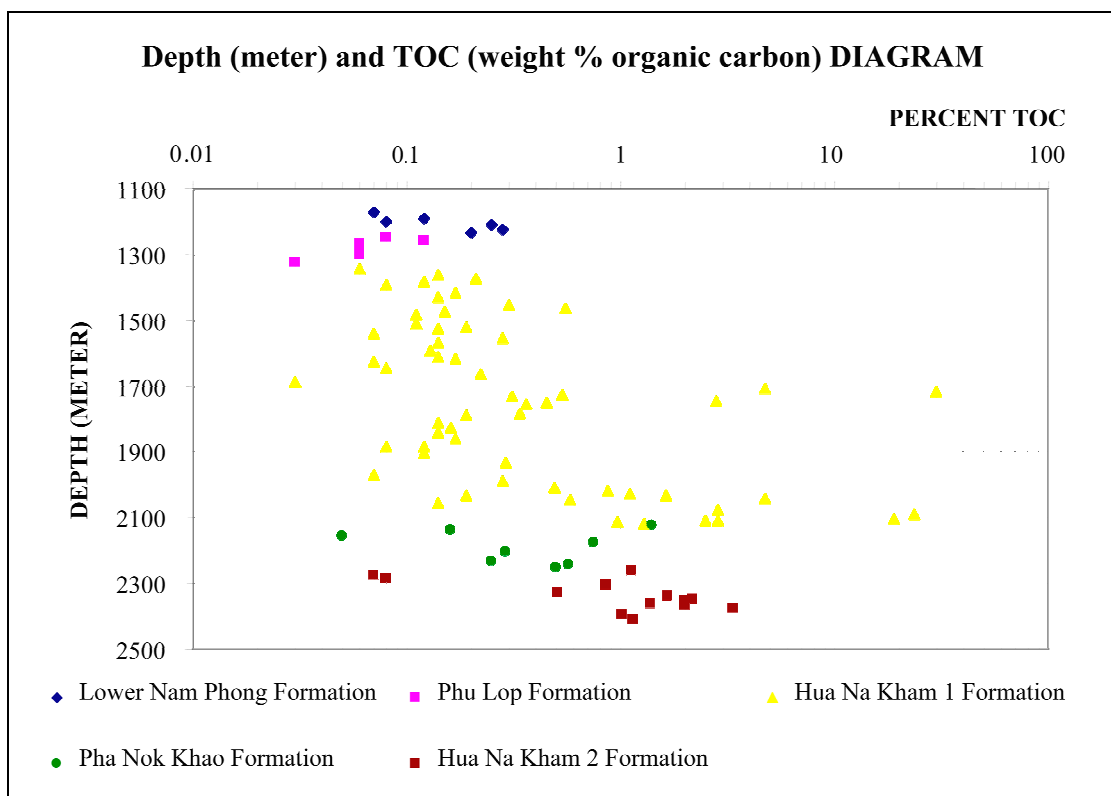


Figure 2.12 Distribution of total organic carbon with depth of Phu Lop-1 well (Modified from Thongboonruang, C., 2008).

Figure 2.12 displays the organic richness in Pha Nok Khao formation of the Phu Lop-1 well is consistently fair to excellent as suggested by the TOC determinations ranging from 0.01 wt.% TOC to more than 1% wt.% TOC. The TOC value from 8 samples indicated that the TOC ranging from fair quality (3 samples), good quality (2 samples), very good quality (2 samples), and excellent quality (1 sample) (Thongboonruang, C., 2008).

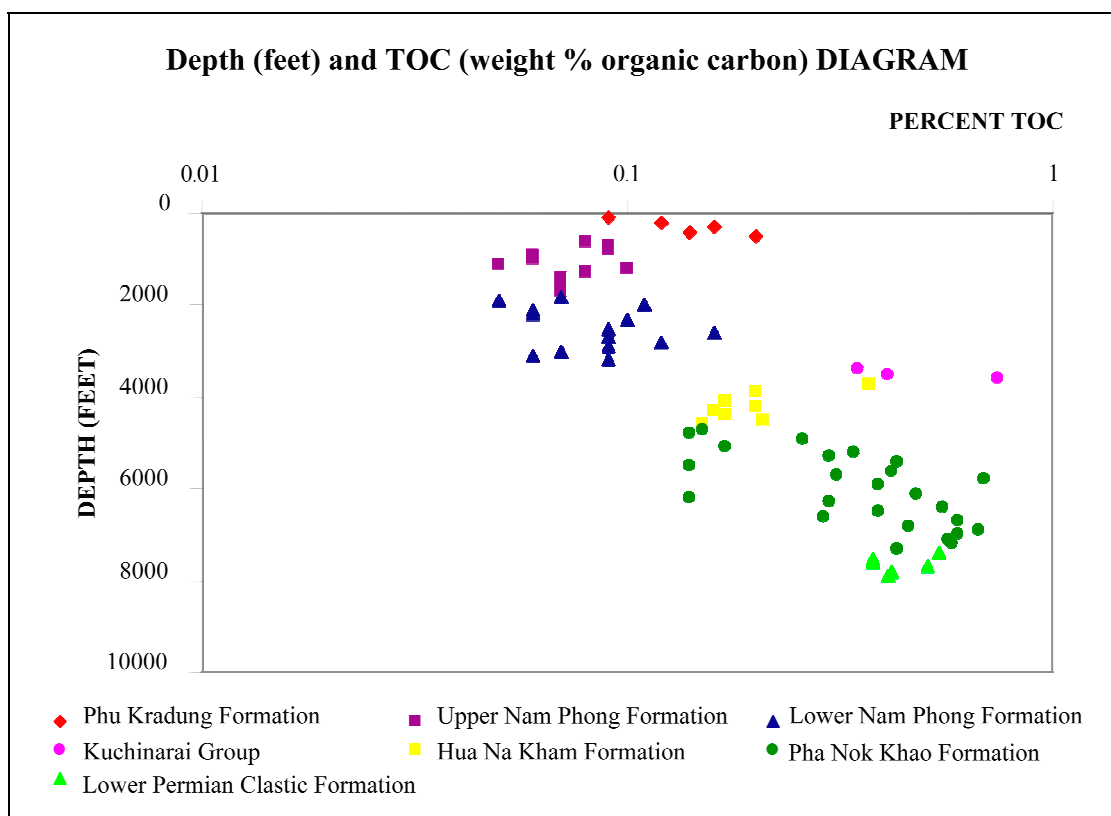


Figure 2.13 Distribution of total organic carbon with depth of Dao Ruang-1 well (Modified from Thongboonruang, C., 2008).

Thongboonruang, C. (2008) concluded the organic richness in Pha Nok Khao formation of Dao Ruang-1 well is almost consistently fair to very good with the majority of the TOC value falling in the range 0.1 wt.% TOC to 0.7 wt.% TOC (Figure 2.13). Occasional very good organic richness occur where the TOC value range from 0.50 wt.% TOC to 1.0 wt.% TOC which have 7 samples. Good organic richness do occur with the TOC value range from 0.25 wt.% TOC to 0.50 wt.% TOC that have 13 samples. Fair organic richness do occur with the TOC value range from 0.01 wt.% TOC to 0.25 wt.% TOC which have 5 samples.

2.10.2 Source rock maturity evaluation

The thermal maturity of source rock has been assessed using a combination of rock-eval Tmax and vitrinite reflectance.

The Rock-Eval instrument provides a rapid source rock analysis on small sample of rock by heating over temperature range of 300-600°C, after an initial gas purge at 90°C. Tmax is the temperature in °C at which the pyrolytic yield of hydrocarbon from a rock sample reaches its maximum. It is a thermal maturity parameter if the samples are free from contamination and the kerogen compositions are well known or established (dominant kerogen).

Table 2.2 The classification of kerogen maturity by Tmax (°C)

(after Thongboonruang, C., 2008).

Tmax (°C)	Maturity
<435	Immature
435-540	Mature
>540	Overmature

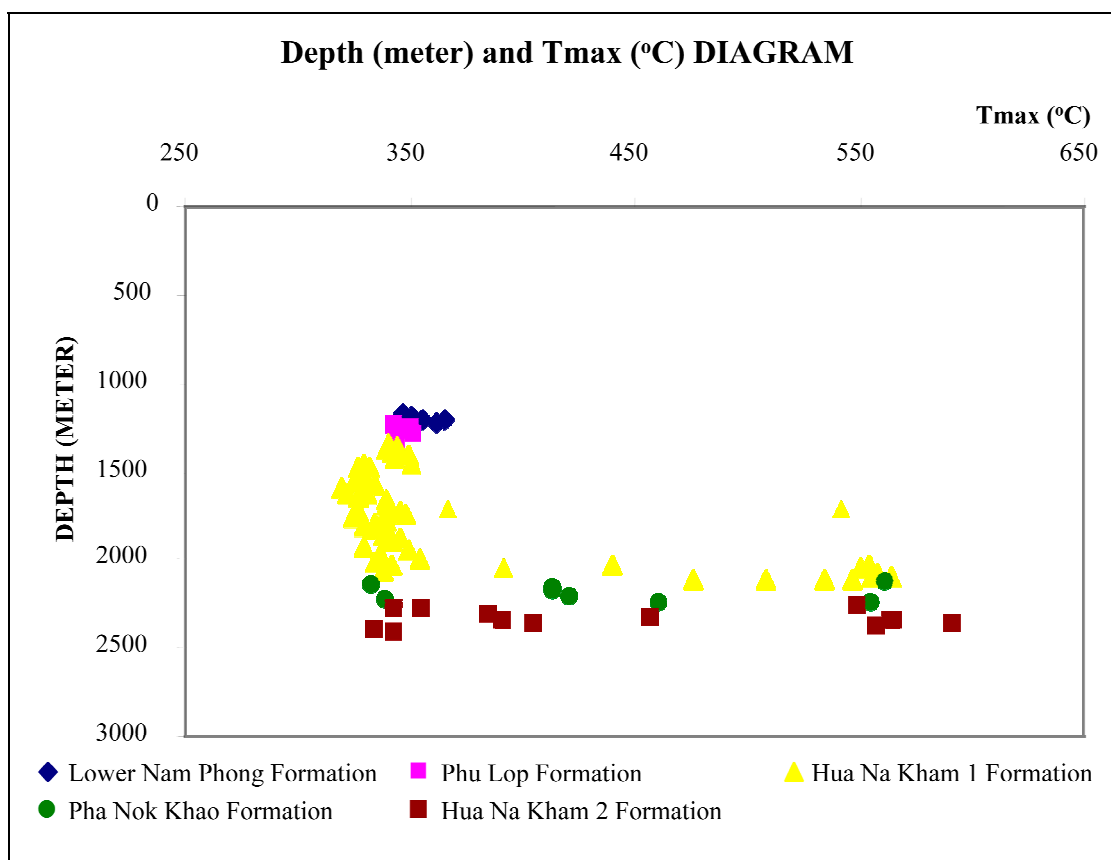


Figure 2.14 Relationship between Tmax with depth of Phu Lop-1 well (Modified from Thongboonruang, C., 2008).

Thongboonruang, C. (2008) considered thermal maturity of 8 samples in Pha Nok Khao formation of Phu Lop-1 well to indicated immature to overmature stage by Tmax value (Figure 2.14). The Tmax value varied from less than 435°C are immature stage that has 5 samples, between 435°C to 540°C are mature stage for hydrocarbon generation, and more than 540°C are overmature stage that has 2 samples.

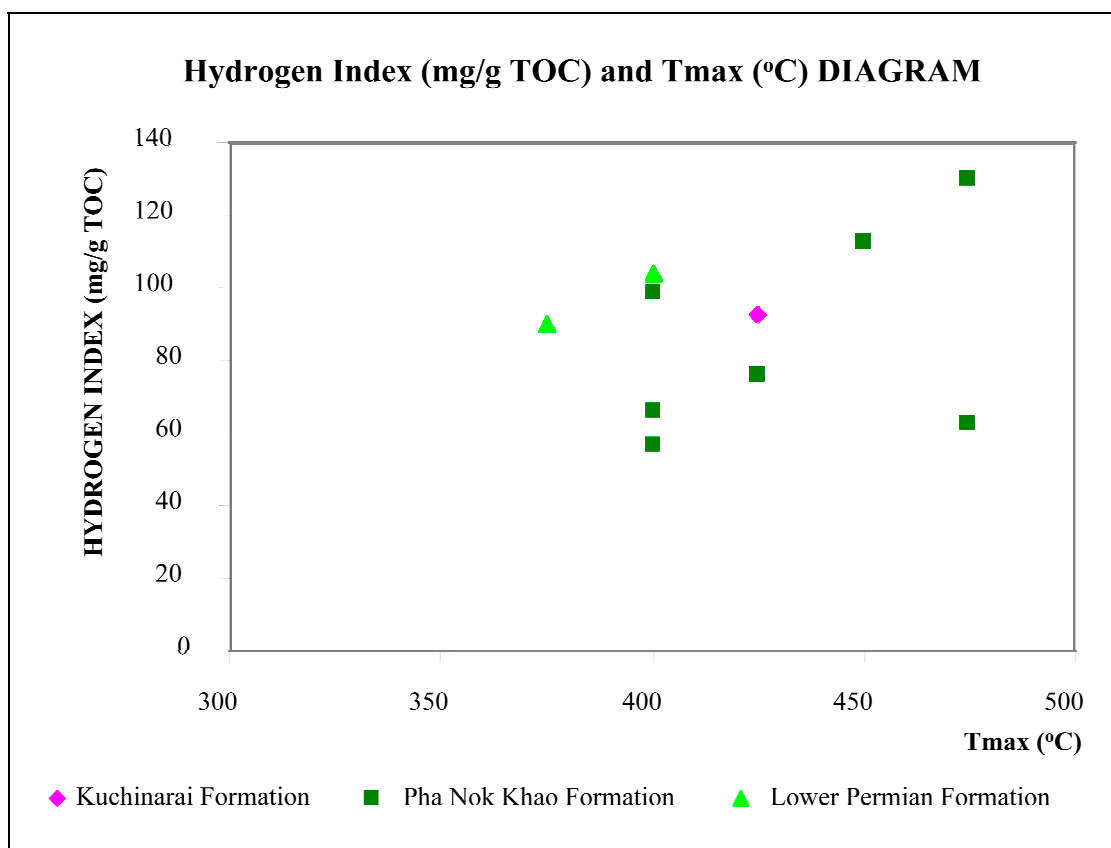


Figure 2.15 Correlation between Tmax with hydrogen index (HI) of Dao Ruang-1 well (Modified from Thongboonruang, C., 2008).

Figure 2.15 shows the Tmax consistently value range from 400°C to 480°C suggested that samples in Pha Nok Khao formation of Dao Ruang-1 well are immature stage in value lower than 435°C (4 samples) and mature stage for oil window in value of 435-540°C (3 samples) (Thongboonruang, C., 2008).

Vitrinite reflectance (Ro) is provides a method for determining the thermal alteration history of sediment based on the change in the reflectance of polished vitrinite particles with increasing time and temperature. Increases in the reflectance are caused by the progressive aromatization of the kerogen with accompanying loss of hydrogen in the form of hydrocarbon gases and the product of the process is graphite.

Table 2.3 The classification of kerogen maturity by vitrinite reflectance (Ro)
(after Thongboonruang, C, 2008).

Vitrinite reflectance (%Ro)	Maturity
<0.50	Immature
0.50-0.62	Early mature
0.62-2.00	Mature
>2.00	Overmature

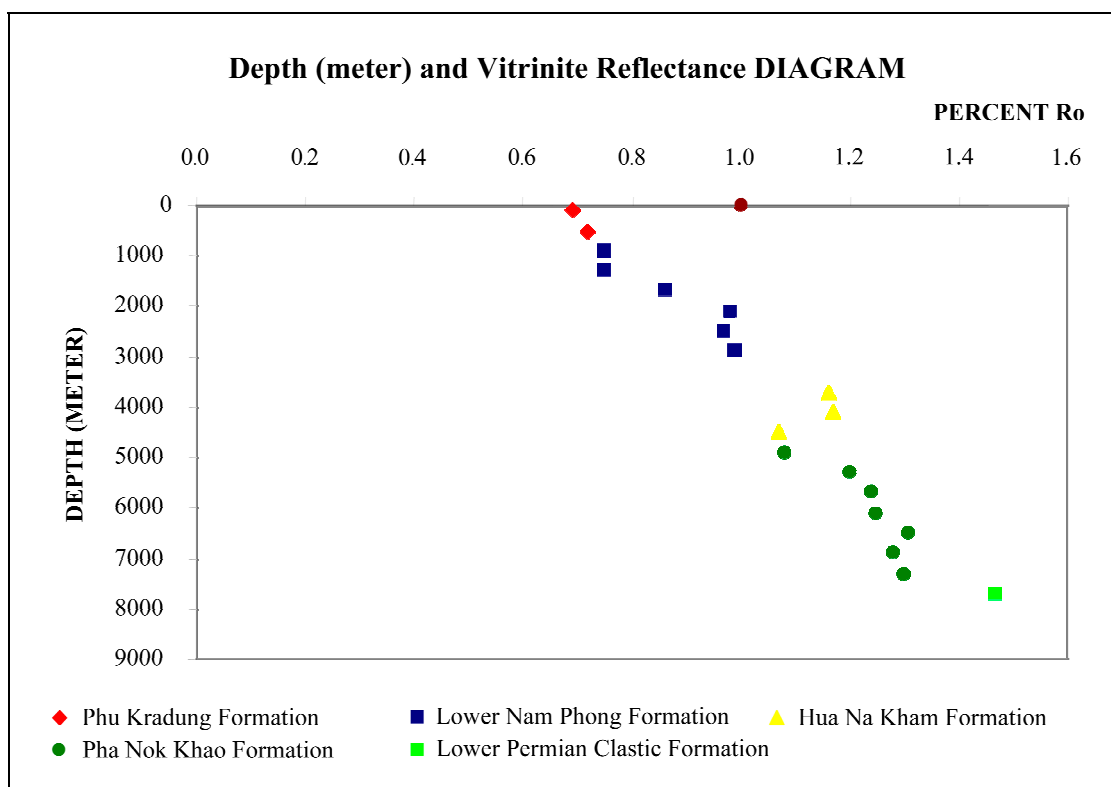


Figure 2.16 Relationship between vitrinite reflectance (Ro) with depth of Dao Ruang-1 well (Modified from Thongboonruang, C., 2008).

Figure 2.16 shown the related of Ro in Pha Nok Khao formation (Permian limestone) of Dao Ruang-1 well from a total of 7 cutting samples. The Ro values recorded for these samples range from Ro >1.0% to Ro ~1.4% and thus indicate that is thermally mature stage for hydrocarbon generation (Thongboonruang, C., 2008).

2.11 Carbonate reservoir characterisation

For the time being, Permian carbonates are the main gas producing reservoir rocks in the northeastern region. The best reservoir rocks of this group are limestones and dolomites, especially dolomitized limestone, well-bedded dolomite, or the reefal origin. The rock units are coarsely crystalline and may have very high intercrystalline porosities. Various type of the limestone such as fusulinid and crinoid calcarenites, oolite limestones, and the limestone reef bodies. Besides the matrix and vugular porosity, fractures are very important parameter to enhance its reservoir quality (Sattayarak, N., 2005).

Praditdan, S. (1995) described the characteristics and properties of the Permian carbonate reservoir are summarized as follows;

- 1) The carbonate was deposited on the platforms or related with the platforms. Lithofacies of the carbonates as observed in core are mainly of fossiliferous packstone and grainstone with minor wackestone and mudstone.
- 2) The porosity and permeability of these carbonates are generally low. The porosity values ranges from 0 to 18 percent with an average matrix porosity of about 4.0 percent.
- 3) The Permian carbonates were deposited and buried at the great depth. They were subjected to many phases of karstifications and severe erosion.
- 4) The carbonates which contain a high mud such as mudstone, and wackestone, have a higher porosity values than those bearing a high grain such as packstone, grainstone, and boundstone. The dolomites have higher porosity than the limestones.

5) The permeability of the carbonate is generally depends on the microfractures. The high flow rate of the Nam Phong gas field evidently related to existence of open microfractures in limestones.

Chinoroje, O. and Cole (1995) discussed that the Permian carbonate reservoir in both cutting and core samples of Dao Ruang-1 well as follows;

1) Carbonate microfacies were mainly dark grey mud supported micritic limestone (wackestone) with minor grain support fossiliferous packstone/grainstone and dolomitic in part.

2) The biostratigraphic study from Foraminifera showed that the carbonate section aged Late Early Permian to Earliest Middle Permian and suggested that low energy, peritidal, restricted marine (lagoon) paleoenvironment with some high energy open marine margin of carbonate platform.

3) Primary and secondary porosities were observed in both cutting and core samples. Most porosity has been occluded by calcite cements. Microfractures are the main porosities for hydrocarbon and cross cutting of fractures represent the complexity of tectonic regime. Inter-crystalline porosity is minor in the carbonate section due to the lack of dolomitization.

4) Well testing results indicate the Permian carbonates at the Dao Ruang-1 well were proved low permeability or small amount of gas encountered at the well location.

2.12 Seal and Trap rock characterisation

The seal capped overlying the carbonate reservoir rocks which the lower units of the Khorat Group is consisted of volcanoclastic and conglomerate. These clastic rocks are tightly compacted with argillaceous matrix and are relatively low permeabilities. They are good seal rocks overlying the carbonate reservoirs. The fine-grained sediments of the Permian Upper Clastic and/or Triassic rocks also possess good seal characteristic.

The geologic structures and stratigraphic petroleum traps of the Permian carbonate play in the northeastern region are successful tested and summarized as follows;

- 1) The angular unconformity between the Triassic of Huai Hin Lat Group and the Permian of Saraburi Group.
- 2) The traps in the Permian reefal and fore slop reefal limestone.
- 3) The half-graben structures in the Triassic and Permian sediments underlying the Khorat Group.