ลักษณะเฉพาะของหินต้นกำเนิดปิโตรเลียมและการสร้างแบบจำลองแอ่งสะสมตะกอนของแอ่งเมอร์กุย ทะเลอันดามัน ประเทศไทย

นายณัฐวัฒน์ เชื้อดี

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิทยาศาสตรมหาบัณฑิต
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CHARACTERISTICS OF PETROLEUM SOURCE ROCK AND BASIN MODELLING OF MERGUI BASIN, ANDAMAN SEA, THAILAND

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A Thesis Submitted in Partial Fulfillment of the Requirements
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Thesis Title	CHARACTERISTICS OF PETROLEUM SOURCE ROCK AND BASIN MODELLING OF MERGUI BASIN, ANDAMAN SEA, THAILAND
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Field of Study	Geology
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(Surawit Pradidtan)

ณัฐวัฒน์ เชื้อดี : ลักษณะเฉพาะของหินต้นกำเนิดปิโตรเลียมและการสร้างแบบจำลองแอ่งสะสมตะกอนของแอ่งเมอร์กุย ทะเลอันดามัน ประเทศไทย (CHARACTERISTICS OF PETROLEUM SOURCE ROCK AND BASIN MODELLING OF MERGUI BASIN, ANDAMAN SEA, THAILAND) อ. ที่ปรึกษาวิทยานิพนธ์หลัก : อ.ดร. เครือวัลย์ จันทร์แก้ว, 120หน้า.

แอ่งเมอร์กุย เป็นแอ่งสะสมตะกอนยุคเทอร์เชียรีในทะเลอันดามันฝั่งตะวันตกของประเทศไทย การสำรวจปิโตรเลียมในแอ่งเมอร์กุยยังไม่พบแหล่งปิโตรเลียมที่มีศักยภาพเชิงพาณิชย์ ที่ผ่านมาการศึกษาเน้นความสนใจไปที่หินกักเก็บและโครงสร้างกักเก็บแต่ยังไม่ได้เน้นการศึกษาด้านหินต้นกำเนิดปิโตรเลียม การศึกษานี้จึงเน้นศึกษาข้อมูลเพิ่มเติมในส่วนธรณีเคมีของหินต้นกำเนิดปิโตรเลียมและการสร้างแบบจำลองการสะสมตัวของแอ่งเมอร์กุยเพื่อเพิ่มความเข้าใจระบบปิโตรเลียมของแอ่งเมอร์กุยให้ดียิ่งขึ้น การศึกษาครั้งนี้ได้นำตัวอย่างเศษชิ้นหินจากหลุมเจาะจำนวน 7 หลุม (Kra Buri-1, Kantang-1A, Thalang-1, W9-A-1, Mergui-1, W9-D-1 และ W9-E-1) มาวิเคราะห์ธรณีเคมีหินต้นกำเนิดปิโตรเลียมประกอบด้วย TOC, Rock-Eval Pyrolysis และ Vitrinite Reflectance เพื่อหาปริมาณถ่านอินทรีย์รวม ชนิดของสารอินทรีย์ในหินต้นกำเนิด และความพร้อมในการให้ปิโตรเลียม ผลการวิเคราะห์ที่ได้เมื่อนำไปรวมกับข้อมูลการศึกษาในอดีตโดยบริษัทน้ำมัน พบว่าปริมาณถ่านอินทรีย์ที่มีอยู่ในหินส่วนใหญ่ในแอ่งเมอร์กุยมีศักยภาพในการเป็นหินต้นกำเนิดน้อยถึงปานกลาง มีเพียงบางส่วนเท่านั้นที่มีศักยภาพอยู่ในช่วงดีหรือดีมากแต่ปรากฏเป็นชั้นบางๆ ชนิดของสารอินทรีย์ในหินตัวอย่างพบเป็น Type III และ Type II/III (Type III SEA) เป็นส่วนใหญ่ระบุได้ว่าปิโตรเลียมที่ได้จะเป็นแก๊สธรรมชาติเป็นหลักโดยมีโอกาสพบน้ำมันและคอนเดนเสทร่วมด้วย หินที่มีศักยภาพเป็นหินต้นกำเนิดส่วนใหญ่ยังไม่พร้อมที่จะให้ปิโตรเลียม (immature) ผลการสร้างแบบจำลองแอ่งสะสมตะกอนของหลุม Kra Buri-1, W9-E-1 และ Thalang-1พบว่าหินต้นกำเนิดจะมีความพร้อมให้กำเนิดปิโตรเลียมที่ความลึก 9,500 ถึง 10,000 ฟุต เริ่มกำเนิดเมื่อ 7 ล้านปีที่ผ่านมาในส่วนตื้นของแอ่ง (หลุม Kra Buri-1) และ 17 ล้านปีที่ผ่านมาในส่วนลึกของแอ่ง (หลุม W9-E-1).

ภาควิชา............ธรณีวิทยา............ ลายมือชื่อนิสิต...
สาขาวิชา...........ธรณีวิทยา............ ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก........................
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NATTAWAT CHAARDEE : CHARACTERISTICS OF PETROLEUM SOURCE ROCK AND BASIN MODELLING OF MERGUI BASIN, ANDAMAN SEA, THAILAND. ADVISOR : KRUAWUN JANKAEW, Ph.D., 120 pp.

Exploration in the Mergui Basin, located in the Andaman Sea offshore southern Thailand, has so far been unsuccessful. There were no commercial hydrocarbons found in this basin. Previous study has focused on structure and trap but had overlooked source rock study. It was deemed necessary to study the geochemical and basin modeling in order to understand the petroleum system of this basin. Source rock cutting samples from 7 wells (Kra Buri-1, Kantang-1A, Thalang-1, W9-A-1, Mergui-1, W9-D-1 and W9-E-1) were geochemically analyzed including Total Organic Carbon content (TOC), Rock-Eval pyrolysis and vitrinite reflectance to determine their source rock potential, organic matter type and thermal maturity. Geochemical interpretations are made based on results from this study and from previous studies by oil companies. Source potential of the analyzed sediments are generally poor to fair. Organic-rich beds representing good or very good potential source rocks were discovered but are rather thin. Organic matter type within the sample sediments is predominantly gas-prone (type III) kerogen or mixed oil/gas-prone (type II/III-Type III SEA kerogen). The basin modeling of Kra Buri-1, W9-E-1 and Thalang-1 wells shows depth of petroleum generation at about 9,500-10,000 feet and had been started since 7 Ma in the shallow part of the basin (Kra Buri-1 well) and 17 Ma in the deeper part of the basin (W9-E-1 well).

Department : Geology Student's Signature ....
Field of Study : Geology Advisor's Signature ....
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CHAPTER I

INTRODUCTION

Tertiary basins are the prime target for petroleum exploration in Southeast Asia. Many important oil and gas fields have been found in these basins from active exploration in the past decade. Seventy Tertiary basins (Figure 1.1) have been identified so far in Thailand (Chaodumrong and Chaimanee, 2002). Petroleum exploration has been carried out in less than half of them. Natural gas, oil, coal and oil shale are commonly found in these basins. These basins are mainly fault-bounded grabens and/or half grabens formed by reactivation of basement structures (Chaodumrong et al., 1983). In the Mergui Basin offshore southern Thailand which is the subject of this study, exploration has so far been unsuccessful. There were no commercial hydrocarbons found, except minor gas and oil shows in six wells. Seismic data confirm the presence of a sedimentary sequence up to eight kilometers thick. Geological data from wells drilled suggest that more hydrocarbons should have been generated in the basin (Schroeder et al., 1979).

The Mergui Basin extends southwards into the North Sumatra Basin where large oil and gas fields have been found. It is therefore important to determine the reasons for the lack of successful exploration within the Mergui Basin. Previous study has focused on structure and trap but rather had overlooked source rock study. It was deemed necessary to study the geochemical and basin modeling in order to understand the petroleum system of this basin.

1.1 Location of the study area

The study area covers the Mergui Basin, Andaman sea between latitudes 6º21´48´´N and 9º45´30´´N and longitudes 95º31´48´´E and 98º12´00´´E. The area is approximately 50,000 square kilometers where offshore petroleum concession blocks A4/48, A5/48 and A6/48 (PTTEP Siam Ltd.) are located. These blocks lie in water ranging in depth from 650 feet to over 7,500 feet (Figure 1.2).

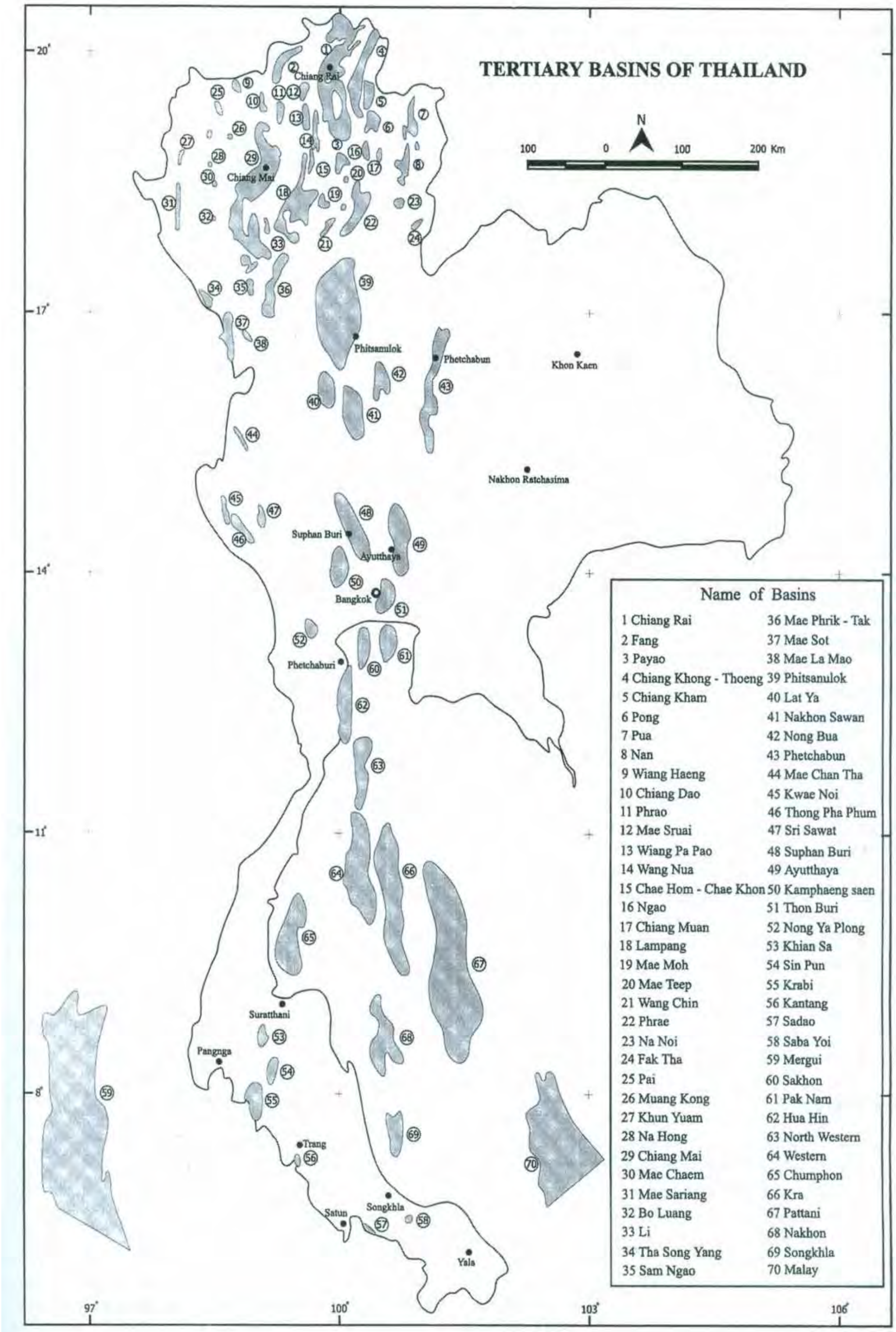


Figure 1.1 Tertiary basins of Thailand (Chaodumrong et al., 1983).

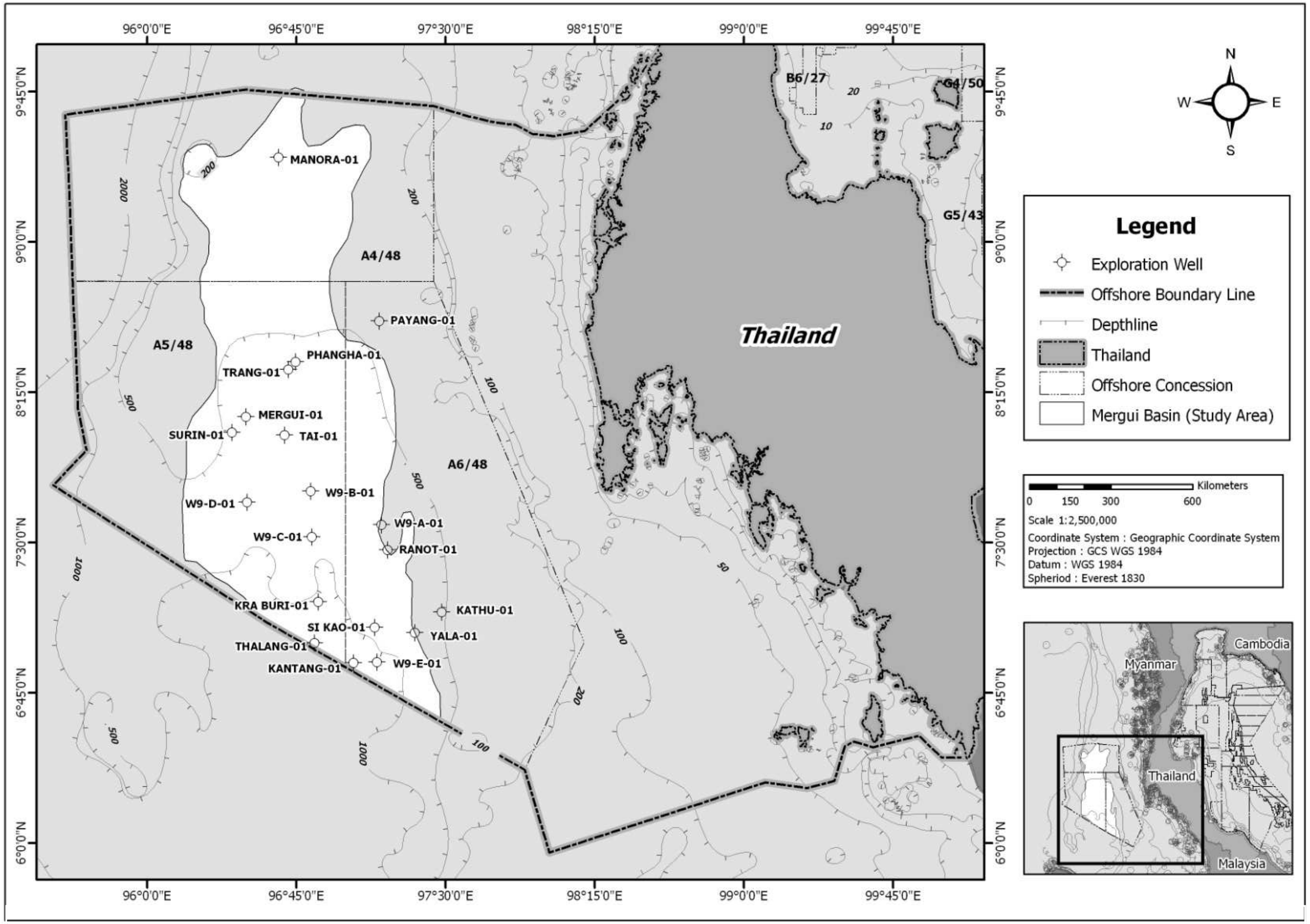


Figure 1.2 Location of the study area.

1.2 Objectives of the study

The purpose of this research is to determine the characteristics of petroleum source rock in the Mergui Basin including source potential, type of organic matter and thermal maturity. Geological and geochemical data are used to construct maturity modeling to estimate time and depth of petroleum generation and to better understand petroleum system of the Mergui Basin.

1.3 Data sources

The data used for this study area is provided by the Department of Mineral Fuels (DMF), Thailand. Under the Petroleum Act of Thailand, exploration data were given to the DMF after oil companies had relinquished their concessions. The data consist of unwashed cutting samples, geochemical reports, well completion reports, and general geological data (Table 1.1).

1.4 Exploration history of the Mergui Basin

Petroleum exploration of the Andaman Sea, offshore Thailand began in 1971 when six shallow water (less than 200 meters deep) concession blocks: W-1, W-2, W-3, W-4, W-5 and W-6, were awarded to several oil companies. Minor seismic surveys were done, but further exploration was abandoned due to a thin sedimentary succession which is generally less than 1,000 meters thick. Subsequently, the oil companies relinquished their concessions with no wells having been drilled (Polachan, 1988).

In 1974, three deep water blocks (W-7, W-8 and W-9) which cover the Mergui Basin were awarded to the Oceanic Group, Union Oil Company of Thailand and Esso Exploration and Production Thailand Inc. Extensive seismic surveys totaling more than 20,000 kilometers were conducted. Ten exploratory wells were drilled by Esso and Union Oil Company, but none by the Oceanic Group. None commercial hydrocarbon were found, but only the W9-B-1 and Mergui-1 wells had significant gas and oil shows.

After these concessionaires had relinquished their licenses due to unsuccessful results, the eastern part of W-8 and W-9 blocks were awarded to the Placid Oil

Company in 1984. Another two wells have been drilled in the southeastern part of the basin by the company in 1987, but resulted in dry wells.

No.	Well Name	Geochemical report	Well completion report	Unwashed cutting
1	W9-A-1	●	●	●
2	W9-B-1	●	●	
3	W9-C-1	●	●	
4	W9-D-1	●	●	●
5	W9-E-1	●	●	●
6	Trang-1		●	
7	Tai-1		●	
8	Phangha-1		●	
9	Mergui-1		●	●
10	Payang-1		●	
11	Yala-1	●		
12	Ranot-1	●	●	
13	Thalang-1	●	●	●
14	Kantang-1	●		●
15	Kra Buri-1	●	●	●
16	Si Kao-1	●	●	
17	Manora-1	●		

Table 1.1 Summary of data used in this study.

In 1996, Unocal Bangkok Company and the collaborators obtained the concessions of W8/38 and W9/38 blocks in the fourteenth petroleum concession bidding round. Seismic survey of these two blocks total of 11,737 kilometers was conducted. The total of 5 exploration wells was drilled. Three wells were located in W8/38 block and the other 2 wells were in W9/38 block, but no significant petroleum was discovered.

In 1998, Kerr-McGee (Thailand) Co.Ltd. and the collaborators were awarded the concession of W7/38 block in the sixteenth round of petroleum concession bidding. The Manora-1 well was drilled but no petroleum was discovered.

At the present, petroleum concession blocks A4/48, A5/48 and A6/48 were awarded to PTTEP Siam Ltd. in the nineteenth round of petroleum concession bidding in 2007. Seismic survey of these blocks, total of 7,200 kilometers, was conducted but so far no well has been drilled.

1.5 Previous geochemical studies

Geochemical study of the Andaman Sea had been conducted in four occasions since 1975 after the exploration wells were drilled. Results of previous source rock geochemical study are summarized in Table 1.2. Hydrocarbon source potential is generally poor and poor to fair; although two wells (W9-B-1, Yala-1) had good source potential. The organic matter throughout source sediments is composed of gas prone and gas/oil prone but in shallow sediments of W9-1-A well, it is oil prone. Thermal maturity is generally immature, except three wells (W9-B-1, W9-C-1, and W9-E-1) which were drilled deeper than 10,000 feet and are mature.

The earliest source rock geochemical study was carried out by Metter (1976) from 5 exploration wells drilled by ESSO Exploration in 1976. He analyzed samples from W9-A-1, W9-B-1, W9-C-1, W9-D-1 and W9-E -1 wells. The results are summarized below.

In W9-A-1 well, samples above 5,800 feet contained enough organic matter to be rated as potentially fair oil sources when mature. The section below 5,800 feet is lean in organic matter and is poor or non-sources. Most of the samples down to 5,800 feet contained predominantly oil-prone amorphous or algal kerogen. Below 5,800 feet the kerogen in the samples was predominantly woody, but most of these samples had secondary amounts of algal or amorphous kerogen. This deeper kerogen mixture is considered to be inherently a potential generator of gas plus oil wherever it is rich enough to be a significant. The entire sample section (2,300-7,900 feet) is immature.

Well Name	Spudded year	Operator	TD. (ft)	Source Rock Potential	Potential Petroleum Generation	Mean Ro	Maturation
W9-A-1	1975	Esso	7,900	Poor to fair	oil	0.34	Immature
W9-B-1	1976	Esso	11,921	Good/Fair	Gas	0.47	Mature
W9-C-1	1976	Esso	12,219	Poor	Gas	0.67	Mature
W9-D-1	1976	Esso	8,173	Poor	-	0.31	Immature
W9-E-1	1976	Esso	14,036	Poor to fair	Gas	0.58	Mature
Yala-1	1987	Placid Oil	5,781	Good	Gas	0.27	Immature
Ranot-1	1987	Placid Oil	8,500	Poor	Gas	-	Immature
Thalang-1	1997	Unocal	8,518	Poor to fair	Gas/Oil	0.39	Immature
Kantang-1A	1997	Unocal	6,858	Poor	Gas/Oil	0.35	Immature
Kra Buri-1	1997	Unocal	10,342	Fair	Gas	0.40	Immature
Si Kao-1	1997	Unocal	5,685	Poor	-	-	-
Manora-1	2000	Kerr McGee	6,933	Poor	No Hydrocarbon	0.45	Immature

Table 1.2 Summary of previous geochemical studies of Mergui source sediments.

The W9-B-1 well section is richer than W9-A-1 well. It has good to fair organic content and is also more mature, particularly in the Oligocene-Miocene intervals. However, in both wells the older Oligocene strata proved to be mostly disappointing in source character.

The thickest and richest potential source interval in W9-C-1 well consists of calcareous shale and marls in the Upper, Middle and Uppermost Lower Miocene section. However, these beds are still immature. The most promising source in the mature zone is the brownish shale interval at roughly 9,500 feet. The thick arenaceous intervals in the Oligocene and Lower Miocene section are poor hydrocarbon sources.

The entire sedimentary section at W9-D-1 well is rated as a poor hydrocarbon source. Metter rated the section as immature down to 7,200 feet and as transitional below that, but one could argue that entire section is immature.

The Oligocene argillaceous sediments in well W9-E-1 have poor to fair source rock potential and contained gas-prone organic matter. However, they are clearly mature. Some of the immature samples were marls and calcareous shale from the Miocene.

In the second period of exploration, Placid Oil drilled 2 wells in 1987. After that Catherine (1988) had analyzed samples from Ranot-1 and Yala-1 wells.

In Ranot-1 well, the Oligocene sediments have total organic carbon values ranging from 0.06 to 0.68 wt%, indicating low potential as a source rock. The sediments were found to be thermally immature. The generated hydrocarbons would most likely be gas. Geochemical analysis of the Miocene section resulted in similar findings of thermal immaturity and gas-prone character; however, total organic carbon values indicated the section would be a fair potential source rock if mature.

In Yala-1well, the clastic sediments section (3,564 feet to 4,710 feet) had good to very good source potential. Below this depth (4,710 feet to 5,700 feet) the TOC values are very low in carbonate section. Pyrolysis result suggests that the sediments contained gas-prone organic matter. However, visual kerogen evaluation indicates the presence of predominantly amorphous sapropel and algal debris. Thermal maturity of sample is immature.

During the third period of exploration in the area, Unocal drilled 5 wells in 1997. Taylor (1998) interpreted organic geochemical data from Thalang-1, Kantang-1A, Si Kao-1 and Kra Buri-1 wells. There was no geochemical data reported for Kathu-1 well.

For Thalang-1 Well, the Miocene and Oligocene sediments at depths 5,260 feet to 8,500 feet were analyzed. The source potential is marginal to fair. Organic-rich beds representing good potential source rocks for oil or gas were not observed. Total organic carbon content in the Oligocene sediments averaged 0.8%. TOC content of the overlaying Miocene sediments averaged about 1.2%. Organic matter within the sediments is composed of mixed Type II/III kerogen that would generate gas and associated liquids when mature. Type III (gas prone) kerogen is more abundant in the Oligocene sediment sequence than in the younger sequences. The organic matter that comprises the kerogen is predominantly marine with minor proportions of land detritus. The sediments are thermally immature. A maximum vitrinite reflectance of 0.5% was encountered at a depth of 8,300 feet.

For Kantang-1A well, the Miocene and Oligocene sediments from depths 5,532 feet to 6,858 feet were geochemically analyzed. The source potential of the Miocene sediments is marginal to fair (mean TOC 0.96%, ranging 0.1% to 1.9%). No potential source rocks were encountered, but several zones did contain TOC consistently greater than 1%. TOC content of the Oligocene sediments was very low (0.2%). Organic matter within the sediments is predominantly gas-prone, Type III or mixed Type III/II kerogen, composed of varying proportions of amorphinite and herbaceous/woody kerogen with minor coaly and algal organic matter. The sediments are thermally immature. Maximum vitrinite reflectance in the Oligo-Miocene sediments was 0.4% Ro. A reflectance of 5.5% was measured in basement at 6,858 feet.

In Sikao-1 well, samples from below 5,040 feet depth were submitted for measurement of total organic carbon. The TOC content of these samples was very low and did not warrant further investigation for possible source potential.

Kra Buri-1 well, sediments between 5,380 feet and 10,380 feet MD were analyzed. Organic matter within the sediments has fair hydrocarbon source potential. Mean TOC values throughout the well most likely ranges 0.6%-0.9%. No outstanding potential source beds were identified. Organic matter within the sediments is gas-prone (Type III). The sediments are thermally immature. Vitrinite reflectance values of 0.5% occur at a depth of 9,000 feet MD. Expected vitrinite reflectance at TD (10,342 feet) is approximately 0.65%.

The last period of exploration in the area, Kerr McGee drilled 1 well in 2000. Dow (2000) had analyzed samples from Manora-1 wells. The organic matter is very low and no source rocks for oil or gas were identified. Organic carbon ranges from 0.03 to 0.49

wt% TOC. The most organic rich samples are the shallowest two analyzed (1,025-1,070 meters) which contain 0.44 and 0.49 wt% TOC. Rock-Eval data show the samples are of Type IV kerogen with Tmax data showing in that samples are immature (Tmax below 435°C).

CHAPTER II

GEOLOGY OF MERGUI BASIN

2.1 General geology of the Mergui Basin

Mergui Basin is located in the Andaman Sea, Thailand, west of the Thai-Malay peninsula. The latitude of the basin is between 5 ˚and 10˚ N, and longitude is between 94˚ and 98˚ E. The water depth typically ranges from 600 to over 3,500 feet but some areas are deeper than 7,500 feet. Sediments in the basin are deep sea deposit, shallow marine clastic and carbonate reef buildup. The basement of the basin comprises igneous rocks; granite, volcanic rocks, and Late Cretaceous to Late Miocene low-grade metamorphic rocks.

2.2 Structural geology of the Mergui Basin

The Mergui Basin is a transitional back arc basin that is continuous with the North Sumatra Basin to the south. The basin overlies continental crust at the western edge of Sundaland, where the Indian Oceanic plate is subducting obliquely beneath the south-east Asian plate. The basin developed rapidly during the late Oligocene as a series of N-S trending half-grabens, and rifting developed progressively northward (Polachan, 1988). These syn-sedimentary faults are a result of the transitional dextral shear along the NW-SE trend.

The basin is divisible into three main sub-basins (the Western Mergui sub-basin, Eastern Mergui sub-basin and Ranong Trough) separated by the Central High and the Ranong Ridge (Figure 2.1) (Polachan, 1988). The Eastern Mergui sub-basin is wider than the Western Mergui sub-basin. The sediment is thicker in the west and south of the Eastern Mergui sub-basin. Moreover, in the east of the basin there are small basin; Ranong Trough which is separated by the Ranong Ridge (Prasit and Kevin, 2000). Faults in Mergui Basin are strike-slip faults and normal faults. The main strike-slip faults have two trends, NW-SE Mergui Fault Zone and NE-SW Ranong and Klong Marui Fault Zone, N-S and NNE- SSW are normal faults trend (Srigulwong, 1986).

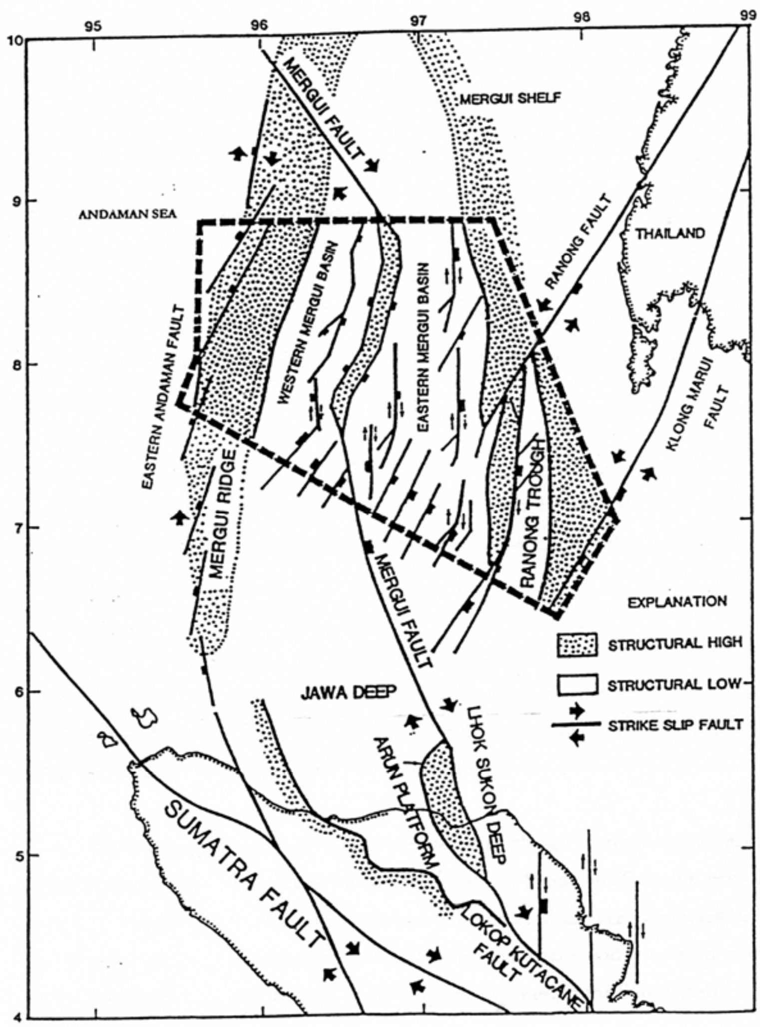


Figure 2.1 Structural map of the Mergui Basin (Polachan, 1988)

2.3 Stratigraphy of the Mergui Basin

Pre-Tertiary basement rocks in the Mergui Basin are composed of metamorphic rocks (slate, quartzite) and igneous rocks (granite, monzonite) and low-grade metamorphic rocks. Polachan and Racey (1994) studied stratigraphy of the Mergui Basin and correlated them with that of the Sumatra Basin (Figure 2.2). They named stratigraphic section studied as Mergui Group and divided Tertiary sediments into 9 formations from bottom to top as below.

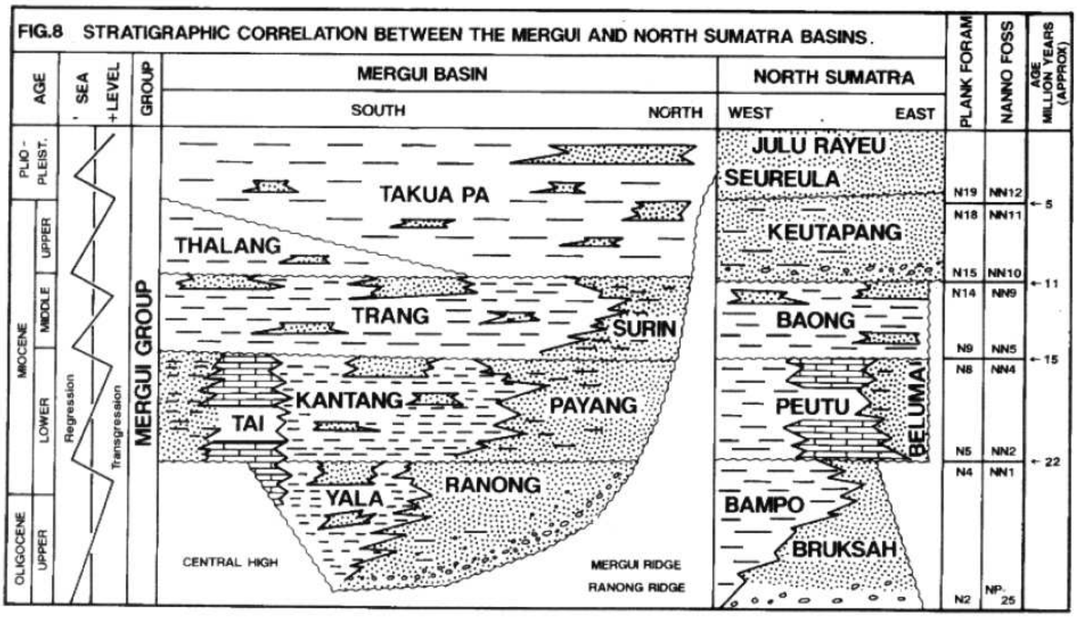


Figure 2.2 Stratigraphic correlations between the Mergui Basin and the North Sumatra Basin (Polachan and Racey, 1994).

2.3.1 Ranong Formation

Ranong Formation comprises three lithological units. (1) The basal unit consists of massive or thick bedded sandstones and conglomerates in grey and red colors. Sandstones are medium- to very coarse-grained, sub-angular to sub-rounded, and poorly sorted, and grade into conglomerate in their lower part. (2) The middle unit consists of green-grey sandstones interbedded with siltstones, dark grey shale and occasional thin coals. Sandstones are predominantly very fine- to medium-grained, sub-angular to sub-rounded, poorly to moderately sorted, and are often calcareous, micaceous and/or carbonaceous. (3) The upper unit comprises massive green-grey, very fine- to fine-grained, calcareous, micaceous, thick-bedded sandstones. The thickness of this formation varies from 764 feet in Payang-1 well to 3,680 feet in W9-B-1 well.

Interpreted depositional environments of the upper, middle and lower parts of Ranong Formation are delta front, deltaic shallow marine and fluviatile-deltaic shallow marine, respectively. Average thickness of the formation is 1,162 meters and the minimum thickness is 229 meters. Age of deposition is Late Oligocene to Early Miocene.

2.3.2 Yala Formation

Yala Formation can be divided into two lithological units. (1) The lower unit comprises grey glauconitic shale with abundant planktonic foraminifera and occasional thin sandstone, siltstones and detrital limestones. Sandstones in the lower unit are white to light grey in color, and very fine- to fine-grained. (2) The upper unit comprises white to light grey, very fine to fine-grained, very calcareous and micaceous, moderately to well sorted, glauconitic sandstones, containing abundant planktonic foraminifera and shell fragments. Thickness of the formation is between 1,110 meters and 2,085 meters. Age of deposition is Late Oligocene to Early Miocene.

2.3.3 Payang Formation

Payang Formation comprises white to light grey, medium- to coarse-grained, calcareous, micaceous, glauconitic sandstones interbedded with grey shales. Benthic foraminifera and shell fragments are abundant in the upper part of the formation. Depositional environment ranges from delta front to shelf front or coastal line. Average thickness is about 603 meters at type locality. Depositional age is Early Miocene.

2.3.4 Tai Formation

Tai Formation is divisible into three units. (1) The basal unit comprises microcrystalline dolomite interbedded with anhydrite, dark grey shales and fine-grained sandstones. (2) The middle unit consists of white to light grey, recrystaline, massive, coral-algal reef limestones. (3) The upper unit comprising thin-bedded detrital limestones containing abundant angular to sub-angular, poorly sorted limestone clasts, interbedded with grey, silty shale and fine-grained glauconitic sandstones.

Depositional environment interpretation based on foraminifera and calcareous algae suggests a progressive deepening from inner to outer shelf. The basal unit comprising fine-grained dolomite and anhydrite is interpreted to represent deposition in a high-salinity sabkha or lagoonal environment. The middle reefal unit represents shallow marine carbonate buildups deposited on a structural high or in a shelf-edge shoal environment. Thickness of formation is 585 meters at type locality and increases to about 768 meters. Depositional age is Early Miocene.

2.3.5 Kantang Formation

Kantang Formation comprises two major lithological units; lower shales and upper silty shales interbedded with sandstones. The lower unit consists mainly of grey to brown-grey glauconitic shales containing abundant planktonic foraminifera, and occasional thin siltstones, fine grain glauconitic sandstone and detrital limestones. The upper unit consists of grey, very silty, glauconitic shales interbedded with thin siltstones, fine-grained glauconitic sandstones and occasional calcarenites.

Deposition of Kantang Formation was at the same time as Payang Formation. However, the depositional environments of these formations are different. Depositional environment of Kantang Formation based on benthic foraminifera indicate deposition in a fluctuating environment which progressively deepened from neritic shelf to upper bathyal. Average thickness is 1,404 meters at type locality and minimum thickness is about 324 meters. The depositional age is Early Miocene.

2.3.6 Surin Formation

Surin Formation mainly comprises green-grey, medium to coarse-grained, calcareous, micaceous and glauconitic sandstones interbedded with grey shales and brown-grey calcarenites. Abundant benthic foraminifera, gastropod and bivalve fragments are present. A larger foraminiferal assemblage indicates a very shallow marine environment. Thickness of formation is 198 meters at type locality. Age of deposition is Middle Miocene.

2.3.7 Trang Formation

Trang Formation has two major lithological units: the lower shales and the upper turbidites. The lower unit consists predominantly of grey to brown-grey, glauconitic shales containing abundant planktonic foraminifera and occasional thin siltstones, fine-grained glauconitic sandstone and limestone stringers. The upper unit consists of a turbidite sequence containing abundant glauconite, fossil debris and carbonaceous detritus. The Trang Formation is a lateral facies equivalent of the Surin Formation. Benthic foraminifera found in this formation suggest a bathyal environment. Thickness of formation is 732 meters at type locality and thin to 231 meters in the W9-E-1 well. Age of deposition is Middle Miocene

2.3.8 Talang Formation

Talang Formation comprises silty glauconitic shales containing abundant planktonic, agglutinating and benthic foraminifera, shell fragments and carbonaceous detritus interbedded with siltstones and fine-grained glauconitic sandstones. This formation unconformably overlies the Trang Formation and is unconformably overlain by the Takua Pa Formation.

Depositional environment of this formation is lower bathyal. The lower part deposited from slump sediments in marine setting while the upper part deposit in lower portion of submarine fan. Thickness of formation is about 174 meters at type locality. Age of deposition is Late Miocene.

2.3.9 Takua Pa Formation

Takua Pa Formation consists predominantly of green-grey, very soft, calcareous, glauconitic shales containing abundant planktonic foraminifera, and occasional siltstones. The foraminifera indicate a lower bathyal environment. Thickness of formation is 319.5 meters at type locality. Age of deposition is Pliocene to Present.

2.4 Petroleum system of the Mergui Basin

2.4.1 Source rock

Possible source rocks units are the Thalang, Trang, Kantang and Yala Formations. However, the Thalang, Trang and Kantang Formations are thermally immature relative to petroleum generation, while the Yala Formation is mature only in the W9-C-1 and W9-E-1 Wells. The thinner mature source rocks may be present in the middle unit of the Ranong Formation (Polachan and Racey, 1994). Source rocks potential of the penetrated sections are poor to fair and generally comprise Type III gas-prone kerogen, and Type III and Type II gas-oil prone kerogen.

2.4.2 Reservoir rock

The main reservoirs of the Mergui Basin comprise two types of rocks, limestones and sandstone. The limestone (Tai Formation) of carbonate buildups were prime targets of exploration. Carbonate buildups occur in the basement high of the Ranot Trough and Ranong Ridge. Depositional setting of these carbonate buildups is reef. Porosity varies from 13-25% in Late Oligocene reef and 13-22% in Miocene reef. These values are of good quality of reservoirs (Khursida, 2002).

Sandstones of the fluviatile-deltaic shallow marine depositional environment are other main targets of exploration. These sandstones are found at the deeper part of the half-graben basin. These sandstones are of Ranong Formation deposited in Late Oligocene. The porosity of sandstone varies from 9-20% indicating a fair quality reservoir potential.

2.4.3 Seal

Seal is the rock which has low porosity, low permeability and does not allow fluid to pass through itself. The effective hydrocarbon seals of Mergui Basin are marine shale or claystone unit (Yala, Kantang, Trang and Thalang Formation) which mostly deposited throughout the basin from Late Oligocene to Recent.

2.4.4 Trap

The majority of the traps in the study area are structural and stratigraphic traps (Atop, 2006). Potential structural traps are along the N-S trending normal faults. The reefs located on the isolate basement high have potential to be both structural and stratigraphic traps due to the reefs were drown and being buried in the bathyal shale.

2.4.5 Migration

The presence of gas shows in the upper, immature sediments of exploration wells is an evidence of migration from the deeper unit of Yala Formation, the thermally mature section. The hydrocarbons may have migrated up from deeper in the basin along the fault planes into shallower sections or seeped away (Khursida, 2002).

CHAPTER III

METHODOLOGY

The method of this study is summarized in Figure 3.1 and detailed below;

3.1 Literature survey

Study previous works and published papers about the Mergui Basin to understand the petroleum system, source rock geochemistry, geology, stratigraphy and structural geology of the basin. Other data that are related to source rock geochemical study and basin modeling are also reviewed.

3.2 Data collection

Parameters needed in basin modeling are collected from the Mergui Basin. The data were extracted from previous study reports, final well reports and seismic data. The main needed input parameters consist of stratigraphy, lithology, ages, source rock properties, boundary conditions and data for calibration.

3.3 Source rocks geochemical analysis and interpretation

3.3.1 Total Organic Carbon content (TOC)

Eighteen cutting samples of source rock from 3 wells; Kra Buri-1, Kantang-1A and Thalang-1 from different intervals were analyzed for TOC by DMF laboratories to determine their potential as source rock. All cutting samples are from wells that were drilled using water-based mud. Cuttings were selected on intervals of dark grey-colored, fine-grained sediments. TOC is an amount of organic matter contain in the rock sample in a unit of %wt. 10% hydrochloric acid was added to samples, to remove carbonate, until on further reaction occur prior to analyzing by Leco EC-12 Carbon Analyzer. Organic carbon in sample will be combusted in oxygen atmosphere and converted to

CO_2. TOC analysis is the first screening parameter for source rock appraisal. The higher the concentration of organic matter the better source rock potential. Peters (1986) classified TOC content into five grades as shown in Table 3.1.

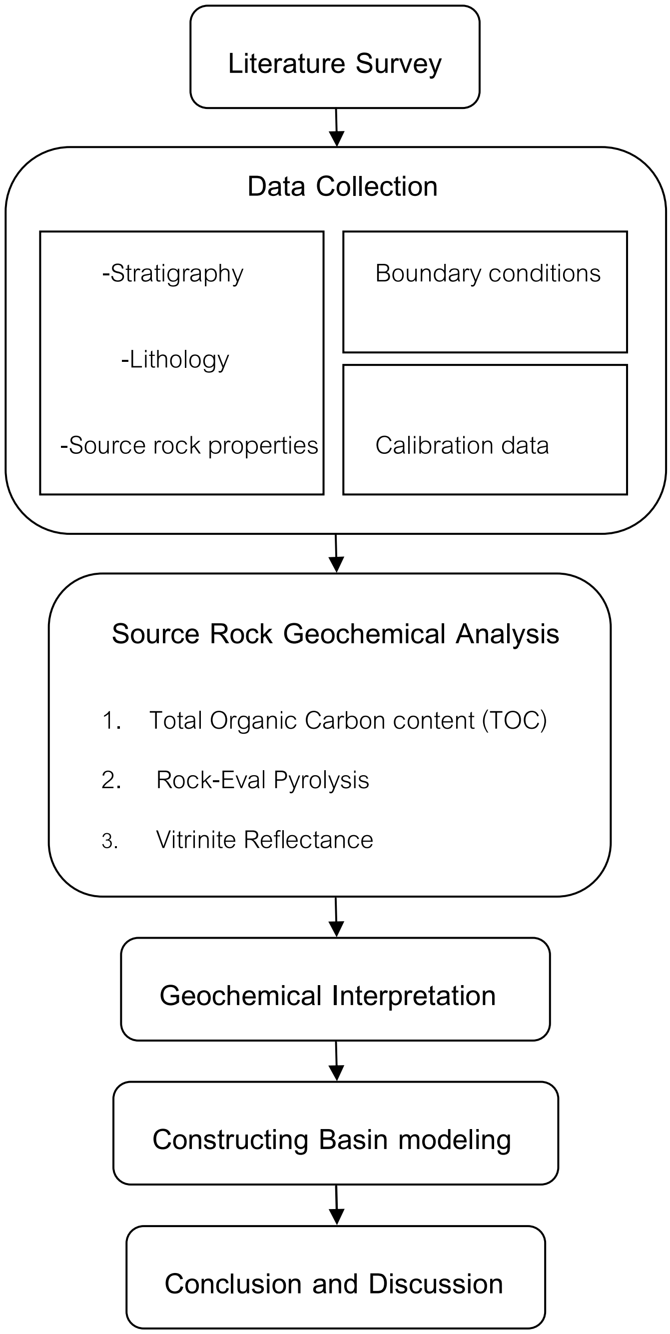


Figure 3.1 Flow chart of methods used in this study.

TOC (wt.%)	Source Potential
< 0.5	Poor
0.5 - 1	Fair
1-2	Good
2 - 4	Very good
> 4	Excellent

Table 3.1 Classification of source rock richness based on Total Organic Carbon content (Peters, 1986).

3.3.2 Rock-Eval pyrolysis

Eighteen cutting samples with TOC higher than 1 wt% from 3 wells; Kraburi-1, Kantang-1A and W9-A-1 from different depths were analyzed by Rock-Eval pyrolysis by Core laboratories (Indonesia) to determine their organic matter type and level of maturity. Pyrolysis is the decomposition of organic matter by heating in an inert atmosphere (usually helium or nitrogen) followed by the recovery and measurement of the volatile components (Milner, 1996). The technique that has been widely used in geochemical study is Rock-Eval pyrolysis. There are three peaks which are typically recorded from pyrolysis as follows (Milner, 1996),

- **S1** is the amount of free or adsorbed hydrocarbon C_1 to C_{12} thermally liberated at a 300˚C isotherm which present in the rock before pyrolysis. A unit of S1 peak is mg hydrocarbon/g rock (mg HC/g rock).
- **S2** represents the hydrocarbons generated from the thermal breakdown of kerogen or from C_{24+} bitumen by heating up to 550˚C. A unit of the S2 peak is mg hydrocarbon/g rock (mg HC/g rock).

- **S3** peak is produced by carbon dioxide pyrolyzed from the kerogen at high temperature (between 300˚C and 390˚C)
- **Tmax** is the temperature at the highest yield of S2 hydrocarbon which is supposed to increase steadily with maturation (Hunt, 1996).
- **Hydrogen Index (HI)** is calculated from S2x100/TOC. The unit of HI is mg HC/g TOC.
- **Oxygen Index (OI)** is calculated from S3x100/TOC. The unit of OI is mg HC/g TOC.
- **Production Index (PI)** is calculated from S1/(S1+S2).

Rock-Eval pyrolysis data can be used to assess the organic matter type within sediment samples by plotting the Hydrogen Index (HI) values against the Oxygen Index (OI) values in a pseudo-van Krevelen diagram as shown in Figure 3.2 (Taylor, 1997). Maturation of the samples can be roughly classified using Tmax into three groups (Table 3.2) base on Teichmuller and Durand (1983) as immature (< 435˚C), mature (437˚C - 470˚C) and over mature (> 470˚C). However, the range of Tmax depends on kerogen types contain in the samples.

3.3.3 Vitrinite reflectance

Eighteen cutting samples from 3 wells; Mergui-1, W9-D-1 and W9-E-1 at different depths were analyzed for vitrinite reflectance by Core laboratories (Indonesia) to determine their thermal maturity relative to petroleum generation. Vitrinite reflectance is the technique used in measuring thermal maturity of source rocks. Preparation method involves washing, crushing, and then mounting the samples in resin. The samples were studied under reflected light microscope to measure the percentage of incident light reflected by polished vitrinite fragments.

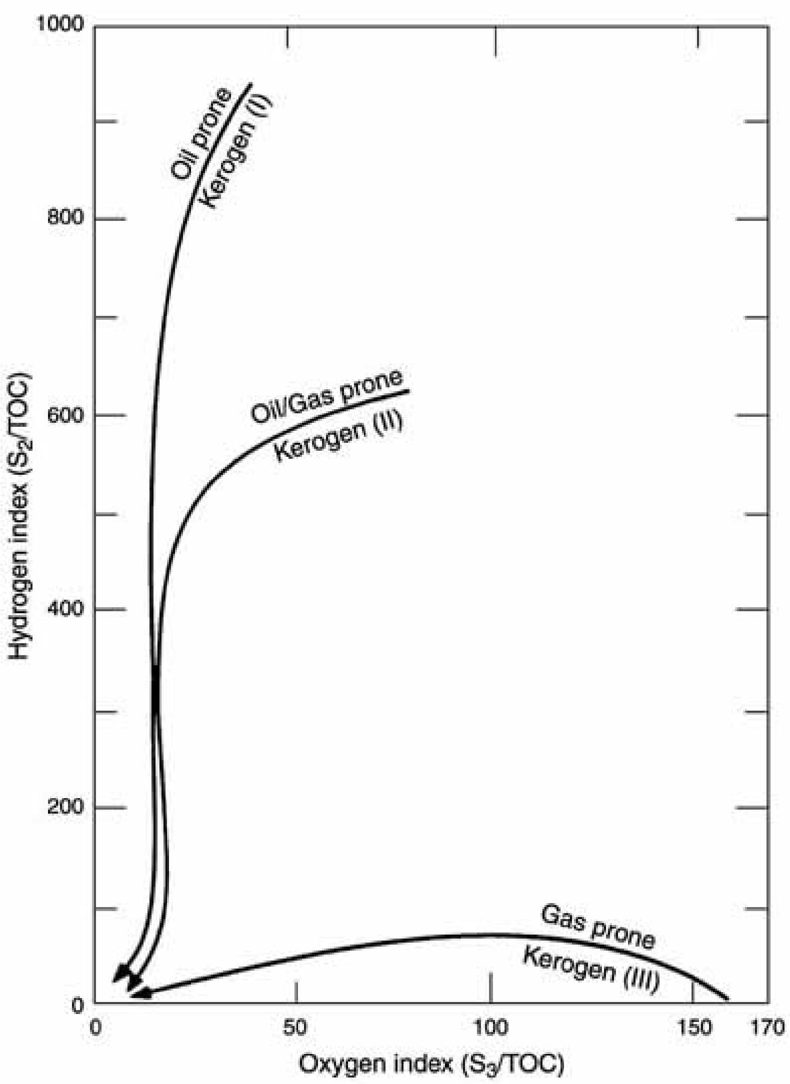


Figure 3.2 “Pseudo-van Krevelen diagram” which plot between HI and OI obtained from Rock-Eval pyrolysis data (Taylor, 1997).

Tmax (˚C)	Maturity Level
< 435˚C	Immature
435˚C - 470˚C	Mature
> 470˚C	Over mature

Table 3.2 Classification of thermal maturity levels of samples based on Rock-Eval Tmax (Teichmuller and Durand, 1983).

The number of individual reflection measurements will be dependent on the abundance of vitrinite particles in the sample, but in this study 50 randomly oriented vitrinite particles were measured for average apparent reflectance. Vitrinite reflectance may be correlated with the main zones and thresholds of petroleum generation as in Table 3.3 (Sweeney and Burnham, 1990). However, ranges of vitrinite reflectance vary slightly in different proportion of kerogen types contain in samples.

Vitrinite Reflectance	Maturity
0.25 - 0.55	Immature
0.55 – 0.7	Early Oil
0.7 - 1	Main Oil
1 – 1.3	Late Oil
1.3 - 2	Wet Gas
2 - 4	Dry Gas
> 4	Over mature

Table 3.3 Classification of thermal maturity level based on vitrinite reflectance (Sweeney and Burnham, 1990).

3.4 Constructing basin modeling

Basin modeling of selected wells was constructed using PetroMod 1D (Version11) program. A summary of processes in the software is shown in Figure 3.3. Input parameters in the model can be divided into 3 groups as follows;

3.4.1 Stratigraphic and source rock properties data

Stratigraphic data extracted from previous study and well completion reports include deposition thickness and age, erosion thickness and age, lithology of each layer and petroleum system essential elements (PSE) which are based on the concept introduced and described by Magoon and Dow (1994). The source rock parameters were collected from geochemistry reports.

Lithology: lithologies can be specified as available basic data that are used as physical properties controller for rock units, which consist of porosity, density and permeability.

Ages: the age of rocks are needed for basin modeling to specify all rock units that deposited during the time interval being modeled. Sedimentary ages have been identified from paleontology, which are published in final well reports.

Thickness: the thicknesses are collected from final well reports and published reports. They are used as input data to simulate basin models.

Source rock properties: there are two source rock properties, the total organic carbon (TOC) and the hydrogen Index (HI), are required as the input data for PetroMod to simulate the hydrocarbon generation potential.

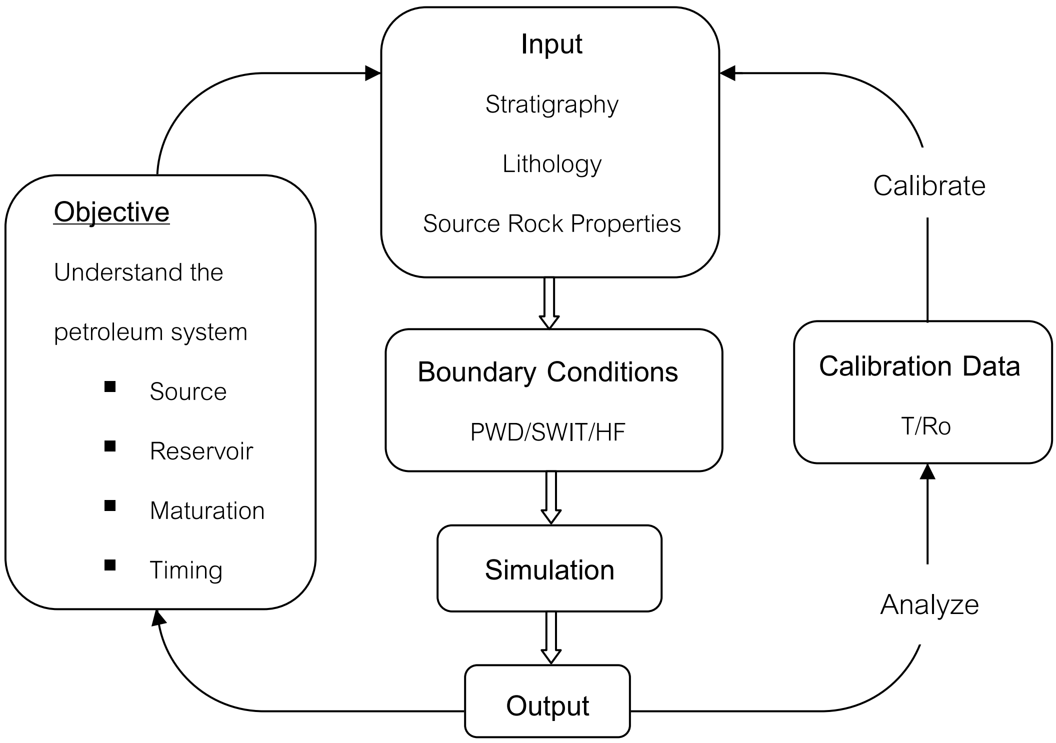


Figure 3.3 Workflow of 1D Basin modeling.

3.4.2 Boundary conditions

Boundary conditions are essential in petroleum system modeling. The boundary conditions define the basic energetic conditions for the temperature development for all layers, especially the source rock, and consequently for the maturation of organic matter through time. The three boundary conditions used for the model are:

- Paleo Water Depth (PWD): the water depth of the basin during deposition of sediments through geologic time
- Sediment water interface temperature (SWIT): the temperature of the interface between sediment and water trough time
- Basal heat flow (HF): the amount of heat through the basin in mW/m^2 (milliWatts per square meter).

3.4.3 Calibration

Calibration data are essential for the verification of geological models and necessary for adapting the model to fit data observed in the field. In cases where no calibration data is available the simulation result is questionable and resulted in uncertainty in modeling results. Calibration data include bottom hole temperature, vitrinite reflectance (Ro), Tmax and other available thermal maturity data (SCI, TAI, FAMM, VIRF).

3.5 Conclusion and discussion

The results of source rock geochemistry, including potential of source rock, type of organic matter and thermal maturation will be concluded. Moreover, discussion about basin modeling (maturation and timing of hydrocarbon generation) and petroleum system of the Mergui Basin will be discussed.

CHAPTER IV

RESULT AND INTERPRETATION

4.1 Organic matter abundance

Eighteen cutting samples from 3 wells; Kra Buri-1, Kantang-1A and Thalang-1 from different depths were analyzed for TOC content by DMF laboratory to determine their source rock potential. TOC contents that were analyzed by service companies are also gathered and will be interpreted together with TOC content analyzed by DMF laboratory in order to get a better and more reliable picture of the source potential.

Figure 4.1 shows plot between depths and TOC content (wt%) analyzed in this study. Source rock potential assessment of samples based on TOC content is shown in Table 4.1. TOC values from previous studies are shown in Figure 4.2. Source potential of the samples was grouped into five grades on the basis of TOC content; namely “poor” (<0.5%), “fair” (0.5-1.0%), “good” (1.0-2.0%), very good (2.0-4.0%) and “excellent” (>4.0%).

Source potential of the Mergui Basin sediments is generally poor or fair (TOC < 1%), though approximately 23% of the samples has TOC values between 1% and 2% (good potential). Only 7% of samples have TOC higher than 2%.

Average TOC values for each formation are shown in Figure 4.3. It is clear from this diagram that the relatively organic rich sediments tend to be in the Early Miocene Kantang Formation and younger strata. Mean TOC values for the Kantang, Surin, Trang, Thalang and Takua Pa Formations suggest good potential source rocks whereas the TOC values of the older formations (Yala and Ranong Formations) are generally poor to fair source potential. Unfortunately, the relatively organic rich Kantang Formation and younger strata are unlikely to be sufficiently mature to generate hydrocarbons in the Mergui Basin.

Code	Well Name	Sample Depth (ft)	Formation	Average TOC wt%	Source potential
KAN01	Kantang-1	5,590	Takua Pa	1.4	good
KAN02	Kantang-1	5,620	Takua Pa	1.36	good
KAN03	Kantang-1	5,770	Trang	1.33	good
KAN04	Kantang-1	5,800	Trang	1.28	good
KAN05	Kantang-1	6,010	Tai	0.79	fair
KAN06	Kantang-1	6,040	Tai	1.06	good
THA01	Thalang-1	5,260	Takua Pa	3.82	very good
THA02	Thalang-1	5,320	Takua Pa	4.09	excellent
THA03	Thalang-1	5,380	Thalang	3.75	very good
THA04	Thalang-1	5,440	Thalang	3.38	very good
THA05	Thalang-1	5,500	Thalang	7.41	excellent
THA06	Thalang-1	5,530	Thalang	6.89	excellent
KRA01	Kra Buri-1	5,500	Kantang	5.32	excellent
KRA02	Kra Buri-1	5,560	Kantang	6.85	excellent
KRA03	Kra Buri-1	6,100	Kantang	3.65	very good
KRA04	Kra Buri-1	6,160	Kantang	4.88	excellent
KRA05	Kra Buri-1	6,670	Kantang	6.25	excellent
KRA06	Kra Buri-1	6,700	Kantang	5.81	excellent

Table 4.1 TOC result from this study.

Figures 4.4-4.19 show down-hole variation of TOC in 16 wells sorted by formation. The first priority of source potential study is to focus on mature section, Yala and Ranong Formations. An average TOC value of deep marine shale, Yala Formation is 0.67% indicating fair source potential. Yala Formation of W9-C-1, Thalang-1 and W9-E-1 wells have TOC values generally between 0 and 1%. Although TOC values in Yala Formation of Kra Buri-1 well are generally higher than 1 % but Yala Formation in this well is relatively thin. Ranong Formation, the fluvio-deltaic shallow marine section, has average TOC values of 0.55 %. Source potential of Ranong Formation is poor (TOC < 0.5 %) but in Kra Buri-1, Trang and in upper part of Ranong Formation in Mergui-1, W9-A-1, W9-B-1 and W9-C-1 well TOC content are higher than 0.5%.

Marine shale immature section, Kantang, Trang, Thalang and Takua Pa Formations has average TOC higher than 1 % (between 1.09-1.86 %). Average TOC of Kantang Formation is 1.13 %, between 0.5 % and 1.5 %. Although in Kra Buri-1 and Mergui-1 wells, sections with TOC spike higher 4% are encountered with two data with TOC more than 11% (Figure 4.2), but they are thin and not continuous. Trang Formation has an average TOC of 1.32 %. The highest average TOC value of 1.86% is in Thalang Formation, the shallowest section. The Takua Pa Formation, the soft sediment section, has limited TOC data because this formation is an overburden section. Average TOC is 1.09 %.

The local sections in the Mergui Basin include Tai, Payang and Surin Formations. Tai Formation is the shallow marine carbonate buildups deposited on a structural high. It has an average TOC of 0.48%. Source potential of Tai Formation is generally poor to fair but in Katang-1 and Yala-1 wells average TOC values are higher than 1% indicating that TOC values of Tai Formation vary by location. In the shallow marine section of Payang and Surin Formations, average TOC values are 0.52% and 1.59 %, respectively (base on limited TOC data of these two formations).

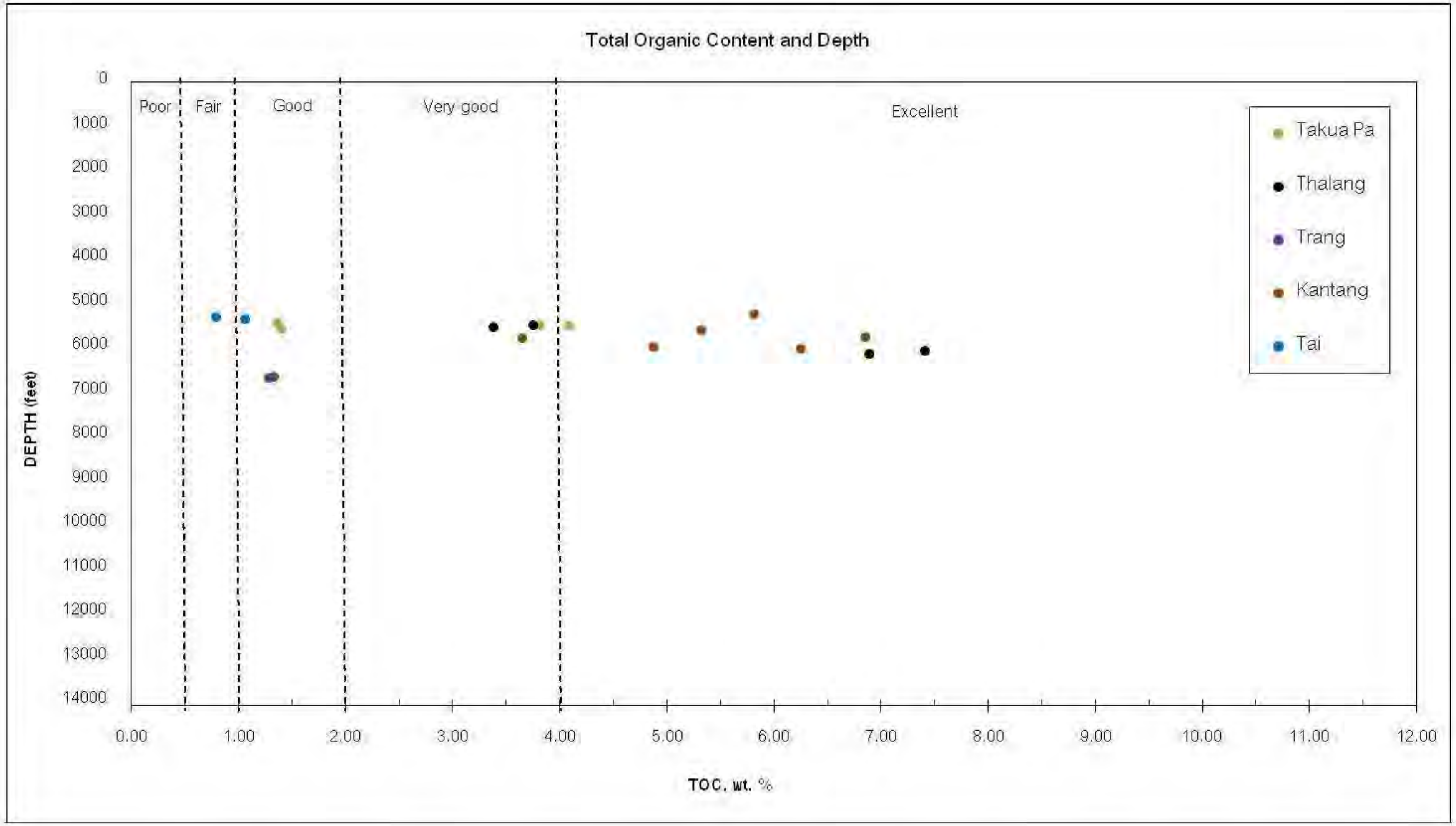


Figure 4.1 TOC results from this study sorted by formation.

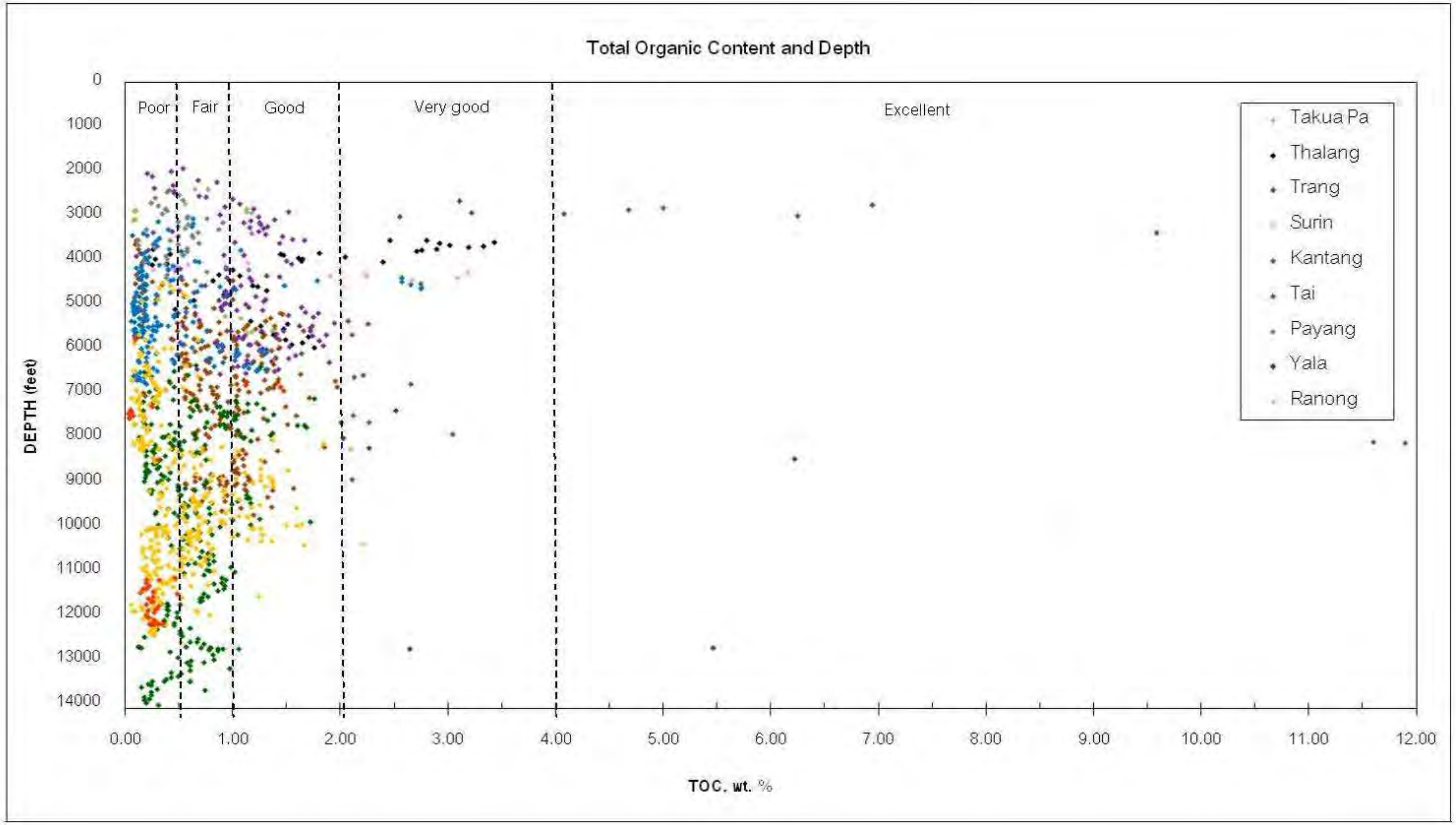


Figure 4.2 TOC results from previous studies sorted by formation.

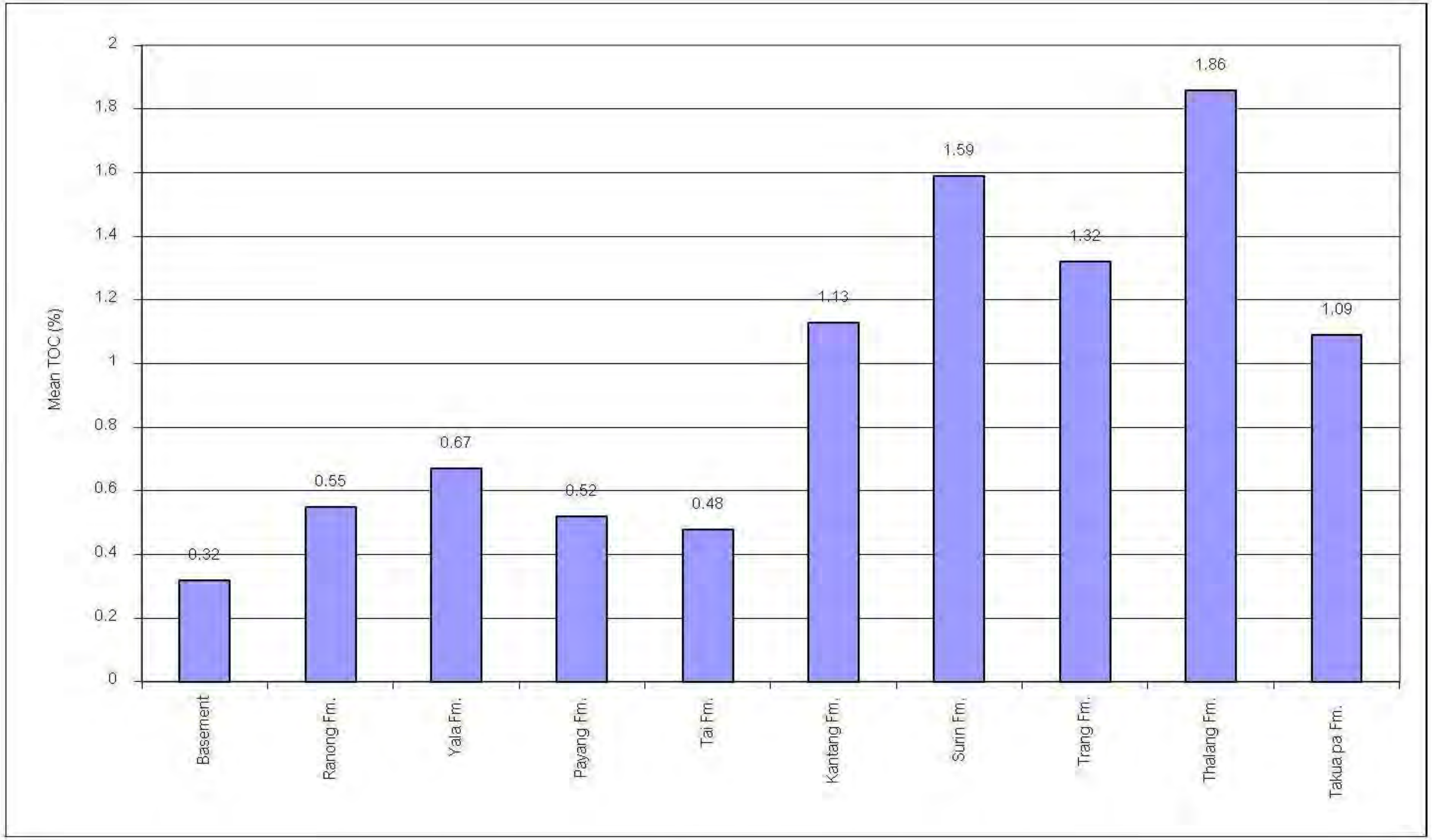


Figure 4.3 Average TOC values for Mergui Basin sediments sorted by formation.

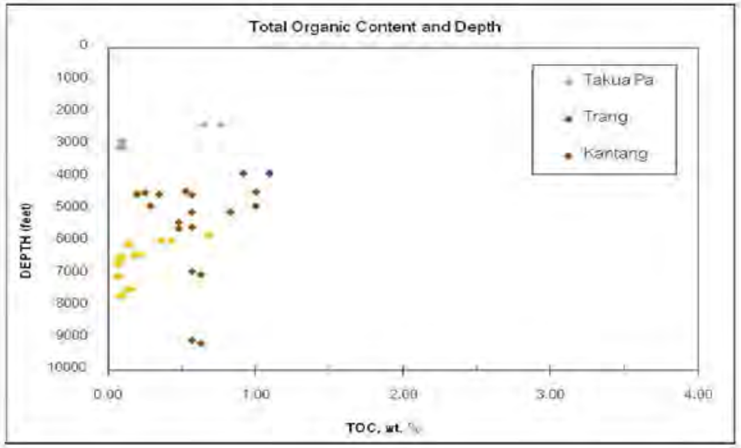


Figure 4.4 TOC results from previous studies of W9-A-1 well.

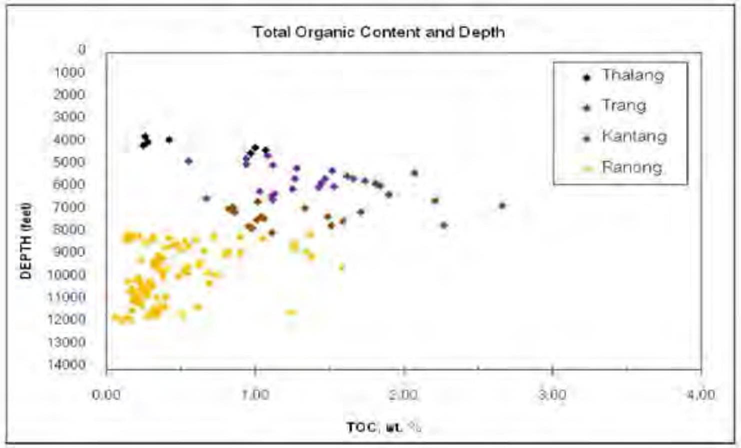


Figure 4.5 TOC results from previous studies of W9-B-1 well.

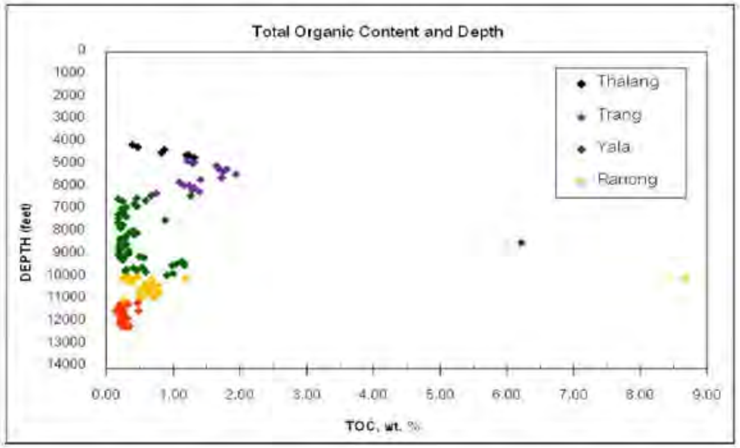


Figure 4.6 TOC results from previous studies of W9-C-1 well.

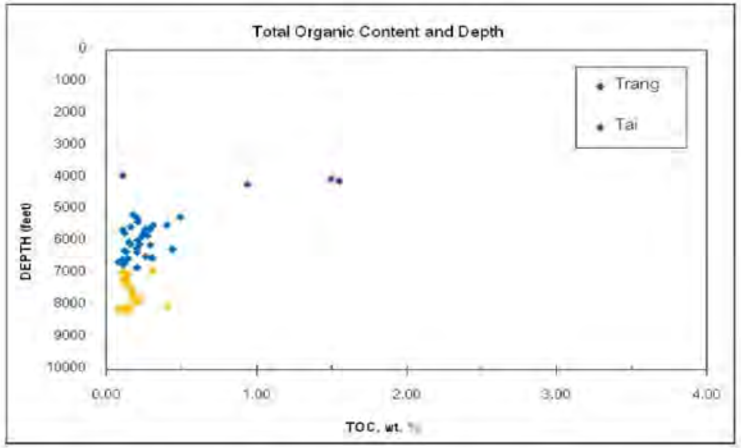


Figure 4.7 TOC results from previous studies of W9-D-1 well.

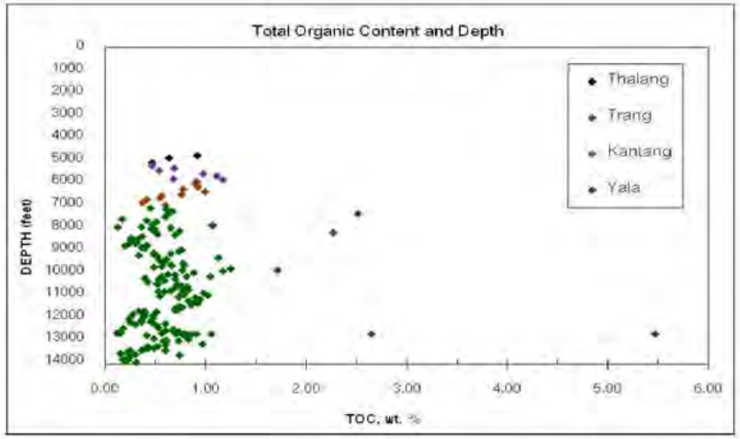


Figure 4.8 TOC results from previous studies of W9-E-1 well.

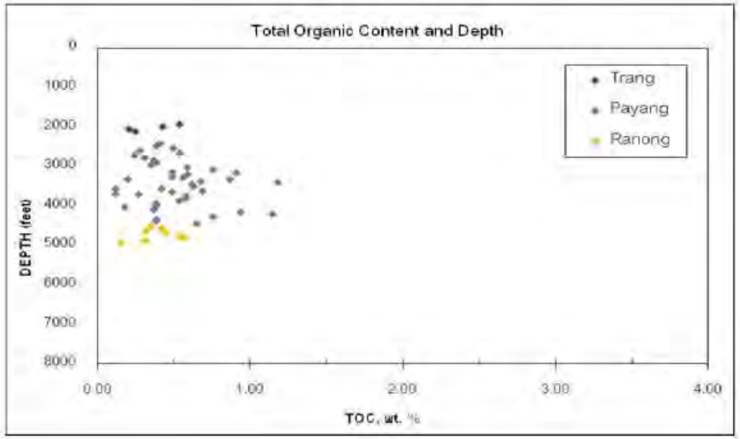


Figure 4.9 TOC results from previous studies of Payang-1 well.

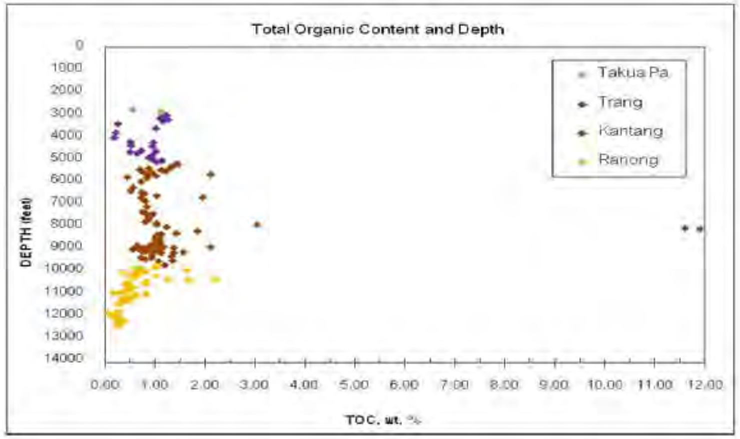


Figure 4.10 TOC results from previous studies of Mergui-1 well.

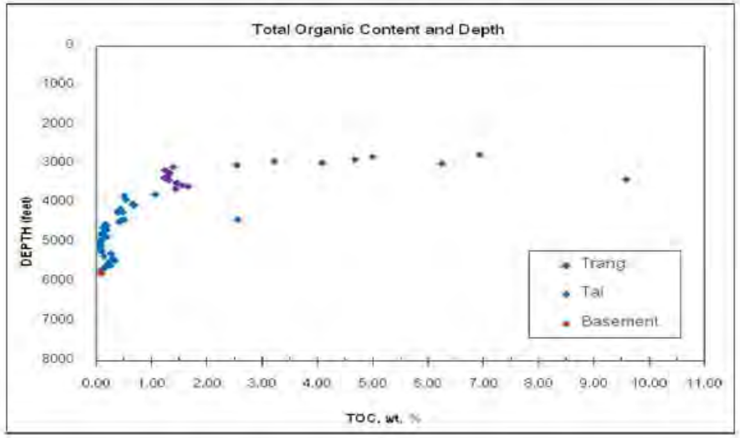


Figure 4.11 TOC results from previous studies of Tai-1 well.

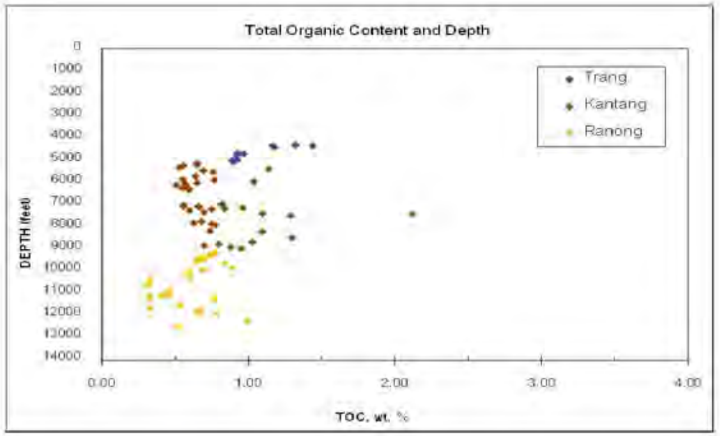


Figure 4.12 TOC results from previous studies of Trang-1 well.

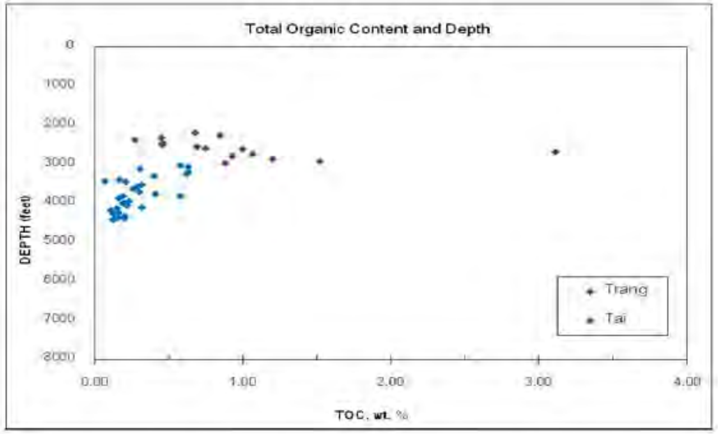


Figure 4.13 TOC results from previous studies of Phangha-1 well.

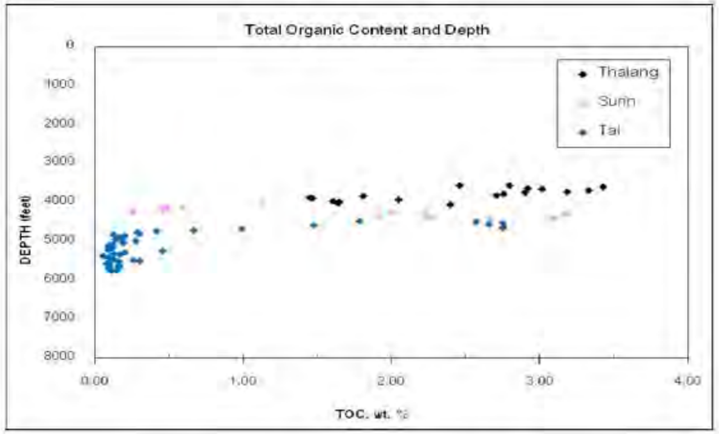


Figure 4.14 TOC results from previous studies of Yala-1 well.

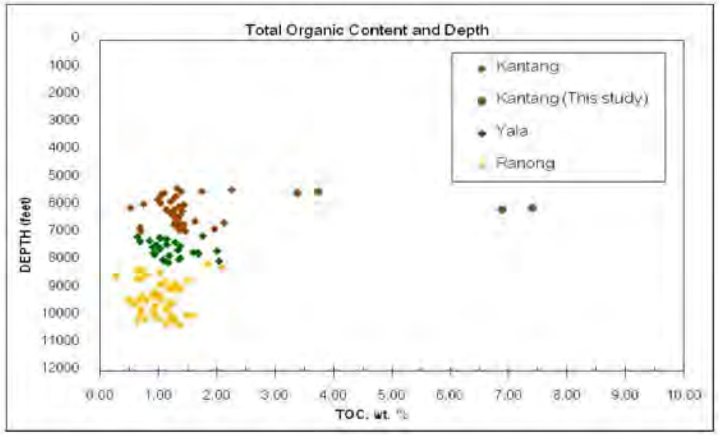


Figure 4.15 TOC results from this study and previous studies of Kra Buri-1 well.

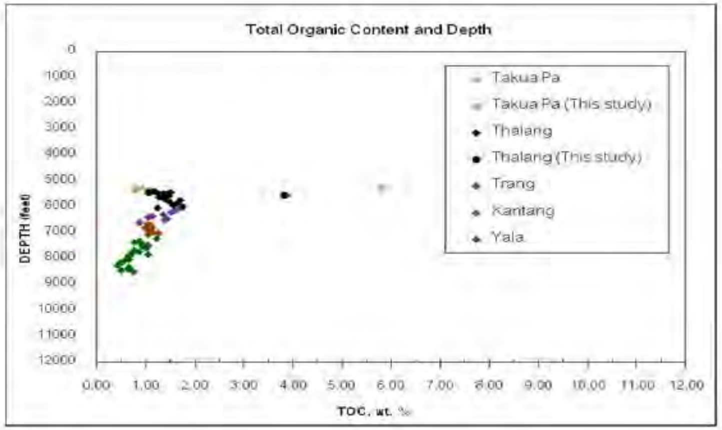


Figure 4.16 TOC results from this study and previous studies of Thalang-1 well.

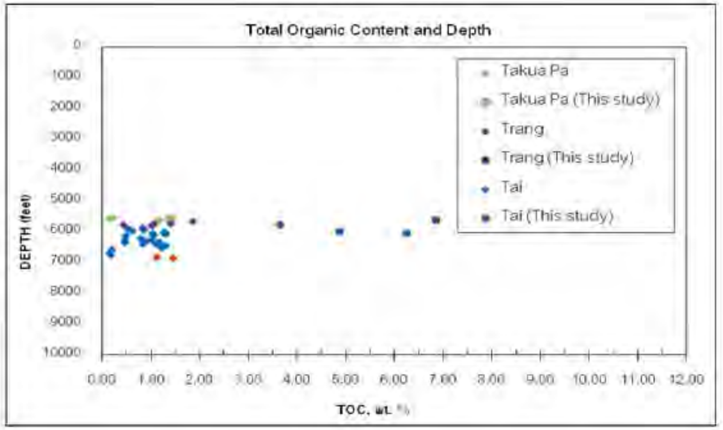


Figure 4.17 TOC results from this study and previous studies of Kantang-1A well.

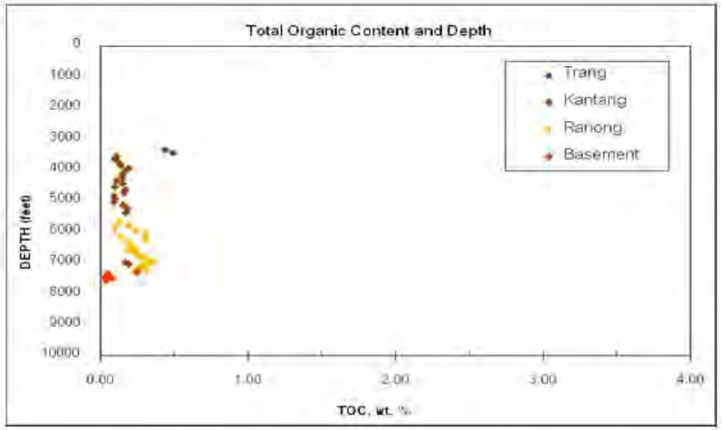


Figure 4.18 TOC results from previous studies of Manora-1 well.

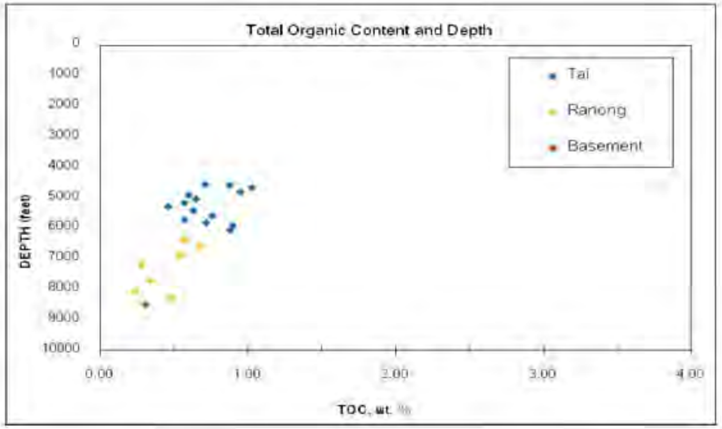


Figure 4.19 TOC results from previous studies of Ranot-1 well.

4.2 Organic matter type

Eighteen cutting samples which have high TOC from 3 wells; Kraburi-1, Kantang-1A and W9-A-1 from different depths were analyzed by Rock-Eval pyrolysis. Pyrolysis results of these samples are shown in Table 4.2. Rock-Eval data can be used to assess the organic matter type within sediment samples by plotting the hydrogen index value (HI) against the value of oxygen index (OI) on a “pseudo-van Krevelen” diagram. Such diagram for the Mergui Basin samples analyzed in this study is shown in Figure 4.20 and for results from previous studies is shown in Figure 4.21.

Source rock samples from the Mergui Basin composed of mainly Type III and Type II/III (or Type III South East Asia – hydrocarbon rich Type III) kerogen that would generate mainly gas and associated liquids when mature.

Most of HI data distribute between 0 and 300, indicate that the organic matter is predominantly gas-prone (HI between 0-150) and gas/oil-prone (HI between150-300). But only about 2% of samples analyzed have the potential to generate a significant proportion of oil-prone source rocks (HI > 300, Figure 4.21).

Wide range of OI in the samples (11 to 598) with most samples have OI between 11 and 150 is observed in Figure 4.21. Only about 8 % of OI results are higher than 300.

Yala Formation generally has HI between 0 and 300, OI between 0 and 100 indicating Type III SEA kerogen.

No.	Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI
1	Kra Buri-1	7,720-7,750	Yala	1.60	61.88	2.10	0.75	417.00	131.25	46.88	0.97
2	Kra Buri-1	7,780-7,810	Yala	0.94	72.21	2.41	0.67	421.00	256.38	71.28	0.97
3	Kra Buri-1	8,980-9,010	Ranong	1.37	57.12	1.86	0.83	420.00	135.77	60.58	0.97
4	Kra Buri-1	9,010-9,040	Ranong	1.19	59.69	2.22	0.89	418.00	186.55	74.79	0.96
5	Kra Buri-1	10,000-10,030	Ranong	1.50	64.30	2.56	0.71	420.00	170.67	47.33	0.96
6	Kra Buri-1	10,060-10,090	Ranong	1.20	68.09	3.48	0.85	425.00	290.00	70.83	0.95
7	Kantang-1A	6,100-6,130	Tai	1.06	0.31	1.82	1.53	424.00	171.70	144.34	0.15
8	Kantang-1A	6,130-6,160	Tai	0.48	0.19	1.88	2.08	424.00	391.67	433.33	0.09
9	Kantang-1A	6,460-6,490	Tai	1.24	0.53	2.92	1.20	424.00	235.48	96.77	0.15
10	Kantang-1A	6,490-6,520	Tai	1.22	1.04	3.55	0.97	420.00	290.98	79.51	0.23
11	Kantang-1A	6,820-6,850	Basement	1.12	0.15	0.11	0.14	392.00	9.82	12.50	0.58
12	Kantang-1A	6,858-TD	Basement	1.45	0.20	0.18	0.16	379.00	12.41	11.03	0.53
13	W9-A-1	3,900-3,930	Trang	1.10	0.43	2.50	2.38	423.00	227.27	216.36	0.15
14	W9-A-1	4,470-4,500	Kantang	0.57	0.39	2.70	3.36	426.00	473.68	589.47	0.13
15	W9-A-1	4,560-4,590	Kantang	0.63	1.06	4.05	2.61	426.00	642.86	414.29	0.21
16	W9-A-1	5,400-5,430	Kantang	1.00	7.04	6.30	1.36	351.00	630.00	136.00	0.53
17	W9-A-1	5,680-5,710	Kantang	0.57	0.49	1.79	1.33	424.00	314.04	233.33	0.21
18	W9-A-1	5,800-5,830	Ranong	0.68	0.32	1.66	1.58	424.00	244.12	232.35	0.16

Table 4.2 Rock-Eval pyrolysis results from this study.

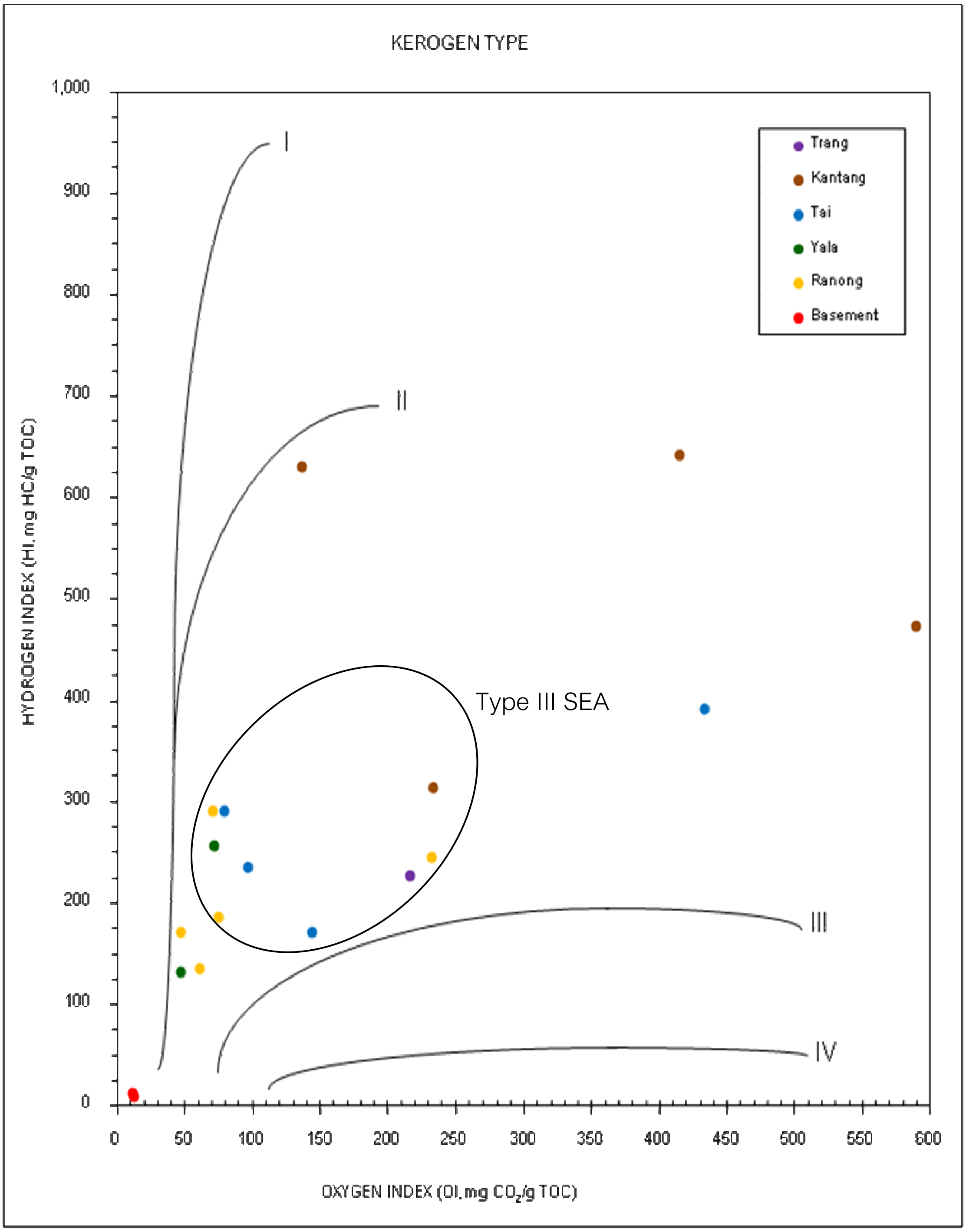


Figure 4.20 Pseudo-van Krevelen plot showing the organic matter types of samples from the Mergui Basin obtained from this study.

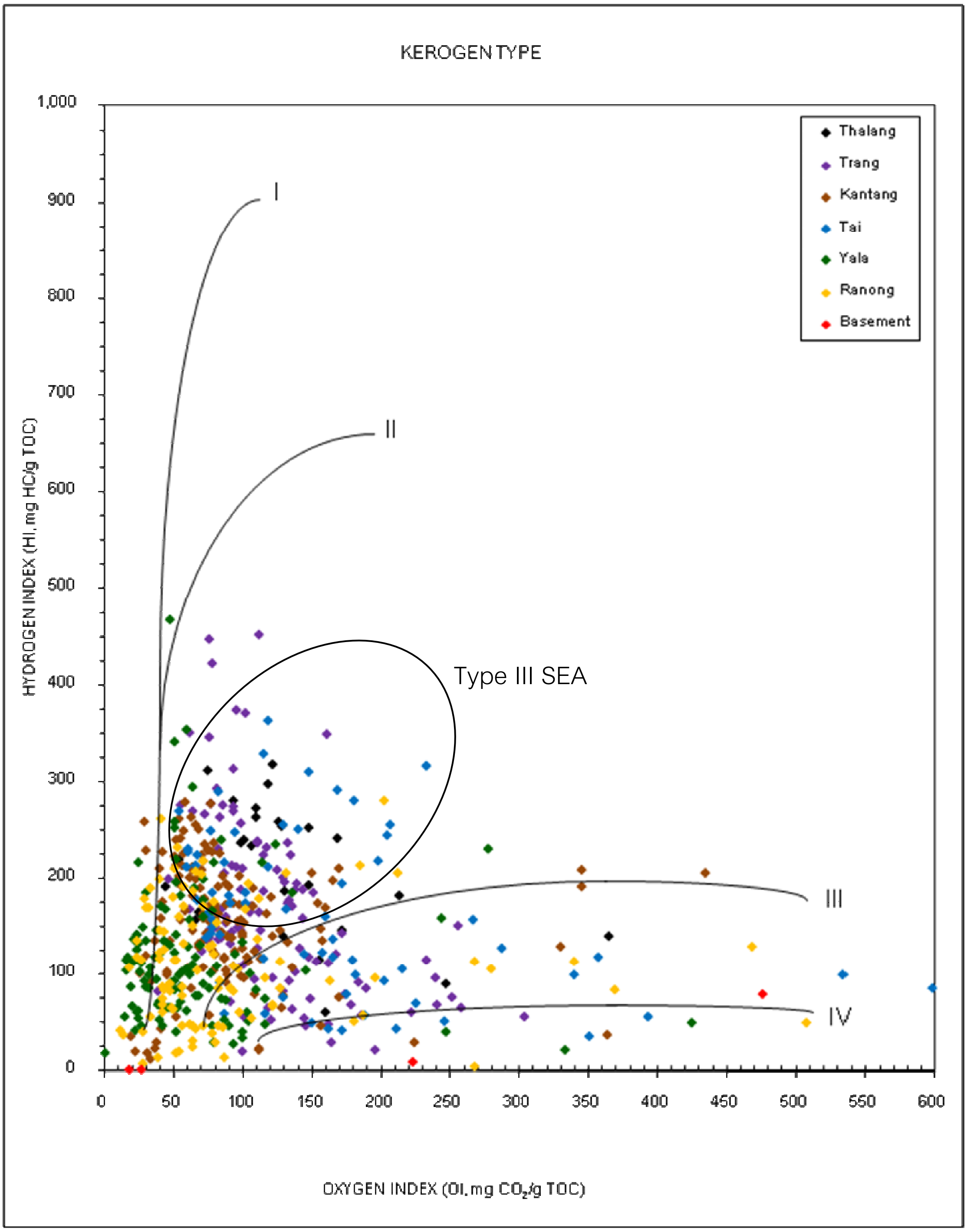


Figure 4.21 Pseudo-van Krevelen plot showing the organic matter types of the Mergui Basin samples compile from previous studies.

4.3 Thermal maturity

Thermal maturity of sediment samples in this study will be assessed from Rock-Eval pyrolysis Tmax and PI, and vitrinite reflectance (Ro).

Tmax data suggest sediment samples in this study are still immature (Table 4.2). Average Tmax is 414 ˚C, Tmax ranges between 351 and 426 ˚C. Nine sediment samples show low PI data, ranging 0.09-0.23, which also indicating that sediments samples are immature. Some PI data are high, ranging 0.95-0.97 (6 samples), which could be a result of mud drilling contamination.

Cutting samples from Mergui-1, W9-D-1 and W9-E-1 wells were analyzed for vitrinite reflectance to determine their thermal maturity. Vitrinite reflectance results obtained from this study are shown in Figure 4.22 while those from previous studies are shown in Figures 4.23 (sorted by formation) and 4.24 (sorted by well).

In shallow section, between 2,500 to 8,000 feet, vitrinite reflectance data clearly show increasing trend with depth from 0.2% to 0.4%. At depth greater than 8,000 feet vitrinite reflectance trends are different in each well. Estimated early oil generation of 0.55% vitrinite reflectance is reached at depth about 9,500 to 10,000 feet. Abnormally high vitrinite reflectance values in wells W9-B-1, W9-C-1 and W9-E-1 are of the samples from bottom of the holes, indicating basement.

W9-A-1:

Vitrinite reflectance data of W9-A-1 well show a good trend of maturity, with exception of some vitrinite reflectance data of Takua Pa Formation which are scattered in the shallow section (Figure 4.25). Trang Formation contains 3 vitrinite reflectance values slightly higher than the maturity trend. Early mature relative to oil generation (0.55% Ro) is reached at depth of 9,000 feet and main oil zone (0.7 % Ro) is reached at 11,000 feet.

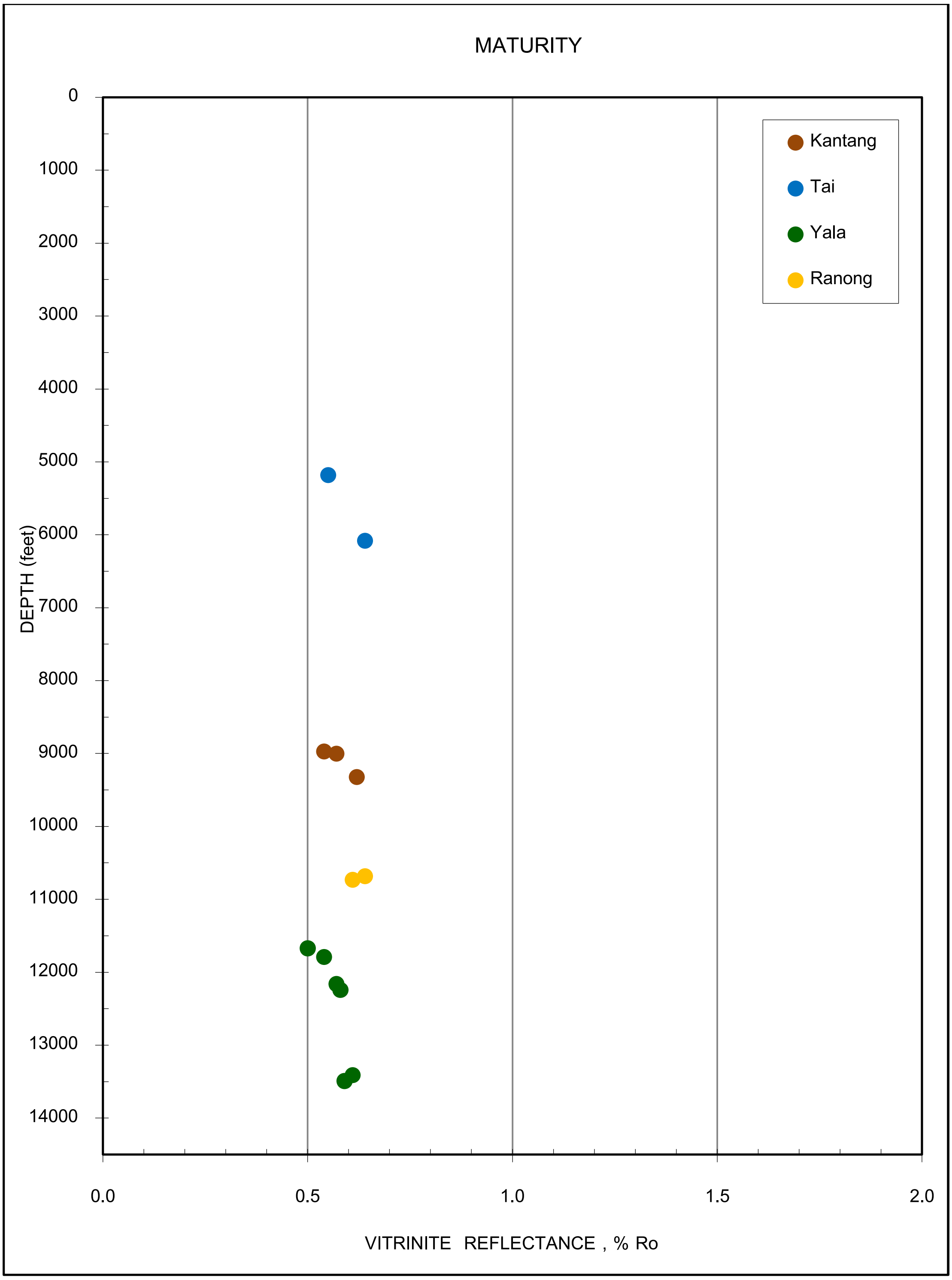


Figure 4.22 Vitrinite reflectance data from this study sorted by formation.

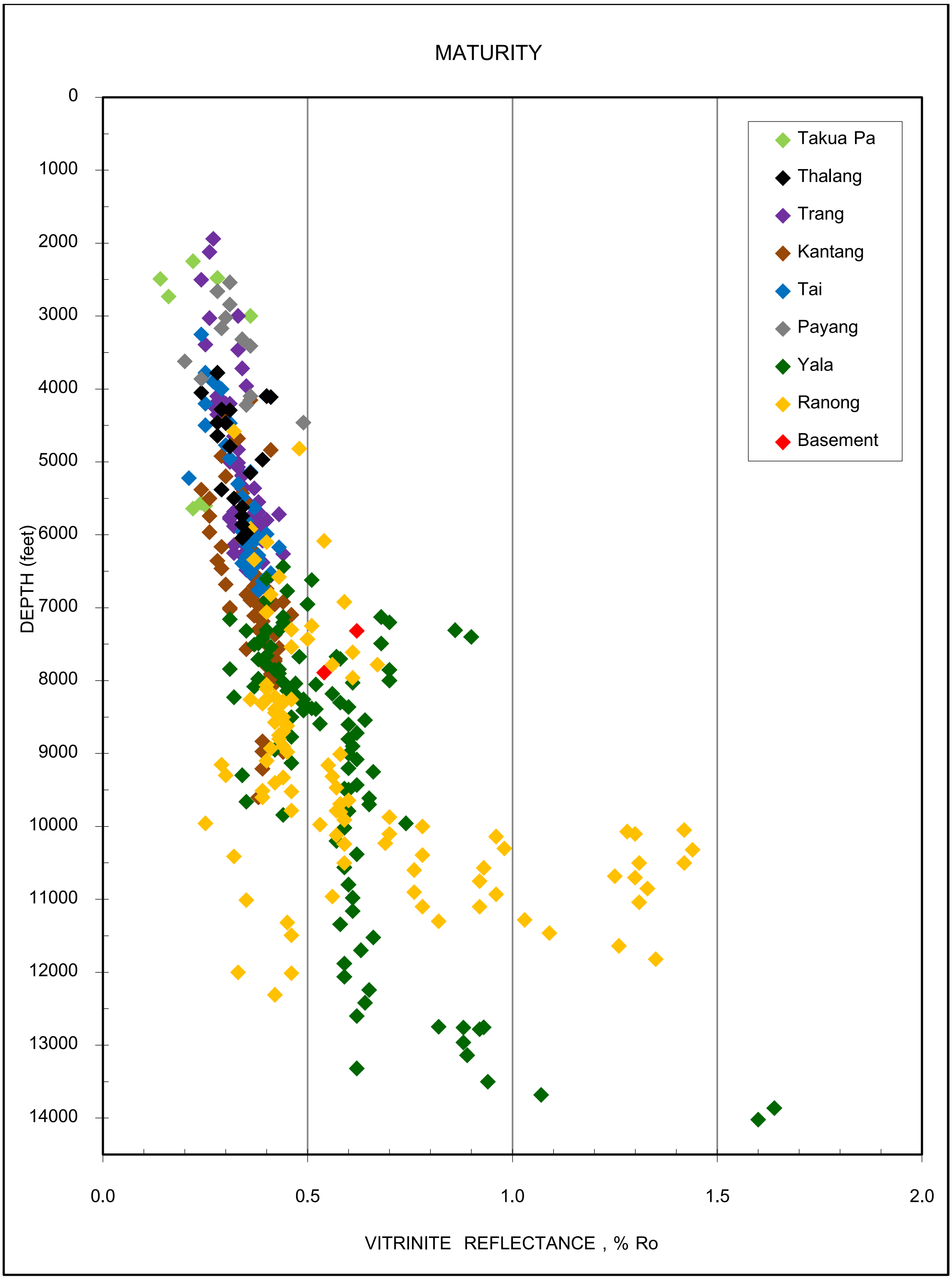


Figure 4.23 Vitrinite reflectance data of the Mergui Basin from previous studies sorted by formation.

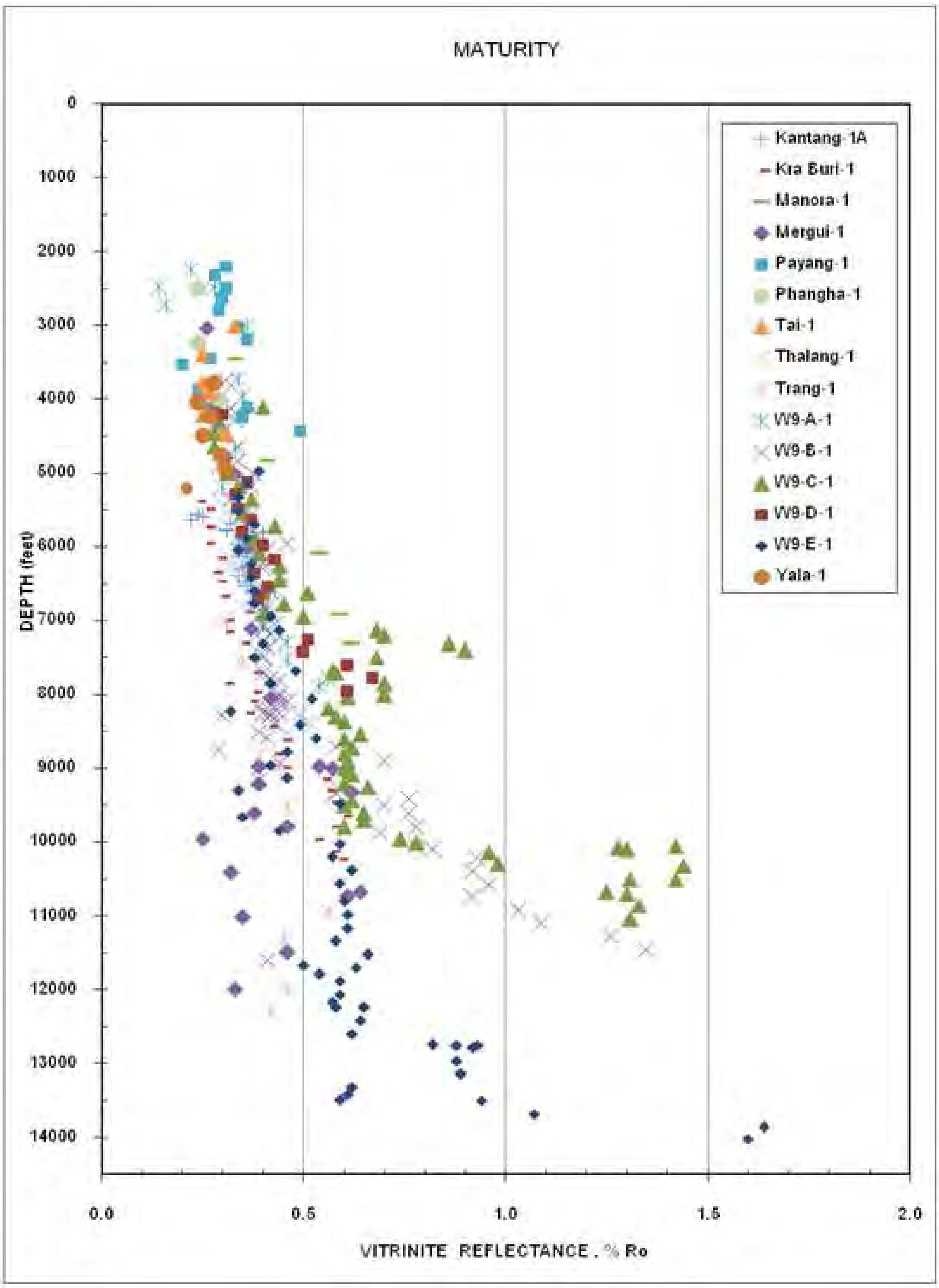


Figure 4.24 Vitrinite reflectance data of the Mergui Basin from previous studies sorted by well names.

W9-B-1:

Vitrinite reflectance data of W9-B-1 well show 2 trends, one between depth 4,000-10,000 feet and another in interval deeper than 10,000 feet (Figure 4.26). Vitrinite reflectance of Ranong Formation increases from 0.6% at 10,000 feet to 1.4% at 12,000 feet. Estimated early oil generation (0.55% Ro) is at 10,000 feet and estimated main oil generation (0.7% Ro) is at 10,500 feet, both are in Ranong Formation.

W9-C-1:

Maturity trend of W9-C-1 well is similar to that of W9-B-1 well (Figure 4.27). Vitrinite reflectance values show distinctive two different trends. Shallow trend of vitrinite reflectance between 4,000 feet and 10,000 feet covers Thalang, Trang and Yala Formations. At depth greater than 10,000 feet of Ranong Formation, vitrinite reflectance values increase rapidly from 1.3 to 1.5%. Basement rock shows outstanding vitrinite reflectance value up to 5.5%.

W9-D-1:

There is limited vitrinite reflectance data in W9-D-1 well because this well was drilled in a structural high in Tai Formation. Tai Formation, the carbonate section contains two groups of vitrinite reflectance data. Most vitrinite reflectance data of Tai Formation sediments were in trend with maturity trend of this well, except two vitrinite reflectance values (Figure 4.28). Trend of maturity in Ranong Formation is different from those of shallower section. Estimated early oil generation (0.55% Ro) is at 8,000 feet and main oil generation is at 8,500 feet.

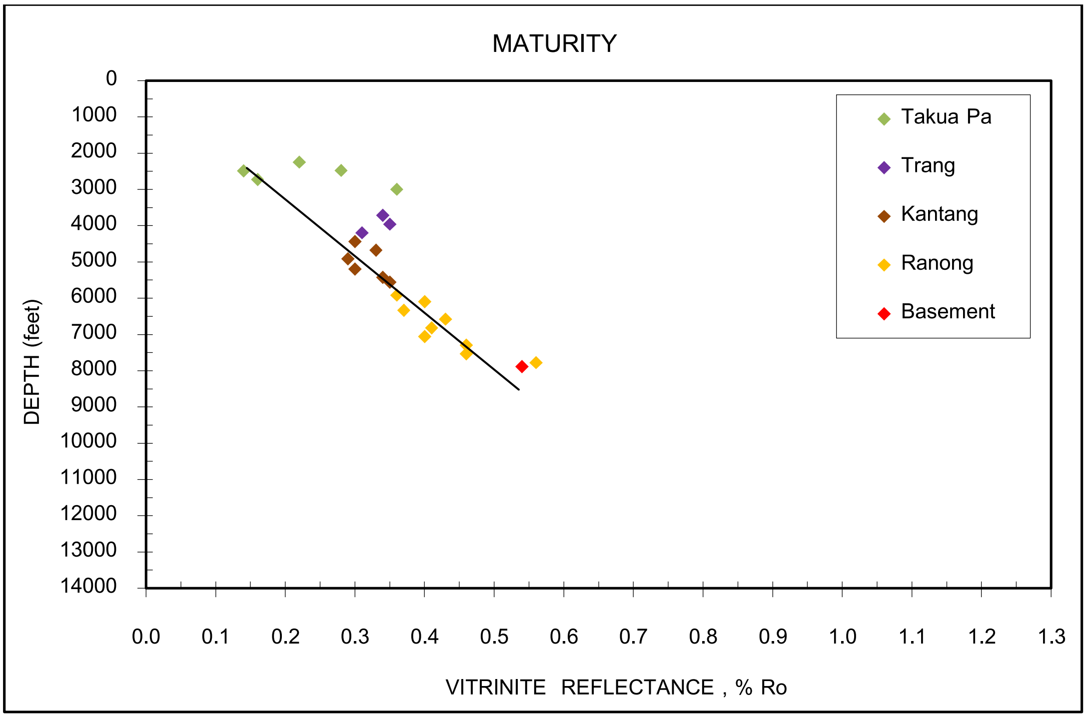


Figure 4.25 Vitrinite reflectance data of W9-A-1 well.

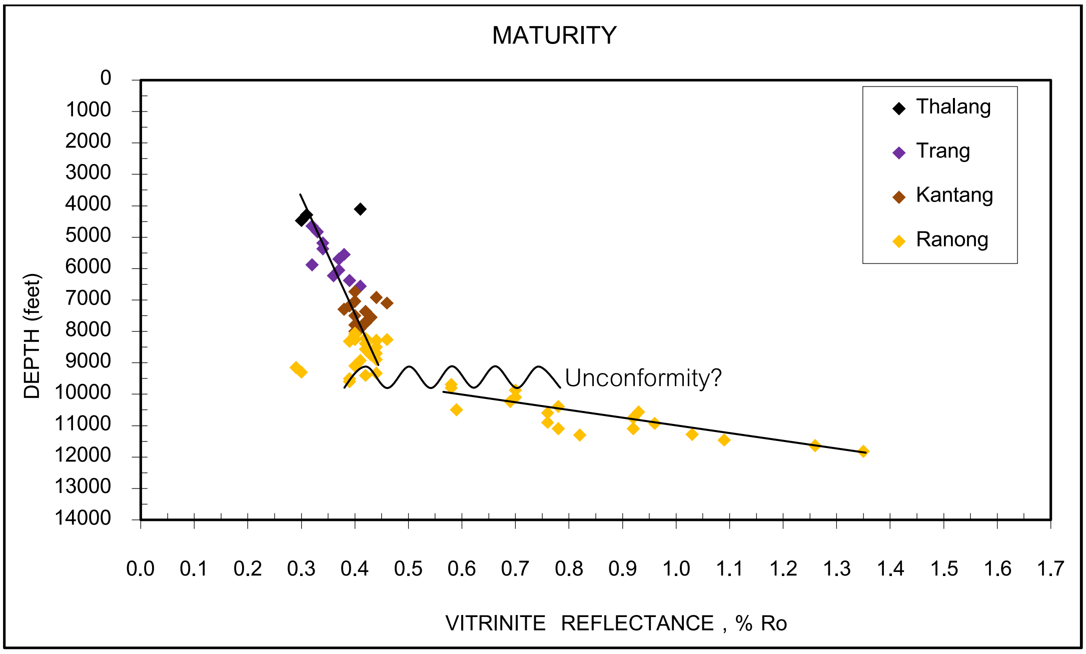


Figure 4.26 Vitrinite reflectance data of W9-B-1 well.

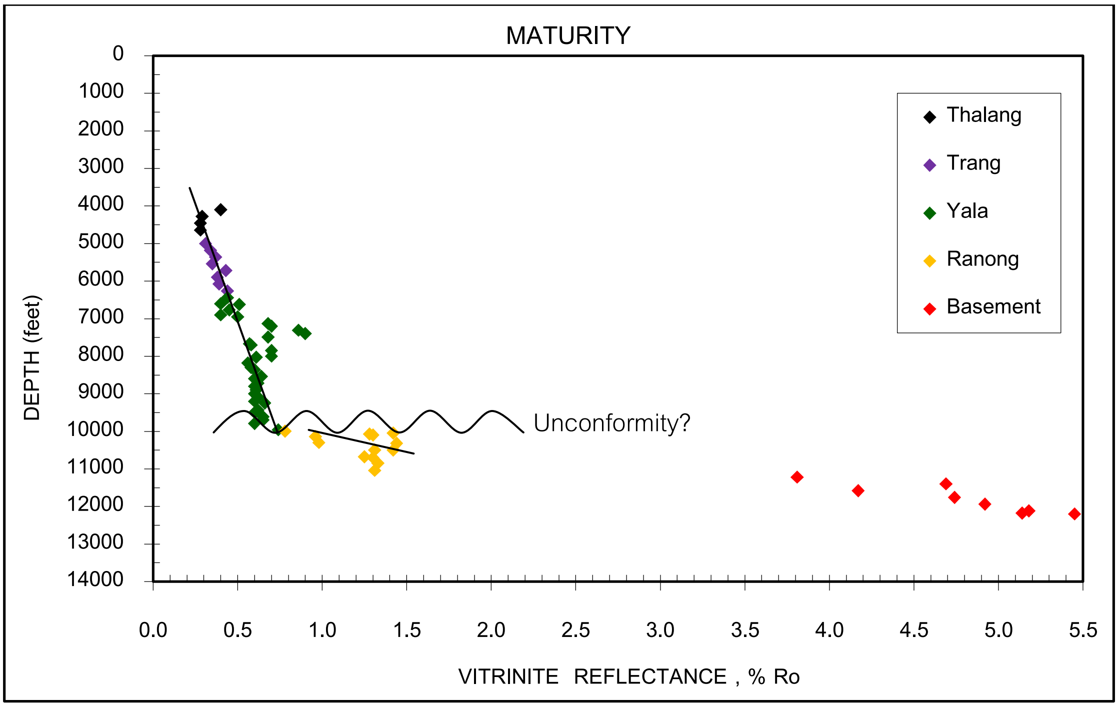


Figure 4.27 Vitrinite reflectance data of W9-C-1 well.

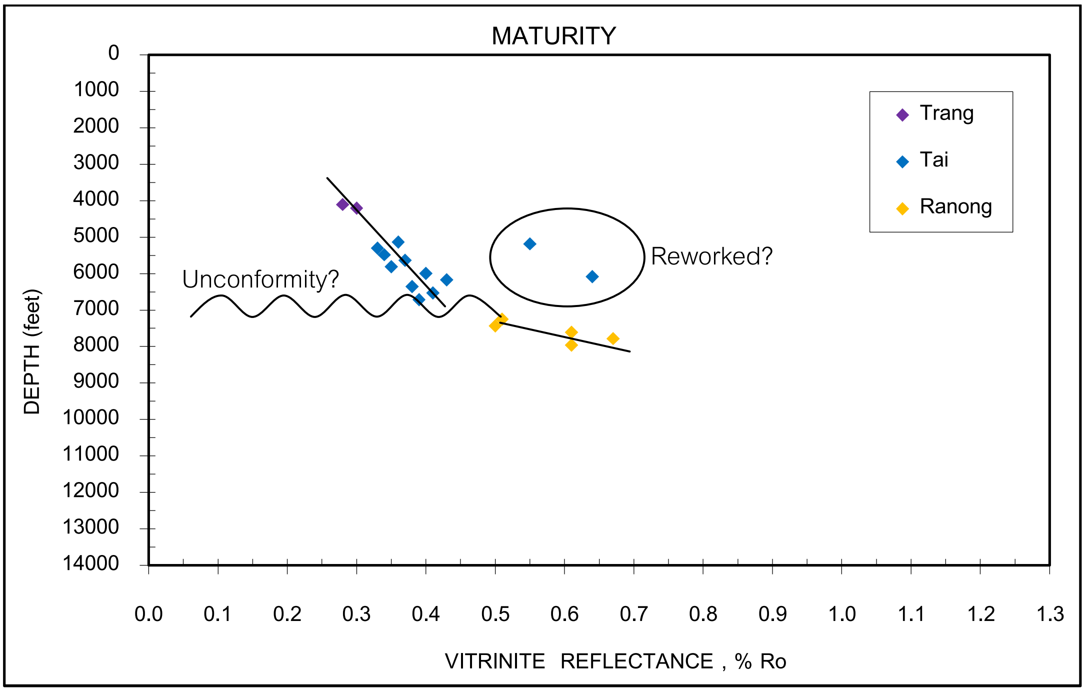


Figure 4.28 Vitrinite reflectance data of W9-D-1 well.

W9-E-1:

Vitrinite reflectance data of W9-E-1 well in shallow section of Thalang, Trang and Kantang Formations, show a relatively fair trend of maturity (Figure 4.29). Main section encountered in W9-E-1 well is Yala Formation, which shows wide range of vitrinite reflectance. Yala Formation at depth greater than 13,000 feet clearly shows different trend of maturity with vitrinite reflectance increases from 0.6% at 12,500 feet to 1.65% at 14,000 feet. Possible reason for having more than one maturity trends in a single well profile could be due to differences in geothermal gradients or differences in thermal histories through time. Early oil generation of 0.55% vitrinite reflectance is at 11,000 feet and main oil (0.7% Ro) is at about 13,000 feet.

Payang-1:

Payang-1 well was drilled through sediments to shallow target. Main section encountered is Payang Formation. Vitrinite reflectance data also include 2 sediment samples of Trang Formation in shallow section and 2 sediment samples of Ranong Formation at the bottom. Vitrinite reflectance of Payang Formation generally ranges from 0.2 to 0.5% (Figure 4.30).

Mergui-1:

Mergui-1 well was drilled through more than 12,000 feet of sediments but only limited vitrinite reflectance data is available (Figure 4.31). Data in shallow section between 3,000 and 8,500 feet form a clear trend of maturity. Sediment samples below 8,500 feet, however, have scattered vitrinite reflectance values. This is possibly due to caving and reworked materials. Estimated top of oil generative window (0.55% Ro) is at 12,000 feet.

Tai-1:

Only vitrinite reflectance data of two formations (Trang and Tai) are available in Tai-1 well (Figure 4.32). All of these data are from previous studies by oil company.

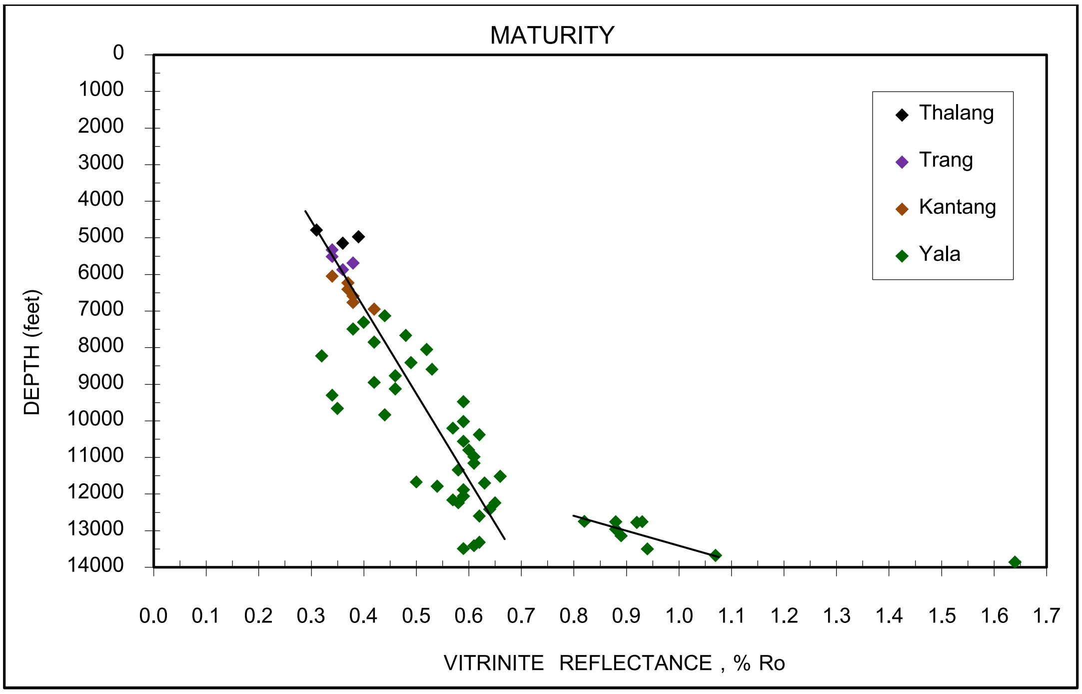


Figure 4.29 Vitrinite reflectance data of W9-E-1 well.

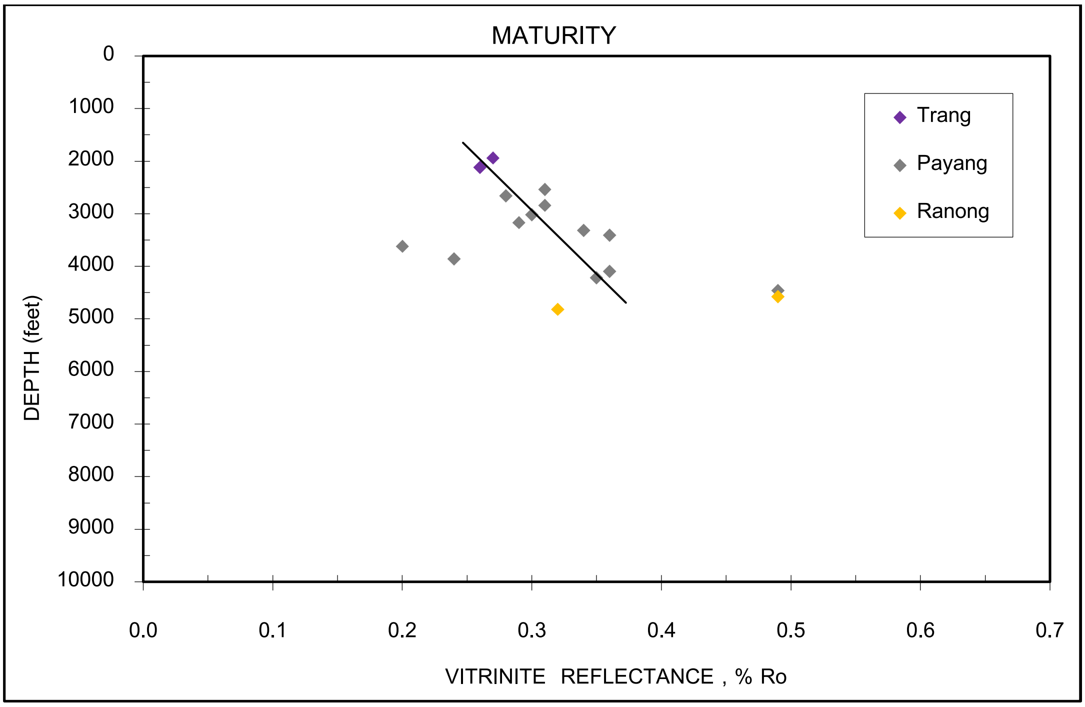


Figure 4.30 Vitrinite reflectance data of Payang-1 well.

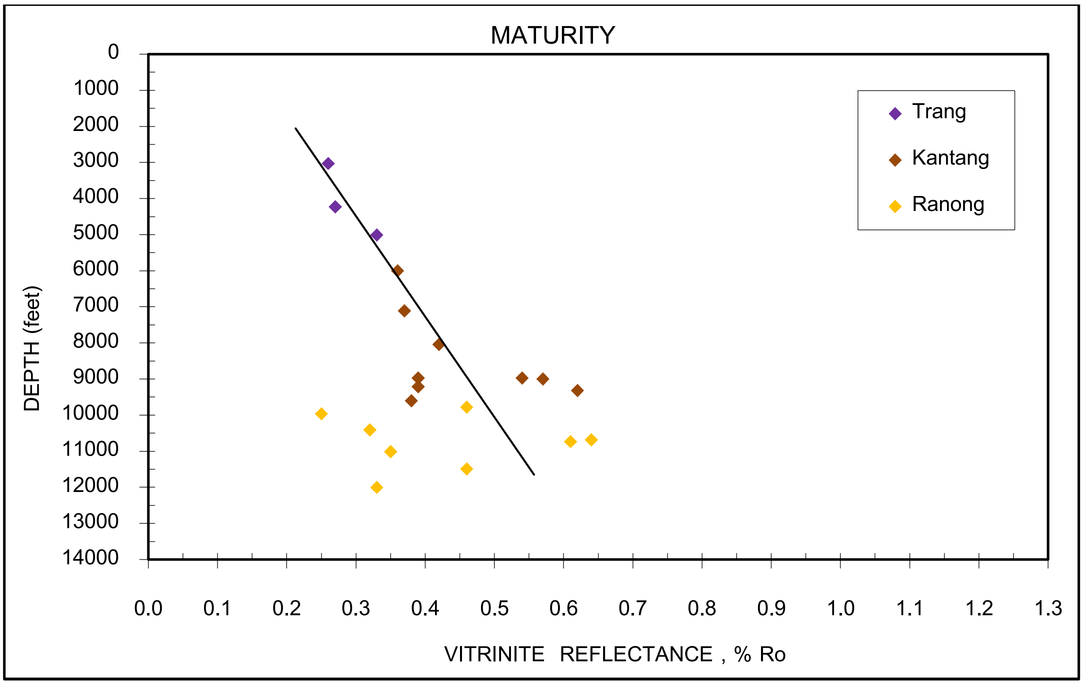


Figure 4.31 Vitrinite reflectance data of Mergui-1 well.

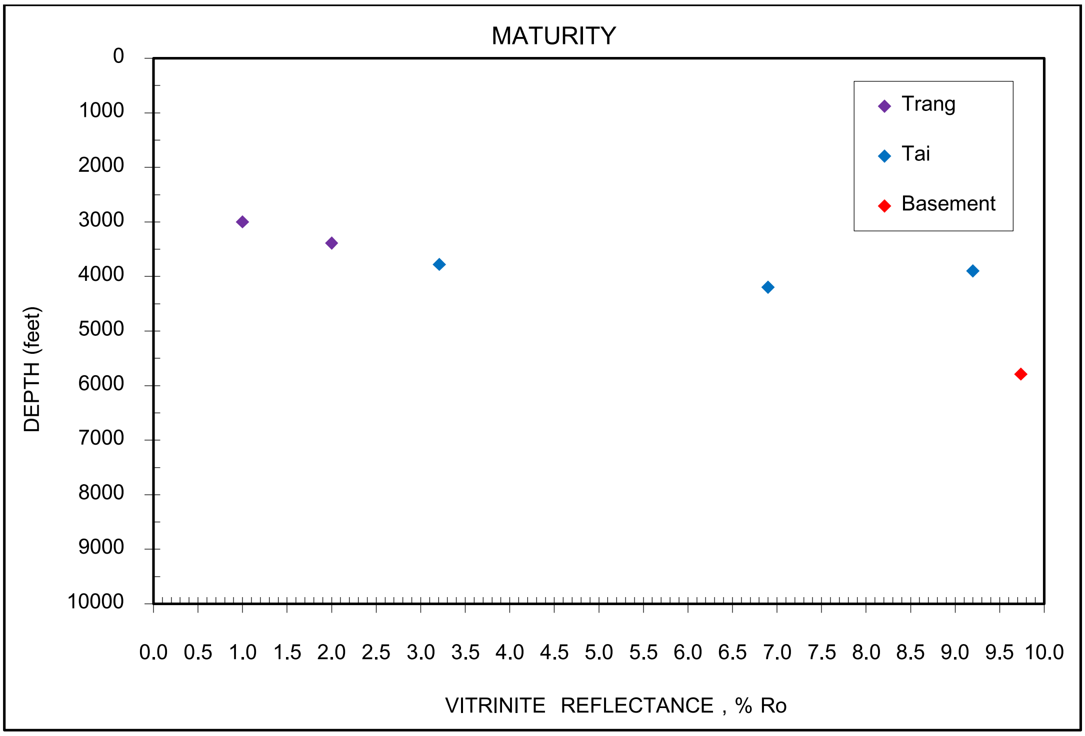


Figure 4.32 Vitrinite reflectance data of Tai-1 well.

Two sediment samples from Trang Formation have 1% and 2% vitrinite reflectance, respectively. Tai Formation in shallow (between 3,500 and 4,500 feet) section has low vitrinite reflectance values (0.2-0.3%), but the deeper section (> 5,000 feet) vitrinite reflectance values widely distributed from 0.3 up to 9.2. Basement unit has vitrinite reflectance 9.8%. These vitrinite reflectance values are very high in respect to their burial depth and in comparison with reflectance values of Trang and Tai Formations of other wells in Mergui Basin and of equivalent formations in the North Sumatra Basin. It is not possible to check the quality of these data (i.e. histogram of reflectance measurements and number of measurements per sample) because of limited information contained in the internal report from the oil company. However, these relatively high vitrinite reflectance values reported for this well could be due to, although unlikely, reworked organic materials derived from the basement or evidence of uplift in the area.

Trang-1:

Vitrinite reflectance in the upper part of sediment samples of Trang and Kantang Formations form a good trend of maturity (Figure 4.33). Ranong Formation samples in deeper section (10,000 feet to 12,500 feet) contain scattered vitrinite reflectance values

Phangha-1:

There are only 3 vitrinite reflectance data for this well (Figure 4.34); one from Trang Formation and two of Tai Formation. Vitrinite reflectance ranges from 0.23 to 0.3%.

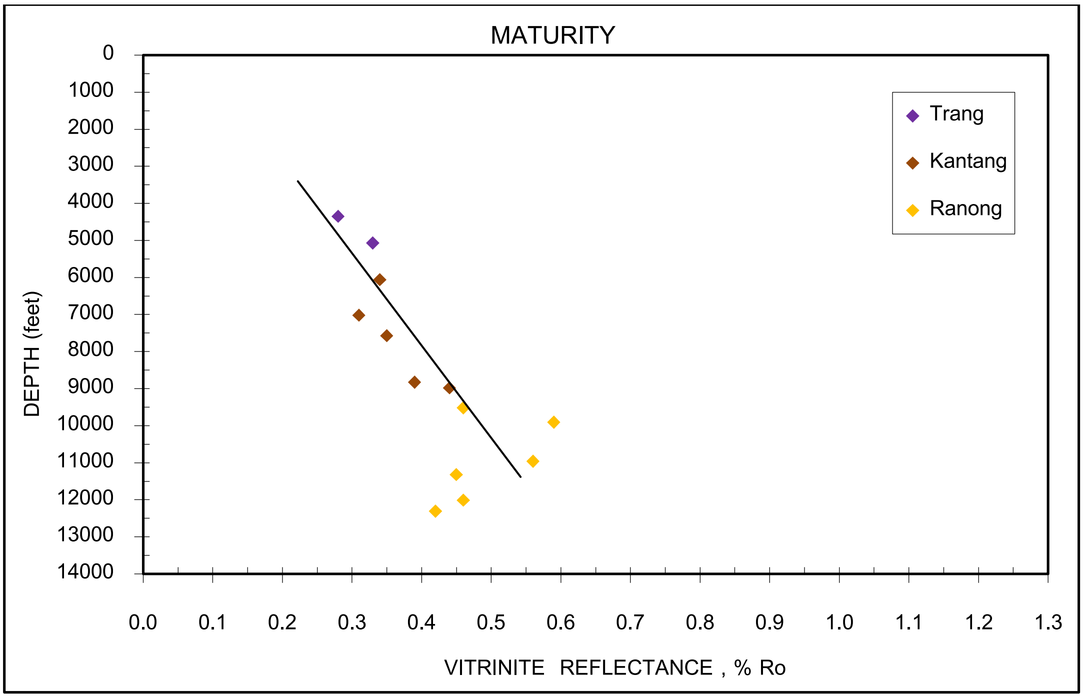


Figure 4.33 Vitrinite reflectance data of Trang-1 well.

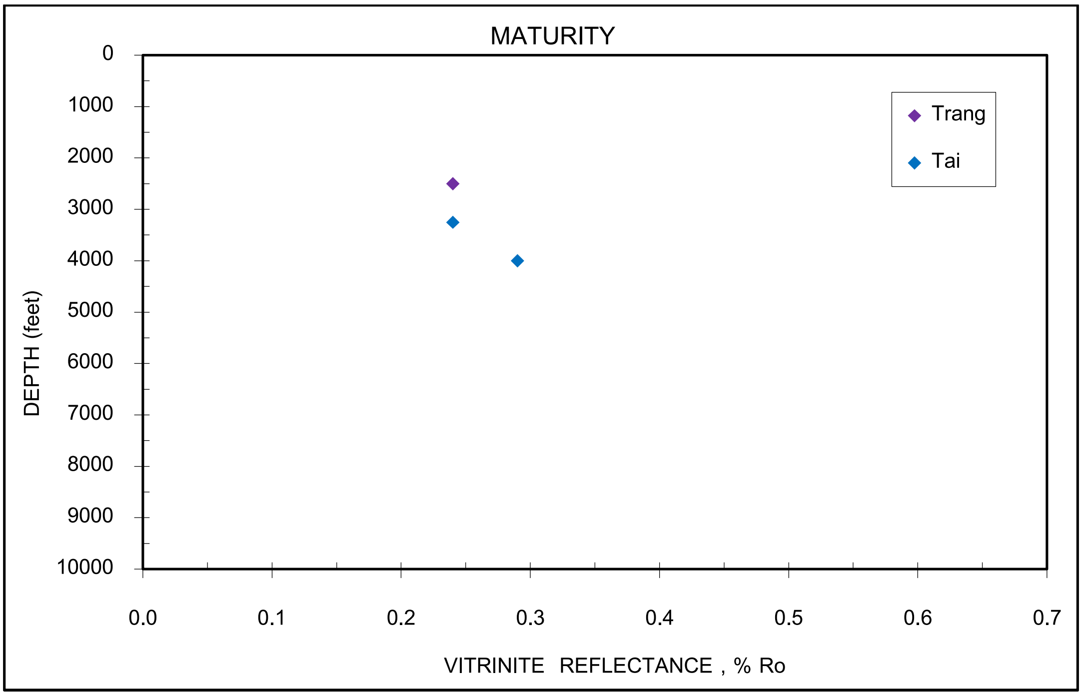


Figure 4.34 Vitrinite reflectance data of Phangha-1 well.

Yala-1:

Yala-1 well has limited number of vitrinite reflectance data and all of available data do not show any maturity trend. Sediment samples compose of 2 samples from Thalang Formation, 1 sample from Surin Formation and 4 samples from Tai Formation ranging in depth from 3,500 feet to 5,500 feet. Vitrinite reflectance of this relatively shallow section is unsurprisingly low (0.2-0.3% Ro) as shown in Figure 4.35.

Kra Buri-1:

Two different maturity trends are clearly shown in Kra Buri-1 well's vitrinite reflectance data (Figure 4.36). Lower part of Ranong Formation from 9,000 to 10,000 feet show an increase in maturity trend. Early oil generative window (0.55% Ro) is reached at 10,000 feet and main oil window (0.7% Ro) is at approximately at 11,000 feet.

Thalang-1:

Maturity trend in Thalang-1 well is clearly shown by vitrinite reflectance data in Figure 4.37. Sediment samples comprise Thalang, Trang Kantang and Yala Formations. Vitrinite reflectance values increase from 0.3% at 5,500 feet to 0.5% at 8,500 feet. Early oil generation (0.55% Ro) is at 10,000 feet and main oil (0.7% Ro) is at approximately 12,000 feet.

Kantang-1A:

Most vitrinite reflectance data of Kantang-1A well are from Tai Formation. Three samples from Takua Pa Formation have vitrinite reflectance about 0.25%, and 5 samples from Trang Formation have vitrinite reflectance in range between 0.3 and 0.4% (Figure 4.38). Vitrinite reflectance of Tai Formation sediments ranges from 0.35-0.4%. There is no visible maturity trend in this well. It is difficult to interpret depth of petroleum generation in Kantang-1 well.

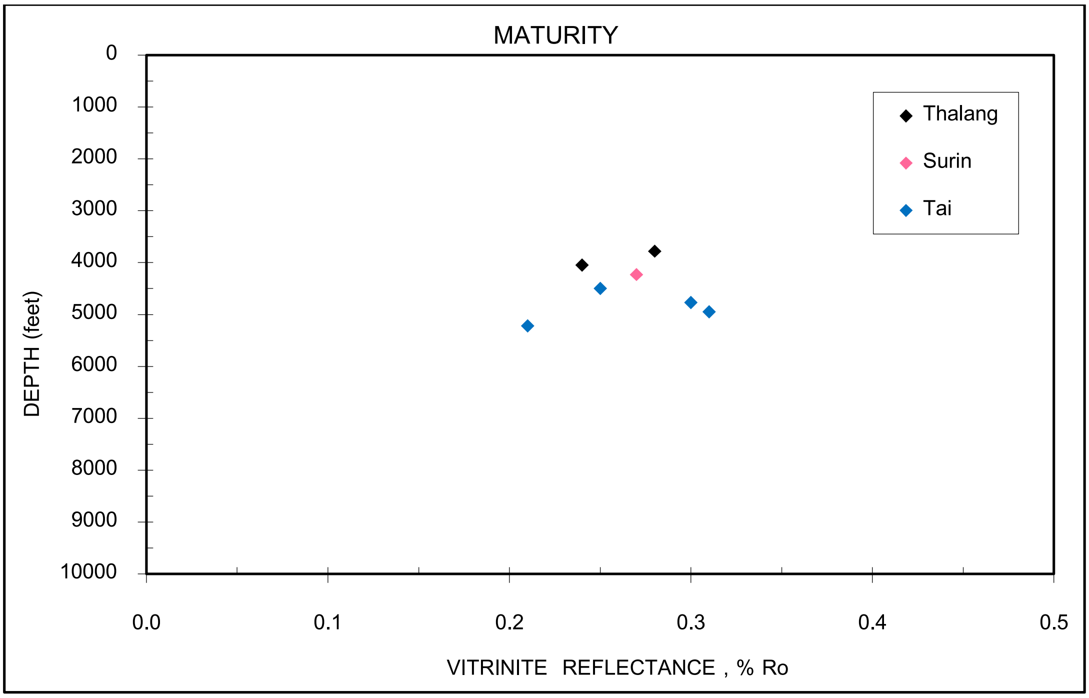


Figure 4.35 Vitrinite reflectance data of Yala-1 well.

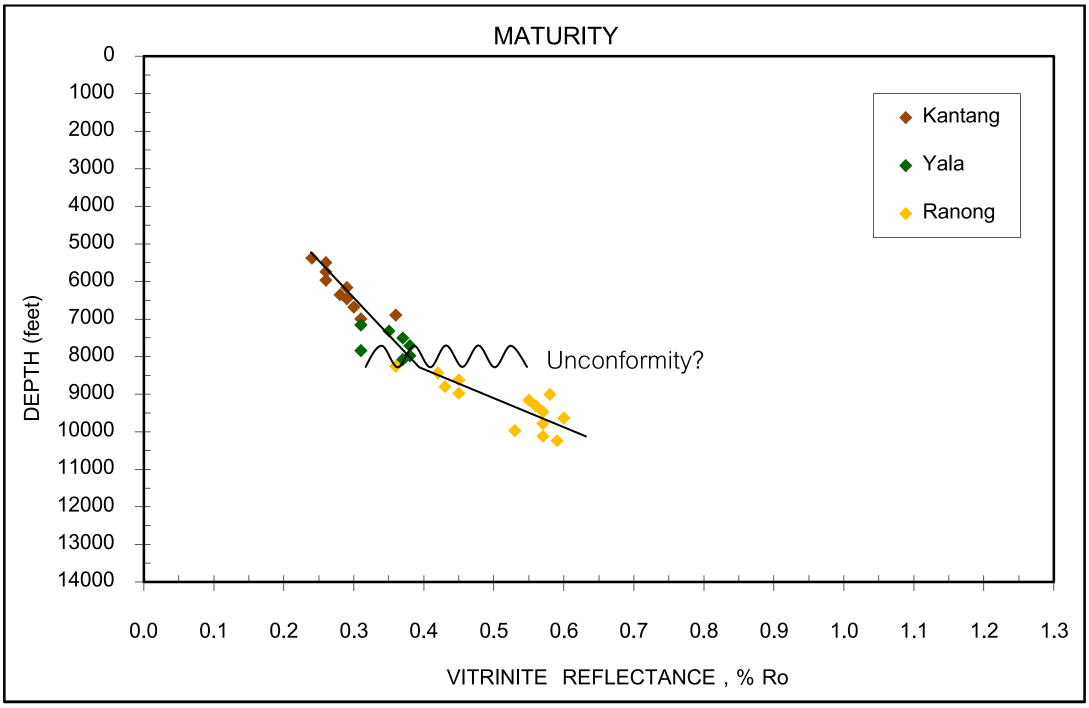


Figure 4.36 Vitrinite reflectance data of Kra Buri-1 well.

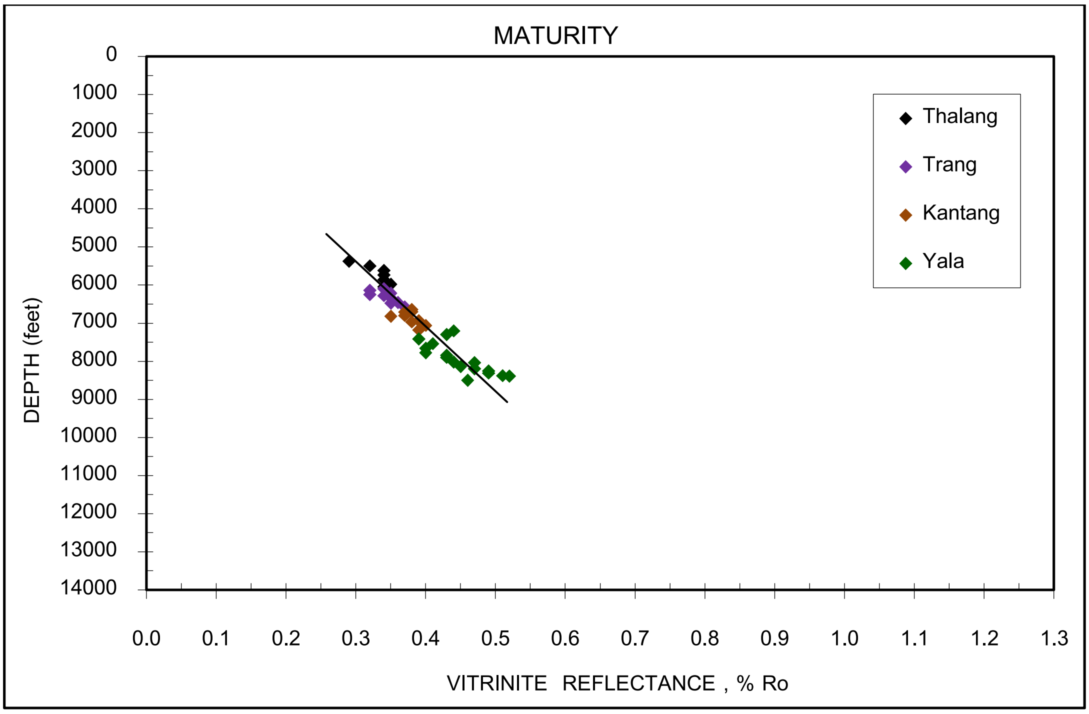


Figure 4.37 Vitrinite reflectance data of Thalang-1 well.

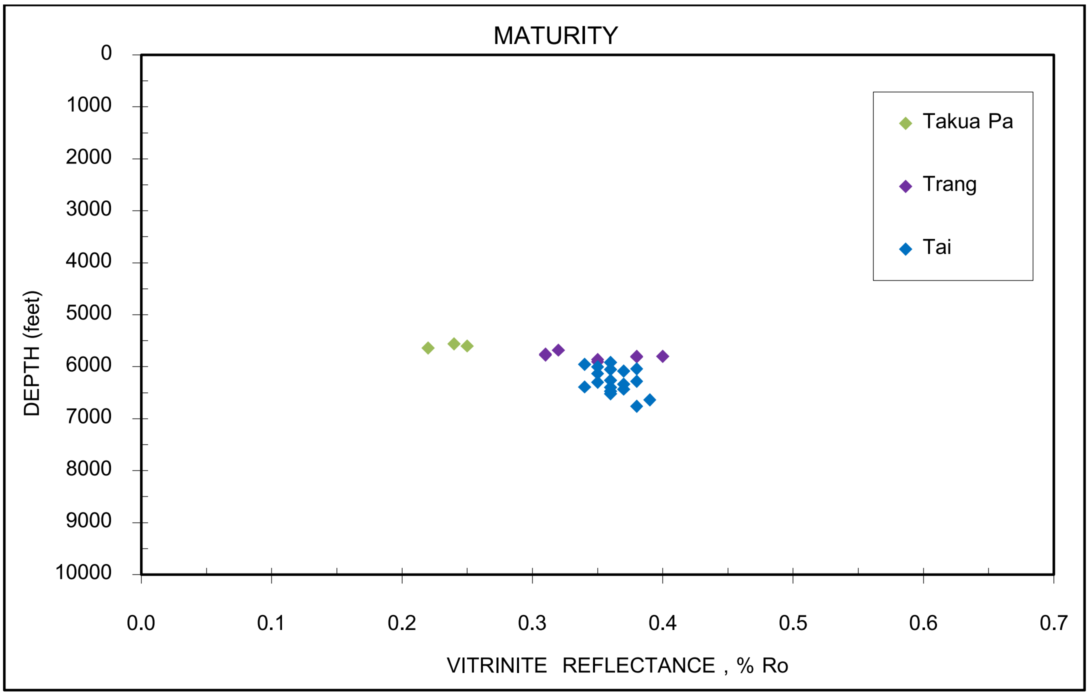


Figure 4.38 Vitrinite reflectance data of Kantang-1A well.

Manora-1:

Vitrinite reflectance data in Manora-1 well is limited; only 6 data of sediment samples from depth 3,500 to 8,000 feet are available. Nevertheless, the maturity trend of this well can be observed (Figure 4.39). Estimated early oil generation (0.55% Ro) is at 7,000 feet and main oil is at 9,000 feet.

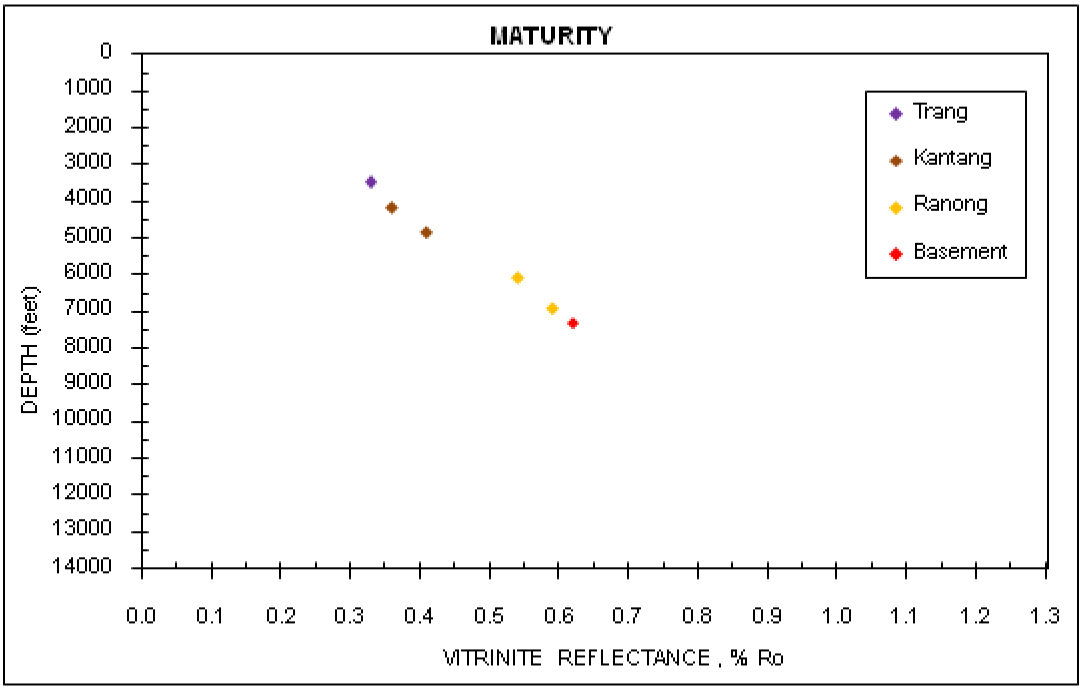


Figure 4.39 Vitrinite reflectance data of Manora-1 well.

4.4 Basin modeling

Basin modeling is constructed for 3 wells including Kra Buri-1, W9-E-1 and Thalang-1 wells as required data for basin modeling are relatively more complete in these wells. Geochemical data used in basin modeling of these wells are from this study as well as from previous studies. The selected wells were drilled through Yala Formation, a mature section and main source rock formation of the Mergui Basin. Total depth of W9-E-1 well was the deepest amongst the wells studied and contain thick Yala Formation.

4.4.1 Stratigraphic and rock properties data

Sequence stratigraphy, lithology and age of each layer were extracted from final well report and are summarized in Tables 4.3-4.5. Biostratigraphy and paleoenvironment data are also from the reports. Geochemical data such as source rock quality, percentage of TOC and HI were from this study and previous reports.

4.4.2 Boundary conditions and calibration.

The surface water interface temperature (SWIT), the position of the plate through geologic time and the water column is automatically defined by PetroMod software. The settings are for southeastern Asia, northern hemisphere, 7 degrees latitude (Figure 4.40). The data for plate position through geologic time and paleo-temperatures are stored in a data base of the 1D PetroMod. The values are based on a publication by Wygrala (1989).

Paleo water depths used in this study are estimated based on the deposition environments of each unit as interpreted from biostratigraphic and paleontologic reports. Takau Pa, Thalang and Yala Formations are of lower bathyal environment, estimated water depth used in the model is 5,000 feet (1500 m). Trang Formation was deposited in a bathyal environment, estimated water depth used in the model is 2,600 feet (800 m). Environment of deposition of Kantang Formation is an upper bathyal, estimated water depth used in the model is 1,300 feet (400 m).

Formation	Top (ft)	Base (ft)	Thick (ft)	Depo to (Ma)	Depo from (Ma)	Lithology	PSE	TOC (%)	HI (mgHC/gTOC)
Takua Pa Fm.	3,185	4,050	865	5.3	1.2	Shale	Overburden rock	1.09	224.00
Thalang Fm.	4,050	5,012	962	11.6	5.3	Shale	Source rock	2.43	209.50
Trang Fm.	5,012	5,350	338	16.0	11.6	Shale	Source rock	1.33	168.25
Kantang Fm.	5,350	7,080	1,730	20.4	16.0	Shale	Source rock	1.90	80.84
Yala Fm.	7,080	8,106	1,026	31.0	20.4	Shale	Source rock	1.22	112.47
Ranong Fm.	8,106	10,342	2,236	38.0	31.0	Sandstone	Reservoir rock	1.04	121.05

Table 4.3 Summary of the input data for Kra Buri-1 well basin modeling.

Formation	Top (ft)	Base (ft)	Thick (ft)	Depo to (Ma)	Depo from (Ma)	Lithology	PSE	TOC (%)	HI (mgHC/gTOC)
Takua Pa Fm.	3,416	4,750	1,334	5.3.00	1.20	Shale	Overburden rock	1.09	227.00
Thalang Fm.	4,750	5,200	450	11.60	5.30	Shale	Source rock	0.86	75.50
Trang Fm.	5,200	6,000	800	16.00	11.60	Shale	Source rock	0.82	101.40
Kantang Fm.	6,000	7,050	1,050	20.40	16.00	Shale	Source rock	0.72	91.83
Yala Fm.	7,050	14,036	6,986	38.00	20.40	Shale	Source rock	0.63	103.99

Table 4.4 Summary of the input data for W9-E-1 well basin modeling.

Formation	Top (ft)	Base (ft)	Thick (ft)	Depo to (Ma)	Depo from (Ma)	Lithology	PSE	TOC (%)	HI (mgHC/gTOC)
Takua Pa Fm.	3,416	5,380	1,964	5.30	1.20	Shale	Overburden rock	2.48	169.00
Thalang Fm.	5,380	6,048	668	11.60	5.30	Shale	Source rock	2.43	261.25
Trang Fm.	6,048	6,620	572	16.00	11.60	Shale	Source rock	1.33	366.00
Kantang Fm.	6,620	7,204	584	20.40	16.00	Shale	Source rock	1.07	200.88
Yala Fm.	7,204	8,500	1,296	31.00	20.40	Shale	Source rock	0.76	136.44

Table 4.5 Summary of the input data for Thalang-1 well basin modeling.

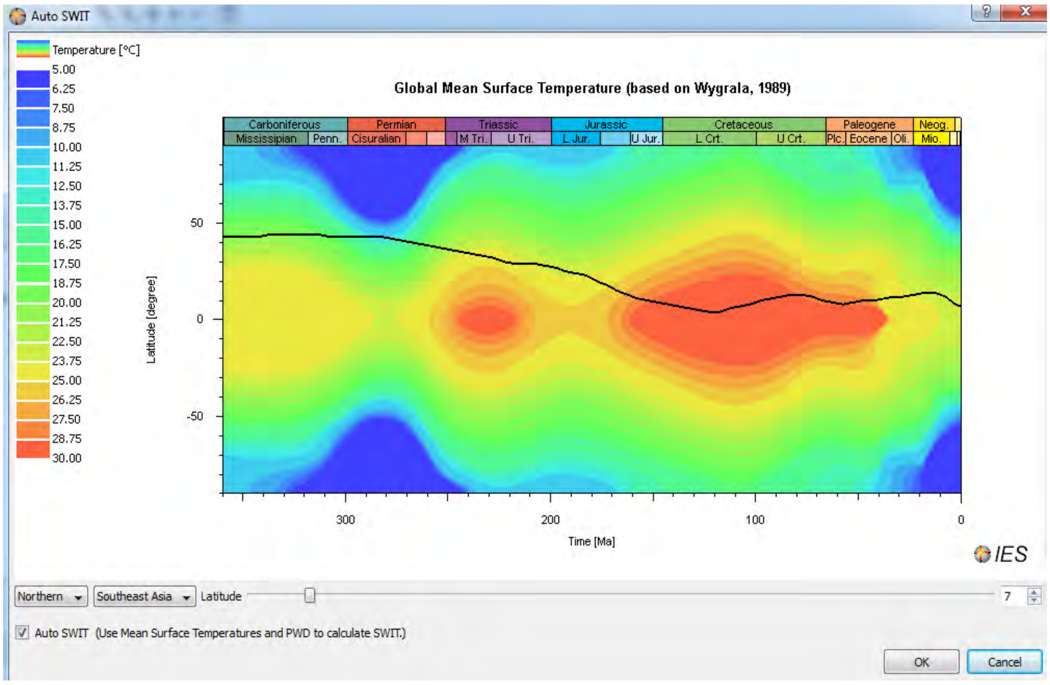


Figure 4.40 Global mean surface temperature calculation based on Wygrala, 1989.

Ranong Formation is interpreted to be deposited in a fluviatile-deltaic environment, estimated water depth used is 650 feet (200 m).

Calibration data (Ro, Tmax, BHT and other available thermal maturity data) are created in the Well Editor, a software within PetroMod 1D package. Calibration data are then loading from Well Editor to PetroMod for model verification. Figures 4.41A, 4.43A and 4.45A show temperature maturity model with vitrinite reflectance data used as calibration data. Calibration is a process of adapting model to the thermal maturity data which record temperature history in the samples, by varying heat flow (HF) of the basin through time. In case that the built temperature model is not matched with vitrinite reflectance data, model can be adapted manually by modifying HF values to find a better fit (Figures 4.41B, 4.43B and 4.45B).

4.4.3 Modeling results and discussion

Kra Buri-1 well was drilled through main formations deposited in the Mergui Basin, includingYala Formation which contains deep marine shale source rock layers and Ranong Formation of shallow marine sandstone layers. Yala Formation, the deepest marine shale source rock layer has average TOC of 1.22 %wt. Kra Buri-1 well has TOC value of Yala Formation higher than other wells (0.67 %wt). Maturity model generated from software shows higher trend in maturity than those of calibration data (Figure 4.41A). Heat flow values were changed from default values to values show in Table 4.6 to fit modeled maturity trend with observed data (Figure 4.41B).

Age (Ma)	PWD (ft.)
3.25	5000.00
8.45	5000.00
13.80	2600.00
18.20	1300.00
25.70	5000.00
34.50	650.00

Age (Ma)	SWIT (ºC)
3.25	5.00
8.45	5.00
13.80	5.00
18.20	12.98
25.70	7.50
34.50	21.85

Age (Ma)	HF (mW/m^2)
3.25	65.00
8.45	70.00
13.80	75.00
18.20	80.00
25.70	85.00
34.50	85.00

Table 4.6 Summary of the boundary conditions data for Kra Buri-1 well.

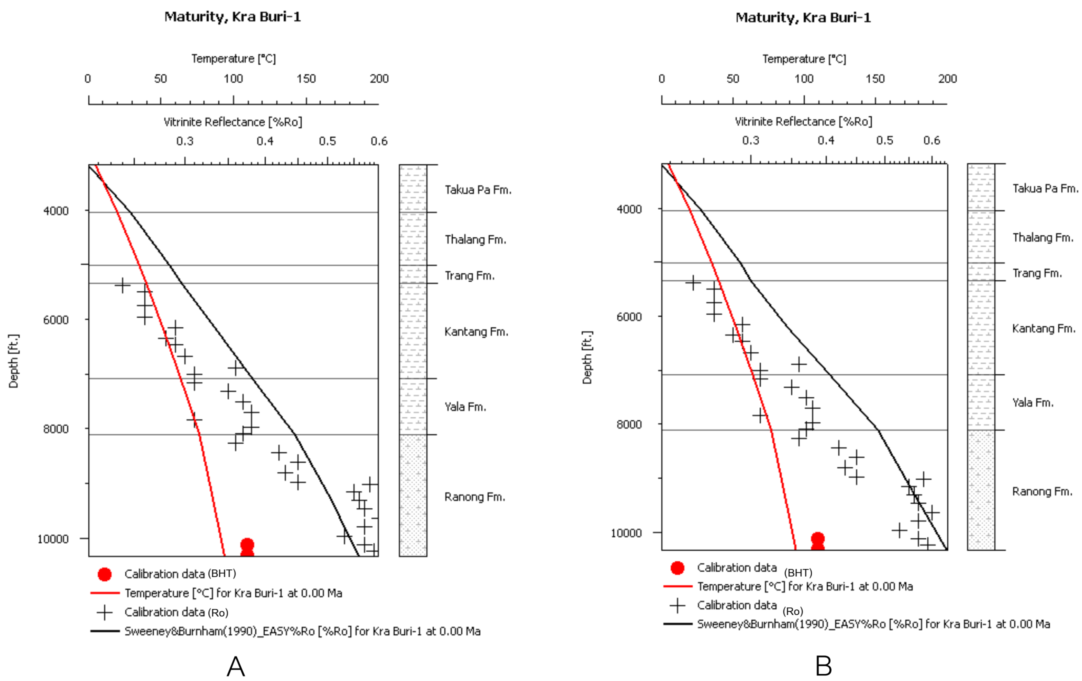


Figure 4.41 Comparison of maturity model of Kra Buri-1 well between before (A) and after calibration (B).

Output of basin modeling consists of burial history curve and maturity model. Burial history curve overlay with vitrinite reflectance maturity of Kra Buri-1 well is shown in Figure 4.42. From this figure it is noticeable that sedimentation rate is generally constant, although in Early Miocene (20-24 Ma) there was a rapid subsidence of the basin. From the figure, depth of petroleum generation (early mature) is at about 9,800 feet in lower Ranong Formation about 7 Ma ago. At the present time, depth of petroleum generation is about 9,500 feet.

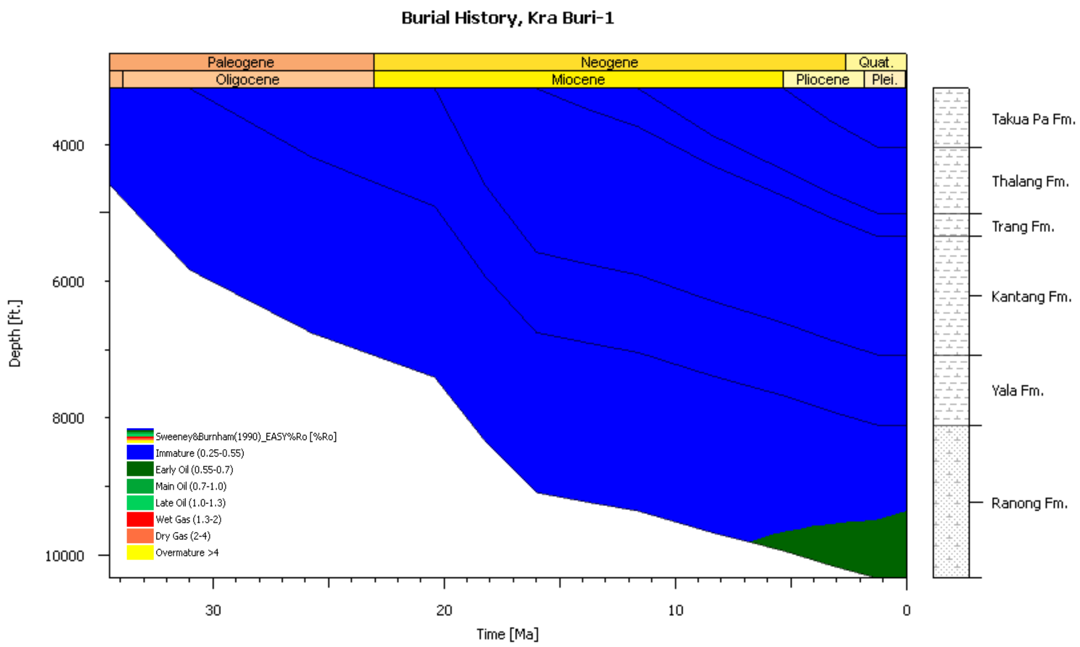


Figure 4.42 Burial history curve of Kra Buri-1 well.

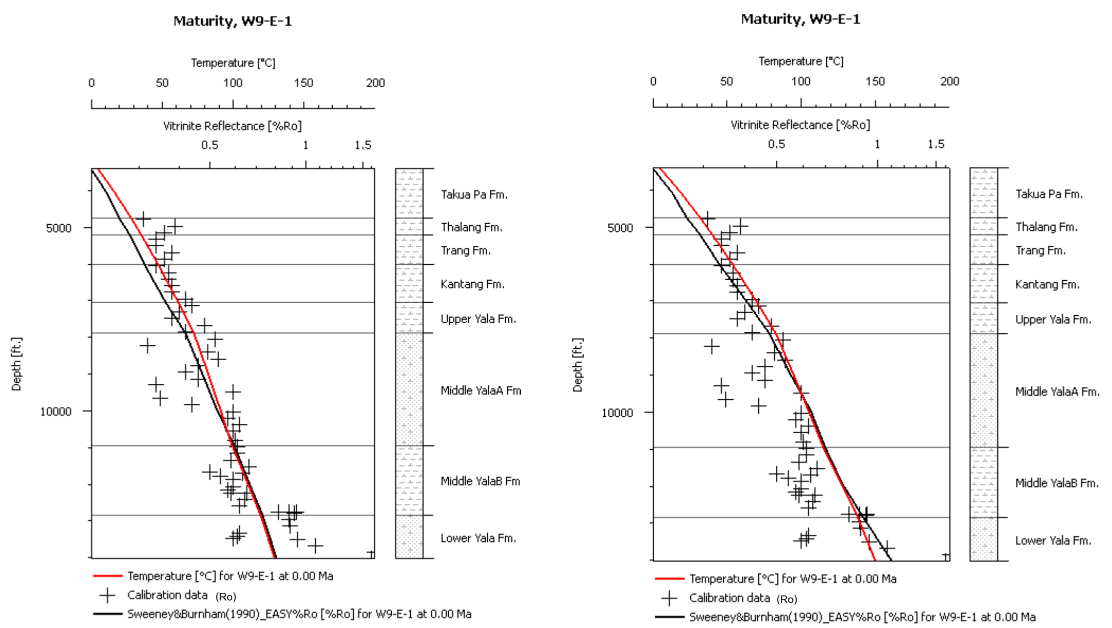
W9-E-1 well is the deepest well drilled in the Mergui Basin (14,036 feet) and contains thick Yala Formation. Yala Formation in this well may have deposited in the deep part of a sub basin. Average TOC of Yala Formation in this well is 0.63 %. Lithology of Yala Formation in this well is mostly fine-grained sediments of deep marine shale or claystone. This well also contains other possible source rock layers with Takua Pa Formation act as an overburden layer but has no potential reservoir layer. Maturity model of W9-E-1 well generated from the software was calibrated with vitrinite reflectance data (Figure 4.43A). Calibration was done by adapting heat flow to values listed in Table 4.7 to fit modeled maturity trend with vitrinite reflectance data (Figure 4.43B).

Age (Ma)	PWD (ft.)
3.95	5000.00
8.45	5000.00
13.80	2600.00
18.20	1300.00
24.40	5000.00

Age (Ma)	SWIT (ºC)
3.95	5.00
8.45	5.00
13.80	5.00
18.20	12.98
24.40	7.12

Age (Ma)	HF (mW/m^2)
3.95	70.00
8.45	70.00
13.80	75.00
18.20	75.00
24.40	80.00

Table 4.7 Summary of the boundary conditions data for W9-E-1 well.



A B

Figure 4.43 Comparison of maturity model of W9-E-1 well between before (A) and after calibration (B).

Burial history curve of W9-E-1 well (Figure 4.44) shows that the sedimentation rate is generally constant, but rather low. Burial history curve does not show evidence of break in deposition, but during Pliocene (2 – 4 Ma) sedimentation rate is slightly higher than other times. Trace of gas show was reported in this well. The model shows that petroleum generation in W9-E-1 well started at 12,500 feet around 17 Ma. At present time depth of petroleum generation is at 10,000 feet. This well has thick mature section to generate early oil (0.55-0.7 %Ro) and main oil (0.7-1.0 %Ro) in the lower Yala Formation.

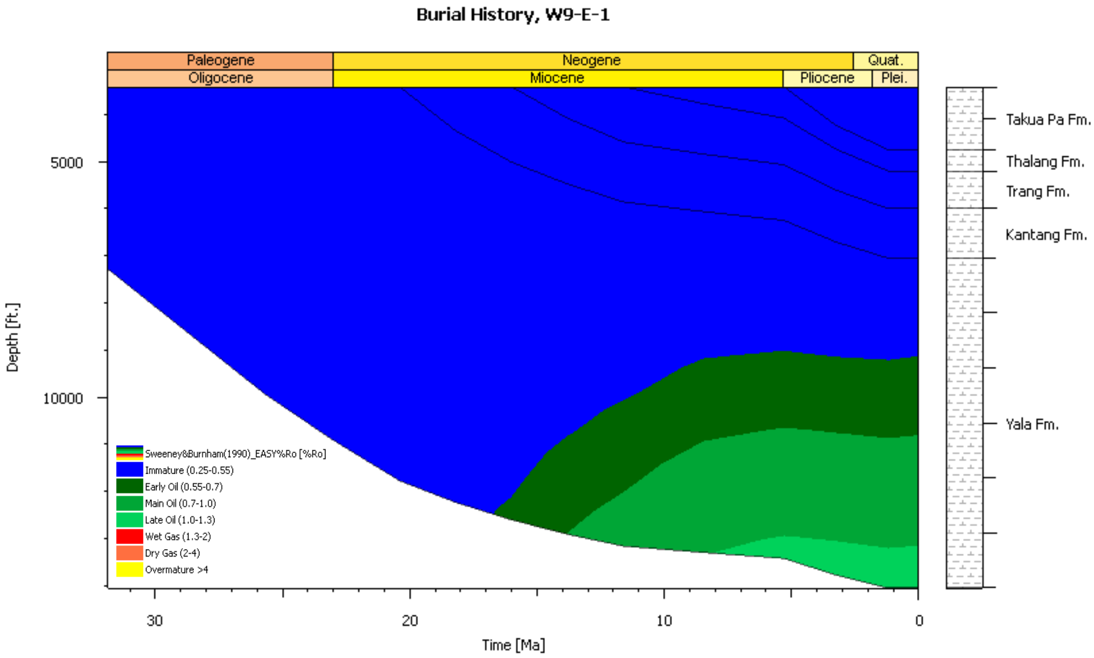


Figure 4.44 Burial history curve of W9-E-1 well.

Thalang-1 exploration well was drilled to total depth of 8,518 feet but the result was dry. Sediments layers in the well are similar to those in W9-E-1 well, which has only deep marine shale source rock layer. Thickness is high in Takua Pa Formation, overburden section, and Yala Formation, a mature source rock section. This well drilled through about 1,269 feet of Yala Formation. Average TOC in Yala Formation is 0.76 %wt. Maturity model generated from the software is generally lower than maturity input data, vitrinite reflectance (Figure 4.45A). Heat flow for each formation is listed in Table 4.7 and the model result is shown in Figure 4.45B.

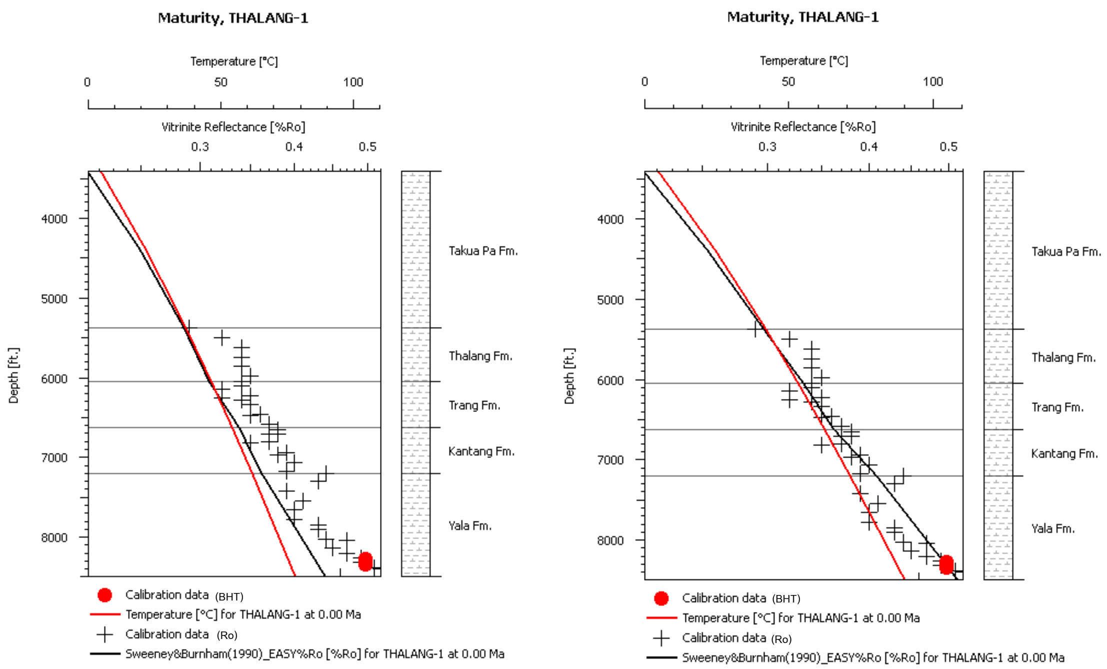
Burial history curve of Thalang-1 (Figure 4.46) shows low sedimentation rate but higher than those of W9-E-1 well. High rate of sedimentation occurred in Pliocene (1-5 Ma), similar time interval as W9-E-1 well. Sedimentation rate was generally slower later in Pleistocene to recent (1-0 Ma). The entire section drilled is immature (Ro < 0.55 %).

Age (Ma)	PWD (ft.)
3.25	5000.00
8.45	5000.00
13.80	2600.00
18.20	1300.00
25.70	5000.00

Age (Ma)	SWIT (°C)
3.25	5.00
8.45	5.00
13.80	5.00
18.20	12.98
25.70	7.50

Age (Ma)	HF (mW/m^2)
3.25	70.00
8.45	75.00
13.80	80.00
18.20	85.00
25.70	85.00

Table 4.8 Summary of the boundary conditions data for Thalang-1 well.



A

B

Figure 4.45 Comparison of maturity model of Thalang-1 well between before (A) and after calibration (B).

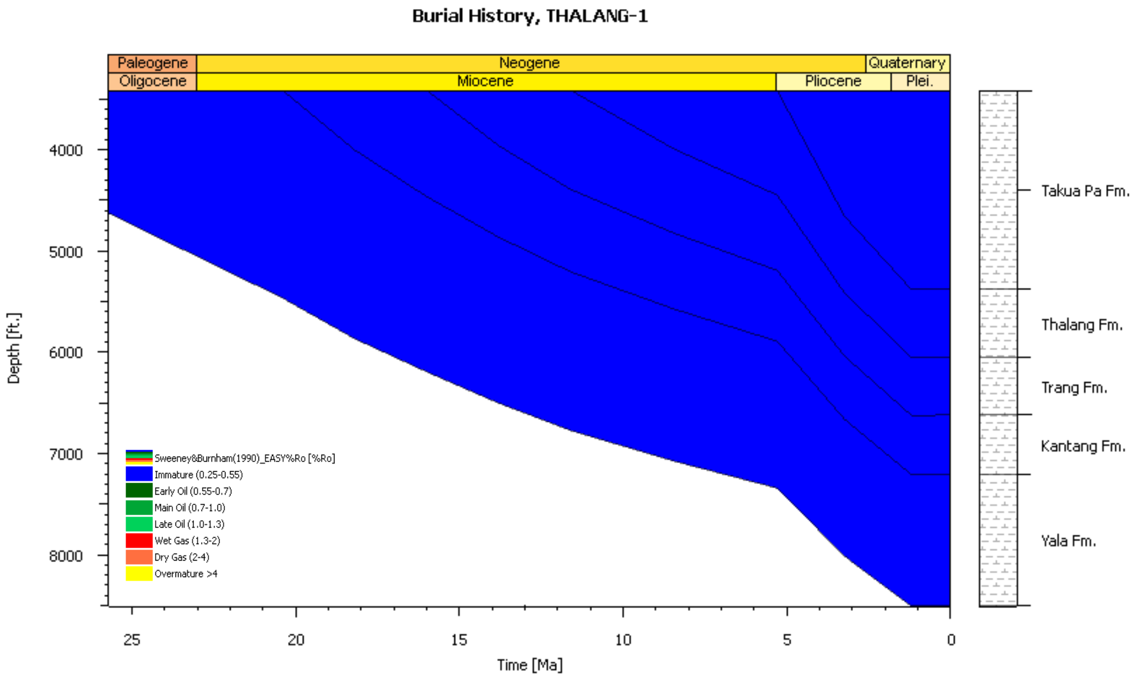


Figure 4.46 Burial history curve of Thalang-1 well.

In conclusion, basin modeling of Kra Buri-1, W9-E-1 and Thalang-1 wells show low but constant sedimentation rate. Burial history curves show no main evidence of uplift or break in deposition. At the present time, petroleum generation occurred at depth about 9,500-10,000 feet.

In comparison with basin modeling of the North Sumatra Basin by Buck and McCulloh (1994) in which they used similar model input to the Mergui Basin (fair TOC, Type III kerogen). Maturation model of the North Sumatra Basin is higher than the Mergui Basin. Depth of petroleum generation is approximately 8,500 - 9,000 feet at 7 – 14 Ma. Sedimentation rate was constant. Basin modeling of Kra Buri-1 well, Mergui Basin, by Aukkanit (2008) showed slightly different maturation model with depth of petroleum generation of 8,200 feet.

Possible error in the Mergui Basin modeling may be related to uncertainties of the input data such as age, lithology and thickness and also to measured maturation data (Ro and BHT) used in model calibration.

CHAPTER V

DISCUSSION AND CONCLUSION

5.1 DISCUSSION

1). Objectives of this source rock study are to determine source potential, type of organic matter and thermal maturity of the Mergui Basin. 18 cutting samples were selected for TOC content analyses and samples with high TOC (> 1 wt%) were selected further for Rock-Eval pyrolysis and vitrinite reflectance measurement. These analyses results and the available geochemical analyses carried out by the previous concessionaires were integrated and utilized.

Generally, cutting samples were collected for every 30 feet and these cutting samples were sent for the geochemical analyses. In this study, TOC analysis is focused on the samples from section of wells that have limited TOC data. Due to time and financial constraints only 18 samples were selected for the analyses. Samples used in TOC analysis are from wells that used water-based mud to avoid contamination. These samples were selected based on their color (dark grey) and lithology (fine-grained sediments such as claystone and shale) to ensure of having adequate amount of organic materials that suitable for the further geochemical analyses.

2). Samples analyzed in this study have vitrinite reflectance (Ro) less than 0.64%, therefore the TOC contents are reported as they are without correction for maturation and hydrocarbon expulsion. TOC contents of samples in this study indicate fair to excellent source potential (Table 4.1), a conclusion of which is different from previous studies. TOC contents from previous studies is generally poor to fair (Figure 4.2) with some locally high TOC content layers which are relatively thin and discontinuous.

Samples analyzed for TOC content in this study are also from relatively shallower depth, marine and deep marine facies, of Takau Pa, Thalang, Trang, Kantang and Tai Formations which generally have relatively higher TOC contents compared with deeper source rock layer of Yala Formation (c.f. Figures 4.1 and 4.2). Moreover, due to heterogeneous properties, both laterally and vertically, of the source rock layers in terms of lithologies, variation in organic matter contents may also exists. In general, source rock richness of the Mergui Basin is comparable with that of the source rock of gas-condensate petroleum system of North Sumatra Basin. Both basins contain lean source rocks (TOC < 1%) but discontinuous high TOC content layers are encountered in the Mergui Basin. It is advisable to evaluate thickness of the source rock layers in the Mergui Basin using regional seismic data tied to well data, where available, to assure that source rock thickness in the Mergui Basin can account for meager organic richness which is the case for the North Sumatra Basin.

3). Type of organic matter which is a main factor in estimating generated volume of hydrocarbon is defined by the Rock-Eval pyrolysis analyses. Organic matter types of all 18 samples in this study are mainly Type II/III kerogen or Type III South East Asia (SEA). This result is in line with previous studies. Rock-Eval pyrolysis data from previous studies suggest predominantly gas-prone (Type III) or mixed oil/gas-prone type (II/III kerogen-Type III SEA) (Figure 4.21). HI data distribute between 0 and 450, indicate that the organic matter is predominantly gas-prone (HI between 0-150) and gas/oil-prone. Quality of organic matter in the Mergui Basin is better than that of the North Sumatra Basin which was reported to have HI between 0-200 and OI ranges of 10-140, typical of gas-prone Type III kerogen (Buck and McCulloh, 1994).

4). Vitrinite reflectance analysis (Ro) is used to determine source rock thermal maturity. Ro of the selected 18 samples are thermally immature, with Ro less than 0.6%.

Ro plot of theses analyzed data combine with the previous analyses show the same trend in maturity in shallow section between 2,500 to 9,000 feet (Figure 4.22-4.24), with increasing vitrinite reflectance from 0.2% to 0.5%.

At depth greater than 9,000 feet, different Ro trends are identified in several wells, i.e. W9-B-1, W9-C-1 and W9-E-1. The different trends could be a result of higher heat flow during early development of the rifted Mergui basin or a major unconformity. Mudford (1997) suggested high heat flow in late Oligocene is a result of rapid slip on graben-bounding faults occurred during that time. Top of hydrocarbon generation window as implied by vitrinite reflectance plot is in a depth between 9,500 and 10,000 feet. Geothermal gradient in the Mergui Basin is not clearly known but could be in the same order as, or slightly lower than that of, the North Sumatra Basin which has average gradient of 48.3°C/km (from 113 wells) and vitrinite reflectance of 0.7% is reached at depth about 10,248 feet (Buck and McCulloh, 1994). Prasit (2001) reported that geothermal temperature of North Sumatra and Mergui Basin varies below depth 10,000 feet which was caused by differences in geothermal gradient and heat flow.

5). The burial history of Kra Buri-1, W9-E-1 and Thalang-1 wells show low and continuous sedimentation rate of the Mergui Basin. This is contrast to the North Sumatra Basin which has higher sedimentation rate, especially in during Middle Miocene (Figure 38.8, P. 632, Buck and McCulloh, 1994).

Based on the 3 basin modeling, Thalang-1 does not indicate mature section. However, the modeling of Kra Buri-1 and W9-E-1 wells indicate that the hydrocarbon was generated at depth of some 9,500-10,000 feet. Further results from the Kra Buri-1 basin modeling suggest petroleum generation occurred since 7 Ma. Whereas the W9-E-1 basin modeling, in the deeper part of basin of basin, generated since 17 Ma is implied. When comparing the results of Kra Buri-1 modeling of this study with that of Aukkanit (2008), it is found that depth of maturations are slightly different, with Aukkanit reported 8,200 feet as depth of petroleum generation.

Basin modeling in this study is based on data from 3 wells, which may be considered to be the representative of the Mergui Basin. However, these wells with particularly Thalang-1 and Kea Buri-1 are exploration wells which were not drilled in the deep part of the basin, but located on structural high and thus rarely encountered source rock layers. Data input for these wells are therefore limited and may not give the true picture of petroleum generation potential of the basin. Moreover, input data for these wells may not truly represent the source rocks in the entire Mergui Basin due to heterogeneous properties of the source rock layers in terms of lithologies, variation in organic matter contents and quality and levels of thermal maturity. Basin modeling if constructed for the deeper part of the basin, with thicker source rock and different organic matter types and quantity will undoubtedly be different.

6). The traces and significant gas and oil shows encountered in penetrated sections in the basin imply that may have mature section may exist in the deeper part of the basin. The reason for no commercial hydrocarbons discovery in the Mergui Basin may be from the lack of effective seal. Multiple overpressured layers exist in the North Sumatra Basin acting as effective basal and top seals for gas and condensate. Moreover, in the Mergui Basin migration from mature source layer-Yala Formation, which locates deeper than 9500 feet-through thick layers of tight formation, deep marine shale and claystone section is rather difficult without an effective fault system.

Carbonate targets on basement high, Tai Formation, had been tested but only gas shows were encountered in the previous exploration, the targets generally are located at shallow depth that is rather far from the anticipated kitchen area. Further exploration is necessary but needed to find target locate closer to the kitchen area where source rocks of Yala Formation are thick and buried deep in the basin.

5.2 CONCLUSIONS

1. Hydrocarbon source potential of the Upper and younger formations (Kantang, Trang, Thalang, Takua Pa), in Mergui Basin is generally fair to good. For the Lower and older formations with particularly Yala Formation has poor to fair source potential (average TOC 0.67 wt%) with some locally thin and discontinuous high TOC content layers. Further, better source rock potential is anticipated in the deeper part of the basin

2. Organic matter within the sediments is predominantly gas-prone (Type III) or mixed oil/gas-prone kerogen (Type II/III) that would generate main gas and associated liquids when mature.

3. Generally, the sediments are thermally immature, except only Yala and Ranong Formations in a few wells. Vitrinite reflectance values of all the analyses generally ranges 0.2%-0.6%. Top of hydrocarbon generation window is at a depth some between 9,500 and 10,000 feet. The basin modeling studies of Kra Buri-1, W9-E-1, and Thalang-1 wells indicate that on set of hydrocarbon generate had been started since 7 Ma in the shallow part of the basin (Kra Buri-1 well) and 17 Ma in the deeper part of the basin (W9-E-1 well).

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APPENDIX

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Kantang-1A	5532	Takua Pa	0.23								
Kantang-1A	5560	Takua Pa	1.39	0.33	4.37	1.71	420	314	123	0.07	0.24
Kantang-1A	5570	Takua Pa	0.15								
Kantang-1A	5600	Takua Pa	1.37	0.34	4.65	1.34	412	339	98	0.07	0.25
Kantang-1A	5620	Takua Pa	1.18	0.47	3.71	1.12	414	314	95	0.11	
Kantang-1A	5640	Takua Pa	1.13	0.23	3.27	0.92	416	289	81	0.07	0.22
Kantang-1A	5680	Trang	1.87	0.19	5.14	1.03	425	275	55	0.04	0.32
Kantang-1A	5740	Trang	1.06	0.12	1.42	0.80	427	134	75	0.08	
Kantang-1A	5757	Trang	1.41	0.15	2.98	1.39	430	211	99	0.05	0.31
Kantang-1A	5778	Trang	0.43								0.31
Kantang-1A	5800	Trang	1.02	0.13	1.49	1.00	425	146	98	0.08	0.4
Kantang-1A	5801	Trang	1.03	0.11	1.94	1.42	433	188	138	0.05	0.38
Kantang-1A	5810	Trang	1.01	0.11	1.87	1.53	432	185	151	0.06	0.38
Kantang-1A	5860	Trang	0.51								
Kantang-1A	5862	Trang	0.84	0.10	0.62	1.25	425	74	149	0.14	0.35
Kantang-1A	5907	Trang	0.86								0.35
Kantang-1A	5920	Tai	0.53								0.36
Kantang-1A	5957	Tai	0.86	0.14	1.06	1.35	425	123	157	0.12	0.34
Kantang-1A	5980	Tai	0.62								
Kantang-1A	6002	Tai	1.28	0.13	3.18	1.20	430	248	94	0.04	0.35
Kantang-1A	6040	Tai	1.04	0.18	2.25	0.89	425	216	86	0.07	0.38
Kantang-1A	6052	Tai	1.27	0.15	2.31	1.14	430	182	90	0.06	0.36
Kantang-1A	6083	Tai	1.32	0.09	1.82	0.97	433	138	73	0.05	0.37
Kantang-1A	6100	Tai	1.03	0.01	1.82	0.69	429	177	67	0.01	
Kantang-1A	6130	Tai	1.06	0.12	1.51	0.88	427	142	83	0.07	0.35
Kantang-1A	6160	Tai	0.48								
Kantang-1A	6220	Tai	0.78	0.19	1.17	0.61	430	150	78	0.14	
Kantang-1A	6222	Tai	0.80								
Kantang-1A	6265	Tai	1.02	0.09	2.16	0.60	424	212	59	0.04	0.36
Kantang-1A	6280	Tai	0.46								0.38
Kantang-1A	6300	Tai	0.91								0.35
Kantang-1A	6338	Tai	1.18	0.11	1.87	0.92	439	158	78	0.06	0.37
Kantang-1A	6340	Tai	0.46								
Kantang-1A	6390	Tai	1.10	0.11	1.80	0.81	427	164	74	0.06	0.34
Kantang-1A	6400	Tai	0.83								0.36

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Kantang-1A	6433	Tai	1.15	0.08	1.64	0.89	432	143	77	0.05	0.37
Kantang-1A	6460	Tai	1.31	0.15	2.98	0.78	426	227	60	0.05	
Kantang-1A	6472	Tai	1.24	0.13	2.78	0.83	429	224	67	0.04	0.36
Kantang-1A	6520	Tai	1.22	0.15	2.61	0.80	426	214	66	0.05	0.36
Kantang-1A	6580	Tai	0.21	0.03	0.09	0.34	420	43	162	0.25	
Kantang-1A	6640	Tai	0.18	0.04	0.08	0.38	428	44	211	0.33	0.39
Kantang-1A	6700	Tai	0.14	0.05	0.05	0.49	420	36	350	0.50	
Kantang-1A	6760	Tai	0.18								0.38
Kantang-1A	6820	Basement	1.12	0.04	0.01	0.29	422	1	26	0.80	
Kantang-1A	6858	Basement	1.45	0.05	0.02	0.26	361	1	18	0.71	5.49
Kantang-1A	5590-5620	Takua Pa	1.4								
Kantang-1A	5620-5650	Takua Pa	1.36								
Kantang-1A	5770-5800	Trang	1.33								
Kantang-1A	5800-5830	Trang	1.28								
Kantang-1A	6010-6040	Tai	0.79								
Kantang-1A	6040-6070	Tai	1.06								
Kantang-1A	6100-6130	Tai	1.06	0.31	1.82	1.53	424	171.7	144	0.15	
Kantang-1A	6130-6160	Tai	0.48	0.19	1.88	2.08	424	391.7	433	0.09	
Kantang-1A	6460-6490	Tai	1.24	0.53	2.92	1.2	424	235.5	96.8	0.15	
Kantang-1A	6490-6520	Tai	1.22	1.04	3.55	0.97	420	291	79.5	0.23	
Kantang-1A	6820-6850	Basement	1.12	0.15	0.11	0.14	392	9.821	12.5	0.58	
Kantang-1A	6858-TD	Basement	1.45	0.2	0.18	0.16	379	12.41	11	0.53	
Kra Buri-1	5380	Kantang	1.39	43.24	2.65	4.79	434	191	345	0.94	0.24
Kra Buri-1	5440	Kantang	1.97	32.37	3.21	2.30	436	163	117	0.91	
Kra Buri-1	5500	Kantang	1.31	5.63	1.81	1.20	429	138	92	0.76	
Kra Buri-1	5500	Kantang	2.26	45.26	3.01	1.53	433	133	68	0.94	0.26
Kra Buri-1	5560	Kantang	1.74	24.97	2.54	2.21	434	146	127	0.91	
Kra Buri-1	5620	Kantang	1.39	31.09	1.08	1.79	428	78	129	0.97	
Kra Buri-1	5680	Kantang	1.10								
Kra Buri-1	5740	Kantang	1.05								0.26
Kra Buri-1	5800	Kantang	1.30								
Kra Buri-1	5860	Kantang	1.28								
Kra Buri-1	5920	Kantang	1.00								
Kra Buri-1	5965	Kantang	1.22	18.06	0.24	0.27	342	20	22	0.99	0.26
Kra Buri-1	5980	Kantang	1.04								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Kra Buri-1	6040	Kantang	0.74								
Kra Buri-1	6100	Kantang	1.44	44.87	0.27	0.44	407	19	31	0.99	
Kra Buri-1	6160	Kantang	1.36	41.99	0.18	0.45	404	13	33	1.00	
Kra Buri-1	6163	Kantang	0.53								0.29
Kra Buri-1	6220	Kantang	1.14								
Kra Buri-1	6280	Kantang	1.27								
Kra Buri-1	6340	Kantang	1.40	40.82	0.32	0.50	420	23	36	0.99	
Kra Buri-1	6355	Kantang	1.20	14.22	0.43	0.23	342	36	19	0.97	0.28
Kra Buri-1	6400	Kantang	1.27								
Kra Buri-1	6460	Kantang	1.38	30.78	0.79	1.05	434	57	76	0.97	0.29
Kra Buri-1	6520	Kantang	1.26								
Kra Buri-1	6580	Kantang	1.33								
Kra Buri-1	6640	Kantang	1.32								
Kra Buri-1	6680	Kantang	1.63	11.16	2.21	0.58	435	136	36	0.83	0.3
Kra Buri-1	6700	Kantang	2.13	50.80	1.84	1.33	432	86	62	0.97	
Kra Buri-1	6760	Kantang	1.43	33.55	0.80	0.74	430	56	52	0.98	
Kra Buri-1	6820	Kantang	1.30								
Kra Buri-1	6880	Kantang	1.42	40.93	0.42	0.52	417	30	37	0.99	
Kra Buri-1	6895	Kantang	0.69								0.36
Kra Buri-1	6940	Kantang	1.38	29.20	0.59	0.56	419	43	41	0.98	
Kra Buri-1	6955	Kantang	1.34	8.42	1.37	0.33	428	102	25	0.86	
Kra Buri-1	7000	Kantang	0.70								0.31
Kra Buri-1	7060	Kantang	1.47	23.95	0.97	0.62	429	66	42	0.96	
Kra Buri-1	7120	Yala	1.76	36.18	1.21	0.66	432	69	38	0.97	
Kra Buri-1	7160	Yala	0.64								0.31
Kra Buri-1	7180	Yala	1.03								
Kra Buri-1	7215	Yala	1.04	9.63	0.58	0.15	338	56	14	0.94	
Kra Buri-1	7240	Yala	1.14								
Kra Buri-1	7300	Yala	0.85								
Kra Buri-1	7316	Yala	0.68								0.35
Kra Buri-1	7360	Yala	1.29								
Kra Buri-1	7420	Yala	1.14								
Kra Buri-1	7435	Yala	0.96								
Kra Buri-1	7480	Yala	1.38	26.46	0.64	0.58	428	46	42	0.98	
Kra Buri-1	7505	Yala	0.91								0.37

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Kra Buri-1	7540	Yala	1.02								
Kra Buri-1	7600	Yala	1.03								
Kra Buri-1	7618	Yala	1.33	8.55	1.50	0.25	430	113	19	0.85	
Kra Buri-1	7660	Yala	2.01	40.18	1.85	0.96	434	92	48	0.96	
Kra Buri-1	7710	Yala	0.92								0.38
Kra Buri-1	7720	Yala	1.67	32.06	1.47	0.92	432	88	55	0.96	
Kra Buri-1	7780	Yala	1.69	35.66	1.42	0.84	432	84	50	0.96	
Kra Buri-1	7805	Yala	0.94								
Kra Buri-1	7840	Yala	1.18								0.31
Kra Buri-1	7900	Yala	1.37	28.73	0.98	0.55	432	72	40	0.97	
Kra Buri-1	7960	Yala	1.35	20.97	0.97	0.53	428	72	39	0.96	
Kra Buri-1	7978	Yala	1.08	2.76	2.00	0.32	432	185	30	0.58	0.38
Kra Buri-1	8020	Yala	1.10	2.99	2.39	0.26	434	217	24	0.56	
Kra Buri-1	8020	Yala	2.03	34.38	1.88	1.02	432	93	50	0.95	
Kra Buri-1	8080	Yala	1.17								0.37
Kra Buri-1	8140	Ranong	1.84	32.95	1.73	1.52	433	94	83	0.95	
Kra Buri-1	8260	Ranong	2.09	44.80	2.19	1.41	434	105	67	0.95	0.36
Kra Buri-1	8320	Ranong	0.72								
Kra Buri-1	8410	Ranong	0.64								
Kra Buri-1	8440	Ranong	1.03								0.42
Kra Buri-1	8500	Ranong	0.80								
Kra Buri-1	8560	Ranong	0.28								
Kra Buri-1	8620	Ranong	0.71								0.45
Kra Buri-1	8680	Ranong	0.64								
Kra Buri-1	8740	Ranong	1.51	37.28	0.60	0.43	426	40	28	0.98	
Kra Buri-1	8800	Ranong	1.11								0.43
Kra Buri-1	8860	Ranong	1.27	26.23	0.95	0.53	432	75	42	0.97	
Kra Buri-1	8920	Ranong	1.03								
Kra Buri-1	8980	Ranong	1.26	34.36	0.71	0.42	430	56	33	0.98	0.45
Kra Buri-1	9010	Ranong	1.37	10.49	1.58	0.36	435	115	26	0.87	0.58
Kra Buri-1	9040	Ranong	1.19	28.03	0.78	0.57	432	66	48	0.97	
Kra Buri-1	9100	Ranong	1.31	24.72	1.14	0.73	434	87	56	0.96	
Kra Buri-1	9160	Ranong	0.93								0.55
Kra Buri-1	9220	Ranong	0.91								
Kra Buri-1	9280	Ranong	1.00								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Kra Buri-1	9314	Ranong	0.73								0.56
Kra Buri-1	9340	Ranong	0.92								
Kra Buri-1	9400	Ranong	1.06								
Kra Buri-1	9425	Ranong	0.49								
Kra Buri-1	9460	Ranong	0.80								
Kra Buri-1	9469	Ranong	0.65								0.57
Kra Buri-1	9520	Ranong	1.25	32.90	1.11	0.58	432	89	46	0.97	
Kra Buri-1	9580	Ranong	1.18	21.78	1.45	0.46	434	123	39	0.94	
Kra Buri-1	9585	Ranong	0.56								
Kra Buri-1	9640	Ranong	0.97								0.6
Kra Buri-1	9700	Ranong	0.93								
Kra Buri-1	9760	Ranong	1.13								
Kra Buri-1	9785	Ranong	0.70								0.57
Kra Buri-1	9820	Ranong	1.15	23.24	1.67	0.49	438	145	43	0.93	
Kra Buri-1	9880	Ranong	0.90								
Kra Buri-1	9940	Ranong	0.93								
Kra Buri-1	9972	Ranong	0.69								0.53
Kra Buri-1	10000	Ranong	1.59	32.51	1.84	0.80	435	116	50	0.95	
Kra Buri-1	10060	Ranong	1.26	20.23	1.67	0.72	433	133	57	0.92	
Kra Buri-1	10120	Ranong	0.99								
Kra Buri-1	10122	Ranong	0.78								0.57
Kra Buri-1	10180	Ranong	1.28	13.97	1.61	0.55	434	126	43	0.90	
Kra Buri-1	10240	Ranong	0.64								0.59
Kra Buri-1	10300	Ranong	1.14								
Kra Buri-1	10342	Ranong	1.36	11.85	2.00	0.55	443	147	40	0.86	
Kra Buri-1	10000-10030	Ranong	1.50	64.3	2.56	0.71	420	170.7	47.3	0.96	
Kra Buri-1	10060-10090	Ranong	1.20	68.09	3.48	0.85	425	290	70.8	0.95	
Kra Buri-1	5500-5530	Kantang	5.32								
Kra Buri-1	5560-5590	Kantang	6.85								
Kra Buri-1	6100-6130	Kantang	3.65								
Kra Buri-1	6160-6190	Kantang	4.88								
Kra Buri-1	6670-6700	Kantang	6.25								
Kra Buri-1	6700-6730	Kantang	5.81								
Kra Buri-1	7720-7750	Yala	1.60	61.88	2.1	0.75	417	131.3	46.9	0.97	
Kra Buri-1	7780-7810	Yala	0.94	72.21	2.41	0.67	421	256.4	71.3	0.97	

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Kra Buri-1	8980-9010	Ranong	1.37	57.12	1.86	0.83	420	135.8	60.6	0.97	
Kra Buri-1	9010-9040	Ranong	1.19	59.69	2.22	0.89	418	186.6	74.8	0.96	
Manora-1	3363-3412	Trang	0.44								
Manora-1	3461-3510	Trang	0.49	0.01	0.11	0.96	414	22	196	0.08	0.33
Manora-1	3560-3609	Kantang	0.17								
Manora-1	3658-3707	Kantang	0.19								
Manora-1	3757-3806	Kantang	0.11								
Manora-1	3855-3904	Kantang	0.10								
Manora-1	3953-4003	Kantang	0.12								
Manora-1	4052-4101	Kantang	0.14								
Manora-1	4105-4199	Kantang	0.19	0.01	0.07	0.69	405	37	363	0.13	0.36
Manora-1	4249-4298	Kantang	0.16								
Manora-1	4347-4396	Kantang	0.15								
Manora-1	4446-4495	Kantang	0.15								
Manora-1	4544-4593	Kantang	0.11								
Manora-1	4642-4692	Kantang	0.15								
Manora-1	4741-4790	Kantang	0.10								
Manora-1	4839-4888	Kantang	0.17	0.01	0.05	0.38	418	29	224	0.17	0.41
Manora-1	4938-4987	Kantang	0.16								
Manora-1	5036-5085	Kantang	0.09								
Manora-1	5135-5184	Kantang	0.10								
Manora-1	5233-5249	Kantang	0.09								
Manora-1	5348-5397	Kantang	0.15								
Manora-1	5397-5446	Kantang	0.18								
Manora-1	5495-5545	Kantang	0.18								
Manora-1	5594-5643	Kantang	0.17								
Manora-1	5692-5741	Ranong	0.13								
Manora-1	5791-5840	Ranong	0.19								
Manora-1	5889-5938	Ranong	0.09								
Manora-1	5988-6037	Ranong	0.24								
Manora-1	6086-6135	Ranong	0.30	0.06	0.17	0.56	424	57	187	0.26	0.54
Manora-1	6184-6234	Ranong	0.14								
Manora-1	6283-6332	Ranong	0.31								
Manora-1	6381-6430	Ranong	0.19								
Manora-1	6480-6529	Ranong	0.22								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Manora-1	6578-6627	Ranong	0.23								
Manora-1	6627-6677	Ranong	0.19								
Manora-1	6677-6726	Ranong	0.24								
Manora-1	6726-6775	Ranong	0.25								
Manora-1	6775-6824	Ranong	0.27								
Manora-1	6824-6873	Ranong	0.27								
Manora-1	6873-6923	Ranong	0.30								
Manora-1	6923-6972	Ranong	0.36	0.01	0.05	0.31	412	14	86	0.17	0.59
Manora-1	6972-7021	Ranong	0.32								
Manora-1	7021-7070	Ranong	0.33								
Manora-1	7070-7119	Ranong	0.30								
Manora-1	7119-7169	Ranong	0.27								
Manora-1	7169-7218	Ranong	0.27								
Manora-1	7218-7267	Ranong	0.31								
Manora-1	7267-7316	Ranong	0.23								
Manora-1	7316-7365	Basement	0.25	0.20	0.20	1.19	341	80	476	0.50	0.62
Manora-1	7365-7415	Basement	0.05								
Manora-1	7415-7464	Basement	0.06								
Manora-1	7464-7513	Basement	0.03								
Manora-1	7513-7562	Basement	0.08								
Manora-1	7562-7579	Basement	0.04								
Manora-1	7579-7582	Basement	0.04								
Mergui-1	8872	Kantang	0.71	0.09	1.51	0.45	436	212	63	0.06	
Mergui-1	8882	Kantang	0.79	0.11	1.69	0.41	433	213	51	0.06	
Mergui-1	8912	Kantang	0.65	0.06	1.31	0.40	436	201	61	0.04	
Mergui-1	8932	Kantang	0.91	0.13	1.73	0.63	437	190	69	0.07	
Mergui-1	8952	Kantang	0.88	0.11	2.45	0.68	437	278	77	0.04	
Mergui-1	8972	Kantang	0.87	0.19	1.76	0.74	434	202	85	0.10	
Mergui-1	9002	Kantang	2.11	1.32	4.19	3.50	430	198	165	0.24	
Mergui-1	9032	Kantang	0.75	0.07	1.01	0.99	438	134	132	0.06	
Mergui-1	9063	Kantang	0.65	0.14	1.53	0.47	437	235	72	0.08	
Mergui-1	9093	Kantang	0.56	0.09	1.28	0.44	430	228	78	0.07	
Mergui-1	9123	Kantang	0.88	0.15	1.88	0.50	435	213	56	0.07	
Mergui-1	9153	Kantang	0.93	0.19	2.25	0.52	434	241	55	0.08	
Mergui-1	9183	Kantang	0.74	0.10	1.42	0.61	434	191	82	0.07	

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Mergui-1	9304	Kantang	0.79	0.44	1.79	0.66	435	226	83	0.20	
Mergui-1	9344	Kantang	1.37	0.35	3.11	0.58	438	227	42	0.10	
Mergui-1	9435	Kantang	0.95	0.46	2.48	0.52	435	261	54	0.16	
Mergui-1	9435	Kantang	1.33	0.15	1.70	1.33	435	127	100	0.08	
Mergui-1	9475	Kantang	0.72	0.11	1.25	0.70	437	173	97	0.08	
Mergui-1	9566	Kantang	0.93	0.13	1.59	0.48	435	170	159	0.08	
Mergui-1	9757	Kantang	0.81	0.16	1.77	0.58	434	218	71	0.08	
Mergui-1	9897	Ranong	0.74	0.08	1.94	0.31	437	262	41	0.04	
Mergui-1	10089	Ranong	0.37	0.02	0.42	0.47	437	113	127	0.05	
Mergui-1	10099	Ranong	0.61	0.12	1.25	0.43	433	204	70	0.09	
Mergui-1	10119	Ranong	0.69	0.07	1.42	0.90	436	205	131	0.05	
Mergui-1	10129	Ranong	0.68	0.09	1.41	0.45	435	207	66	0.06	
Mergui-1	10149	Ranong	0.59	0.06	1.13	0.34	435	191	57	0.05	
Mergui-1	10239	Ranong	0.59	0.04	1.24	0.30	436	210	50	0.03	
Mergui-1	10260	Ranong	0.53	0.04	0.85	0.29	438	160	54	0.04	
Mergui-1	10521	Ranong	0.45	0.00	0.27	0.44	440	60	97	0.00	
Mergui-1	10541	Ranong	0.80	0.02	0.85	0.77	437	106	96	0.02	
Mergui-1	10581	Ranong	0.42	0.07	0.72	0.24	436	171	57	0.09	
Mergui-1	10682	Ranong	0.52	0.13	1.21	0.28	436	232	53	0.10	
Mergui-1	10732	Ranong	0.56	0.08	0.77	0.62	435	137	110	0.09	
Mergui-1	10793	Ranong	0.51	0.10	0.92	0.25	437	180	49	0.10	
Mergui-1	10853	Ranong	0.53	0.05	1.16	0.38	438	218	71	0.04	
Mergui-1	10974	Ranong	0.16	0.00	0.33	0.34	438	206	212	0.00	
Mergui-1	11135	Ranong	0.44	0.06	0.79	0.49	435	179	111	0.07	
Mergui-1	11889	Ranong	0.07	0.00	0.15	0.13		214	185	0.00	
Mergui-1	10050-10110	Ranong	0.80	0.17	1.43	0.23	431	179	29		
Mergui-1	10140-10170	Ranong	0.60								
Mergui-1	10170-10200	Ranong	0.68								
Mergui-1	10230-10260	Ranong	1.00	0.07	0.31	0.64	437	31	64		
Mergui-1	10290-10320	Ranong	0.60								
Mergui-1	10350-10380	Ranong	1.27	0.11	0.62	0.78	434	49	61		
Mergui-1	10410-10440	Ranong	2.21	0.14	1.04	1.81	433	47	82		0.32
Mergui-1	10440-10470	Ranong	1.67	0.10	0.49	1.34	431	29	80		
Mergui-1	10500-10530	Ranong	0.82	0.48	1.56	0.27	433	190	33		
Mergui-1	10680-10690	Ranong	0.52								0.64

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Mergui-1	10730-10740	Ranong	0.56								0.61
Mergui-1	10890-10920	Ranong	0.41								
Mergui-1	10950-10980	Ranong	0.30								
Mergui-1	11010-11040	Ranong	0.83	0.30	1.41	0.25	429	170	30		0.35
Mergui-1	11070-11100	Ranong	0.63								
Mergui-1	11130-11160	Ranong	0.55								
Mergui-1	11190-11220	Ranong	0.43								
Mergui-1	11220-11250	Ranong	0.47								
Mergui-1	11250-11280	Ranong	0.35								
Mergui-1	11310-11340	Ranong	0.35								
Mergui-1	11370-11400	Ranong	0.45								
Mergui-1	11430-11460	Ranong	0.28								
Mergui-1	11490-11520	Ranong	0.28								0.46
Mergui-1	11820-11850	Ranong	0.26								
Mergui-1	11880-11910	Ranong	0.23								
Mergui-1	11940-11970	Ranong	0.21								
Mergui-1	12000-12030	Ranong	0.19								0.33
Mergui-1	12030-12060	Ranong	0.20								
Mergui-1	12060-12090	Ranong	0.19								
Mergui-1	12090-12120	Ranong	0.17								
Mergui-1	12120-12150	Ranong	0.24								
Mergui-1	12150-12180	Ranong	0.29								
Mergui-1	12180-12210	Ranong	0.33								
Mergui-1	12240-12270	Ranong	0.38								
Mergui-1	12270-12300	Ranong	0.27								
Mergui-1	12300-12330	Ranong	0.28								
Mergui-1	12330-12360	Ranong	0.25								
Mergui-1	12360-12390	Ranong	0.27								
Mergui-1	12390-12420	Ranong	0.23								
Mergui-1	12420-12450	Ranong	0.26								
Mergui-1	12450-12480	Ranong	0.27								
Mergui-1	2748-2760	Takua Pa	0.56								
Mergui-1	2850-2880	Takua Pa	1.13	0.37	1.41	3.32	426	125	294		
Mergui-1	2910-2940	Takua Pa	1.13	0.46	1.33	2.75	418	118	243		
Mergui-1	2940-2970	Takua Pa	1.18	0.47	1.46	2.60	421	124	220		

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Mergui-1	3030-3060	Trang	1.24	0.35	1.78	2.12	425	144	171		0.26
Mergui-1	3120-3150	Trang	1.17	0.26	1.20	1.61	424	103	138		
Mergui-1	3150-3180	Trang	1.10	0.21	1.05	1.19	424	95	108		
Mergui-1	3210-3240	Trang	1.26	0.31	1.44	1.93	426	114	153		
Mergui-1	3270-3300	Trang	1.16	0.30	1.30	1.88	424	112	162		
Mergui-1	3390-3420	Trang	0.26								
Mergui-1	3600-3630	Trang	1.02	0.14	0.85	0.39	426	83	38		
Mergui-1	3780-3810	Trang	0.22								
Mergui-1	4020-4050	Trang	0.18								
Mergui-1	4200-4230	Trang	0.51								
Mergui-1	4230-4320	Trang	0.97	0.24	1.05	0.94	429	108	97		0.27
Mergui-1	4380-4410	Trang	0.52								
Mergui-1	4410-4500	Trang	0.95	0.25	1.30	0.78	429	137	82		
Mergui-1	4590-4620	Trang	0.74	0.23	1.08	0.56	425	146	76		
Mergui-1	4620-4680	Trang	1.01	0.21	1.40	0.77	430	139	76		
Mergui-1	4680-4740	Trang	0.50								
Mergui-1	4740-4800	Trang	0.64								
Mergui-1	4830-4890	Trang	0.95	0.40	1.60	0.80	421	168	84		
Mergui-1	4920-4980	Trang	0.87	0.20	1.22	0.64	426	140	74		
Mergui-1	5010-5070	Trang	0.97	0.18	1.64	0.59	428	169	61		0.33
Mergui-1	5070-5130	Trang	1.15	0.25	2.29	0.53	428	199	46		
Mergui-1	5130-5190	Trang	1.04	0.14	1.29	0.73	428	124	70		
Mergui-1	5190-5220	Kantang	1.36	0.21	2.67	0.72	425	196	53		
Mergui-1	5220-5250	Kantang	1.20	0.19	2.50	0.75	429	208	63		
Mergui-1	5310-5340	Kantang	1.45	0.26	2.88	0.95	426	199	66		
Mergui-1	5370-5400	Kantang	1.46	0.19	2.99	0.99	427	205	68		
Mergui-1	5430-5460	Kantang	1.35	0.20	2.77	2.02	429	205	150		
Mergui-1	5490-5520	Kantang	1.31	0.19	2.49	1.40	431	190	107		
Mergui-1	5550-5580	Kantang	0.70								
Mergui-1	5610-5640	Kantang	1.13	0.11	1.40	1.06	432	124	94		
Mergui-1	5670-5700	Kantang	1.21	0.14	1.69	1.08	430	140	89		
Mergui-1	5730-5760	Kantang	0.95	0.11	1.37	0.95	431	144	100		
Mergui-1	5790-5820	Kantang	0.88	0.09	1.28	0.74	430	145	84		
Mergui-1	5820-5850	Kantang	1.01	0.10	1.19	0.87	431	118	86		
Mergui-1	6000-6030	Kantang	0.45								0.36

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Mergui-1	6240-6270	Kantang	0.85	0.10	0.83	0.83	430	98	98		
Mergui-1	6420-6450	Kantang	0.71								
Mergui-1	6480-6510	Kantang	0.56								
Mergui-1	6540-6570	Kantang	0.52								
Mergui-1	6630-6660	Kantang	0.74	0.10	1.01	1.16	431	136	157		
Mergui-1	6690-6720	Kantang	0.79	0.10	0.85	1.07	433	108	135		
Mergui-1	6720-7320	Kantang	1.03	0.11	1.38	0.72	428	134	70		
Mergui-1	6870-6900	Kantang	0.71								
Mergui-1	7110-7140	Kantang	1.95	0.20	2.08	1.39	430	107	71		0.37
Mergui-1	7350-7380	Kantang	0.80	0.15	1.39	1.23	430	174	154		
Mergui-1	7410-7440	Kantang	0.85	0.14	1.47	0.74	429	173	87		
Mergui-1	7440-7470	Kantang	0.76	0.14	1.30	0.81	430	171	107		
Mergui-1	7500-7530	Kantang	0.82	0.15	1.43	0.76	431	174	93		
Mergui-1	7560-7590	Kantang	0.96	0.16	1.63	0.77	431	170	80		
Mergui-1	7590-7620	Kantang	0.90	0.14	1.39	0.91	429	154	101		
Mergui-1	7680-7710	Kantang	0.89	0.14	1.54	0.71	429	173	80		
Mergui-1	7740-7770	Kantang	0.88	0.18	1.68	0.79	430	191	90		
Mergui-1	7800-7830	Kantang	0.88	0.23	1.58	1.06	430	180	120		
Mergui-1	7860-7890	Kantang	0.84	0.15	1.37	0.60	431	163	71		
Mergui-1	7920-7950	Kantang	0.80	0.14	1.25	0.71	429	156	89		
Mergui-1	7950-7980	Kantang	1.04	0.21	1.62	0.79	430	156	76		
Mergui-1	8040-8070	Kantang	3.04	0.30	3.70	2.43	431	122	80		0.42
Mergui-1	8100-8130	Kantang	1.03	0.19	1.76	0.77	429	171	75		
Mergui-1	8130-8220	Kantang	1.23	0.18	1.79	0.79	428	146	64		
Mergui-1	8220-8280	Kantang	11.60	1.37	11.64	10.36	424	100	89		
Mergui-1	8310-8340	Kantang	11.90	1.01	13.89	10.18	427	117	86		
Mergui-1	8370-8400	Kantang	1.85	0.28	2.65	1.35	427	143	73		
Mergui-1	8400-8430	Kantang	1.42	0.29	2.51	1.00	426	177	70		
Mergui-1	8460-8490	Kantang	1.12	0.27	2.26	0.60	428	202	54		
Mergui-1	8490-8520	Kantang	1.06	0.27	2.25	0.69	430	212	65		
Mergui-1	8550-8580	Kantang	1.02	0.24	2.15	1.72	429	211	169		
Mergui-1	8580-8610	Kantang	1.09	0.27	2.50	0.33	430	229	30		
Mergui-1	8640-8670	Kantang	1.01	0.25	2.13	0.40	429	211	40		
Mergui-1	8700-8730	Kantang	1.00	0.28	2.23	0.50	433	223	50		
Mergui-1	8760-8790	Kantang	1.10	0.27	2.48	0.77	431	225	70		

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Mergui-1	8790-8820	Kantang	1.04	0.28	2.00	0.58	431	192	56		
Mergui-1	8820-8850	Kantang	1.00	0.26	2.37	0.79	432	237	79		
Mergui-1	8880-8910	Kantang	1.03	0.25	2.08	1.00	431	202	97		
Mergui-1	8940-8970	Kantang	1.06	0.31	2.21	0.74	431	208	70		
Mergui-1	8970-8980	Kantang	0.87								0.54
Mergui-1	8970-9000	Kantang	1.14	0.55	2.74	0.58	424	240	51		0.39
Mergui-1	9000-9010	Kantang	2.11								0.57
Mergui-1	9030-9060	Kantang	1.16	0.39	2.99	0.34	432	258	29		
Mergui-1	9060-9090	Kantang	1.15	0.34	2.60	0.66	432	226	57		
Mergui-1	9090-9120	Kantang	1.04	0.27	2.38	0.77	432	229	74		
Mergui-1	9150-9180	Kantang	1.11	0.22	2.02	0.70	429	182	63		
Mergui-1	9180-9210	Kantang	1.02	0.20	2.01	0.54	430	197	53		
Mergui-1	9210-9600	Kantang	1.57	0.23	2.04	1.06	432	130	68		0.39
Mergui-1	9320-9330	Kantang	1.37								0.62
Mergui-1	9370-9380	Kantang	0.95								
Mergui-1	9600-9630	Kantang	1.11	0.21	1.95	0.47	428	176	42		0.38
Mergui-1	9660-9690	Kantang	1.13	0.19	1.88	0.66	429	166	58		
Mergui-1	9720-9750	Kantang	1.08	0.21	1.71	0.59	430	158	55		
Mergui-1	9780-9810	Ranong	1.06	0.26	2.11	0.41	430	199	39		0.46
Mergui-1	9840-9870	Ranong	0.98	0.23	1.67	0.31	431	170	32		
Mergui-1	9900-9930	Ranong	0.57								
Mergui-1	9960-9990	Ranong	1.64	0.12	0.74	1.40	435	45	85		0.25
Payang-1	1940-2000	Trang	0.54	0.19	0.30	1.64	407	56	304		0.27
Payang-1	2000-2060	Trang	0.43								
Payang-1	2060-2120	Trang	0.21								
Payang-1	2120-2180	Trang	0.25								0.26
Payang-1	2420-2480	Payang	0.41								
Payang-1	2480-2540	Payang	0.39								
Payang-1	2540-2600	Payang	0.50	0.13	0.25	1.29	399	50	258		0.31
Payang-1	2600-2660	Payang	0.28								
Payang-1	2660-2720	Payang	0.54	0.13	0.33	1.20	388	61	222		0.28
Payang-1	2720-2780	Payang	0.24								
Payang-1	2780-2840	Payang	0.31								
Payang-1	2840-2900	Payang	0.37								0.31
Payang-1	2900-2960	Payang	0.39								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Payang-1	2960-3020	Payang	0.35								
Payang-1	3020-3080	Payang	0.59	0.21	0.66	1.38	381	112	234		0.3
Payang-1	3080-3140	Payang	0.76	0.19	0.58	1.41	402	76	186		
Payang-1	3140-3170	Payang	0.49	0.07	0.10	1.01	418	20	206		
Payang-1	3170-3200	Payang	0.91	0.19	0.56	1.72	414	62	189		0.29
Payang-1	3200-3260	Payang	0.59	0.15	0.34	1.21	416	58	205		
Payang-1	3260-3290	Payang	0.49	0.05	0.10	0.82	441	20	167		
Payang-1	3290-3320	Payang	0.56	0.11	0.25	1.03	427	45	184		
Payang-1	3320-3350	Payang	0.20								
Payang-1	3320-3380	Payang	0.87	0.09	0.23	1.30	419	26	149		0.34
Payang-1	3380-3410	Payang	0.68	0.09	0.12	1.35	428	18	199		
Payang-1	3410-3440	Payang	1.18	0.11	0.35	1.72	420	30	146		0.36
Payang-1	3440-3470	Payang	0.62	0.05	0.09	0.79	443	15	127		
Payang-1	3500-3530	Payang	0.63	0.03	0.07	0.87	445	11	138		
Payang-1	3560-3590	Payang	0.12								
Payang-1	3560-3620	Payang	0.42								
Payang-1	3620-3650	Payang	0.69	0.12	0.35	1.72	440	51	249		0.2
Payang-1	3650-3680	Payang	0.49	0.14	0.48	1.05	393	98	214		
Payang-1	3680-3710	Payang	0.12								
Payang-1	3710-3740	Payang	0.27								
Payang-1	3740-3800	Payang	0.58	0.11	0.26	1.08	413	45	186		
Payang-1	3800-3860	Payang	0.58	0.24	0.63	1.82	407	109	314		
Payang-1	3860-3920	Payang	0.54	0.28	0.73	1.79	393	135	331		0.24
Payang-1	3920-3980	Payang	0.38								
Payang-1	3980-4040	Payang	0.39								
Payang-1	4040-4100	Payang	0.18								
Payang-1	4100-4160	Payang	0.37								0.36
Payang-1	4160-4220	Payang	0.94	0.12	0.27	1.25	416	29	133		
Payang-1	4220-4280	Payang	1.15	0.26	0.55	2.19	400	48	190		0.35
Payang-1	4280-4340	Payang	0.76	0.29	0.51	1.48	401	67	195		
Payang-1	4340-4400	Payang	0.39								
Payang-1	4400-4460	Payang	0.38								
Payang-1	4460-4520	Payang	0.65	0.12	0.32	0.94	420	49	145		0.49
Payang-1	4520-4580	Ranong	0.35								
Payang-1	4580-4640	Ranong	0.42								0.32

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Payang-1	4640-4700	Ranong	0.32								
Payang-1	4700-4730	Ranong	0.45								
Payang-1	4760-4820	Ranong	0.54	0.51	0.61	1.44	400	113	267		
Payang-1	4820-4880	Ranong	0.57	0.27	0.65	1.94	418	114	340		0.48
Payang-1	4880-4940	Ranong	0.31								
Payang-1	4940-5000	Ranong	0.16								
Phangha-1	3440	Tai	0.07	0.13	0.03	0.12		42	171	0.81	
Phangha-1	3812	Tai	0.58	0.07	0.74	1.67	429	127	287	0.09	
Phangha-1	3993	Tai	0.20	0.00	0.16	0.35	434	80	175	0.00	
Phangha-1	4114	Tai	0.32	0.15	0.16	0.48	432	50	150	0.48	
Phangha-1	4385	Tai	0.20	0.06	0.14	0.45		70	225	0.30	
Phangha-1	4416	Tai	0.12	0.02	0.19	0.32	441	158	266	0.10	
Phangha-1	2200-2230	Trang	0.68	0.15	0.46	1.21	427	68	178		
Phangha-1	2260-2290	Trang	0.85	0.10	0.41	1.38	422	48	162		
Phangha-1	2320-2350	Trang	0.45	0.11	0.27	1.00	411	60	222		
Phangha-1	2380-2410	Trang	0.27								
Phangha-1	2440-2470	Trang	0.46	0.16	0.56	0.77	416	122	167		
Phangha-1	2500-2530	Trang	0.46	0.10	0.39	0.87	534	85	189		0.24
Phangha-1	2560-2590	Trang	0.69	0.11	0.39	1.28	420	57	186		
Phangha-1	2590-2620	Trang	0.75	0.11	0.35	1.09	412	47	145		
Phangha-1	2620-2650	Trang	1.00	0.14	0.64	1.35	420	64	135		
Phangha-1	2680-2710	Trang	3.11	0.24	2.04	3.66	429	66	118		
Phangha-1	2740-2770	Trang	1.07	0.19	1.03	1.30	427	96	121		
Phangha-1	2800-2830	Trang	0.93	0.15	0.51	1.34	419	55	144		
Phangha-1	2860-2890	Trang	1.20	0.31	1.43	1.76	422	119	147		
Phangha-1	2920-2950	Trang	1.52	0.26	1.67	1.54	422	110	101		
Phangha-1	2980-3010	Trang	0.88	0.08	0.47	1.06	421	53	120		
Phangha-1	3040-3070	Tai	0.58	0.06	0.34	0.67	424	59	116		
Phangha-1	3070-3100	Tai	0.63	0.11	0.48	0.81	426	76	129		
Phangha-1	3130-3160	Tai	0.31								
Phangha-1	3190-3220	Tai	0.63	0.16	0.54	3.77	426	86	598		
Phangha-1	3250-3280	Tai	0.62	0.17	0.62	3.31	424	100	534		0.24
Phangha-1	3310-3340	Tai	0.40	0.11	0.40	1.36	425	100	340		
Phangha-1	3400-3430	Tai	0.17								
Phangha-1	3460-3490	Tai	0.21								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Phangha-1	3520-3550	Tai	0.32								
Phangha-1	3580-3610	Tai	0.29								
Phangha-1	3640-3670	Tai	0.26								
Phangha-1	3700-3730	Tai	0.30								
Phangha-1	3760-3790	Tai	0.41	0.08	0.23	1.61	513	56	393		
Phangha-1	3820-3850	Tai	0.19								
Phangha-1	3880-3910	Tai	0.16								
Phangha-1	3940-3970	Tai	0.23								
Phangha-1	4000-4030	Tai	0.19								0.29
Phangha-1	4060-4090	Tai	0.22								
Phangha-1	4120-4150	Tai	0.15								
Phangha-1	4180-4210	Tai	0.11								
Phangha-1	4240-4270	Tai	0.16								
Phangha-1	4270-4300	Tai	0.13								
Phangha-1	4330-4360	Tai	0.20								
Phangha-1	4360-4390	Tai	0.16								
Phangha-1	4420-4450	Tai	0.13								
Ranot-1	4570	Tai	0.71	0.20	2.33	0.82	426	328	115	0.08	
Ranot-1	4600	Tai	0.88	0.22	1.63	0.90	423	185	102	0.12	
Ranot-1	4660	Tai	1.03	0.12	1.80	1.05	425	175	102	0.06	
Ranot-1	4810	Tai	0.95	0.08	0.87	0.79	421	92	83	0.08	
Ranot-1	4930	Tai	0.60	0.14	1.86	0.88	425	310	147	0.07	
Ranot-1	5050	Tai	0.65	0.12	1.63	0.91	425	251	140	0.07	
Ranot-1	5170	Tai	0.57	0.13	1.10	0.92	425	244	204	0.11	
Ranot-1	5290	Tai	0.46	0.27	1.33	1.21	423	218	198	0.17	
Ranot-1	5410	Tai	0.63	0.20	1.01	1.00	424	160	159	0.17	
Ranot-1	5590	Tai	0.76	0.19	2.20	0.62	425	289	82	0.08	
Ranot-1	5710	Tai	0.57	0.13	1.21	0.67	426	212	118	0.10	
Ranot-1	5830	Tai	0.72	0.26	2.10	1.21	424	292	168	0.11	
Ranot-1	5920	Tai	0.90	0.09	2.30	1.16	431	256	129	0.04	
Ranot-1	6070	Tai	0.88	0.18	2.19	0.68	424	249	77	0.08	
Ranot-1	6370	Ranong	0.57	0.14	1.11	0.59	426	195	104	0.11	
Ranot-1	6610	Ranong	0.68	0.12	1.20	0.54	423	176	79	0.09	
Ranot-1	6880	Ranong	0.54	0.88	1.52	1.09	397	281	202	0.37	
Ranot-1	7180	Ranong	0.28	0.03	0.01	0.75	432	4	268	0.75	

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Ranot-1	7720	Ranong	0.34	0.13	0.36	0.95	421	106	279	0.27	
Ranot-1	8080	Ranong	0.24	0.02	0.02	0.35	295		146	0.50	
Ranot-1	8320	Ranong	0.48	0.18	0.46	0.94	419	96	196	0.28	
Ranot-1	8500	Basement	0.31	0.06	0.03	0.69	369	10	223	0.67	
Tai-1	2760-2790	Trang	6.94	1.12	4.78	16.67	437	69	240		
Tai-1	2820-2850	Trang	5.00	1.12	3.24	12.88	416	65	258		
Tai-1	2880-2910	Trang	4.68	0.77	3.59	11.77	436	77	251		
Tai-1	2940-2970	Trang	3.22	0.65	3.12	7.69	429	97	239		
Tai-1	2970-3000	Trang	4.08	0.72	3.21	7.10	421	79	174		
Tai-1	3000-3030	Trang	6.25	3.87	5.73	11.51	328	92	184		0.33
Tai-1	3030-3060	Trang	2.55	0.92	2.96	5.94	423	116	233		
Tai-1	3090-3120	Trang	1.39	0.45	2.79	1.79	421	201	129		
Tai-1	3150-3180	Trang	1.25	0.36	2.80	1.68	428	224	134		
Tai-1	3240-3270	Trang	1.33	0.31	2.58	1.85	426	194	139		
Tai-1	3300-3330	Trang	1.29	0.34	2.44	1.85	427	189	143		
Tai-1	3360-3390	Trang	1.24	0.29	2.44	1.61	426	197	130		
Tai-1	3390-3420	Trang	9.59	13.71	16.76	12.69	340	175	132		0.25
Tai-1	3420-3450	Trang	1.31	0.35	2.72	1.64	426	208	125		
Tai-1	3480-3510	Trang	1.46	0.38	3.38	1.71	427	232	117		
Tai-1	3540-3570	Trang	1.56	0.40	3.49	1.79	426	224	115		
Tai-1	3570-3600	Trang	1.67	0.45	3.97	1.83	424	238	110		
Tai-1	3630-3680	Trang	1.44	0.36	3.41	1.59	427	237	110		
Tai-1	3780-3810	Tai	1.08	0.15	1.24	1.93	421	115	179		0.25
Tai-1	3810-3900	Tai	0.52	0.12	0.63	0.75	418	121	144		
Tai-1	3900-4020	Tai	0.54	0.12	0.51	1.09	421	94	202		0.27
Tai-1	4020-4050	Tai	0.65	0.17	0.69	1.40	427	106	215		
Tai-1	4050-4120	Tai	0.69	0.16	0.68	1.25	429	99	181		
Tai-1	4140-4200	Tai	0.45								
Tai-1	4200-4230	Tai	0.40								0.25
Tai-1	4230-4320	Tai	0.48	0.17	0.57	0.79	426	119	165		
Tai-1	4230-4410	Tai	0.40								
Tai-1	4410-4440	Tai	0.51	0.13	0.70	0.84	425	137	165		
Tai-1	4410-4470	Tai	2.57	0.12	1.48	4.82	435	58	188		
Tai-1	4440-4470	Tai	0.45								
Tai-1	4470-4500	Tai	0.42								0.31

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Tai-1	4530-4560	Tai	0.18								
Tai-1	4560-4590	Tai	0.20								
Tai-1	4590-4620	Tai	0.16								
Tai-1	4620-4650	Tai	0.13								
Tai-1	4680-4710	Tai	0.19								
Tai-1	4740-4770	Tai	0.11								
Tai-1	4800-4830	Tai	0.11								
Tai-1	4860-4890	Tai	0.20								
Tai-1	4920-4950	Tai	0.09								
Tai-1	4980-5010	Tai	0.07								
Tai-1	5040-5070	Tai	0.08								
Tai-1	5100-5130	Tai	0.08								
Tai-1	5160-5190	Tai	0.08								
Tai-1	5220-5250	Tai	0.09								
Tai-1	5280-5310	Tai	0.28								3.21
Tai-1	5340-5370	Tai	0.15								
Tai-1	5400-5430	Tai	0.30								9.2
Tai-1	5460-5490	Tai	0.34								
Tai-1	5520-5550	Tai	0.22								
Tai-1	5580-5610	Tai	0.26								
Tai-1	5610-5640	Tai	0.18								6.9
Tai-1	5640-5670	Tai	0.16								
Tai-1	5700-5730	Tai	0.09								
Tai-1	5760-5790	Basement	0.10								
Tai-1	5790-5820	Basement	0.10								9.74
Thalang-1	5260	Takua Pa	0.93								
Thalang-1	5320	Takua Pa	1.08	1.27	1.83	1.31	423	169	121	0.41	
Thalang-1	5380	Thalang	1.17	1.66	2.82	1.97	425	241	168	0.37	0.29
Thalang-1	5440	Thalang	1.51	3.55	2.82	1.97	425	187	130	0.56	
Thalang-1	5500	Thalang	1.26	0.41	3.20	1.61	429	254	128	0.11	0.32
Thalang-1	5560	Thalang	1.47	2.36	3.42	1.56	427	233	106	0.41	
Thalang-1	5620	Thalang	1.27	0.32	3.79	1.50	425	298	118	0.08	0.34
Thalang-1	5680	Thalang	1.38	2.26	4.38	1.67	422	317	121	0.34	
Thalang-1	5740	Thalang	1.70	0.24	5.31	1.25	416	312	74	0.04	0.34
Thalang-1	5800	Thalang	1.49	1.85	4.07	1.63	422	273	109	0.31	

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Thalang-1	5860	Thalang	1.65	7.71	3.96	1.67	422	240	101	0.66	0.34
Thalang-1	5920	Thalang	1.55	2.14	4.08	1.69	423	263	109	0.34	
Thalang-1	5980	Thalang	1.76	3.60	4.95	1.63	419	281	93	0.42	0.35
Thalang-1	6040	Thalang	1.25	0.20	2.95	1.22	422	236	98	0.06	
Thalang-1	6044	Thalang									0.34
Thalang-1	6100	Trang	1.64	0.18	6.14	1.55	416	374	95	0.03	0.34
Thalang-1	6141	Trang									0.32
Thalang-1	6160	Trang	1.58	0.16	6.67	1.24	419	422	78	0.02	
Thalang-1	6220	Trang	1.52	0.21	5.64	1.55	418	371	102	0.04	0.35
Thalang-1	6250	Trang									0.32
Thalang-1	6280	Trang	1.36	0.13	4.75	2.19	422	349	161	0.03	0.34
Thalang-1	6340	Trang	1.14	0.13	5.10	0.85	424	447	75	0.02	0.35
Thalang-1	6400	Trang	1.05	0.12	3.63	0.80	430	346	76	0.03	
Thalang-1	6460	Trang	1.43	0.15	3.85	0.92	427	269	64	0.04	0.36
Thalang-1	6480	Trang									0.35
Thalang-1	6520	Trang	1.39	0.14	4.86	1.12	425	350	61	0.03	
Thalang-1	6580	Trang	0.88								0.37
Thalang-1	6640	Kantang	0.90								
Thalang-1	6647	Kantang									0.38
Thalang-1	6700	Kantang	1.03	0.13	2.59	0.70	433	251	68	0.05	0.38
Thalang-1	6708	Kantang									0.37
Thalang-1	6760	Kantang	1.10	0.13	2.80	0.73	432	255	66	0.04	
Thalang-1	6800	Kantang									0.37
Thalang-1	6820	Kantang	1.13	0.11	3.15	0.66	432	279	58	0.03	0.35
Thalang-1	6880	Kantang	1.04	0.12	2.74	0.64	431	263	62	0.04	
Thalang-1	6940	Kantang	0.98	0.12	2.44	0.56	436	249	57	0.05	0.39
Thalang-1	6968	Kantang									0.38
Thalang-1	7000	Kantang	1.06	0.10	1.69	0.43	432	159	41	0.06	
Thalang-1	7060	Kantang	1.15	0.12	1.18	0.52	433	103	45	0.09	0.4
Thalang-1	7120	Kantang	1.26	0.13	1.16	0.41	431	92	33	0.10	
Thalang-1	7180	Kantang	1.04	0.35	1.63	0.83	431	157	80	0.18	0.39
Thalang-1	7205	Yala									0.44
Thalang-1	7240	Yala	1.22	0.59	1.33	0.99	433	109	81	0.31	
Thalang-1	7300	Yala	0.88								0.43
Thalang-1	7360	Yala	0.76								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Thalang-1	7420	Yala	0.92								0.39
Thalang-1	7480	Yala	1.05	0.37	2.29	1.20	421	216	114	0.14	
Thalang-1	7540	Yala	0.95								0.41
Thalang-1	7600	Yala	1.01	0.56	2.42	0.85	430	240	84	0.19	
Thalang-1	7660	Yala	0.76								0.4
Thalang-1	7720	Yala	0.88								
Thalang-1	7780	Yala	0.74								0.4
Thalang-1	7840	Yala	1.05	0.40	2.65	0.53	432	252	50	0.13	
Thalang-1	7845	Yala									0.43
Thalang-1	7900	Yala	0.65	0.46	0.59	0.46	434	91	71	0.44	0.43
Thalang-1	7960	Yala	0.65								
Thalang-1	8020	Yala	0.66	0.72	0.56	0.50	432	85	76	0.56	0.44
Thalang-1	8042	Yala									0.47
Thalang-1	8080	Yala	0.55								
Thalang-1	8140	Yala	0.50	0.39	0.39	0.34	429	78	68	0.50	0.45
Thalang-1	8200	Yala	0.45								0.47
Thalang-1	8260	Yala	0.44								0.49
Thalang-1	8313	Yala									0.49
Thalang-1	8320	Yala	0.67	0.41	0.57	0.37	433	85	55	0.42	
Thalang-1	8380	Yala	0.65	0.24	0.47	0.36	432	72	55	0.34	0.51
Thalang-1	8392	Yala									0.52
Thalang-1	8440	Yala	0.51								
Thalang-1	8500	Yala	0.75								0.46
Thalang-1	5260-5290	Takua Pa	3.82								
Thalang-1	5320-5350	Takua Pa	4.09								
Thalang-1	5380-5410	Thalang	3.75								
Thalang-1	5440-5470	Thalang	3.38								
Thalang-1	5500-5530	Thalang	7.41								
Thalang-1	5530-5560	Thalang	6.89								
Trang-1	48304860	Trang	0.92	0.14	1.31	0.68	429	142	74		
Trang-1	10000-10090	Ranong	0.69								
Trang-1	10120-10330	Ranong	0.59								
Trang-1	10360-10540	Ranong	0.60								
Trang-1	10540-10750	Ranong	0.32								
Trang-1	10750-10960	Ranong	0.31								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Trang-1	10960-11170	Ranong	0.46								0.56
Trang-1	11170-11200	Ranong	0.46								
Trang-1	11230-11260	Ranong	0.41								
Trang-1	11260-11290	Ranong	0.33								
Trang-1	11320-11590	Ranong	0.77	0.16	0.90	0.31	436	117	40		0.45
Trang-1	11620-11670	Ranong	0.53								
Trang-1	11740-11770	Ranong	0.33								
Trang-1	11890-11920	Ranong	0.66								
Trang-1	11950-11980	Ranong	0.67								
Trang-1	12010-12310	Ranong	0.79	0.12	0.66	0.34	435	84	43		0.46
Trang-1	12310-12610	Ranong	0.99	0.15	0.67	0.42	438	68	42		0.42
Trang-1	12610-12900	Ranong	0.52								
Trang-1	4350-4380	Trang	1.32	0.31	2.18	1.38	429	165	105		0.28
Trang-1	4380-4410	Trang	1.44	0.30	2.55	1.92	425	177	133		
Trang-1	4410-4440	Trang	1.16	0.23	2.00	1.57	426	172	135		
Trang-1	4470-4500	Trang	1.18	0.23	2.02	1.25	426	171	106		
Trang-1	4710-4740	Trang	0.93	0.16	1.48	1.33	428	159	143		
Trang-1	4770-4800	Trang	0.97	0.17	1.41	0.89	428	145	92		
Trang-1	5010-5040	Trang	0.92	0.17	1.38	0.74	430	150	80		
Trang-1	5070-5100	Trang	0.89	0.17	1.37	0.77	430	154	87		0.33
Trang-1	5130-5160	Trang	0.90	0.18	1.35	0.85	431	150	96		
Trang-1	5190-5220	Trang	0.65								
Trang-1	5250-5280	Kantang	0.66								
Trang-1	5280-5310	Kantang	0.67								
Trang-1	5400-5430	Kantang	0.65								
Trang-1	5460-5490	Kantang	0.56								
Trang-1	5520-5550	Kantang	0.53								
Trang-1	5590-5620	Kantang	1.14	1.94	2.35	4.95	409	206	434		
Trang-1	5770-5780	Kantang	0.69								
Trang-1	5900-5920	Kantang	0.76	0.50	1.59	2.62	426	209	345		
Trang-1	5940-5960	Kantang	0.64								
Trang-1	6000-6020	Kantang	0.55								
Trang-1	6060-6080	Kantang	0.77	0.37	1.00	2.54	419	130	330		0.34
Trang-1	6120-6140	Kantang	1.04	0.11	0.80	1.76	431	77	169		
Trang-1	6180-6200	Kantang	0.65								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Trang-1	6240-6260	Kantang	0.57								
Trang-1	6310-6320	Kantang	0.51								
Trang-1	6360-6380	Kantang	0.58								
Trang-1	6380-6400	Kantang	0.55								
Trang-1	7020-7040	Kantang	0.59								0.31
Trang-1	7080-7100	Kantang	0.60								
Trang-1	7140-7160	Kantang	0.82	0.28	1.21	1.28	428	148	156		
Trang-1	7200-7220	Kantang	0.56								
Trang-1	7220-7240	Kantang	0.56								
Trang-1	7280-7300	Kantang	0.96	0.11	1.09	1.00	427	114	104		
Trang-1	7340-7360	Kantang	0.84	0.14	0.98	0.95	429	117	113		
Trang-1	7400-7420	Kantang	0.75	0.15	1.05	0.91	426	140	121		
Trang-1	7450-7480	Kantang	0.60								
Trang-1	7510-7540	Kantang	0.70								
Trang-1	7570-7840	Kantang	1.10	0.18	1.12	0.60	428	102	55		0.35
Trang-1	7840-7870	Kantang	2.12	0.20	1.68	2.28	424	79	108		
Trang-1	7900-7930	Kantang	1.29	0.12	0.84	1.65	428	65	128		
Trang-1	7930-7960	Kantang	0.68								
Trang-1	7990-8020	Kantang	0.63								
Trang-1	8260-8290	Kantang	0.75	0.15	0.93	0.81	429	124	108		
Trang-1	8290-8320	Kantang	0.78	0.13	0.92	0.80	429	118	103		
Trang-1	8560-8650	Kantang	0.74	0.12	0.89	0.22	428	120	30		
Trang-1	8740-8830	Kantang	1.09	0.22	1.18	0.65	426	108	60		
Trang-1	8830-8920	Kantang	1.30	0.25	1.35	1.03	427	104	79		0.39
Trang-1	8920-8950	Kantang	1.03	0.19	1.30	0.80	430	126	78		
Trang-1	8980-9010	Kantang	0.80	0.15	1.25	0.77	430	156	96		0.44
Trang-1	9040-9070	Kantang	0.70								
Trang-1	9070-9160	Kantang	0.88	0.14	0.87	0.40	427	99	45		
Trang-1	9160-9250	Kantang	0.95	0.22	1.28	0.45	425	135	47		
Trang-1	9250-9340	Ranong	0.78	0.15	1.06	0.18	428	136	23		
Trang-1	9340-9460	Ranong	0.74	0.15	0.87	0.17	429	118	23		
Trang-1	9460-9490	Ranong	0.67								
Trang-1	9520-9550	Ranong	0.70								0.46
Trang-1	9580-9610	Ranong	0.66								
Trang-1	9640-9670	Ranong	0.65								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Trang-1	9700-9910	Ranong	0.84	0.16	0.72	0.69	433	86	82		
Trang-1	9910-10000	Ranong	0.89	0.17	0.61	1.08	434	69	121		0.59
W9-A-1	2400	Takua Pa	0.77								
W9-A-1	2900	Takua Pa	0.11								
W9-A-1	3100	Takua Pa	0.10								
W9-A-1	3900	Trang	1.10								
W9-A-1	4500	Kantang	0.57								
W9-A-1	4557.5	Kantang	0.63								
W9-A-1	4900	Kantang	0.25								
W9-A-1	5100	Kantang	0.35								
W9-A-1	5400	Kantang	1.00								
W9-A-1	5600	Kantang	0.57								
W9-A-1	5800	Ranong	0.68								
W9-A-1	6000	Ranong	0.43								
W9-A-1	6100	Ranong	0.15								
W9-A-1	6400	Ranong	0.22								
W9-A-1	6500	Ranong	0.10								
W9-A-1	6700	Ranong	0.07								
W9-A-1	7100	Ranong	0.07								
W9-A-1	7500	Ranong	0.16								
W9-A-1	7700	Ranong	0.10								
W9-A-1	2250-2280	Takua Pa									0.22
W9-A-1	2400-2430	Takua Pa	0.65								
W9-A-1	2480-3510	Takua Pa									0.28
W9-A-1	2490-2520	Takua Pa									0.14
W9-A-1	2730-2760	Takua Pa									0.16
W9-A-1	2900-2930	Takua Pa	0.09								
W9-A-1	3000-3030	Takua Pa									0.36
W9-A-1	3100-3130	Takua Pa	0.08								
W9-A-1	3240-3270	Takua Pa									
W9-A-1	3720-3750	Trang									0.34
W9-A-1	3900-3930	Trang	0.92								
W9-A-1	3900-3930	Trang	1.10	0.43	2.5	2.38	423	227.3	216	0.15	
W9-A-1	3960-3990	Trang									0.35
W9-A-1	4200-4230	Trang									0.31

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-A-1	4440-4470	Kantang									0.3
W9-A-1	4470-4500	Kantang	0.57	0.39	2.7	3.36	426	473.7	589	0.13	
W9-A-1	4500-4530	Kantang	0.48								
W9-A-1	4557-4587	Kantang	0.53								
W9-A-1	4560-4590	Kantang	0.63	1.06	4.05	2.61	426	642.9	414	0.21	
W9-A-1	4680-4710	Kantang									0.33
W9-A-1	4900-4930	Kantang	0.20								
W9-A-1	4920-4950	Kantang									0.29
W9-A-1	5100-5130	Kantang	0.29								
W9-A-1	5200-5210	Kantang									0.3
W9-A-1	5400-5430	Kantang	0.83								
W9-A-1	5400-5430	Kantang	1.00	7.04	6.3	1.36	351	630	136	0.53	
W9-A-1	5430-5470	Kantang									0.34
W9-A-1	5560-5590	Kantang									0.35
W9-A-1	5600-5630	Kantang	0.48								
W9-A-1	5680-5710	Kantang	0.57	0.49	1.79	1.33	424	314	233	0.21	
W9-A-1	5800-5830	Kantang	0.57								
W9-A-1	5800-5830	Ranong	0.68	0.32	1.66	1.58	424	244.1	232	0.16	
W9-A-1	5920-5950	Ranong									0.36
W9-A-1	6000-6030	Ranong	0.36								
W9-A-1	6100-6130	Ranong	0.13								0.4
W9-A-1	6340-6370	Ranong									0.37
W9-A-1	6400-6430	Ranong	0.18								
W9-A-1	6500-6530	Ranong	0.08								
W9-A-1	6580-6610	Ranong									0.43
W9-A-1	6700-6730	Ranong	0.06								
W9-A-1	6820-6850	Ranong									0.41
W9-A-1	7060-7090	Ranong									0.4
W9-A-1	7100-7130	Ranong	0.06								
W9-A-1	7300-7330	Ranong									0.46
W9-A-1	7500-7530	Ranong	0.13								
W9-A-1	7540-7550	Ranong									0.46
W9-A-1	7700-7730	Ranong	0.08								
W9-A-1	7780-7800	Ranong									0.56
W9-A-1	7890-7900	Basement									0.54

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-B-1	5000	Trang	1.12								
W9-B-1	5600	Trang	1.27								
W9-B-1	5960	Trang	1.53								
W9-B-1	6000	Trang	1.43								
W9-B-1	6300	Trang	1.90								
W9-B-1	6600	Kantang	1.66								
W9-B-1	6800	Kantang	1.44								
W9-B-1	6900	Kantang	2.21								
W9-B-1	7100	Kantang	2.66								0.46
W9-B-1	7300	Kantang	1.33								0.38
W9-B-1	7500	Kantang	1.71								0.4
W9-B-1	7700	Kantang	1.49								0.42
W9-B-1	7800	Kantang	1.59								0.4
W9-B-1	8000	Kantang	1.51								0.4
W9-B-1	8060	Ranong	1.37								0.4
W9-B-1	8110	Ranong	0.15								0.4
W9-B-1	8256	Ranong	0.32								0.4
W9-B-1	8259	Ranong	0.42								0.4
W9-B-1	8282	Ranong	0.13								0.44
W9-B-1	8300	Ranong	1.05								0.44
W9-B-1	8500	Ranong	1.26								0.44
W9-B-1	8700	Ranong	1.26								0.44
W9-B-1	8900	Ranong	1.34								0.44
W9-B-1	9100	Ranong	1.38								0.4
W9-B-1	9300	Ranong	0.35								0.3
W9-B-1	9400	Ranong	0.32								0.42
W9-B-1	9600	Ranong	1.59								0.39
W9-B-1	9800	Ranong	0.68								0.58
W9-B-1	10100	Ranong	0.20								0.7
W9-B-1	10200	Ranong	0.15								
W9-B-1	10500	Ranong	0.23								0.59
W9-B-1	10600	Ranong	0.16								0.76
W9-B-1	10900	Ranong	0.20								0.76
W9-B-1	11100	Ranong	0.22								0.78
W9-B-1	11300	Ranong	0.39								0.82

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-B-1	11600	Ranong	0.30								
W9-B-1	11700	Ranong	0.33								
W9-B-1	10050-10070	Ranong	0.22								
W9-B-1	10110-10130	Ranong	0.22								
W9-B-1	10170-10190	Ranong	0.29								
W9-B-1	10230-10250	Ranong	0.29								0.69
W9-B-1	10270-10290	Ranong	0.69	0.13	0.35	1.24	431	51	180		
W9-B-1	10330-10350	Ranong	0.24								
W9-B-1	10390-10410	Ranong	0.31								0.78
W9-B-1	10450-10460	Ranong	0.25								
W9-B-1	10510-10520	Ranong	0.17								
W9-B-1	10570-10580	Ranong	0.28								0.93
W9-B-1	10630-10640	Ranong	0.26								
W9-B-1	10690-10700	Ranong	0.19								
W9-B-1	10750-10760	Ranong	0.25								0.92
W9-B-1	10810-10820	Ranong	0.28								
W9-B-1	10870-10880	Ranong	0.40								
W9-B-1	10930-10940	Ranong	0.34								0.96
W9-B-1	10990-11000	Ranong	0.17								
W9-B-1	11040-11050	Ranong	0.21								
W9-B-1	11100-11110	Ranong	0.23								0.92
W9-B-1	11160-11170	Ranong	0.21								
W9-B-1	11220-11230	Ranong	0.24								
W9-B-1	11280-11290	Ranong	0.37								1.03
W9-B-1	11340-11350	Ranong	0.61	0.15	0.70	0.31	427	115	51		
W9-B-1	11400-11410	Ranong	0.32								
W9-B-1	11460-11470	Ranong	0.17								1.09
W9-B-1	11520-11530	Ranong	0.35								
W9-B-1	11580-11590	Ranong	1.24	0.83	1.35	1.15	433	109	93		
W9-B-1	11640-11650	Ranong	0.51	0.31	0.49	0.59	428	96	116		1.26
W9-B-1	11700-11710	Ranong	0.27								
W9-B-1	11760-11770	Ranong	0.06								
W9-B-1	11820-11830	Ranong	0.14								1.35
W9-B-1	11880-11890	Ranong	0.16								
W9-B-1	11910-11920	Ranong	0.10								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-B-1	3750-3780	Thalang	0.26								
W9-B-1	3870-3900	Thalang	0.42								
W9-B-1	3930-3960	Thalang									
W9-B-1	3990-4020	Thalang	0.28								
W9-B-1	4110-4140	Thalang	0.25								0.41
W9-B-1	4230-4260	Thalang	1.00	0.20	1.46	1.71	426	146	171		
W9-B-1	4290-4320	Thalang									0.31
W9-B-1	4350-4380	Thalang	1.07	0.25	2.06	1.58	425	193	148		
W9-B-1	4470-4500	Thalang	0.97	0.19	1.13	1.50	422	116	155		0.3
W9-B-1	4590-4620	Trang	1.08	0.21	1.37	1.52	425	127	141		
W9-B-1	4650-4680	Trang									0.32
W9-B-1	4710-4740	Trang	0.94								
W9-B-1	4830-4860	Trang	0.55								0.33
W9-B-1	4980-5010	Trang	0.94								
W9-B-1	5010-5040	Trang									
W9-B-1	5130-5160	Trang	1.28	0.16	1.19	1.70	424	93	133		
W9-B-1	5190-5220	Trang									0.34
W9-B-1	5250-5280	Trang	1.52	0.39	4.10	1.41	422	270	93		
W9-B-1	5370-5400	Trang	2.07	1.05	9.36	2.32	428	452	112		0.34
W9-B-1	5490-5520	Trang	1.62	0.16	0.91	1.63	426	56	101		
W9-B-1	5550-5580	Trang									0.38
W9-B-1	5610-5640	Trang	1.47	0.16	1.04	1.34	428	71	91		
W9-B-1	5700-5730	Trang	1.74	0.32	4.60	1.45	425	264	83		0.37
W9-B-1	5820-5850	Trang	1.81	0.24	4.83	1.30	428	267	72		
W9-B-1	5880-5910	Trang									0.32
W9-B-1	5940-5960	Trang	1.84	0.31	5.09	1.41	427	277	77		
W9-B-1	6050-6080	Trang	1.25	0.13	1.84	1.41	428	147	113		0.37
W9-B-1	6170-6200	Trang	1.03	0.11	1.31	1.13	431	127	110		
W9-B-1	6230-6260	Trang									0.36
W9-B-1	6260-6290	Trang	1.13	0.12	1.86	1.26	429	165	112		
W9-B-1	6380-6410	Trang	1.11	0.11	0.91	1.43	432	82	129		0.39
W9-B-1	6470-6500	Trang	0.67								
W9-B-1	6560-6590	Trang	1.12	0.14	1.56	0.94	432	139	84		0.41
W9-B-1	6620-6650	Kantang	0.97	0.12	0.46	1.51	429	47	156		
W9-B-1	6740-6770	Kantang	1.11	0.19	1.55	1.10	431	140	99		0.4

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-B-1	6860-6890	Kantang	1.02	0.17	1.99	0.89	429	195	87		
W9-B-1	6920-6950	Kantang									0.44
W9-B-1	6950-6980	Kantang	0.85								
W9-B-1	7040-7070	Kantang									0.4
W9-B-1	7070-7100	Kantang	0.82								
W9-B-1	7190-7220	Kantang	0.85								0.39
W9-B-1	7310-7340	Kantang	0.86								
W9-B-1	7370-7400	Kantang									0.42
W9-B-1	7430-7460	Kantang	1.04	0.18	1.64	1.02	430	158	98		
W9-B-1	7550-7580	Kantang	1.06	0.20	2.44	0.78	428	230	74		0.43
W9-B-1	7670-7700	Kantang	1.01	0.22	2.13	0.64	428	211	63		
W9-B-1	7730-7760	Kantang									0.42
W9-B-1	7790-7820	Kantang	2.27	0.35	3.61	1.62	427	159	71		
W9-B-1	7910-7940	Kantang	0.96	0.17	1.72	0.69	430	179	72		0.41
W9-B-1	8030-8060	Kantang	0.98	0.12	0.90	0.85	436	92	87		
W9-B-1	8079-8109	Ranong	0.16	0.06	0.06	0.02	432	38	13		
W9-B-1	8164-8169	Ranong	0.22								
W9-B-1	8169-8199	Ranong	0.18								
W9-B-1	8220-8230	Ranong	0.90	0.18	1.54	0.64	429	171	71		0.42
W9-B-1	8230-8240	Ranong	0.72	0.11	1.09	0.45	433	151	63		
W9-B-1	8255.5-8259.5	Ranong	0.31								
W9-B-1	8259.5-8262.2	Ranong	0.31								0.46
W9-B-1	8262.2-8279	Ranong	0.17								
W9-B-1	8314.6-8330	Ranong	0.16								0.39
W9-B-1	8330-8360	Ranong	0.60	0.10	0.49	0.56	433	82	93		
W9-B-1	8390-8420	Ranong	0.53	0.08	0.46	0.22	428	87	42		0.42
W9-B-1	8450-8480	Ranong	0.26								
W9-B-1	8510-8540	Ranong	0.47	0.06	0.39	0.22	432	83	47		
W9-B-1	8570-8600	Ranong	0.45	0.07	0.29	0.22	428	64	49		0.42
W9-B-1	8630-8660	Ranong	0.55	0.08	0.50	0.26	431	91	47		
W9-B-1	8690-8720	Ranong	0.40								
W9-B-1	8750-8780	Ranong	0.50	0.09	0.39	0.28	431	78	56		0.43
W9-B-1	8810-8840	Ranong	0.66	0.09	0.56	0.60	430	85	91		
W9-B-1	8870-8900	Ranong	0.82	0.10	0.99	0.65	429	121	79		
W9-B-1	8930-8950	Ranong	0.90	0.19	1.52	0.92	431	169	102		0.41

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-B-1	8970-8990	Ranong	0.80	0.12	1.04	0.60	427	130	75		
W9-B-1	9030-9050	Ranong	0.35								
W9-B-1	9150-9170	Ranong	0.38								0.29
W9-B-1	9210-9230	Ranong	0.23								
W9-B-1	9270-9290	Ranong	0.32								
W9-B-1	9330-9350	Ranong	0.63	0.23	0.97	0.51	421	154	81		0.44
W9-B-1	9390-9410	Ranong	0.63	0.10	0.42	0.76	426	67	121		
W9-B-1	9450-9470	Ranong	0.62	0.08	0.34	0.66	430	55	106		
W9-B-1	9510-9530	Ranong	0.54	0.14	0.50	0.88	429	93	163		0.39
W9-B-1	9570-9590	Ranong	0.33								
W9-B-1	9630-9650	Ranong	0.40								
W9-B-1	9690-9710	Ranong	0.53	0.17	0.69	2.48	430	130	468		0.58
W9-B-1	9750-9770	Ranong	0.37								
W9-B-1	9810-9830	Ranong	0.54	0.12	0.27	2.74	467	50	507		
W9-B-1	9870-9890	Ranong	0.74	0.14	0.62	2.73	432	84	369		0.7
W9-B-1	9930-9950	Ranong	0.49	0.19	0.42	0.62	428	86	127		
W9-B-1	9990-10010	Ranong	0.38								
W9-C-1	4600	Thalang	1.23								
W9-C-1	4900	Trang	1.31								
W9-C-1	5200	Trang	1.80								
W9-C-1	5600	Trang	1.72								
W9-C-1	5900	Trang	1.15								
W9-C-1	6200	Trang	1.40								
W9-C-1	6400	Yala	1.26								
W9-C-1	6600	Yala	0.59								0.4
W9-C-1	6900	Yala	0.29								0.4
W9-C-1	7200	Yala	0.17								0.7
W9-C-1	7400	Yala	0.17								0.9
W9-C-1	7700	Yala	0.24								0.58
W9-C-1	8000	Yala	0.35								0.7
W9-C-1	8300	Yala	0.20								0.58
W9-C-1	8600	Yala	0.28								0.6
W9-C-1	8800	Yala	0.20								0.6
W9-C-1	9000	Yala	0.18								0.6
W9-C-1	9200	Yala	0.23								0.6

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-C-1	9500	Yala	0.99								0.6
W9-C-1	9700	Yala	0.46								0.65
W9-C-1	10000	Ranong	0.47								0.78
W9-C-1	10100	Ranong	0.36								1.3
W9-C-1	10300	Ranong	0.68								0.98
W9-C-1	10500	Ranong	0.66								1.42
W9-C-1	10700	Ranong	0.74								1.3
W9-C-1	10900	Ranong	0.72								
W9-C-1	11200	Basement	0.32								
W9-C-1	11400	Basement	0.20								
W9-C-1	11500	Basement	0.14								
W9-C-1	11700	Basement	0.24								
W9-C-1	11900	Basement	0.22								
W9-C-1	12200	Basement	0.23								
W9-C-1	12208	Basement	0.35								
W9-C-1	10020-10030	Ranong	0.34								
W9-C-1	0043.1-10047	Ranong	0.30								
W9-C-1	0047.5-10050	Ranong	0.26								1.42
W9-C-1	0050.5-10056	Ranong	0.24								
W9-C-1	0056.2-10072	Ranong	1.18	0.16	0.49	0.13	434	42	11		
W9-C-1	0072.9-10080	Ranong	8.67	0.55	9.39	1.52	442	108	18		1.28
W9-C-1	10080.5-1009	Ranong	0.27								
W9-C-1	10094-10100	Ranong	0.68	0.21	0.89	0.53	434	131	78		
W9-C-1	10140-10150	Ranong	0.40								0.96
W9-C-1	10200-10210	Ranong	0.35								
W9-C-1	10260-10270	Ranong	0.39								
W9-C-1	10320-10330	Ranong	0.59	0.05	0.28	0.37	433	47	63		1.44
W9-C-1	10380-10390	Ranong	0.77	0.19	1.44	0.49	422	187	64		
W9-C-1	10440-10450	Ranong	0.61	0.09	0.28	0.34	428	46	56		
W9-C-1	10500-10510	Ranong	0.54	0.08	0.21	0.42	434	39	78		1.31
W9-C-1	10560-10570	Ranong	0.59	0.09	0.26	0.39	421	44	66		
W9-C-1	10620-10630	Ranong	0.49	0.06	0.23	0.35	428	47	71		
W9-C-1	10680-10690	Ranong	0.79	0.13	0.48	0.33	424	61	42		1.25
W9-C-1	10740-10750	Ranong	0.61	0.06	0.15	0.39	434	25	64		
W9-C-1	10800-10810	Ranong	0.74	0.05	0.06	0.21	402	8	28		

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-C-1	10850-10870	Ranong	0.69	0.08	0.10	0.26	425	14	38		1.33
W9-C-1	10920-10930	Ranong	0.52	0.07	0.11	0.28	426	21	54		
W9-C-1	10980-10990	Ranong	0.50	0.06	0.09	0.26	421	18	52		
W9-C-1	11040-11050	Ranong	0.27								1.31
W9-C-1	11104-11110	Ranong	0.29								
W9-C-1	11160-11170	Basement	0.47								
W9-C-1	11220-11230	Basement	0.20								3.81
W9-C-1	11280-11290	Basement	0.20								
W9-C-1	11340-11350	Basement	0.23								
W9-C-1	11400-11410	Basement	0.17								4.69
W9-C-1	11470-11480	Basement	0.26								
W9-C-1	11520-11530	Basement	0.48								
W9-C-1	11580-11590	Basement	0.26								4.17
W9-C-1	11640-11650	Basement	0.22								
W9-C-1	11700-11710	Basement	0.26								
W9-C-1	11760-11770	Basement	0.20								4.74
W9-C-1	11820-11830	Basement	0.31								
W9-C-1	11880-11890	Basement	0.29								
W9-C-1	11940-11950	Basement	0.27								4.92
W9-C-1	12000-12010	Basement	0.20								
W9-C-1	12060-12070	Basement	0.22								
W9-C-1	12120-12130	Basement	0.27								5.18
W9-C-1	12170-12180	Basement	0.26								
W9-C-1	12180-12190	Basement	0.29								5.14
W9-C-1	2201.7-12214	Basement	0.27								5.45
W9-C-1	2214.5-12244	Basement	0.31								
W9-C-1	4100-4130	Thalang	0.39								0.4
W9-C-1	4220-4250	Thalang	0.47								
W9-C-1	4280-4310	Thalang									0.29
W9-C-1	4340-4370	Thalang	0.87	0.34	1.59	1.85	430	183	213		
W9-C-1	4460-4490	Thalang	0.82	0.17	1.15	2.99	428	140	365		0.28
W9-C-1	4580-4610	Thalang	1.19	0.36	3.07	1.50	421	258	126		
W9-C-1	4640-4670	Thalang									0.28
W9-C-1	4700-4730	Thalang	1.32	0.42	3.32	1.95	425	252	148		
W9-C-1	4820-4850	Trang	1.21	0.38	2.85	1.60	422	236	132	0.27	

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-C-1	4940-4970	Trang	1.29	0.31	2.41	1.48	424	187	115		
W9-C-1	5000-5030	Trang									0.31
W9-C-1	5060-5090	Trang	1.64	0.51	5.14	1.53	426	313	93		
W9-C-1	5180-5210	Trang	1.68	0.36	4.61	1.56	423	274	93		0.34
W9-C-1	5300-5330	Trang	1.75	0.29	4.50	1.71	428	257	98		
W9-C-1	5360-5390	Trang									0.37
W9-C-1	5420-5450	Trang	1.94	0.29	5.69	1.58	430	293	81		
W9-C-1	5540-5570	Trang	1.72	0.26	4.75	1.46	428	276	85		0.35
W9-C-1	5660-5690	Trang	1.41	0.16	3.24	1.15	430	230	82		
W9-C-1	5720-5750	Trang									0.43
W9-C-1	5780-5810	Trang	1.09	0.13	1.74	0.95	431	160	87		
W9-C-1	5900-5930	Trang	1.24	0.15	2.56	1.07	430	206	86		0.38
W9-C-1	6020-6050	Trang	1.32	0.18	2.48	1.29	425	188	98		
W9-C-1	6080-6110	Trang									0.39
W9-C-1	6140-6170	Trang	1.29	0.20	2.73	1.22	430	212	95		
W9-C-1	6260-6290	Trang	0.75	0.13	1.13	1.92	432	151	256		0.44
W9-C-1	6380-6410	Yala	0.66	0.15	1.23	0.89	429	186	135		
W9-C-1	6440-6470	Yala									0.44
W9-C-1	6500-6530	Yala	0.46								
W9-C-1	6538-6620	Yala	0.18	0.06	0.18	0.11	526	100	61		
W9-C-1	6620-6650	Yala	0.24								0.51
W9-C-1	6740-6770	Yala	0.41								
W9-C-1	6770-6800	Yala									0.45
W9-C-1	6860-6890	Yala	0.46								
W9-C-1	6950-6980	Yala									0.5
W9-C-1	6980-7010	Yala	0.23								
W9-C-1	7100-7130	Yala	0.26								
W9-C-1	7130-7160	Yala									0.68
W9-C-1	7220-7250	Yala	0.26								
W9-C-1	7310-7340	Yala									0.86
W9-C-1	7340-7370	Yala	0.30								
W9-C-1	7460-7490	Yala	0.88	0.39	2.07	1.08	423	235	123		
W9-C-1	7490-7520	Yala									0.68
W9-C-1	7580-7610	Yala	0.18								
W9-C-1	7670-7700	Yala									0.57

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-C-1	7700-7730	Yala	0.19								
W9-C-1	7820-7850	Yala	0.22								
W9-C-1	7850-7880	Yala									0.7
W9-C-1	7940-7970	Yala	0.40								
W9-C-1	8030-8060	Yala									0.61
W9-C-1	8060-8090	Yala	0.46								
W9-C-1	8120-8150	Yala	0.42								
W9-C-1	8180-8210	Yala	0.28								0.56
W9-C-1	8240-8270	Yala	0.28								
W9-C-1	8300-8330	Yala	0.25								
W9-C-1	8360-8390	Yala	0.27								0.6
W9-C-1	8420-8450	Yala	0.20								
W9-C-1	8480-8510	Yala	6.22	15.85	29.02	2.93	415	467	47		
W9-C-1	8540-8570	Yala	0.30								0.64
W9-C-1	8600-8630	Yala	0.20								
W9-C-1	8630-8660	Yala	0.19								
W9-C-1	8720-8750	Yala	0.21								0.62
W9-C-1	8780-8810	Yala	0.19								
W9-C-1	8840-8870	Yala	0.34								
W9-C-1	8900-8930	Yala	0.19								0.61
W9-C-1	8960-8990	Yala	0.34								
W9-C-1	9020-9030	Yala	0.30								
W9-C-1	9080-9090	Yala	0.49	0.17	0.64	0.34	427	131	69		0.62
W9-C-1	9140-9150	Yala	0.56	0.14	0.62	0.35	430	111	63		
W9-C-1	9190-9200	Yala	0.25								
W9-C-1	9250-9260	Yala	0.24								0.66
W9-C-1	9310-9320	Yala	1.13	0.37	1.94	0.46	432	172	41		
W9-C-1	9370-9380	Yala	1.16	0.42	2.11	0.64	435	182	55		
W9-C-1	9430-9440	Yala	1.05	0.36	1.77	0.46	434	169	44		0.62
W9-C-1	9490-9500	Yala	1.17	0.41	2.56	0.61	432	219	52		
W9-C-1	9550-9560	Yala	0.53	0.10	0.54	0.41	433	102	77		
W9-C-1	9610-9620	Yala	0.40								0.65
W9-C-1	9670-9680	Yala	0.29								
W9-C-1	9730-9740	Yala	0.28								
W9-C-1	9790-9800	Yala	0.58	0.28	1.26	0.46	427	217	79		0.6

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-C-1	9850-9860	Yala	1.00	0.88	3.53	0.59	422	353	59		
W9-C-1	9910-9920	Yala	0.90	0.88	2.65	0.57	420	294	63		
W9-C-1	9960-9970	Yala	0.31								0.74
W9-D-1	5210	Tai	0.49	0.12	0.58	1.75	433	118	357	0.17	
W9-D-1	5482	Tai	0.40	0.00	0.47	0.46	454	117	115	0.00	
W9-D-1	5512	Tai	0.16	0.00	0.27	0.21	435	168	131	0.00	
W9-D-1	5600	Tai	0.29								
W9-D-1	5633	Tai	0.11	0.01	0.40	0.13	434	363	118	0.02	
W9-D-1	5723	Tai	0.12	0.00	0.38	0.28	402	316	233	0.00	
W9-D-1	5800	Tai	0.27								
W9-D-1	5995	Tai	0.15	0.00	0.42	0.27		280	180	0.00	
W9-D-1	6085	Tai	0.16	0.00	0.41	0.33		256	206	0.00	
W9-D-1	6100	Tai	0.29								
W9-D-1	6236	Tai	0.44	2.90	0.26	0.38		59	86	0.92	
W9-D-1	6266	Tai	0.12	0.00	0.21	0.11		175	91	0.00	
W9-D-1	6300	Tai	0.13								
W9-D-1	6500	Tai	0.30								
W9-D-1	6538	Tai	0.14	0.00	0.26	0.11		185	78	0.00	
W9-D-1	6700	Tai	0.11								
W9-D-1	6900	Ranong	0.31								
W9-D-1	7200	Ranong	0.11								
W9-D-1	7600	Ranong	0.18								
W9-D-1	7800	Ranong	0.22								
W9-D-1	8000	Ranong	0.16								
W9-D-1	8173	Ranong	0.14								
W9-D-1	3910-3920	Trang	0.11								
W9-D-1	4030-4040	Trang	1.50								
W9-D-1	4100-4110	Trang	1.55								0.28
W9-D-1	4200-4210	Trang	0.94								0.3
W9-D-1	5135-5150	Tai	0.18								0.36
W9-D-1	5180-5210	Tai									0.55
W9-D-1	5240-5270	Tai	0.20								
W9-D-1	5300-5330	Tai									0.33
W9-D-1	5360-5390	Tai	0.21								
W9-D-1	5480-5510	Tai	0.31								0.34

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-D-1	5480-5510	Tai									
W9-D-1	5510-5540	Tai									
W9-D-1	5600-5630	Tai	0.26								
W9-D-1	5630-5660	Tai									0.37
W9-D-1	5720-5750	Tai	0.24								
W9-D-1	5810-5840	Tai									0.35
W9-D-1	5840-5870	Tai	0.23								
W9-D-1	5960-5990	Tai	0.21								
W9-D-1	5990-6020	Tai									0.4
W9-D-1	6080-6110	Tai	0.22								
W9-D-1	6080-6110	Tai									0.64
W9-D-1	6170-6200	Tai									0.43
W9-D-1	6200-6230	Tai	0.20								
W9-D-1	6230-6260	Tai									
W9-D-1	6260-6290	Tai									
W9-D-1	6320-6350	Tai	0.20								
W9-D-1	6350-6380	Tai									0.38
W9-D-1	6440-6470	Tai	0.26								
W9-D-1	6530-6560	Tai									0.41
W9-D-1	6560-6590	Tai	0.11								
W9-D-1	6629.8-6632	Tai	0.08								
W9-D-1	6632-6662	Tai	0.12								
W9-D-1	6680-6690	Tai	0.12								
W9-D-1	6710-6720	Tai									0.39
W9-D-1	6800-6830	Tai	0.20								
W9-D-1	6890-6920	Ranong									
W9-D-1	6920-6950	Ranong	0.11								
W9-D-1	7040-7070	Ranong	0.14								
W9-D-1	7070-7100	Ranong									
W9-D-1	7130-7160	Ranong	0.12								
W9-D-1	7250-7280	Ranong	0.14								0.51
W9-D-1	7350-7400	Ranong	0.13								
W9-D-1	7430-7460	Ranong									0.5
W9-D-1	7490-7520	Ranong	0.17								
W9-D-1	7610-7640	Ranong	0.17								0.61

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-D-1	7760-7780	Ranong	0.17								
W9-D-1	7780-7800	Ranong									0.67
W9-D-1	7880-7900	Ranong	0.21								
W9-D-1	7960-7980	Ranong									0.61
W9-D-1	8000-8020	Ranong	0.41								
W9-D-1	8060-8070	Ranong	0.12								
W9-D-1	8120-8130	Ranong	0.08								
W9-D-1	8140-8150	Ranong									
W9-D-1	8160-8171	Ranong	0.09								
W9-E-1	5900	Trang	1.17								
W9-E-1	6600	Kantang	1.07								
W9-E-1	6800	Kantang	0.65								
W9-E-1	7000	Kantang	0.57								
W9-E-1	7200	Yala	0.61								
W9-E-1	7400	Yala	0.63								
W9-E-1	7700	Yala	0.42								
W9-E-1	8000	Yala	0.36								
W9-E-1	8200	Yala	0.50								
W9-E-1	8500	Yala	0.33								
W9-E-1	8800	Yala	0.42								
W9-E-1	9200	Yala	0.49								
W9-E-1	9300	Yala	0.51								
W9-E-1	9700	Yala	0.66								
W9-E-1	9757	Yala	0.57	0.00	0.11	0.00		19	0	0.00	
W9-E-1	9900	Yala	0.77								
W9-E-1	10199	Yala	0.57	0.07	1.14	0.41	440	200	71	0.06	
W9-E-1	10200	Yala	0.81								
W9-E-1	10300	Yala	0.54								
W9-E-1	10500	Yala	0.51								
W9-E-1	10700	Yala	0.70								
W9-E-1	10843	Yala	0.65	0.04	0.55	0.71	441	84	109	0.07	
W9-E-1	10853	Yala	0.59	0.04	0.93	0.36	442	157	61	0.04	
W9-E-1	10863	Yala	0.53	0.03	0.55	0.30	442	103	56	0.05	
W9-E-1	11000	Yala	0.79								
W9-E-1	11064	Yala	0.55	0.06	0.72	0.33	439	130	60	0.08	

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-E-1	11300	Yala	0.83								
W9-E-1	11600	Yala	0.72								
W9-E-1	11738	Yala	0.39	0.03	0.42	0.13	441	107	33	0.07	
W9-E-1	11748	Yala	0.34	0.07	0.29	0.11	444	85	32	0.19	
W9-E-1	11869	Yala	0.28	0.17	0.15	0.11	445	53	39	0.53	
W9-E-1	11900	Yala	0.40								
W9-E-1	12100	Yala	0.24	0.00	0.16	0.11	443	66	45	0.00	
W9-E-1	12200	Yala	0.36								
W9-E-1	12221	Yala	0.25	0.03	0.12	0.29	445	48	116	0.20	
W9-E-1	12241	Yala	0.25	0.01	0.10	0.25	454	40	100	0.09	
W9-E-1	12322	Yala	0.30	0.02	0.16	0.26	449	53	86	0.11	
W9-E-1	12400	Yala	0.52								
W9-E-1	12600	Yala	0.67								
W9-E-1	12757	Yala	1.06								
W9-E-1	12800	Yala	0.86								
W9-E-1	13000	Yala	0.83								
W9-E-1	13080	Yala	0.73								
W9-E-1	13300	Yala	0.43								
W9-E-1	13498	Yala	0.25	0.02	0.13	0.26	448	52	104	0.13	
W9-E-1	13500	Yala	0.60								
W9-E-1	13579	Yala	0.24	0.02	0.07	0.19		29	79	0.22	
W9-E-1	13700	Yala	0.74								
W9-E-1	13900	Yala	0.23								
W9-E-1	10020-10030	Yala	0.88	0.14	1.47	0.69	438	167	78		0.59
W9-E-1	10080-10090	Yala	0.63	0.07	0.40	0.37	437	63	59		
W9-E-1	10140-10150	Yala	0.70	0.10	0.72	0.43	436	103	61		
W9-E-1	10200-10210	Yala	1.05	0.17	1.38	0.49	434	131	47		0.57
W9-E-1	10260-10270	Yala	0.40								
W9-E-1	10320-10330	Yala	0.70	0.13	0.74	0.41	434	106	59		
W9-E-1	10380-10390	Yala	0.59	0.06	0.27	0.53	437	46	90		0.62
W9-E-1	10440-10450	Yala	0.43								
W9-E-1	10500-10510	Yala	0.53								
W9-E-1	10560-10570	Yala	0.72	0.14	0.96	0.32	442	133.4	44		0.59
W9-E-1	10620-10630	Yala	0.77	0.13	0.60	0.51	440	78	66		
W9-E-1	10650-10660	Yala	0.82	0.20	1.16	0.43	438	141	52		

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-E-1	10740-10750	Yala	0.77	0.15	1.04	0.33	437	135	43		
W9-E-1	10800-10810	Yala	0.83	0.20	1.22	0.31	439	147	37		0.6
W9-E-1	10860-10870	Yala	0.78	0.07	0.27	0.78	443	35	100		
W9-E-1	10920-10930	Yala	0.98	0.15	1.20	0.38	439	122	39		
W9-E-1	10980-10990	Yala	0.76	0.10	0.76	0.41	439	100	54		0.61
W9-E-1	11040-11050	Yala	1.02	0.23	1.44	0.23	441	141	23		
W9-E-1	11100-11110	Yala	0.73	0.20	0.99	0.22	442	136	30		
W9-E-1	11160-11170	Yala	0.90	0.19	1.23	0.19	440	137	21		0.61
W9-E-1	11220-11230	Yala	0.94	0.19	1.24	0.23	442	132	24		
W9-E-1	11280-11290	Yala	0.90	0.19	1.07	0.15	441	119	17		
W9-E-1	11340-11350	Yala	0.93	0.25	1.39	0.25	442	149	27		0.58
W9-E-1	11400-11410	Yala	0.92	0.16	0.87	0.34	440	95	37		
W9-E-1	11460-11470	Yala	0.86	0.18	0.99	0.14	441	115	16		
W9-E-1	11520-11530	Yala	0.73	0.23	1.04	0.17	440	142	23		0.66
W9-E-1	11580-11590	Yala	0.77	0.17	0.72	0.22	443	94	29		
W9-E-1	11640-11650	Yala	0.70	0.17	0.79	0.15	441	113	21		
W9-E-1	11670-11680	Yala	0.72								0.5
W9-E-1	11700-11710	Yala	0.70	0.19	0.88	0.16	438	126	23		0.63
W9-E-1	11760-11770	Yala	0.51								
W9-E-1	11790-11800	Yala	0.40								0.54
W9-E-1	11820-11830	Yala	0.39								
W9-E-1	11880-11890	Yala	0.39								0.59
W9-E-1	11940-11950	Yala	0.48								
W9-E-1	12000-12010	Yala	0.39								
W9-E-1	12060-12070	Yala	0.48								0.59
W9-E-1	12120-12130	Yala	0.36								
W9-E-1	12160-12170	Yala	0.36								0.57
W9-E-1	12180-12190	Yala	0.46								
W9-E-1	12240-12250	Yala	0.46								0.65
W9-E-1	12240-12250	Yala	0.36								0.58
W9-E-1	12300-12310	Yala	0.60	0.13	0.53	0.18	439	88	30		
W9-E-1	12360-12370	Yala	0.51								
W9-E-1	12420-12430	Yala	0.51								0.64
W9-E-1	12480-12490	Yala	0.53								
W9-E-1	12497-12540	Yala	0.18	0.07	0.04	0.60	442	22	333		

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-E-1	12540-12550	Yala	0.68	0.19	0.76	0.18	437	112	26		
W9-E-1	12600-12610	Yala	0.60	0.15	0.62	0.15	439	103	25		0.62
W9-E-1	12660-12670	Yala	0.73	0.18	0.87	0.26	439	119	36		
W9-E-1	12713-12721	Yala	0.13	0.12	0.30	0.36	372	231	277		
W9-E-1	12720-12730	Yala	0.57								
W9-E-1	12721-12735	Yala	0.12	0.12	0.06	0.51	427	50	425		
W9-E-1	12735-12745.5	Yala	0.15	0.10	0.06	0.37	390	40	247		
W9-E-1	2745.5-12746	Yala	0.80	0.34	0.37	0.21	447	46	26		0.82
W9-E-1	12746.8-12749	Yala	5.47	1.01	3.36	1.25	426	61	23		
W9-E-1	12749-12750.5	Yala	0.79	0.23	0.33	0.17	448	42	22		
W9-E-1	12750.5-12754	Yala	0.71	0.29	0.38	0.17	446	54	24		
W9-E-1	12754-12755	Yala	2.65	0.58	1.63	0.64	448	62	24		0.93
W9-E-1	12755-12758	Yala	0.91	0.33	0.79	0.17	453	87	19		
W9-E-1	12758-12780	Yala	0.86	0.45	0.76	0.26	449	88	30		0.88
W9-E-1	12780-12790	Yala	0.78	0.18	0.77	0.25	443	99	32		0.92
W9-E-1	12840-12850	Yala	0.42								
W9-E-1	12900-12910	Yala	0.82	0.22	0.86	0.12	445	105	15		
W9-E-1	12960-12970	Yala	0.49								0.88
W9-E-1	13020-13030	Yala	0.61	0.14	0.41	0.12	444	67	20		
W9-E-1	13080-13090	Yala	0.58	0.16	0.38	0.31	442	66	53		
W9-E-1	13140-13150	Yala	0.60	0.23	0.39	0.28	446	65	47		0.89
W9-E-1	13200-13210	Yala	0.97	1.15	1.54	2.37	430	159	244		
W9-E-1	13260-13270	Yala	0.60	0.15	0.24	0.31	453	40	52		
W9-E-1	13320-13330	Yala	0.52								0.62
W9-E-1	13380-13390	Yala	0.49								
W9-E-1	13410-13420	Yala	0.43								0.61
W9-E-1	13440-13450	Yala	0.38								
W9-E-1	13490-13500	Yala	0.60								0.59
W9-E-1	13500-13510	Yala	0.36								0.94
W9-E-1	13560-13570	Yala	0.22								
W9-E-1	13620-13630	Yala	0.15								
W9-E-1	13680-13690	Yala	0.30								1.07
W9-E-1	13740-13750	Yala	0.24								
W9-E-1	13800-13810	Yala	0.24								
W9-E-1	13860-13870	Yala	0.18								1.64

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-E-1	13920-13930	Yala	0.18								
W9-E-1	13980-13990	Yala	0.20								
W9-E-1	14020-14030	Yala	0.31								1.6
W9-E-1	4790-4820	Thalang	0.92	0.16	0.55	1.47	413	60	160		0.31
W9-E-1	4910-4940	Thalang	0.64	0.16	0.58	1.58	414	91	247		
W9-E-1	4970-5000	Thalang									0.39
W9-E-1	5120-5150	Thalang	0.47								
W9-E-1	5150-5180	Thalang									0.36
W9-E-1	5240-5270	Trang	0.47								
W9-E-1	5330-5360	Trang									0.34
W9-E-1	5360-5390	Trang	0.69	0.08	0.21	1.13	440	30	164		
W9-E-1	5480-5510	Trang	0.54								
W9-E-1	5510-5540	Trang									0.34
W9-E-1	5600-5630	Trang	0.98	0.17	1.07	0.91	427	109	93		
W9-E-1	5690-5720	Trang									0.38
W9-E-1	5720-5750	Trang	1.11	0.29	2.37	1.02	421	214	92		
W9-E-1	5840-5870	Trang	0.68	0.09	0.14	0.68	428	21	100		
W9-E-1	5870-5900	Trang									0.36
W9-E-1	5960-5990	Trang	0.91	0.16	1.21	0.83	430	133	91		
W9-E-1	6050-6080	Kantang									0.34
W9-E-1	6080-6110	Kantang	0.60	0.05	0.14	0.67	422	23	112		
W9-E-1	6200-6230	Kantang	0.90	0.13	0.94	0.78	431	104	87		
W9-E-1	6230-6260	Kantang									0.37
W9-E-1	6320-6350	Kantang	0.93	0.18	1.52	0.76	432	163	82		
W9-E-1	6410-6440	Kantang									0.37
W9-E-1	6440-6470	Kantang	0.78	0.08	0.17	0.87	424	22	112		
W9-E-1	6560-6590	Kantang	1.00	0.18	1.42	0.76	427	142	76		
W9-E-1	6590-6620	Kantang									0.38
W9-E-1	6680-6710	Kantang	0.76	0.14	0.74	0.77	430	97	101		
W9-E-1	6765-6800	Kantang									0.38
W9-E-1	6800-6830	Kantang	0.55								
W9-E-1	6920-6950	Kantang	0.42								
W9-E-1	6950-6980	Kantang									0.42
W9-E-1	7040-7070	Kantang	0.37								
W9-E-1	7130-7160	Yala									0.44

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-E-1	7160-7190	Yala	0.45								
W9-E-1	7280-7310	Yala	0.67	0.14	0.70	0.97	430	104	145		
W9-E-1	7310-7340	Yala									0.4
W9-E-1	7400-7430	Yala	2.52	0.19	1.89	2.93	431	75	116		
W9-E-1	7490-7520	Yala									0.38
W9-E-1	7520-7550	Yala	0.60	0.10	0.44	0.52	429	73	87		
W9-E-1	7640-7670	Yala	0.17								
W9-E-1	7670-7700	Yala									0.48
W9-E-1	7760-7790	Yala	0.51								
W9-E-1	7850-7880	Yala									0.42
W9-E-1	7880-7910	Yala	0.47								
W9-E-1	8000-8020	Yala	0.13								
W9-E-1	8050-8080	Yala	0.46								0.52
W9-E-1	8110-8140	Yala	0.50								
W9-E-1	8170-8200	Yala	0.74	0.09	0.35	0.58	431	47	78		
W9-E-1	8230-8260	Yala	2.27	0.31	2.78	2.14	433	122	94		0.32
W9-E-1	8290-8320	Yala	0.52								
W9-E-1	8350-8380	Yala	0.70	0.10	0.43	0.72	429	61	103		
W9-E-1	8410-8440	Yala	0.37								0.49
W9-E-1	8470-8500	Yala	0.26								
W9-E-1	8530-8560	Yala	0.28								
W9-E-1	8590-8620	Yala	0.26								0.53
W9-E-1	8650-8680	Yala	0.32								
W9-E-1	8710-8740	Yala	0.30								
W9-E-1	8770-8800	Yala	0.23								0.46
W9-E-1	8830-8860	Yala	0.20								
W9-E-1	8890-8920	Yala	0.36								
W9-E-1	8950-8980	Yala	0.40								0.42
W9-E-1	9010-9040	Yala	0.76	0.06	0.21	0.71	429	28	93		
W9-E-1	9070-9100	Yala	0.73	0.14	0.74	0.77	431	101	105		
W9-E-1	9130-9160	Yala	0.49								0.46
W9-E-1	9190-9220	Yala	0.65	0.13	0.77	0.43	432	118	66		
W9-E-1	9250-9270	Yala	0.34								
W9-E-1	9300-9330	Yala	0.52								0.34
W9-E-1	9360-9390	Yala	1.13	0.15	1.39	0.56	434	123	50		

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
W9-E-1	9420-9450	Yala	0.61	0.12	0.45	0.51	431	74	84		
W9-E-1	9480-9510	Yala	0.55								0.59
W9-E-1	9540-9570	Yala	0.59	0.12	0.79	0.59	433	134	100		
W9-E-1	9600-9630	Yala	0.78	0.19	1.48	0.51	433	190	65		
W9-E-1	9660-9670	Yala	0.65	0.16	1.28	0.34	438	197	52		0.35
W9-E-1	9720-9730	Yala	0.79	0.15	1.41	0.56	438	178	71		
W9-E-1	9780-9790	Yala	0.49								
W9-E-1	9840-9850	Yala	1.25	0.35	3.23	0.62	434	258	50		0.44
W9-E-1	9900-9910	Yala	1.72	0.75	5.87	0.86	434	341	50		
W9-E-1	9960-9970	Yala	1.17	0.25	1.88	0.83	437	161	71		
Yala-1	3564-3570	Thalang	2.80	68.02	3.91	3.62	342	140	129	0.95	
Yala-1	3570-3600	Thalang	2.46								
Yala-1	3600-3630	Thalang	3.43								
Yala-1	3630-3660	Thalang	2.92								
Yala-1	3660-3690	Thalang	3.02								
Yala-1	3690-3720	Thalang	3.33	53.89	6.41	1.46	359	192	44	0.89	
Yala-1	3720-3750	Thalang	3.19								
Yala-1	3750-3780	Thalang	2.90								
Yala-1	3780-3810	Thalang	2.76								0.28
Yala-1	3810-3840	Thalang	2.71	32.56	4.47	1.84	379	165	68	0.88	
Yala-1	3840-3870	Thalang	1.81								
Yala-1	3870-3900	Thalang	1.45								
Yala-1	3900-3930	Thalang	1.47								
Yala-1	3930-3960	Thalang	2.05	14.91	3.21	1.36	356	157	66	0.82	
Yala-1	3960-3990	Thalang	1.61								
Yala-1	3990-4020	Thalang	1.65								
Yala-1	4020-4050	Thalang	1.64								
Yala-1	4050-4080	Thalang	2.40	26.08	5.26	1.30	397	219	54	0.83	0.24
Yala-1	4080-4110	Surin	1.14								
Yala-1	4110-4140	Surin	0.59				341	119			
Yala-1	4140-4170	Surin	0.48								
Yala-1	4170-4200	Surin	0.45								
Yala-1	4200-4230	Surin	0.46								
Yala-1	4230-4260	Surin	0.26								0.27
Yala-1	4260-4290	Surin	2.01				353	175			

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Yala-1	4290-4320	Surin	3.18								
Yala-1	4320-4350	Surin	2.23								
Yala-1	4350-4380	Surin	1.91								
Yala-1	4380-4410	Surin	2.25				405	210			
Yala-1	4410-4440	Surin	3.09								
Yala-1	4440-4470	Surin	2.67	28.37	4.10	2.85	377	154	107	0.87	
Yala-1	4470-4500	Tai	1.79								
Yala-1	4500-4530	Tai	2.57								0.25
Yala-1	4530-4560	Tai	2.75	67.35	7.41	1.48	405	269	54	0.90	
Yala-1	4560-4590	Tai	2.66								
Yala-1	4590-4620	Tai	1.48								
Yala-1	4620-4650	Tai	2.76								
Yala-1	4650-4680	Tai	2.75	53.41	6.33	1.64	422	230	60	0.89	
Yala-1	4680-4710	Tai	0.99								
Yala-1	4710-4740	Tai	0.67								
Yala-1	4740-4770	Tai	0.42	1.08	0.82	0.72	420	195	171	0.57	
Yala-1	4770-4800	Tai	0.29								0.3
Yala-1	4800-4830	Tai	0.30								
Yala-1	4830-4860	Tai	0.13								
Yala-1	4860-4890	Tai	0.20								
Yala-1	4890-4920	Tai	0.17								
Yala-1	4950-4980	Tai	0.14								0.31
Yala-1	4980-5010	Tai	0.28								
Yala-1	5010-5040	Tai	0.19								
Yala-1	5040-5070	Tai	0.19								
Yala-1	5070-5100	Tai	0.12								
Yala-1	5100-5130	Tai	0.10								
Yala-1	5130-5160	Tai	0.09								
Yala-1	5160-5190	Tai	0.12								
Yala-1	5190-5220	Tai	0.10								
Yala-1	5220-5250	Tai	0.09								0.21
Yala-1	5250-5280	Tai	0.46	0.39	0.24	1.13	403	52	246	0.62	
Yala-1	5280-5310	Tai	0.20								
Yala-1	5310-5340	Tai	0.13								
Yala-1	5340-5370	Tai	0.17								

Summary of source rock property from previous works.

Well	Depth (ft)	Formation	TOC	S1	S2	S3	Tmax	HI	OI	PI	Ro
Yala-1	5370-5400	Tai	0.06								
Yala-1	5400-5430	Tai	0.09								
Yala-1	5469-5480	Tai	0.13								
Yala-1	5480-5490	Tai	0.26								
Yala-1	5490-5520	Tai	0.30								
Yala-1	5520-5550	Tai	0.16								
Yala-1	5550-5580	Tai	0.10								
Yala-1	5580-5610	Tai	0.08								
Yala-1	5610-5640	Tai	0.16								
Yala-1	5640-5670	Tai	0.10								
Yala-1	5670-5700	Tai	0.16								
Yala-1	5700-5730	Tai	0.10								
Yala-1	5730-5760	Tai	0.15								
Yala-1	5760-5781	Tai	0.11								

BIOGRAPHY

Mr. Nattawat Chaardee was born in Bangkok in 1980, he studied at Princess Chulabhorn's College for the pre-university education in Satun from 1994 to 1996. He graduated in Bachelor of Sciences of Geology from Chiang Mai University in 2003. After graduation, he worked for the Department of Groundwater Resources, in 2004, and the Department of Mineral Resources, in 2005-2006. He has studied in Master of Sciences of Geology at Chulalongkorn University since 2006 and now he is working as a geologist for the Department of Mineral Fuels.