SEDIMENTARY FACIES ANALYSIS AND EVOLUTION OF SAN SAI OIL FIELD, FANG BASIN

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การวิเคราะห์ลักษณะปรากฏของตะกอนและวิวัฒนาการของแหล่งน้ำมันสันทราย แอ่งฝาง

นายพีระวัฒน์ คงอุไร

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต

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Suranaree University of Technology has approved this thesis submitted in partial fulfillment of the requirements for a Master's Degree.

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พีระวัฒน์ คงอุไร : การวิเคราะห์ลักษณะปรากฏของตะกอนและวิวัฒนาการของแหล่งน้ำมันสันทราย แอ่งฝาง (SEDIMENTARY FACIES ANALYSIS AND EVOLUTION OF SAN SAI OIL FIELD, FANG BASIN) อาจารย์ที่ปรึกษา : อาจารย์ ดร.จงพันธ์ จงลักษมณี, 87 หน้า.

แอ่งฝางเป็นแอ่งตะกอนที่มีการค้นพบน้ำมันดิบเป็นแห่งแรกของประเทศไทย ที่ยังคงมีการสำรวจและผลิตจนถึงปัจจุบันภายใต้การบริหารจัดการ โดยกรมพลังงานทหาร กระทรวงกลาโหม แอ่งฝางตั้งอยู่ในอำเภอฝาง จังหวัดเชียงใหม่ ภาคเหนือของประเทศไทยใกล้กับชายแดน ไทย-พม่า แหล่งน้ำมันสันทราย เป็นหนึ่งในแหล่งน้ำมันที่สำคัญในแอ่งฝาง ลักษณะตะกอนปรากฏและวิวัฒนาการการสะสมตัวของแอ่งตะกอน ได้จากการศึกษาข้อมูลหลุมเจาะ และการแปลความหมายคลื่นไหวสะเทือนแบบสองมิติผ่านโปรแกรม Petrel2011 อายุชั้นตะกอนได้จากการวิเคราะห์การลำดับชั้นทางชีวภาพ ผลการศึกษาแสดงให้เห็นว่าแอ่งฝางเกิดจากการทรุดตัวในลักษณะกึ่งกราเบ็น (half-graben) ตอนปลายของสมัยอีโอซีนจากการเคลื่อนที่ของแผ่นเปลือกโลกระดับภูมิภาค และมีการสะสมตัวของตะกอนบนพื้นทวีปทั้งหมด โดยตะกอนมีความหนาเพิ่มมากขึ้นทางทิศตะวันตกเข้าหาแนวรอยเลื่อน ซึ่งสามารถแบ่งออกได้เป็นสองหมวดหินหลักและห้าสภาวะแวดล้อมของการสะสมตะกอน โดยมีหมวดหินแม่ฝาง (อายุไพลสโตซีนถึงปัจจุบัน) มีความหนาประมาณ 2,500 ฟุต ประกอบไปด้วยตะกอนดินปัจจุบัน ดินเหนียว หินทรายเม็ดขนาดหยาบถึงหยาบมาก กรวด และซากไม้ เป็นการสะสมตัวของตะกอนลำน้ำวางตัวไม่ต่อเนื่องอยู่บนหมวดหินแม่สอด และหมวดหินแม่สอดนี้วางตัวไม่ต่อเนื่องอยู่บนหินฐานรากอายุก่อนเทอร์เชียรี่ หมวดหินแม่สอดสามารถแบ่งออกเป็นสามส่วนและจำแนกสภาวะแวดล้อมในการสะสมตัวออกเป็นสี่สภาวะแวดล้อม การสะสมตัวของหมวดหินแม่สอดตอนบนสามารถแบ่งออกเป็นสองสภาวะแวดล้อม ซึ่งทำหน้าที่เป็นชั้นหินกักเก็บและชั้นหินปิดกั้นปิโตรเลียม ส่วนบนมีความหนาประมาณ 1,400 ฟุต พบชั้นหินดินดานแทรกสลับกับหินทรายเม็ดขนาดปานกลางถึงหยาบมาก เป็นการสะสมตัวแบบชายฝั่งทะเลสาบน้ำจืด (อายุไมโอซีนตอนปลายถึงไพลโอซีน) และส่วนล่างมีความหนาประมาณ 1,000 ฟุต พบหินดินดานหนาและหินทรายเม็ดขนาดละเอียดแทรก เป็นตะกอนจากทะเลสาบน้ำตื้นถึงทะเลสาบน้ำลึก (อายุตอนต้นของไมโอซีนตอนปลาย) หมวดหินแม่สอดตอนกลาง มีความหนาประมาณ 800 ฟุต ประกอบด้วยหินดินดานสีเทาเข้ม หินทรายเม็ดขนาดละเอียดและถ่านหิน มีลักษณะการสะสมตะกอนจากทะเลสาบน้ำลึกและชายฝั่งทะเลสาบ (อายุโอลิโกซีน) โดยชั้นหินนี้ทำหน้าที่เป็นหินต้นกำเนิดปิโตรเลียม และหมวดหินแม่สอดตอนล่าง มีความหนาประมาณ 2,500 ฟุต พบชั้นหินดินดานหนา และพบหินทรายแทรกสลับกับชั้นถ่านหินในส่วนล่าง ตะกอนเป็นลักษณะชายฝั่งเลสาบน้ำจืด

(อายุอีโอซีนตอนปลายหรือแก่กว่า) ผลการวิเคราะห์คุณสมบัติของหินต้นกำเนิดปิโตรเลียม เช่น ค่าปริมาณคาร์บอนอินทรีย์ทั้งหมด (TOC) ค่าแสงสะท้อนจากวิตทริไนต์ (%Ro) ผลการวิเคราะห์ rock-eval pyrolysis และ headspace gas และผลการศึกษารูปแบบจำลองการสุกบ่มของหินต้นกำเนิดโดยใช้โปรแกรม PetroMod1D พบว่าระดับความลึกที่หินต้นกำเนิดปิโตรเลียมประกอบด้วยเคอโรเจนชนิดที่ II และ III โดยมีค่า ปริมาณคาร์บอนอินทรีย์ทั้งหมด 1.78 – 3.13 %wt ซึ่งมีความสุกบ่มที่เหมาะสมให้น้ำมันเป็นส่วนมากอยู่ที่ระดับ 5,600 – 6,700 ฟุต ส่วนหินต้นกำเนิดที่ประกอบไปด้วยเคอโรเจนชนิดที่ II และ III โดยมีค่าปริมาณคาร์บอนอินทรีย์ทั้งหมด 2.07 – 39.07% ในระดับที่ต่ำกว่า 6,700 ฟุต มีความสุกบ่มเหมาะสมถึงสุกบ่มตอนปลาย จึงให้ก๊าซเป็นส่วนมาก ตามแบบจำลอง TTI จากโปรแกรม PetroMod11.1D พบว่าการปิโตรเลียมเกิดขึ้นในสมัยไมโอซีนซีนตอนกลาง ไปสะสมตัวในชั้นหินกักเก็บผ่านตามรอยแตกหรือรอยเลื่อนของหินที่ระดับความลึกประมาณ 2,900 – 4,000 ฟุต

สาขาวิชา <u>เทคโนโลยีธรณี</u> ลายมือชื่อนักศึกษา ฝีระวัฒน์ ดาบุไร

ปีการศึกษา 2556 ลายมือชื่ออาจารย์ที่ปรึกษา ผศ.ดร.อ. เหล็กเสือ

PEERAWAT KONGURAI : SEDIMENTARY FACIES ANALYSIS AND EVOLUTION OF SAN SAI OIL FIELD, FANG BASIN. THESIS ADVISOR : CHONGPHAN CHONGLAKMANI, Ph.D., 87 PP.

FANG BASIN/SEDIMENTARY FACIES/BASIN ANALYSIS/SOURCE ROCK /MATURITY/MIGRATION PATHWAY

Fang oil field was the first discovered field in Thailand and has been operated till today by the Defense Energy Department, Ministry of Defense. Fang basin is located in Fang district, Chiang Mai province of northern Thailand near Thai-Myanmar border. The San Sai oil field is an important oil field in the Fang basin. The sedimentary facies and basin evolution have been complied by well data incorporated with 2D seismic profiles which have been interpreted using Petrel2011 software. The age of sediments is based on the result of biostratigraphic analysis. The study indicates that the Fang basin was subsided as a half-graben in the Late Eocene by regional plate tectonism and the deposit is composed entirely of continental sediments. The deposit is thicker westward toward the major fault. The sedimentary sequence of the Fang basin can be subdivided into two formations which comprise five associated depositional environments. The Mae Fang Formation (Pleistocene to Recent), 2,500 feet thick, is composed mainly of clay, coarse- to very coarse-grained sandstones, gravel and carbonized woods which were deposited in fluvial environment. It overlies unconformably on the Mae Sod Formation. The Mae Sod Formation, overlying unconformably on pre-Tertiary basement, can be divided into three parts which comprise four depositional environments. The upper Mae Sod Formation is divided into two environments and represents the reservoir rocks and traps. The upper part, 1,400 feet thick, is composed mainly of shale interbedded with medium- to very coarse-grained sandstones. It represents a marginal lacustrine environment (Late Miocene to Pliocene in age). The lower part, ranging up to 1,000 feet, is composed mainly of thick shale interbedded with fine-grained sandstone. It indicates a shallow to deep lacustrine environment (Early Late Miocene in age). The middle Mae Sod Formation, 800 feet in thickness, is composed mainly of dark grey shale, fine-grained sandstone and coal. It indicates a marginal and deep lacustrine environment (Oligocene in age). These strata are the main source rocks for petroleum. The lower Mae Sod Formation, 2,500 feet thick, comprises mainly thick shale and sandstone interbedded with coal in the lower part. It indicates a marginal lacustrine environment (Late Eocene in age). The results of total organic carbon content (TOC), vitrinnite reflectance (%Ro), Rock-Eval pyrolysis and headspace gas analyses and the study of basin modeling using PetroMod1D software are compiled and interpreted. They indicate that source rocks of kerogen type II and III with 1.78 – 3.13 %wt. TOC are mature and generate mainly oil at 5,600 – 6,700 feet deep. Source rocks of kerogen type II and III with 2.07 – 39.07 %wt. TOC locating deeper than 6,700 feet are mature to late mature and generate mainly gas at this level. According to TTI modeling by using PetroMod11.1D software hydrocarbon generated took place in the Middle Miocene through fractures or faults to accumulate in traps at 2,900-4,000 feet deep.

School of Geotechnology Student's Signature__________

Acdemic Year 2013 Advisor's Signature__________

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CHAPTER I

INTRODUCTION

The energy is an important factor in the life of human being. It is also an important factor for country development and economic growth. Thailand has imported a lot of petroleum for higher domestic demand of energy. Reliance on domestic energy is necessary. Therefore, exploration for new energy sources is a high priority for the energy security of the country.

The study of sedimentary rocks is important for petroleum, many of metals and minerals resources because most of them are discovered from sedimentary rocks. To understand the occurrence of petroleum, the study of sedimentary basin, basin analysis its product and the subsidence history, must be carried out. In Thailand hydrocarbons are found in pre-Tertiary and Tertiary basins. Pre-Tertiary basins include the Khorat Plateau and its vicinity. Tertiary basins can be found both on shore and off shore including northern intermontane basins, the central plain, the Gulf of Thailand and the Andaman Sea. Most of the Tertiary basins began to accumulate sediments in the Oligocene. Most of deposits are non-marine environment except the Andaman Sea sediments are marine. The depositional basins accumulated on the continental environment include Fang Basin, Phitsanulok Basin, Phetchabun Basin, Suphanburi Basin, Kamphaeng Saen Basin, Chumphon Basin, Pattani Basin and Malay Basin. Crude oils are found in the first six basins, and last 2 basins found natural gas and condensate are found in the last two.

The occurrence of petroleum depends on five important factors including petroleum source rock, reservoir rock, migration pathway, trap and seal. The rock types have different characteristics and properties depending on the environment of deposition, structural style and petrifaction. This rock mass with distinctive characteristics is also known as facies. The study of sedimentary facies and basin analysis are the key to understand the origin of petroleum.

1.1 Study area

The Fang Basin is located in Chiang Mai province, northern Thailand. The basin is an intermontane basin. The basin lies near the Myanmar border approximately 18 kilometers wide and 60 kilometers long. It has a half-graben geometry (Sethakul, 1985) and is bounded on the west by a curved east-dipping fault which, at the north end of the basin, turns into the Mae Chan Fault which trends ENE-WSW and has a strike-slip sense of motion. The average elevation of the mountains is about 1,400 meters above the mean sea level. The area of San Sai oil field is approximately 1.7 square kilometers. The study area is covered about 22 square kilometers at position in UTM datum wgs84 system 515473 – 524177 N and 2196042 – 2201293 E as shown in Figure 1.1.

1.2 Research objectives

The objectives of this study are as follows;

1. To classify the stratigraphic sequences and to establish the depositional environment of the San Sai oil field.

2. To conduct the basin analysis in order to understand the structural,

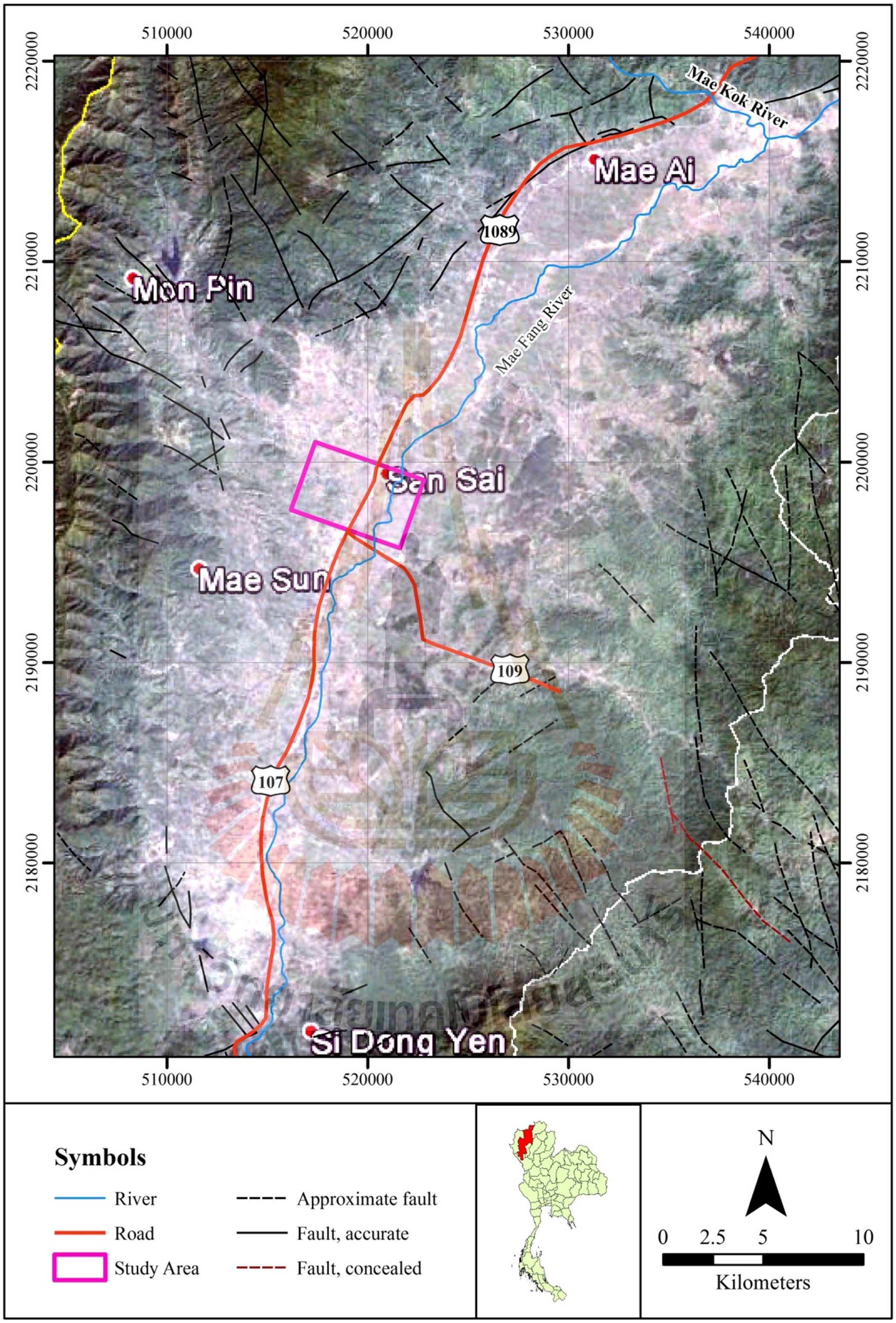

Figure 1.1 Study area in San Sai oil field, Fang Basin.

sedimentation and petroleum evolution.

3. To evaluate petroleum potential of the San Sai oil field.

1. 3 Scope and limitation of the study

The study is focused mainly on stratigraphy, sedimentary facies, basin evolution and petroleum potential of the San Sai oil field in the Fang Basin. This research uses the subsurface data including lithological logs, wireline logs, 2D seismic profiles stratigraphic reports of selected wells in the San Sai oil field. Geochemical laboratory test of rock samples is provided by the Thai Defence Energy Department.

1.4 Research methodology

Research strategies and activities will be performed as followings:

1. Relevant literature will be searched, reviewed, summarized and documented.

2. Subsurface data including wireline logging, lithological logging, geochemical and biostratigraphic analyses in the Fang Basin will be interpreted.

3. Interpretation of 2D seismic profiles.

4. Basin analysis to study hydrocarbon generation and timing, maturity of potential source rocks and migration paths of expelled hydrocarbons will be performed.

5. Petrel2011, Petromod11.1D and ArcGIS softwares will be used in this study.

1.5 Benefits of study

The expected results will lead to the understanding of basin evolution, depositional system, sedimentary facies, structural geology and source rock potential of the San Sai oil field of the Fang basin. The results will clarify more about the nature of petroleum system in terms of source rock and reservoir facies and the oil reserve which can be used for petroleum exploration in the future.

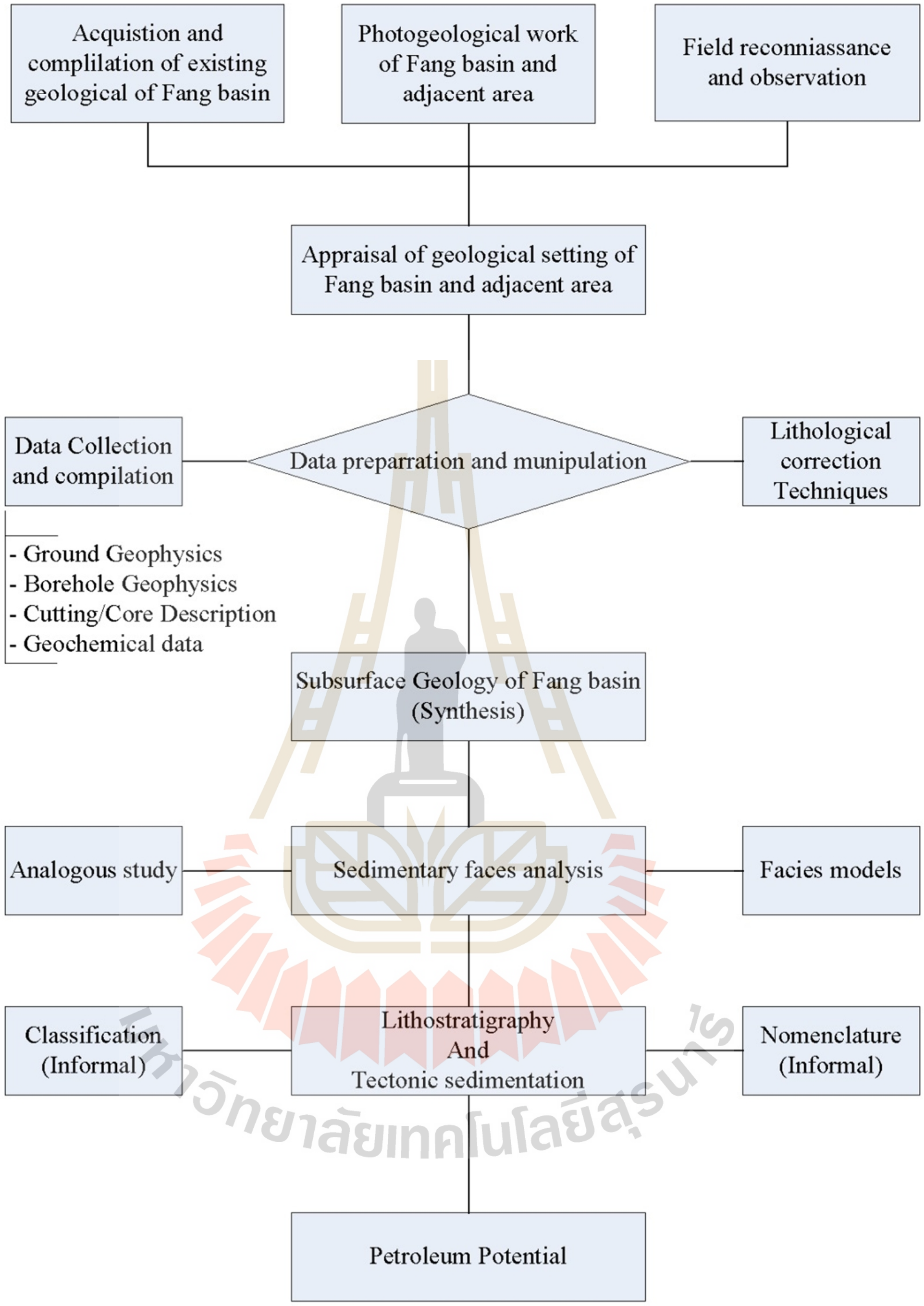

Figure 1.2 Flow-chart illustrating the methodology and steps of work in the analysis of San Sai oil field, Fang Basin.

CHAPTER II

LITERATURE REVIEW

2.1 Geological setting of the Fang Basin

Thailand has over 60 Tertiary basins distributed in various parts, both onshore and offshore. These basins are mainly N-S trending half grabens and most were initiated in the Late Oligocene. These are often 15 - 18 kilometers wide.

The Fang Basin is one of the Cenozoic intermontane basins of northern Thailand (figure 2.1). The central lowland is mostly flat. This flat terrain is the flood plain of approximately 1 to 3 kilometers wide, extending on both sides of the Mae Fang (also called Nam Fang) river. However, in the central part of the basin the flood plain increases in width to 6 kilometers. This flood plain as well as the basin is bisected by a longitudinal trunk stream, the Mae Fang River, which more or less meanders with amplitude often less than 250 meters, to 500 meters and about 90 kilometers long. It can be classified as meandering river with the sinuosity about 1.7 according to channel classification of Miall (1982). This stream is almost not more than 10 meters wide and drains north-northeast to the Mae Kok River, a tributary of the Mae Khong River. Beyond the central lowland, the area is occupied by many hills up to 120 meters high above the lowland. It seems likely that at least one level terrace has been developed in the basin. These hills are also dissected by many small transverse tributaries of the Mae Fang River. Towards the border area, the basin is bounded by relatively high mountains. On the western and the southern sides of the

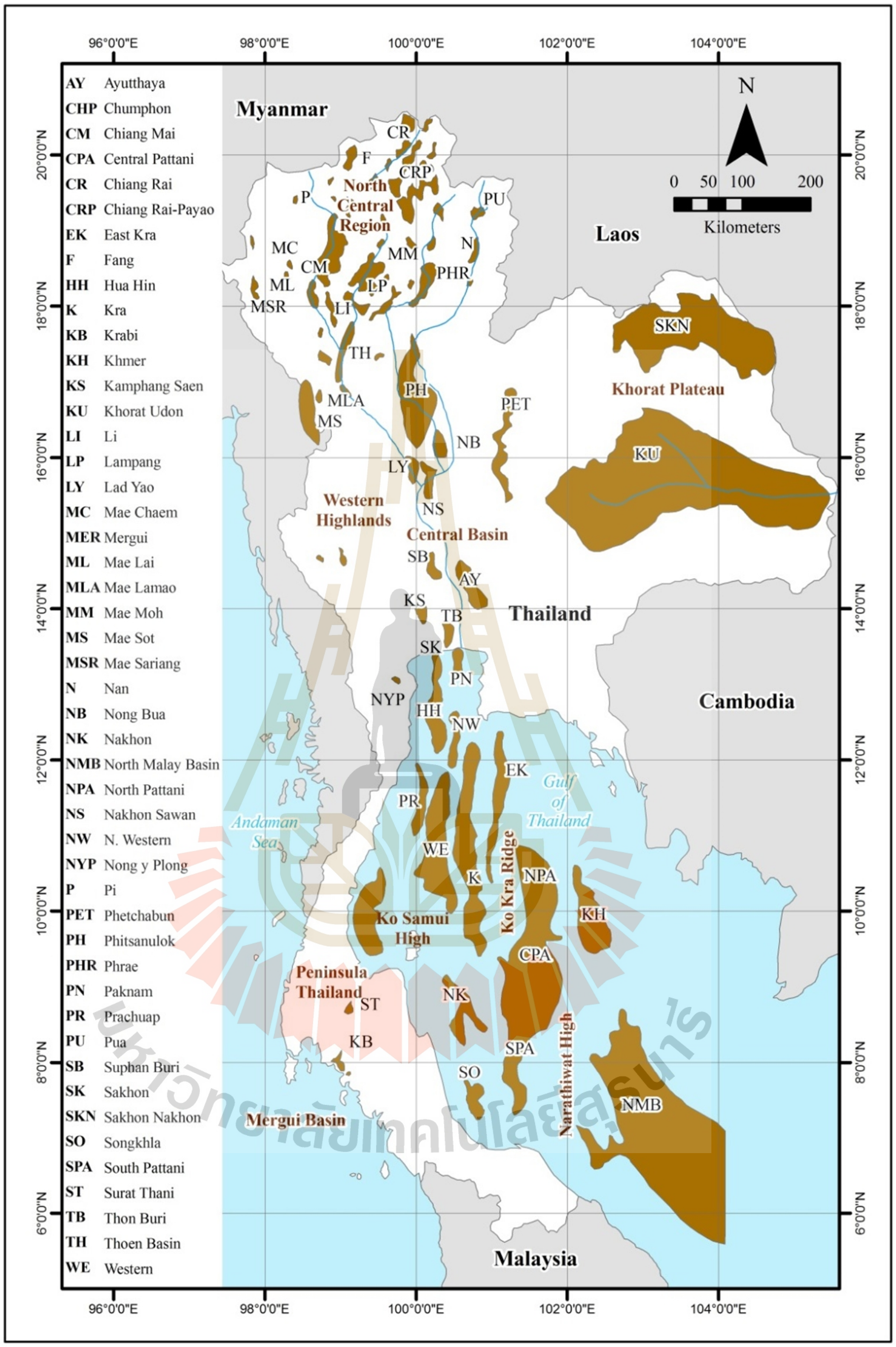

Figure 2.1 Map showing the Tertiary basins of Thailand. The lines onshore are the principal rivers draining Northern and Central Thailand and the Khorat Plateau (Morley and Racey, 2011).

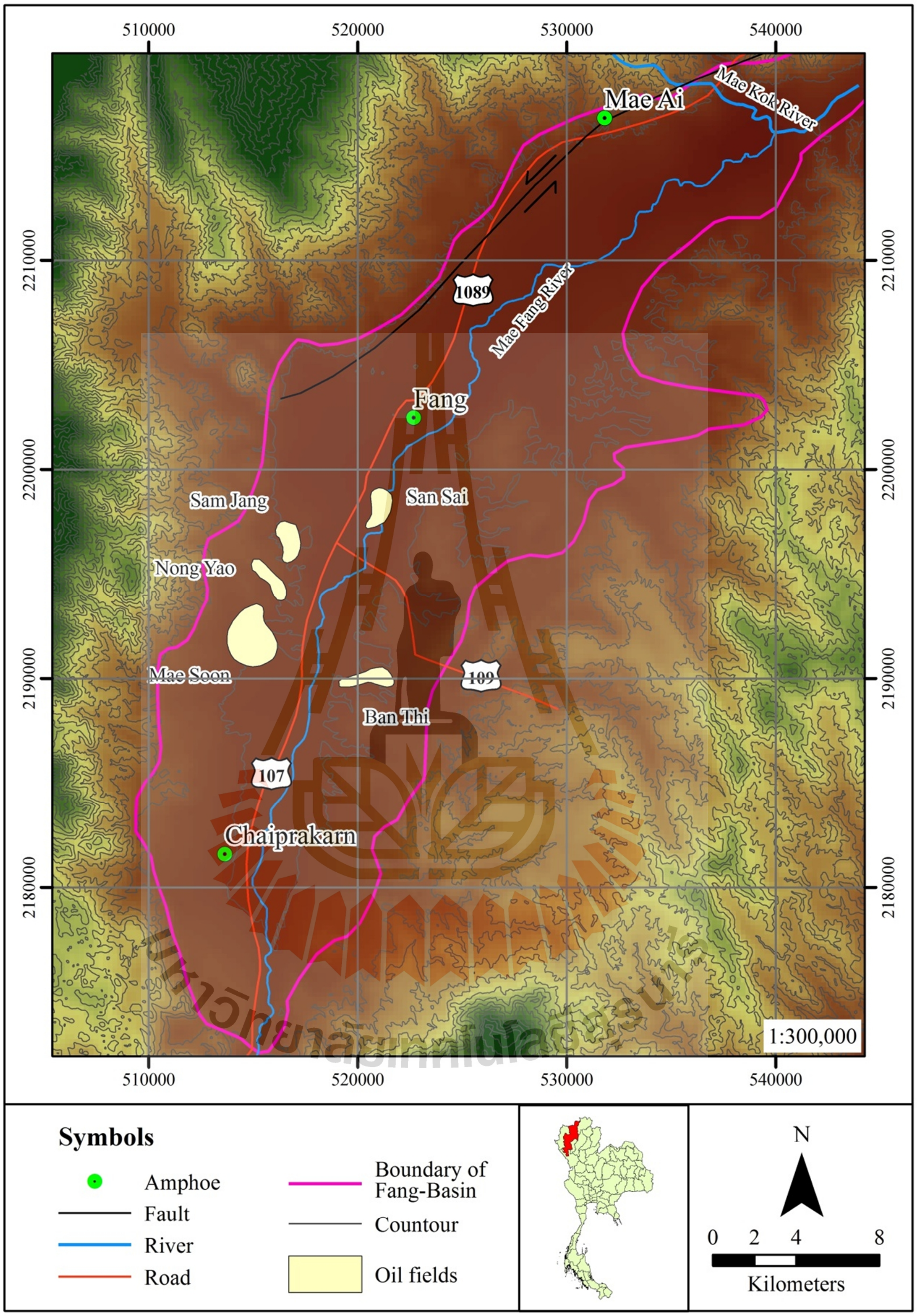

Figure 2.2 Map showing oil fields of Fang Basin.

basin in particular, the inner hilly belt ends abruptly against a high rugged mountain range whose summits rise about 1,400 meters above the basin floor. The eastern margin is lower elevated area. Presumably, the eastern margin is geomorphological more mature than that of the western one (Kaewsang, 1987).

Mountains on the northwestern convex side of the Fang Basin are san Doi Leam, Doi Ton Phung, Doi Ang Khang, Mon Hin Lai, Doi Khun Huai Khi, and Doi Pha Daeng lying from north to south. The southeastern concave side of the basin, a series from north to south mountains comprises Doi Sang, Doi Lum Khao, Doi Mae wang Noi , Doi Lieam, Doi Phrao, and Doi Khun Huai Fang respectively.

The geology of the Fang Basin and the adjacent areas were previously studied by numerous workers, namely, Dutescu et al (1980), Bunopas and Vella (1983), Braun and Hahn (1976), Settakul (1985) etc.

The Fang Basin is located on the western side of the Sukhothai Fold Belt, which comprises Paleozoic and Triassic strata and volcanic rocks that were accumulated on the eastern margin of the Shan-Thai Craton prior to the Indosinian orogeny. This fold belt is complex and trends north and northeast southwest. These rocks were uplifted and deformed by granitic intrusions during the collision of the Indochina and the Shan-Thai Cratons (Bunopas and Vella, 1983).

The base of sedimentary sequence in Fang Basin is marked by unconformity as a result of a great period of erosion that preceded the sedimentation of Miocene-Pliocene deposits. At the end of Pliocene the series of deposits was followed by sedimentation of fluviatile environment.

The Fang Basin was filled with rocks of Tertiary and Quaternary age. These Cenozoic rocks and sediments consist of shale, sandstone, conglomerate, sand, and

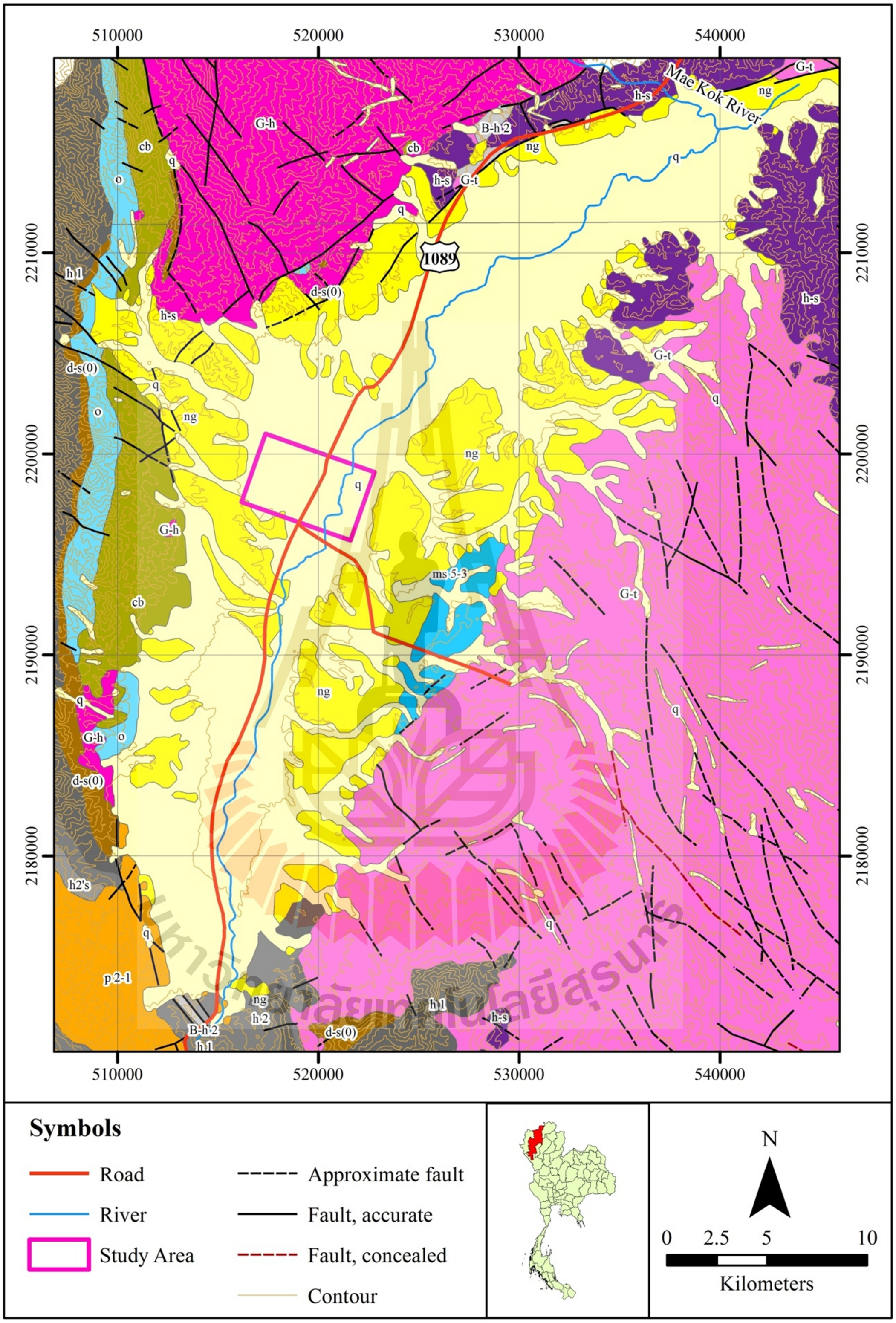

Figure 2.3(a) The geological map of Fang area (after Khantaprab and Keawsang, 1987).

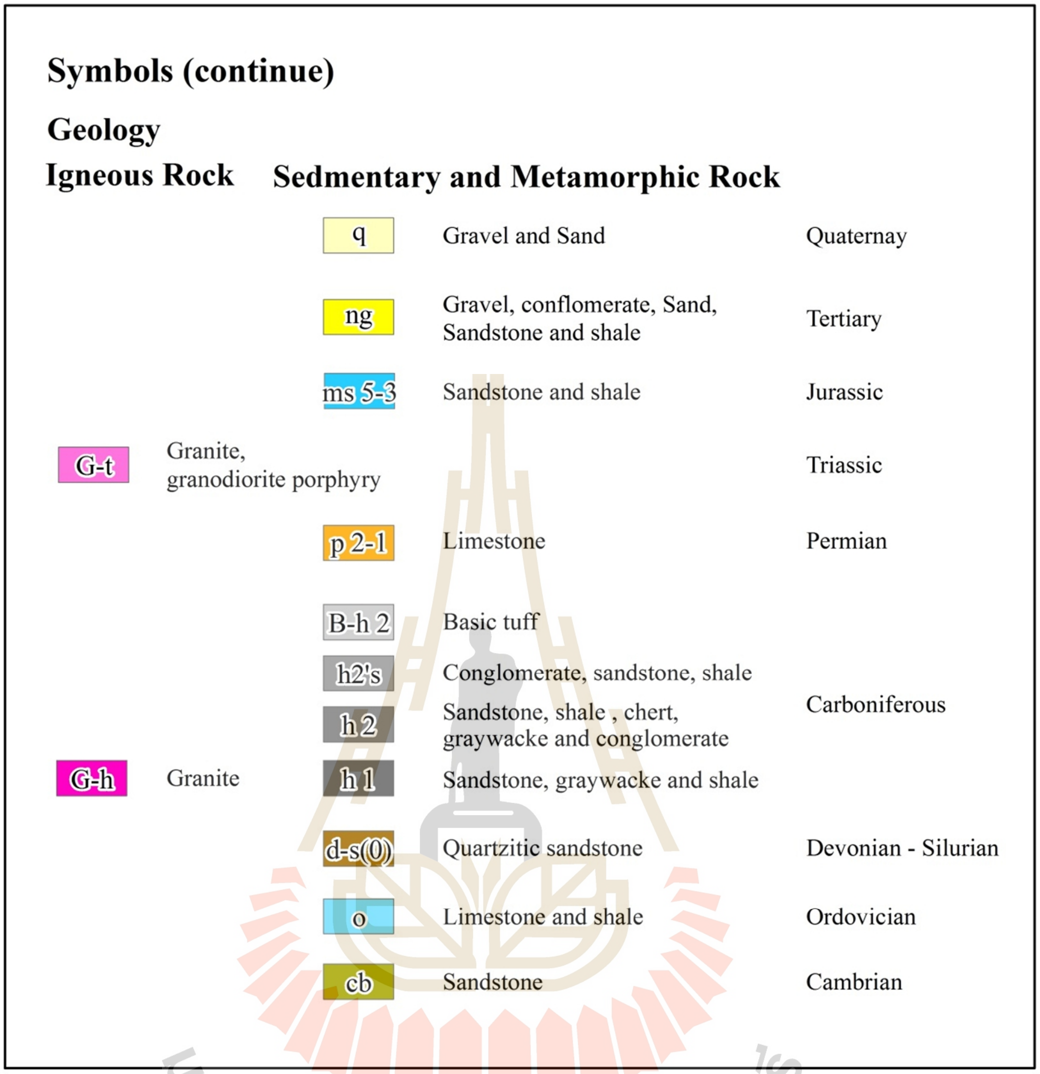

Figure 2.3(b) The geological symbols of Fang area (after Khantaprab and Keawsang, 1987).

gravel (Braun and Hahn, 1976).

The character of lacustrine deposit of Miocene-Pliocene age is indicated by numerous coal seams and carbonaceous sediments. The dominant lithologic type of Miocene-Pliocene deposits is dark clays and sandy clays with lignite. The Fang Basin was subsided in the central part with about 3000 m thick of sediment accumulated.

The wedging out of the beds and the prograding sedimentation are characteristics of fluvialtile deltaic zone (Dutescu et al, 1980).

Settakul (1985) classified sediments and rocks in the Fang Basin into two units. These units are the Mae Fang Formation and the Mae Sod Formation. The depositional environment in the Tertiary time was fluvial-lacustrine and changed to fluvial and alluvial in Quaternary time. The Tertiary rocks of the Fang Basin are conglomerate, sandstone, claystone and shale. The Quaternary deposits are silt, clay, sand and gravel and they occur as stream channels, terrace deposits and alluvial fans. These sediments are covered by recent soil and lateritic sand. The pre-Tertiary basement rocks consist of sedimentary, metamorphic and igneous rocks. On the western side of the basin, the rocks are Cambrian-Permian age and include Carboniferous granite. On the eastern side of the basin, the rocks are Silurian-Devonian and Jurassic, along with Triassic granite.

2.2 Structure of the Fang Basin

Zollner and Moller (1996) summarized the structural setting of Fang Basin as a series of intramontane basin generally trending NNE-SSW. These basins were formed in Early-Mid Tertiary time as pull-apart basins in a transtensional regime followed by Pliocene to Pleistocene compressional tectonics. Fang Basin is subdivided into three sub-basins separated by basement ridges. It is composed of the Huai Pa Sang, the Huai Ngu and the Pa Ngew sub-basins. The basin has an elongated rhombohedra outer shape. The southern part is rending N-S and the northern part is changing to a NE-SW direction. The investigated 3D seismic survey indicates that the Fang Basin is bordered to the west by a steep dipping NNE-SSW trending basin margin fault.

Petersen (2006) described the Fang Basin as an onshore Cenozoic rift-basin and is 2-4 km deep. Approximately 800 bbls/day of crude oil is produced from the Fang field (Fang Basin), which in reality consists of a number of minor structures including the Ban Thi, the Pong Nok, the San Sai, the Nong Yao and the Mae Soon.

2.3 Petroleum geology of the Fang Basin

The Fang Basin in northern Thailand occupies an area of 670 km^2 and is a half-graben with a major bounding fault on its western margin. Historically, the area is well known for oil seeps and the first petroleum production in the country was established here over five decades ago. The basin is divided by strik-slip faults into three sub-basins separated by horst of older rocks. The Miocene-Pliocene lacustrine sediments of the Mae Sot Formation are the main exploration target, with sediment in the main depocentre including organic-rich shales and lignites and reservoir quality sandstone. The oils are waxy and were sourced from fresh water lacustrine shales which contained a high proportion of algal material (Petersen et al., 2006). Maximum Tertiary sediment thickness is c. 3000 m. The geothermal gradient is high at 7.5 °C/ 100 m. and possible as high as 9.3 °C/ 100 m (Petersen et al., 2006). The onset of oil generation is at c. 1400 m depth, which indicates that the main source-rock interval has been generating oil for about 6 Ma. The onset of wet gas generation is c. 1900 m. The deepest part of the basin is at c. 3500 m. Five small oil fields have been discovered to date and yield a total production rate of c. 800 bopd (with a historical maximum of 1500 bopd). These fields produced from Miocene fluvial sandstones in a variety of traps including rollovers and possibly stratigraphic traps. The estimated original reserve of these fields was c. 50 MMbbls. According to the Department of Mineral Fuels, c. 2.7 MMbbls. proven recoverable reserve remains. The first discovery was the Chai Pra Karn field in 1953 which encountered a combined structural and/or stratigraphic trap at 230 m. depth with production from coarse fluvial-lacustrine sandstones of the inferred Mae Sot Formation, sourced and sealed by lacustrine shales of similar age. The reservoir interval comprises thin poorly sorted sands in an interval of 30-100 m. thick. Twenty wells were drilled on the field

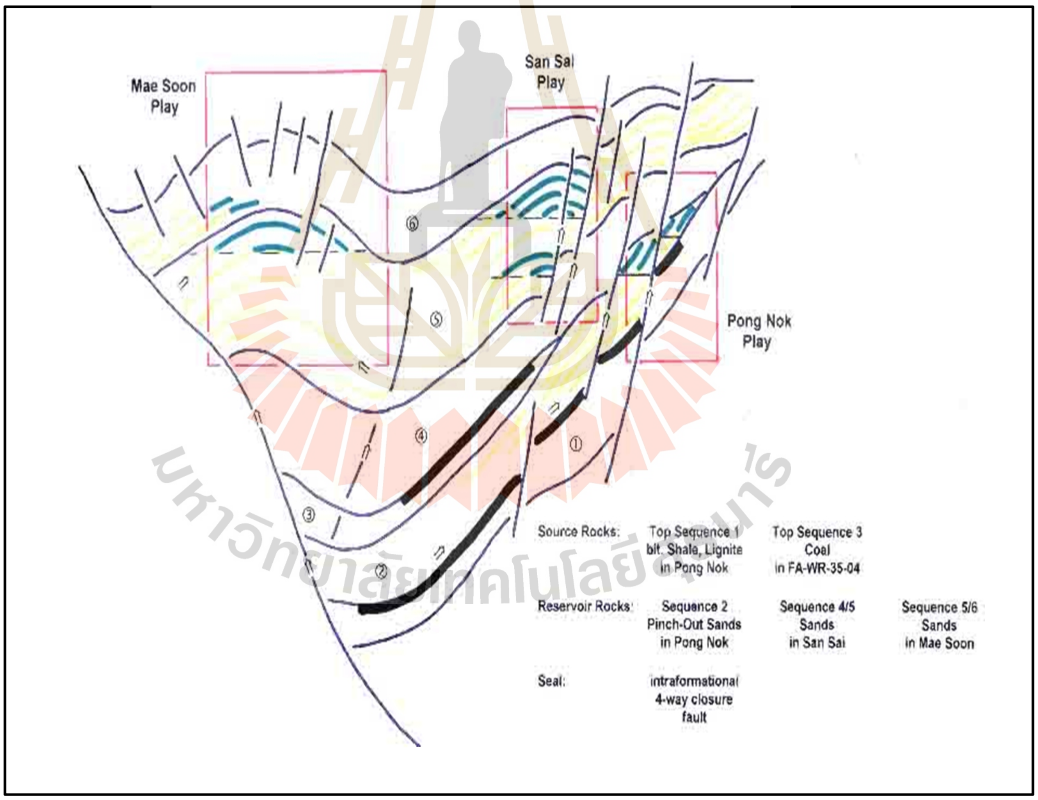

Figure 2.4 Diagram of petroleum system of Mae Soon and San Sai plays (Defense Energy Department, 2006).

with production rates of c. 10-35 bopd per well. The field was abandoned in 1974, having produced 200,000 barrels of 16° API oil.

The Mae Soon Luang oil field was discovered in 1961 and comprises a simple roll-over on the Mae Soon Fault in the centre of the basin. It has reserves of 3.5 MMbbls. of 28.3° API oil with high wax content (15.6%). Thirty wells have been drilled, with one reaching basement at 1005 m. The reservoirs are stacked, fluvial-lacustrine sandstones of the Mae Sot Formation at 580-690 m and 730-770 m depth. The net pay of individual sandstone reservoirs is 2-5 m. and they are separated by inter-bedded shale and mudstones. Porosities are 22-26% and permeabilities are 552-2026 mD. Oil has been produced from 12-18 wells since 1970 and the field-production rate has averaged 91,000 bbls. per year from the upper interval and 120,000 bbls. per yaer from the lower interval.

The Pong Nok Field was discovered in 1979 and produced 30,000 barrels per year of 37°-38° API oil from four wells but is now abandoned. The San Sai discovery was made on the eastern margin of basin and flowed 300 bopd. of 33° API oil from possibly Pliocene sands at 1280 m from a combined structural and stratigraphic trap. The Nong Yau discovery produced c. 600 bopd. from one well.

CHAPTER III

METHODOLOGY

Thesis methodology is based on available analysis data. This research conducted some 2D seismic profiles, lithological facies and geochemical interpretation and modeling in order to study basin evolution and petroleum potential of the San Sai oil field, Fang Basin.

3.1 Methodology

Research strategies and activities will be performed as following:

1. Relevant literature will be searched, reviewed, summarized and documented.

2. Subsurface data including wireline logging, lithological logging, geochemical and biostratigraphic analyses in the Fang Basin will be interpreted.

3. Interpretation of 2D seismic profiles.

4. Basin analysis to study hydrocarbon generation and timing, maturity of potential source rocks and migration paths of expelled hydrocarbons will be performed.

5. Petrel2011, PetroMod11.1D and ArcGIS softwares will be used in this study.

3.2 Theories

3.2.1 Facies models

3.2.1.1 Sedimentary facies

A fundamental tool in the description and interpretation of sedimentary rocks is the concept of sedimentary facies. The word 'facies' is defined in slightly differing ways by different authors, but the consensus is that it refers to the sum of characteristics of a sedimentary unit (Middleton, 1960). These characteristics include the dimensions, sedimentary structures, grain sizes and types, color and biogenic content of the sedimentary rock. It is a means of classifying sedimentary rocks in a way which is infinitely adaptable to individual circumstances.

Reading (1986) defines the sedimentary facies as the rock mass with distinctive characteristics and deposition under certain condition which reflect to sedimentary processes and depositional environment. Characteristics of rock, such as, color, texture, sedimentary structure, mineral, fossil and facies associations have to be determined. These data are used as the basis for sedimentary facies analysis.

The lithofacies characteristics resulting from the physical and chemical processes which were active at the time of deposition of the sediments and the biofacies and ichnofacies provide information about the palaeo-ecology during and after deposition. With knowledge of the physical and ecological condition it is possible to reconstruct the environment at the time of deposition. This process of facies analysis, the interpretation of strata in term of depositional environments, can be considered as the main objective of sedimentology and stratigraphy which is the reconstruction of the past (Reading, 1986).

Stratigraphic units undergo thickness and facies changes across a basin, reflecting contemporaneous paleogeography, subsidence patterns, and location of sediment sources. Most of these aspects of basin development are controlled by tectonics, such as, the development of bounding faulted or folded uplifts and subsidence caused by thermal contraction of continental margins, basement failure, or thrust-sheet loading. Eustatic sea-level changes are also of profound paleogeographic importance. Such effects leave their imprint on sediments via their control on paleoslope by the structuring of land masses that guide oceanic currents, wave advance, or air flow and by the development of depocenters and their control on water depths or rates of internal scour (Maill, 1999).

The seismic reflection profiles are used for the investigation of subsurface stratigraphy. They are based on the analysis of the reflection of sound waves which penetrate rocks below the ground or under sea. A seismic reflection profile is generated by providing a series of artificial shock waves which are reflected by surfaces within rocks and recording the returning waves (McQuillin et al., 1984).

3.2.1.2 Fluvial environment

The models of fluvial sedimentation represent an attempt to combine geomorphological observation of modern rivers with interpretations of ancient successions.

The river draining transversely into a sedimentary basin commonly deposits a cone-shaped wedge of detritus at the basin margin, with the river diverging a series of radiating distributaries (Miall, 2000). These two features would be the key elements of most geologist definition of the term alluvial fan. However, there is considerable controversy among sedimentologists as to the scope of the definition beyond this initial point. For some geologist, the term has no unique facies sense. As noted by Miall (1992), there are small, steep, gravel-dominated fans, within many of which debris flow processes are important; there are sandy systems deposited by braided streams; there are giant modern fans, such as the kosi, of India, which grades from boulder conglomerate near the mountains to fine sand-silt-mud

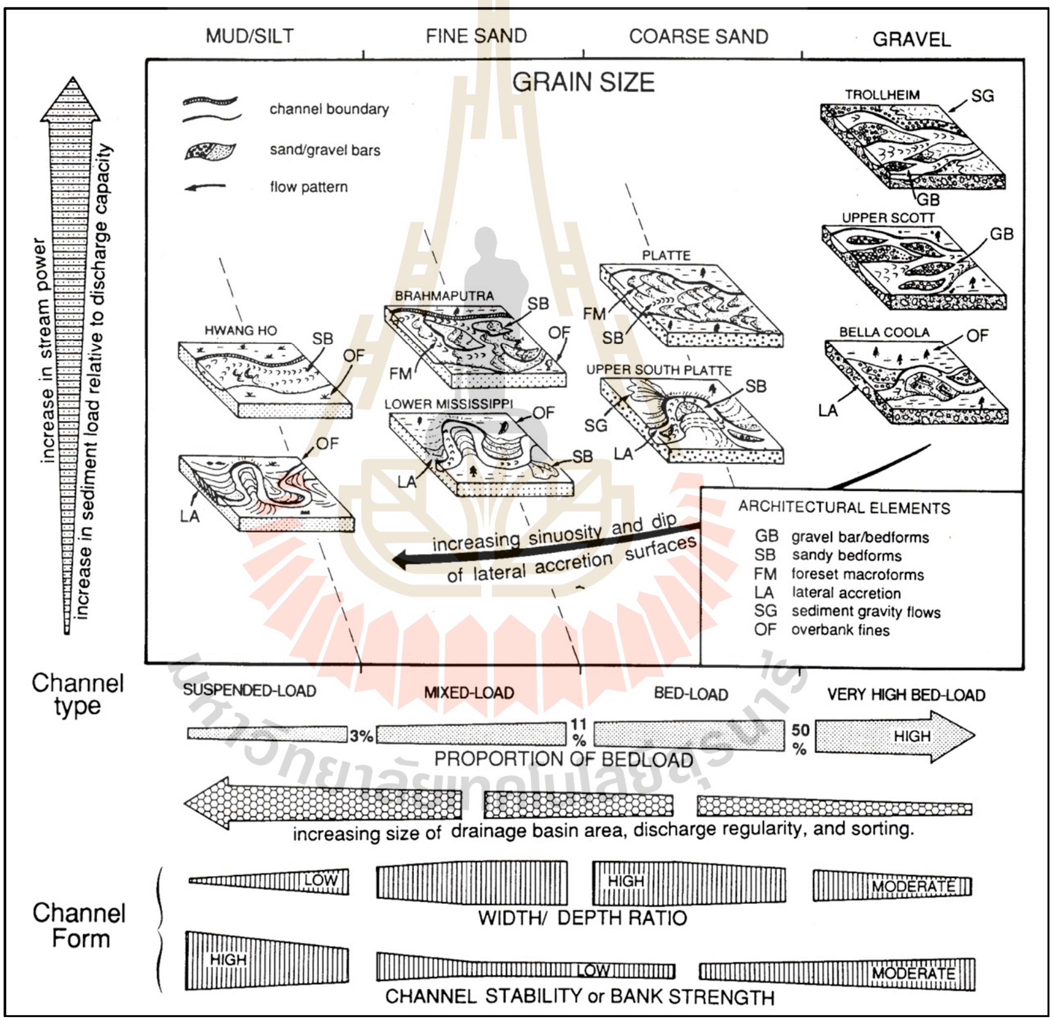

Figure 3.1 Relationship between grain size and fluvial-channel pattern (Orton and Reading 1993).

140 km. down slope at its distal end and there are fine-grained, arid systems termed terminal fans deposited by ephemeral flows that percolate and dissipate into the substrate at their distal fringes.

3.2.1.3 Lacustrine environment

Lakes are among the most varied of all depositional environments, even though they occupy a relatively small percentage of the earth's surface at the present day (about 1%, according to Talbot and Allen, 1996). There are no universal facies models for the lacustrine environment.

According to Miall (1999) most major lake deposits originated when sedimentary basin was tectonically isolated from the sea. The advent of plate tectonics has helped explain the origins of these basins, many of which are surprisingly broad and deep. Typical tectonic settings for lakes include rifts (lake Baikal, East African Rift System), transform plate margins (Dead Sea, Cenozoic basins of California), remnant ocean basin (Black Sea?), some foreland basins (Cenozoic Uinta Basin) and intracratonic depression (Lake Eyre). Other lakes owe their origins to ice damming, volcanic damming or glacial scour. Temporary lakes form in various fluvial and coastal settings and may be the site for minor but distinctive deposits.

Another major sediment control is water chemistry. This can vary widely, reflecting variations in the inflow/evaporation balance, nature and quantity of dissolved riverine sediment load, temperature, water level and water-body structure (presence of stratification, seasonal overturning). As Talbot and Allen (1996) noted, lakes are very sensitive to climatic change. They provided a useful review of this topic and suggested a broad classification of lacustrine deposits into those formed in dilute lakes of hydrologically open basins and those formed in saline lakes of closed basins. However, with variations in climate or tectonic setting, lakes may change from one of these states to the other. Hardie et al. (1978) discussed sub environments and subfacies that exist in saline lakes and shown how lacustrine brines evolve during evaporative concentration.

Analysis of lake sediment may involve an examination of sediments and processes which are more commonly associated with marine or alluvial environments, including turbidites, deltas, evaporitic-carbonate mud flats and fluvial sheet floods. These facies may be complexly interbedded within small stratigraphic thickness because of marked variations in water level that result from tectonic or climatic fluctuations (Donovan, 1973, 1975; Link and Osborne 1978; Smoot, 1978). Analysis of such deposits requires considerable sedimentological versatility. Recent research on continental-shelf environments has focused on the effects of storms and tides and some of this work has found a parallel in study of lacustrine sediments. For example, hummocky cross stratification, once thought to be an indicator of violent, long-fetch, marine storm wave, has now been documented in modern and ancient lake sediments (Duke, 1985; Eyles and Clark, 1986). Shallow water lacustrine carbonates showing evidence of exposure and pedogenesis have been termed palustrine limestone (Freytet and Plaziat, 1982; Platt and Wright, 1992).

Because of their sensitivity to climate change and tectonism and the commonly rapid lateral and vertical facies changes, lacustrine sediments have been much studied by those interested in processes of allogenic cyclic sedimentation.

3.2.2 Petroleum source rock evaluation

Source rock analysis is performed to define the oil and gas generating potential of a sedimentary sequence. Chemical and microscopic analytical techniques are used to determine the richness, type and thermal history of organic matter in potential source rocks.

3.2.2.1 Organic richness

Total organic carbon content (TOC) is measures the organic richness of a rock in weight percent organic carbon. The first requirement for generating oil and gas within sedimentary basin is the presence of sufficient sedimentary organic material. The minimum concentration of TOC which is essential for a formation to serve as a source bed cannot be clearly defined, as this will depend on the type of organic material.

Table 3.1 Total organic carbon classification (Cornford, 1990).

Grade	Clastic (TOC %)	Carbonate (TOC %)
Very poor	< 0.5	< 0.3
Poor	0.5 – 1.0	0.3 – 0.5
Fair	1.0 – 2.0	0.5 – 1.0
Good	2.0 – 4.0	1.0 – 2.0
Very good	4.0 - 12.0	2.0 – 6.0
Excellent	> 12.0	> 6.0

3.2.2.2 Rock-eval pyrolysis analysis

The rock-eval pyrolysis instrument was developed by the Institute Francis du Petrole (Espitalie et al., 1977). Rock samples are analyzed by heating, using a special temperature over a range of 300° - 550° C. Four geochemical parameters are generated by the rock-eval pyrolysis analysis.

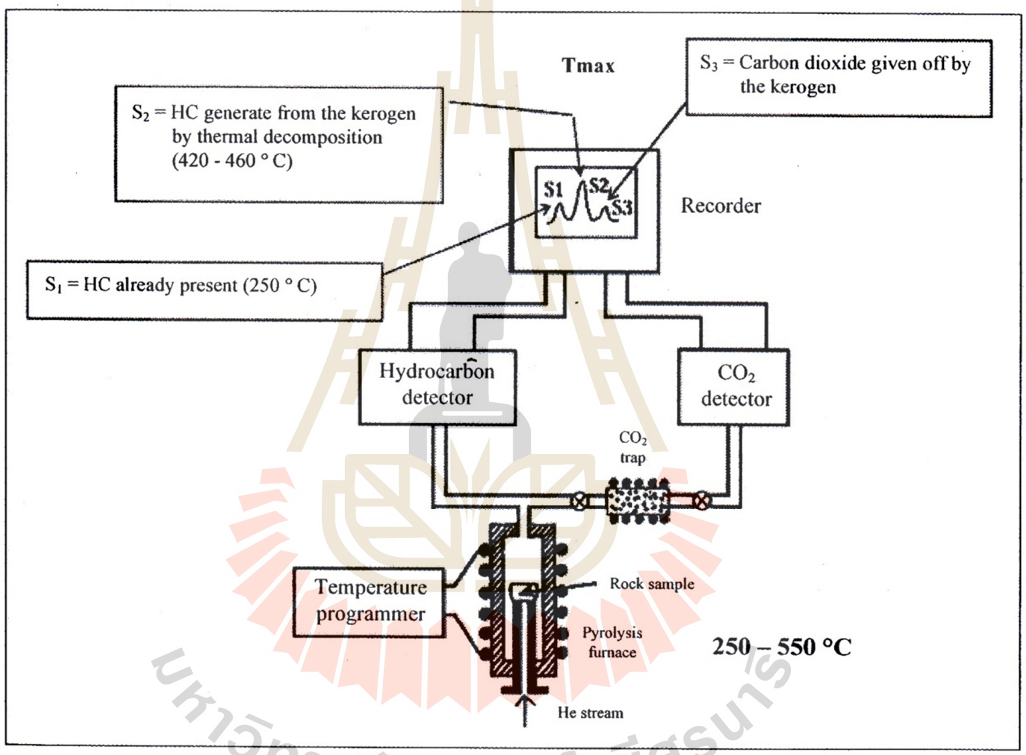

Figure 3.2 Schematic illustration of rock-eval pyrolysis analysis (Waples, 1985).

The S1 peak represents the quantity (mg HC/g rock) of free hydrocarbons that are present in the rock. These are volatilized at a temperature of 300° C.

The S2 peak is representative of the amount of hydrocarbon (mg HC/g rock) produced by conversion of the kerogen in the rock sample by thermal cracking. S2 estimates the amount of hydrocarbons which theoretically could be generated by complete thermal conversion of the kerogen to hydrocarbons in subsurface under natural condition.

The S3 peak represents the amount of organic CO_2 (mg HC/g rock) produced. The carbon oxide generated by the pyrolysis of the kerogen is collected. It is collected only over the temperature 300° – 390° C in order to avoid other inorganic source of CO_2 such as carbonates which decompose at high temperatures.

The Tmax is the temperature at which the maximum rate of hydrocarbons generation occurs during kerogen pyrolysis.

The result of rock-eval pyrolysis can be used to evaluate the type, the petroleum potential and the thermal maturity of organic matter; and oil show.

The type of organic matter is characterized by two indices. The hydrogen index (HI) (S2/TOC) and oxygen index (OI) (S3/TOC). The indices are independent of the abundance of organic matter but, are strongly related to the hydrogen/carbon ratio and the oxygen/carbon ratio obtained by elemental analysis of kerogen. The two indices, when plotted against each other produce a diagram similar to a Van Krevelen diagram for elemental analysis of kerogen although this depends on the reliability of the OI.

The petroleum potential of organic matter is defined by the hydrogen index (HI). For an oil source rock, it is generally above 250, although this will depend on the thermal maturity of sample.

The thermal maturity of organic matter is indicated by the Tmax which increases with depth and is not generally affected by migrated hydrocarbons. Generally, the temperatures between 400° C and 435° C correspond to

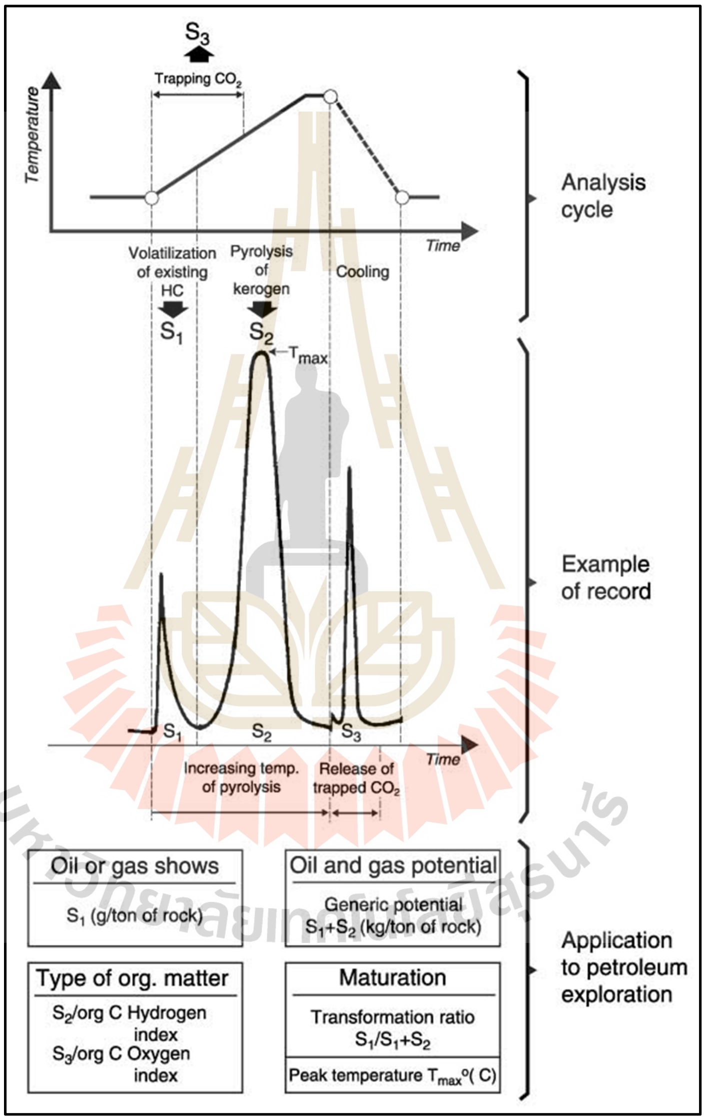

Figure 3.3 Cycle of analysis and example of record obtained by the pyrolysis method (Espitalie et al., 1977).

the immature zone, 435° – 470° C defines the main oil producing zone (oil window), and greater than 470° C defines the post mature zone.

Oil show is the presence of migrated hydrocarbons in a rock sample, even in small amounts. It may be detected by high S1 values (the quantity of free hydrocarbons present in rock sample) associated with a low S2 value (the amount of hydrocarbon produced by thermal conversion of kerogen in the rock sample).

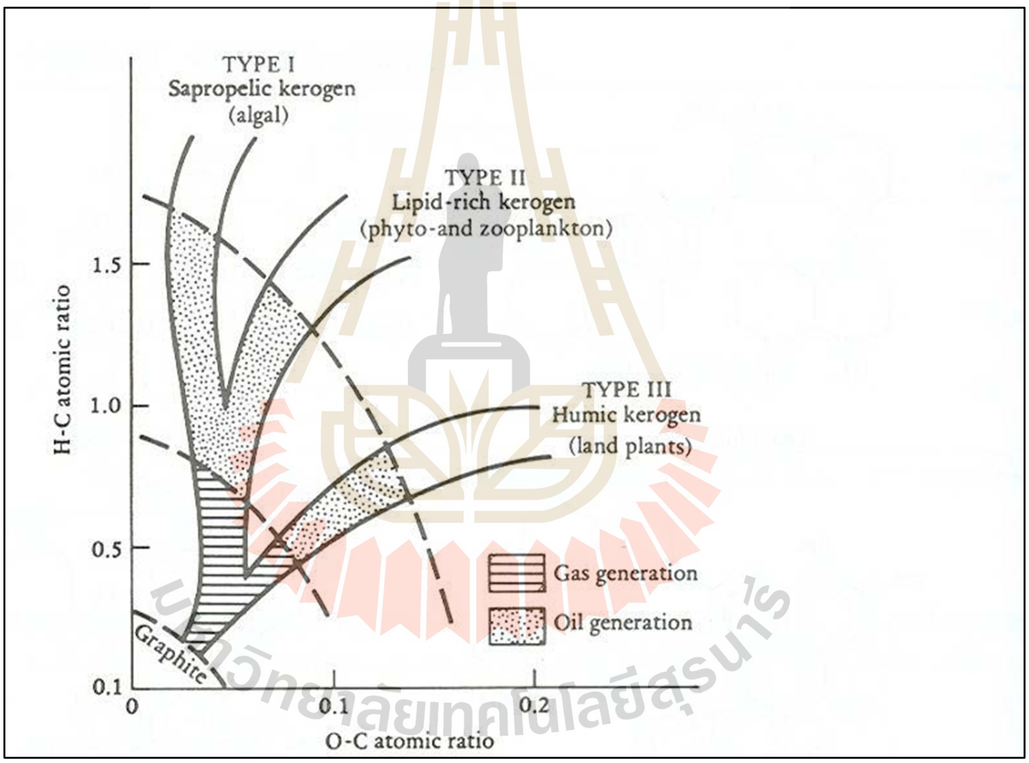

Figure 3.4 Van Krevelen diagram used for classification of source rock type by plotting of hydrogen and oxygen indices.

3.2.2.3 Vitrinite reflectance analysis

Vitrinite reflectance measurements record the percentage of incident light which is reflected by individual vitrinite particles. The measurements are made on isolated kerogen or whole rock imbedded in a polished plastic plug from which individual vitrinite particles are identified. A large number of particles are analyzed in each sample and the results are reported in histogram form with an accompanying statistical analysis. Vitrinite reflectance increases regularly with increased thermal alteration. Therefore, the degree of thermal maturity of the sediment can be determined.

The notation used is % R_o (R = Reflectivity, O = oil). For kerogen maturity, the approximately maturity boundaries between different levels of maturation are:

- Ro < 0.5 to 0.7% diagenesis stage, source rock is immature.
- 0.6 to 0.7% < Ro < 1.3% catagenesis stage, main zone of oil generation, also referred to oil windows.
- 1.3% < Ro < 2.0% catagensis stage, zone of wet gas and condensate.
- Ro > 2.0% metagenesis stage, methane remains as the only hydrocarbon (dry gas zone).

3.2.2.4 Headspacegas analysis

Analysis of gas C_1-C_5+ can be used as a screening technique for evaluation of organic richness and thermal maturity. Cutting samples of potential source rocks are collected and sealed in tin cans. The samples of headspace gas from each can are analyzed by gas chromatography.

Immature sediments usually contain biologically produced methane (C_1) as the main hydrocarbon gas, while mature source rocks contain significant of ethane (C_2), propane (C_3), butanes (C_4) and pentane (C_5) along with methane. In very mature source rocks (Ro about 2.0%), the higher molecular weight hydrocarbons are destroyed by cracking and the main hydrocarbon gas is once again methane. The concentration of gas in the cutting samples increases with increasing organic richness. The headspace gas analysis, therefore, can be used to evaluate both the organic richness and thermal maturity of source rocks.

3.2.2.5 Thermal maturity modeling

Lopatin (1971) and many others believe that two factors, time and temperature, are important in oil generation and destruction. These two factors are interchangeable: a high temperature acting for a short time can have the same maturation effect as a low temperature acting over a long time. Lopatin assumed that the dependence of maturity on time is linear-doubling the cooking time at a constant temperature doubles the maturity.

The chemical reaction rate theory predicts that the temperature dependence of maturity will be exponential. To take into account of this relation between reaction rate and temperature, Lopatin divided the temperature profile into 10° C intervals and drew the isotherms. He then chose the 100° to 110° C interval as the base interval and assigned to it an index value of n = 0. The other intervals were assigned index values as shown in Table 3.2. Lopatin then defined a factor, which reflects the exponential dependence of maturity on temperature. He assumed that the rate of maturation increased by a factor r for every 10° C rise in reaction temperature. Thus for any temperature interval the temperature factor $y = r^n$, where n is the appropriate index value given in Table 3.2.

The total maturation or TTI of sediment is given by the sum of the maturities acquired by each interval. Thus;

$$TTI = \sum_{n_{min}}^{n_{max}} (\Delta T_n)(r^n) \tag{3.1}$$

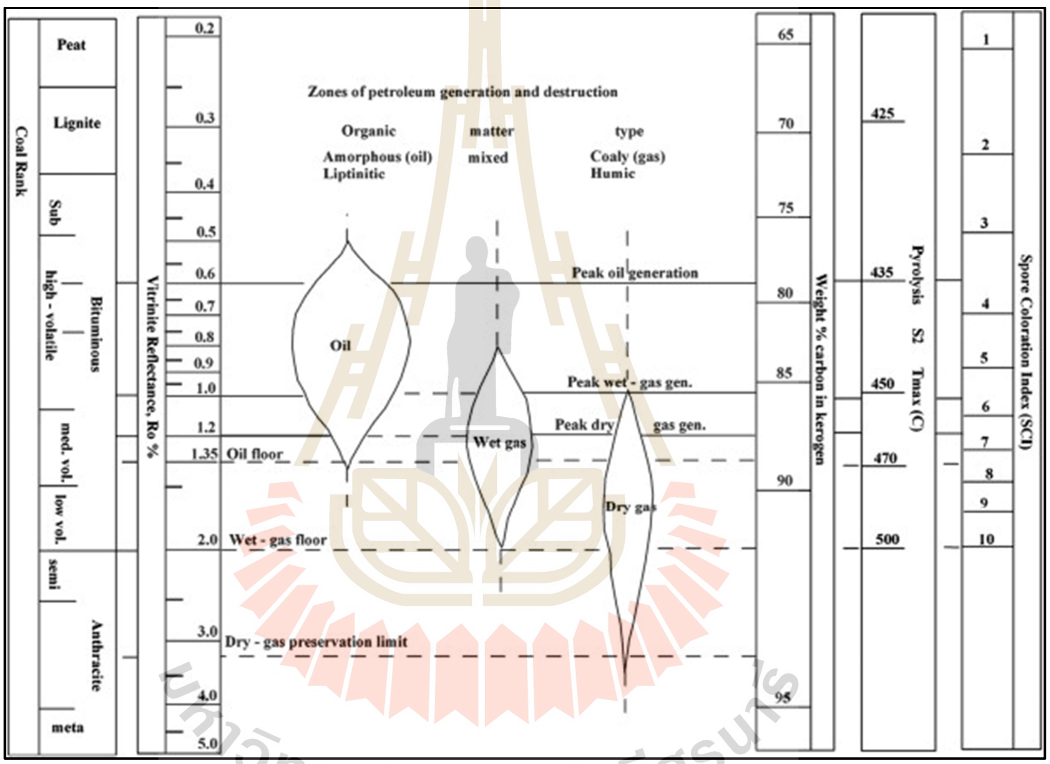

Figure 3.5 A conceptual view of hydrocarbon generation from different kerogen types (Dow and O'Connor, 1982).

Teble 3.2 Temperature factors for different temperature intervals.

Temperature Interval (°C)	**Index Value n**	**Temperature Factor γ**
30 – 40	- 7	r^{-7}
40 – 50	- 6	r^{-6}
50 – 60	- 5	r^{-5}
60 – 70	- 4	r^{-4}
70 – 80	- 3	r^{-3}
80 – 90	- 2	r^{-2}
90 - 100	- 1	r^{-1}
100 - 110	0	1
110 - 120	1	r
120 - 130	2	r^{2}
130 - 140	3	r^{3}
140 - 150	4	r^{4}
150 - 160	5	r^{5}
….[1]	m	r^{m}

The total maturity is expressed by TTI which is the sum of the interval maturity:

TTI	**Hydrocarbon generation**
15	Onset of oil generation
75	Peak oil generation
160	End of oil generation
500	40° API oil preservation deadline
1,000	50° API oil preservation deadline
1,500	Wet gas preservation deadline
> 65,000	Dry gas preservation deadline

Table 3.3 Correlation of Time-Temperature Index of maturity (TTI) with Vitrinite Reflectance (R_o).

R_o	TTI	R_o	TTI
0.30	< 1	**1.36**	180
0.40	< 1	**1.39**	200
0.50	3	**1.46**	260
0.55	7	**1.50**	300
0.60	10	**1.62**	370
0.65	15	**1.75**	500
0.70	20	**1.87**	650
0.77	30	**2.00**	900
0.85	40	**2.25**	1,600
0.93	56	**2.50**	2,700
1.00	75	**2.75**	4,000
1.07	92	**3.00**	6,000
1.15	110	**3.25**	9,000
1.19	120	**3.50**	12,000
1.22	130	**4.00**	23,000
1.26	140	**4.50**	42,000
1.30	160	**5.00**	85,000

3.2.2.6 Petromod11.1D Modeling

PetroMod11.1D is a part of the PetroMod software package that fully integrates seismic, seismic stratigraphic and geologic interpretations with multi-dimensional simulations of thermal, 3 phase fluid-flow and petroleum migration histories in sedimentary basins (Schlumberger, 2010). Petromod11.1D modeling work flow is demonstrated in Figure 3.6. It will predict if, and how a reservoir has been charged with hydrocarbon generation, migration routes, quantities, and hydrocarbon type in the surface conditions. Petroleum systems modeling is a vital additional component in assessing exploration risk prior to drilling. It helps to predict which traps are most likely to contain hydrocarbons and which type of hydrocarbon can be expected as well as their properties. In 2008 Schlumberger acquired IES (Integrated Exploration System), which was founded in 1982 by Prof. Dietrich Welte as a service company for the oil and gas exploration industry to utilize a newly emerging technology called "Basin Modeling" that could improve predictions of when and where oil and gas were generated. The modeling technology is now commonly described as "Petroleum System Modeling" (Schlumberger, 2010). This software has been donated by Schlumberger to School of Geotechnology, Institute of Engineering, Suranaree University of Technology since 2011.

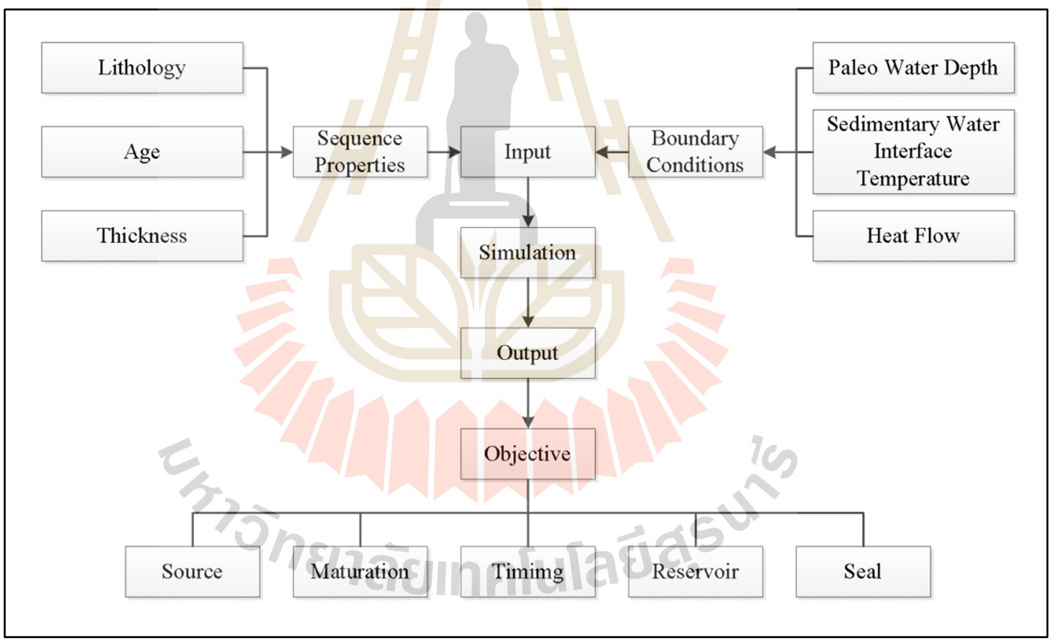

Figure 3.6 PetroMod11.1D modeling workflow (after Schlumberger, 2010).

CHAPTER IV

RESULT OF THE STUDY

The facies analyses are focusing on formal analysis of basin morphology, bedding architecture, determination of lithology and recognition of vertical and lateral succession of facies association. The facies distribution depends on sedimentary process, sedimentary supply, climate, tectonism, sea level change, ground water table change, water chemistry, bio-activity and volcanism. Among these, climate and tectonism are very important in continental environment of deposition.

4.1 Lithological Sequence

Considering the availability of subsurface geological, geophysical and geochemical data of the Fang Basin, the discussion will be firstly focused upon the nature and characteristics of lithological sequences.

The San Sai oil field area, covering approximately two square kilometers, is located in the northeastern of Mae Soon oil field. The area is penetrated by 13 petroleum exploration and/or production wells. Out of these, seven wells are selected for this study. Two wells with cutting/core description and seismic profiles are referred to as the primary reference wells. Five wells with only cutting/core description are referred to as the secondary reference wells.

Upon integration of data previously stated, the lithological sequence of seven wells are compiled and interpreted from the ground surface down to total depth of 500 feet to 9100 feet deep. It is not possible at this stage to present a complete lithological sequence from the ground to pre-Cenozoic basement due to the limited well data available at greater depth.

The typical lithological sequence of San Sai area is represented by the combination of the subsurface data from Wells number FA-HN-47-01 (Figure 4.3), FA-SS-30-01 (Figure 4.4), FA-SS-31-02 (Figure 4.4), FA-SS-33-03 (Figure 4.4), FA-SS-35-04 (Figure 4.5), FA-SS-37-08 (Figure 4.6) and FA-SS-40-10 (Figure 4.6). 2D seismic profiles comprising line F1, line F2, line F3, line F4, line S1, line S2, and line S3 and the seven wells locations are shown in Figure 4.1.

The stratigraphic classification of the San Sai oil field from this study can be divided into two Formations. The upper part is Mae Fang Formation and lower is Mae Sod Formation. Furthermore, intensive investigation of facies succession of Mae Fang and Mae Sod Formations can be described as four facies that are consistent with the basin development.

4.1.1 Mae Fang Formation

The uppermost portion of the Mae Fang Formation is represented by approximately 500 feet thick of mainly sand with some thin layers of gravel, clay and trace of coal with thin top-soil. The sand is generally light gray to dark gray, coarse- to very coarse-grained with some granule and moderately sorted. The gravel is light gray to gray, with some coarse- to very coarse-grained and poorly sorted, sand. The clay is generally gray.

The lithological succession is composed of texturally and mineralogically immature sand and gravel with abundant sand, poor to moderate sorting with high angularity. The overall geometry is tabular or wedge shape which was deposited in a high energy environment of braided stream system. The braided

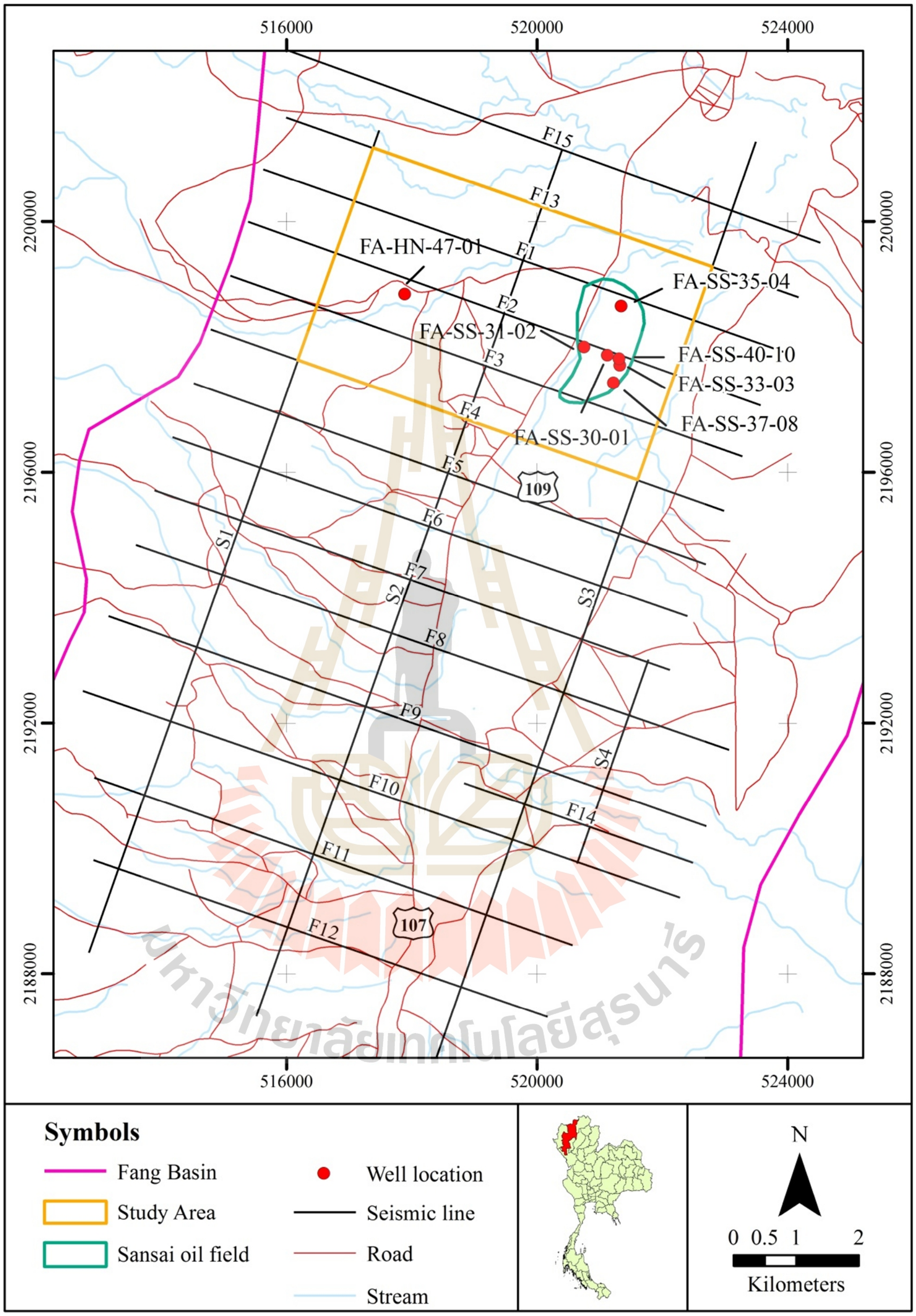

Figure 4.1 Map showing study area with seismic lines and well locations.

stream facies was deposited in a relatively steep slope and contained abundant medium-grained sandstone.

Underlying the upper part is approximately 2,000 feet thick sequence of sand interbedded with shale. The sand is characterized by light gray to dark gray, medium- to very coarse-grained and mostly well sorted. The shale layers are 7 to 25 feet thick and are generally dark gray color.

The fining upward sequence of sand and clay is considered to be deposited under the meandering fluvial system. The thick clay unit was deposited under the low energy environment of ephemeral lake in floodplain area. The overall sedimentary facies was deposited by meandering stream.

4 1.2 Mae Sod Formation

The Mae Sod Formation is divided into 3 sub-units, i.e., A, B, and C respectively in descending order.

Sub-unit A. The unit can be divided into two parts. The upper part consists interbedded of shale and sandstone with shale dominant. It is about 1,400 feet thick. Shale is characterized by gray to dark gray and brown color, whereas the sandstone is generally light gray to gray color and is medium- to very coarse-grained and mostly well sorted. Oil show is present in some sandstone beds. The upper part is interpreted to be the marginal lacustrine facies.

The lower part is composed of thick shale with fine-grained sandstone intercalations. The total thickness of this sequence is approximately 1,000 feet. The shale is characterized by dark gray, black and dark brown color and with some coal layers. It represents a shallow to deep lacustrine facies.

Figure 4.2 Lithological symbols used in this study.

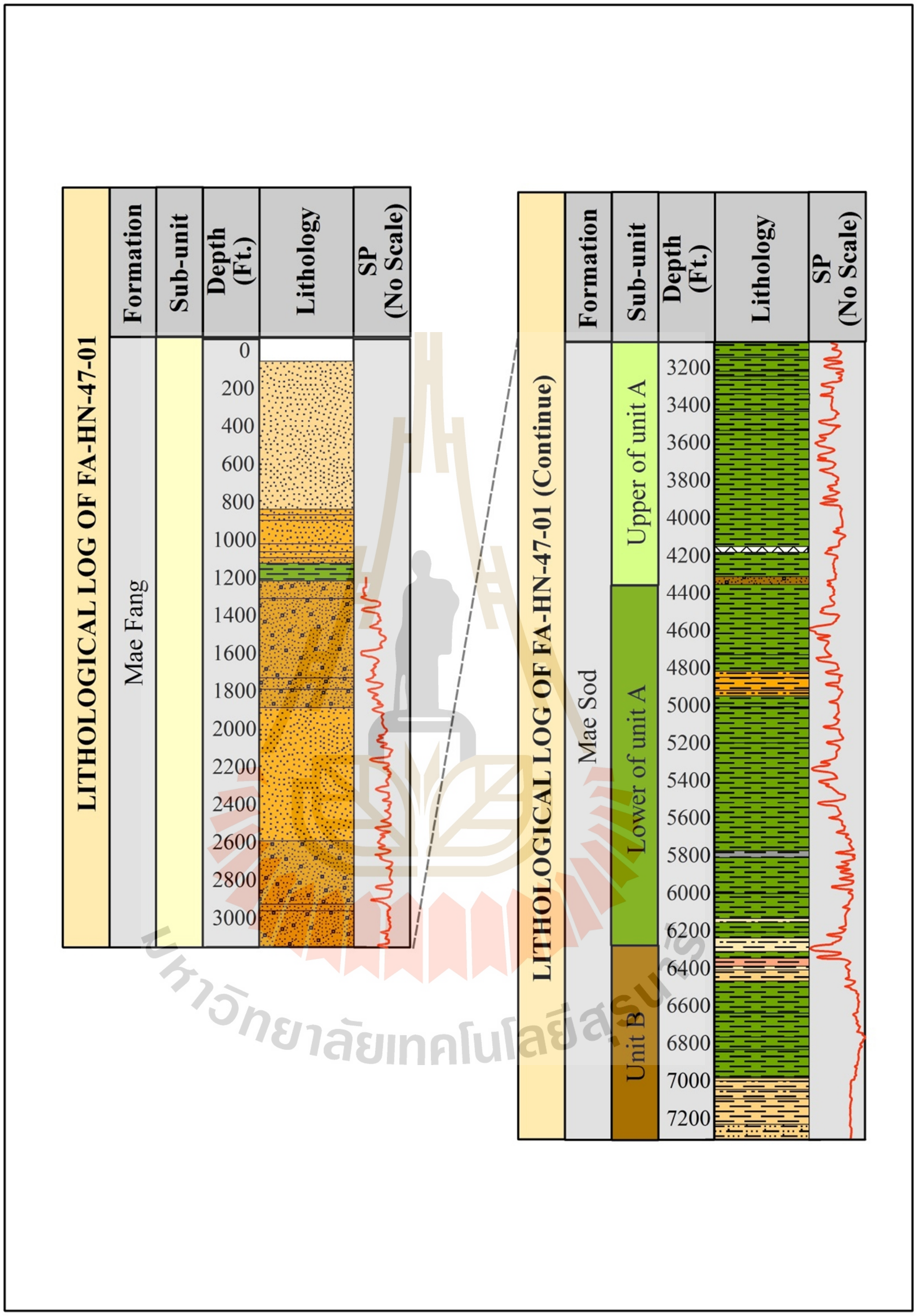

Figure 4.3 Lithological log of Well FA-HN-47-01.

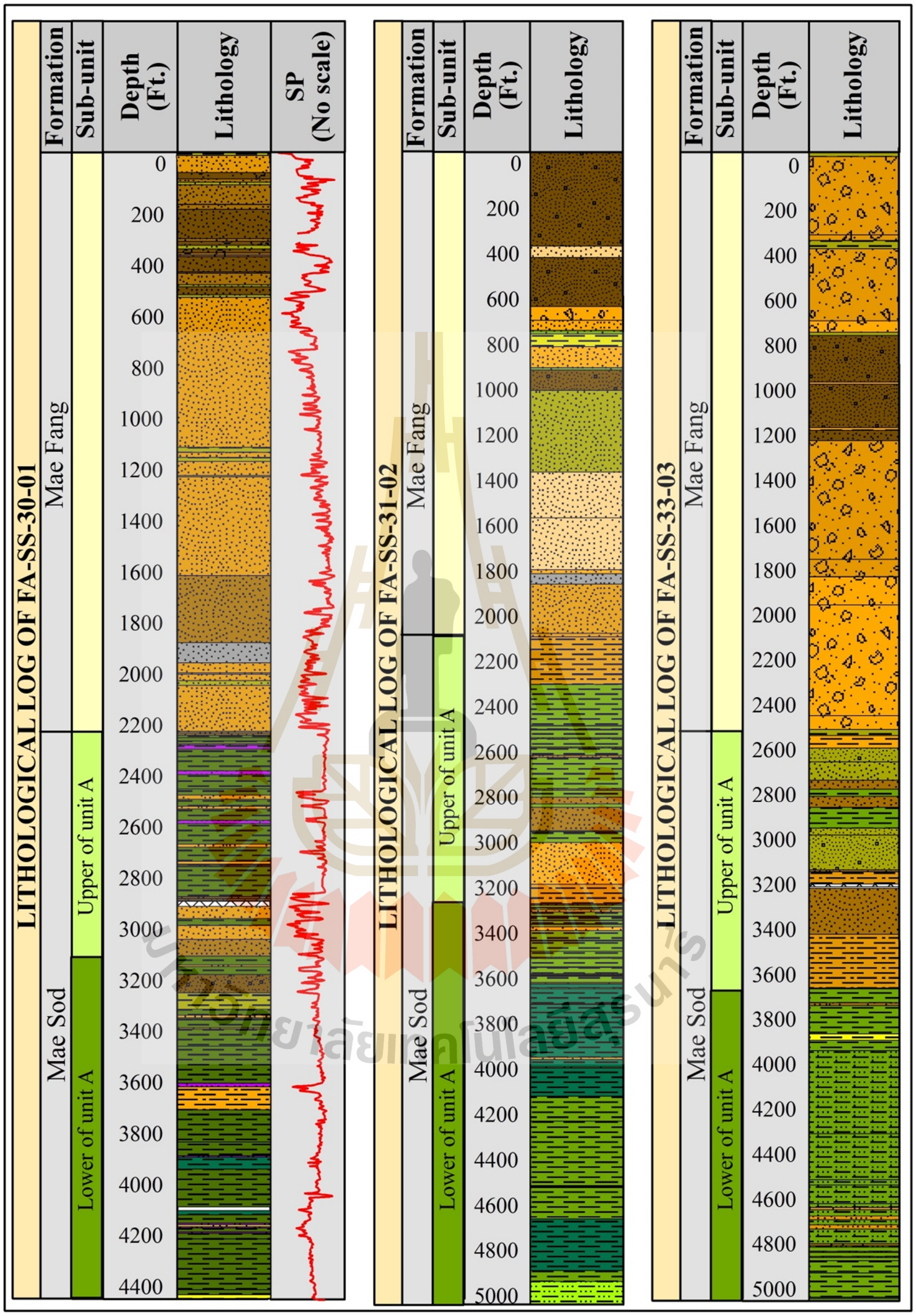

Figure 4.4 Lithological logs of Wells FA-SS-30-01, FA-SS-31-02 and FA-SS-SS-03.

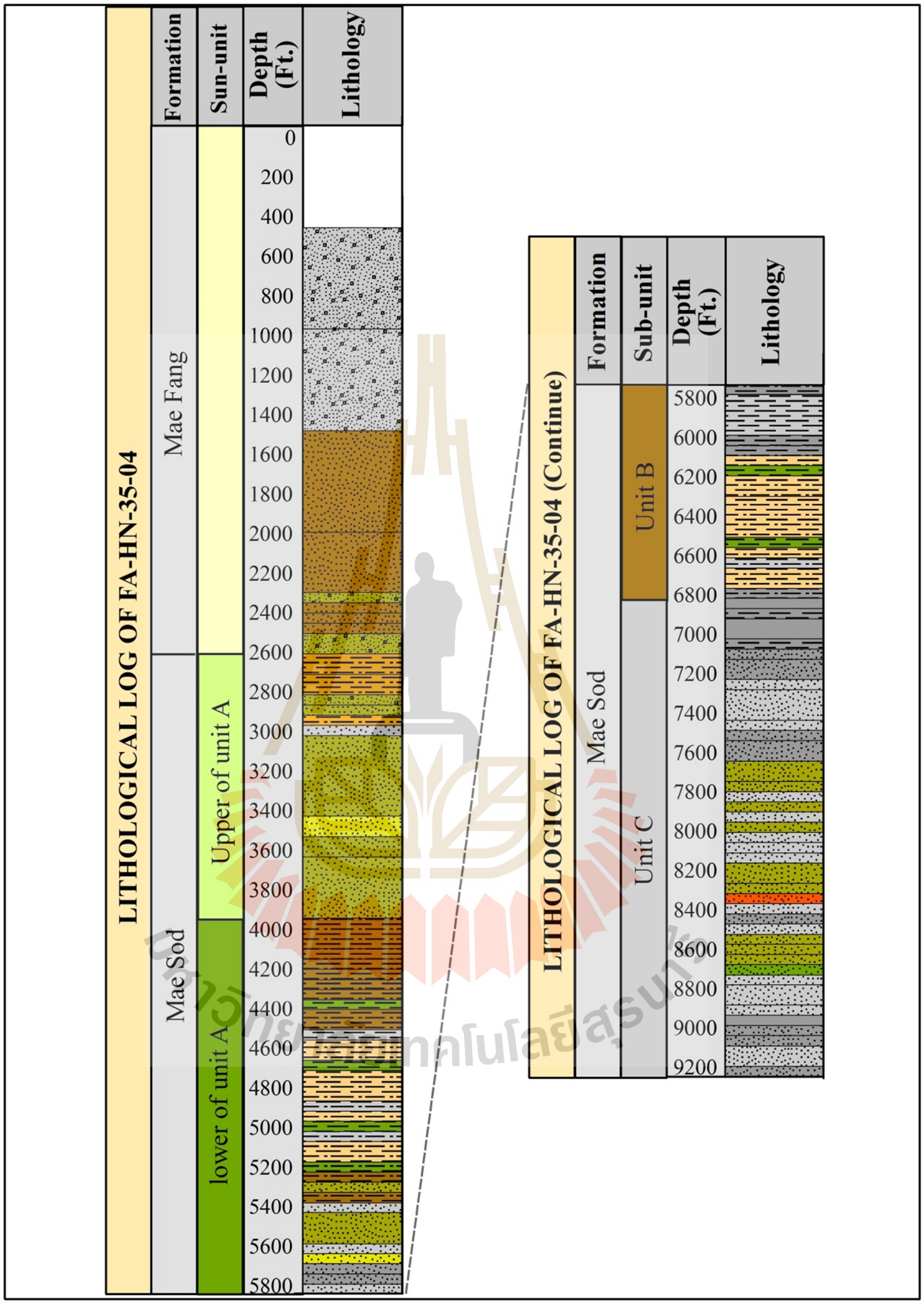

Figure 4.5 Lithological log of Well FA-SS-35-04.

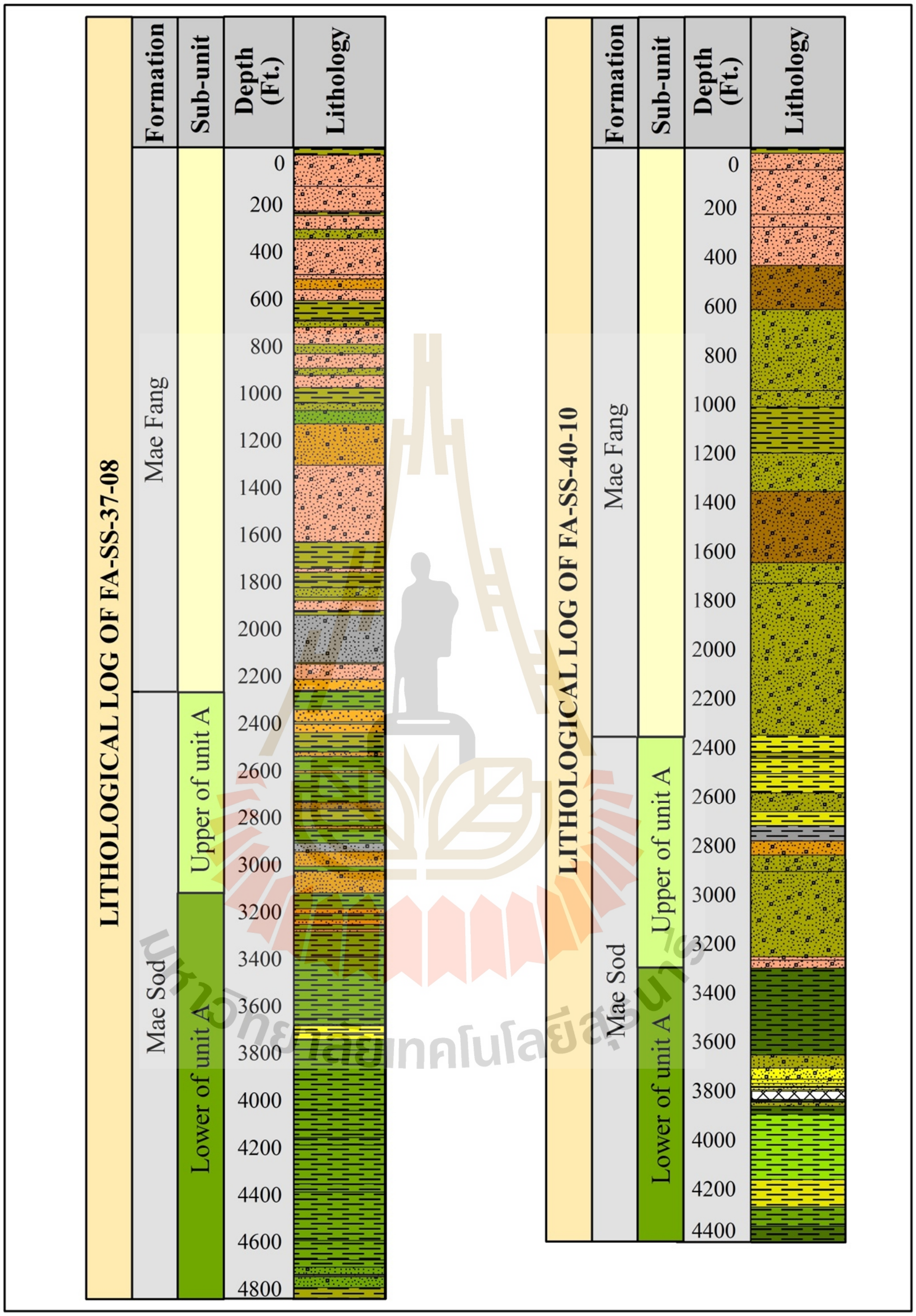

Figure 4.6 Lithological logs of Wells FA-SS-37-08 and FA-SS-40-10.

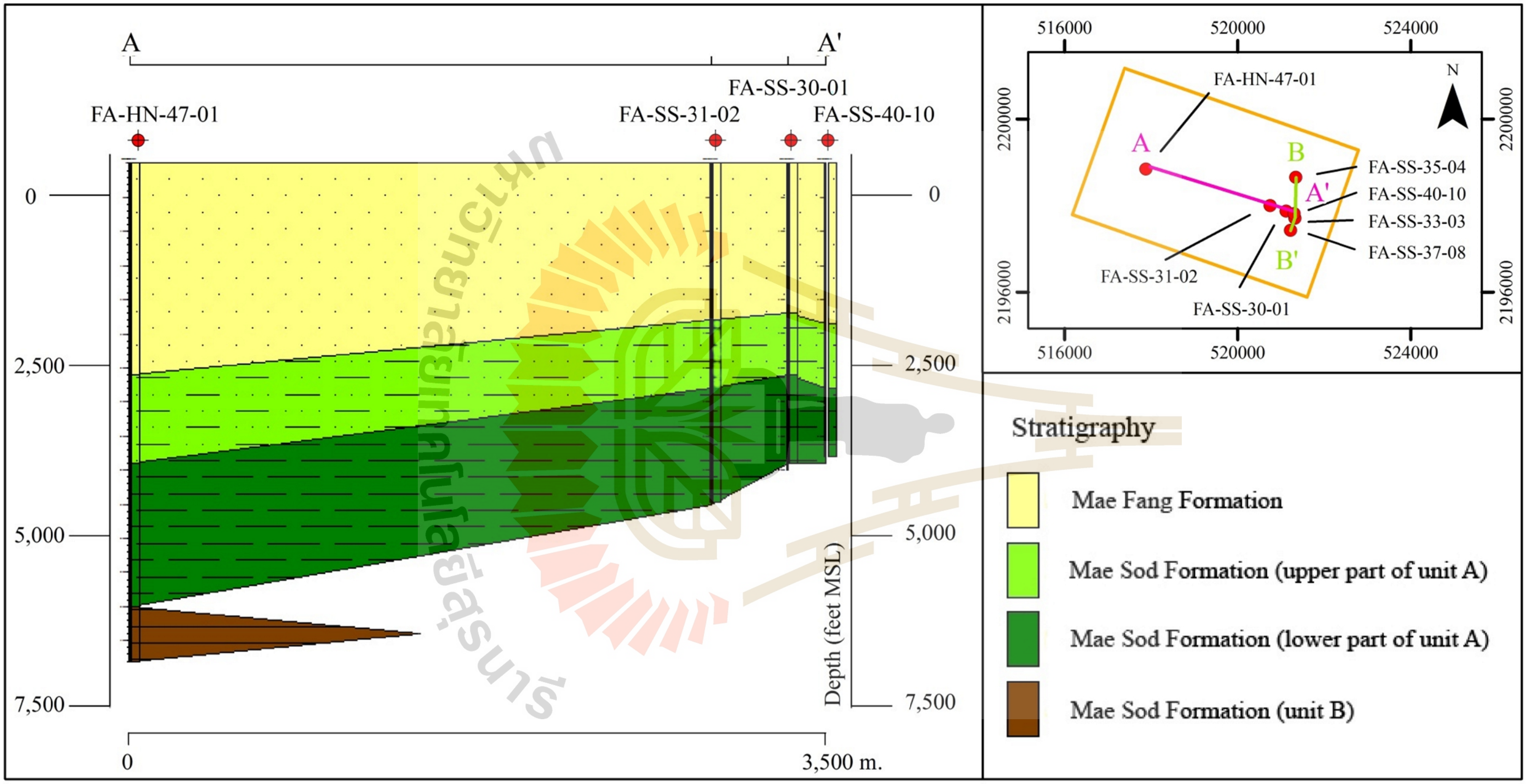

Figure 4.7 Stratigraphic cross section of line A-A’.

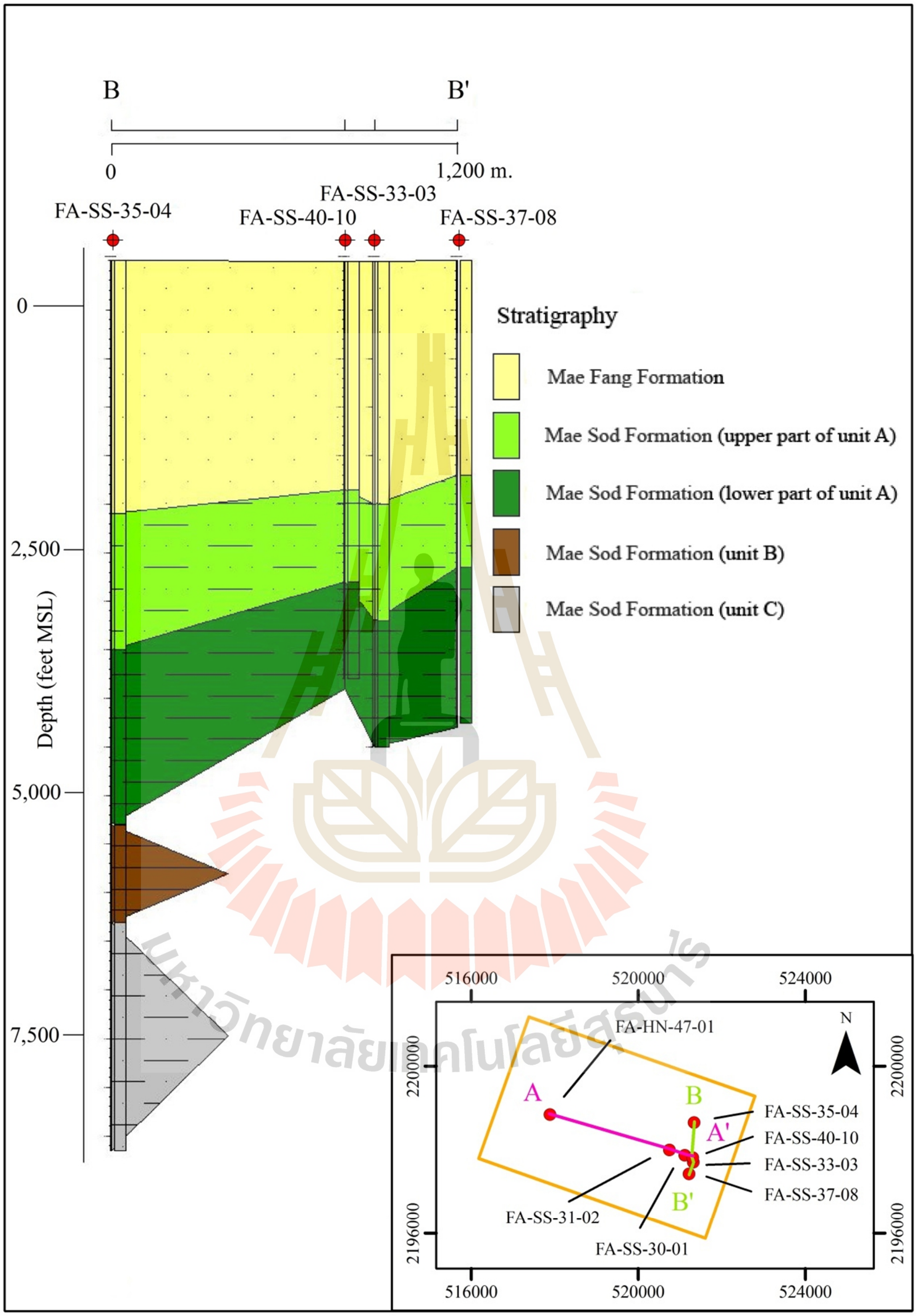

Figure 4.8 Stratigraphic cross section of line B-B'.

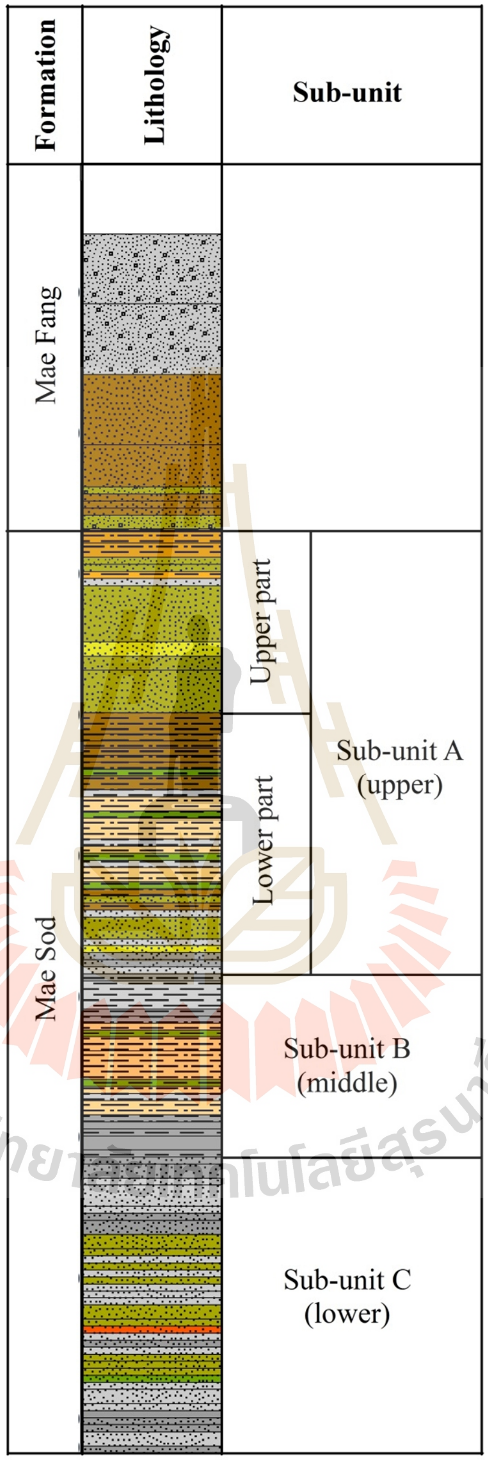

Figure 4.9 Composite lithological sequence of the San Sai area.

Sub-unit B. The unit consists of extremely thick dark gray shale, fine-grained sandstone and coal. This lithological succession is interpreted to be deposited in low energy condition of fresh water paleo-lake. The products accumulate in this environment is sedimentary rocks of lacustrine facies.

Sub-unit C. The lower part of unit consists of sandstone and coal bed interbedded with black shale. The upper part comprises coal beds approximately 200 feet thick and some sandstone. Sandstone is generally red and gray color, fine- to very coarse-grained sandstone with some layers of very clean sand. It represents a marginal lacustrine facies.

The Mae Sod Formation is interpreted to be deposited in meandering stream and lacustrine. The coal seam is regarded to be deposited under the marginal lacustrine condition.

The lithological correlation of seven well based on cutting and core data is shown in Figure 4.7 and the sub-unit classification of the San Sai sequence is shown in Figure 4.8.

4.2 Biostratigraphy and Paleoenvironment

Rock samples of the sedimentary sequence from Well FA-WR-35-04 in Fang Basin have been analyzed by Core Laboratories Malaysia SDN BHL (Abolins, 1992). The objective of analysis is to establish the age and depositional environment of the sedimentary sequence encountered. The age and the paleoenvironment interpretations based upon palynological evidence are summarized in Figure 4.10.

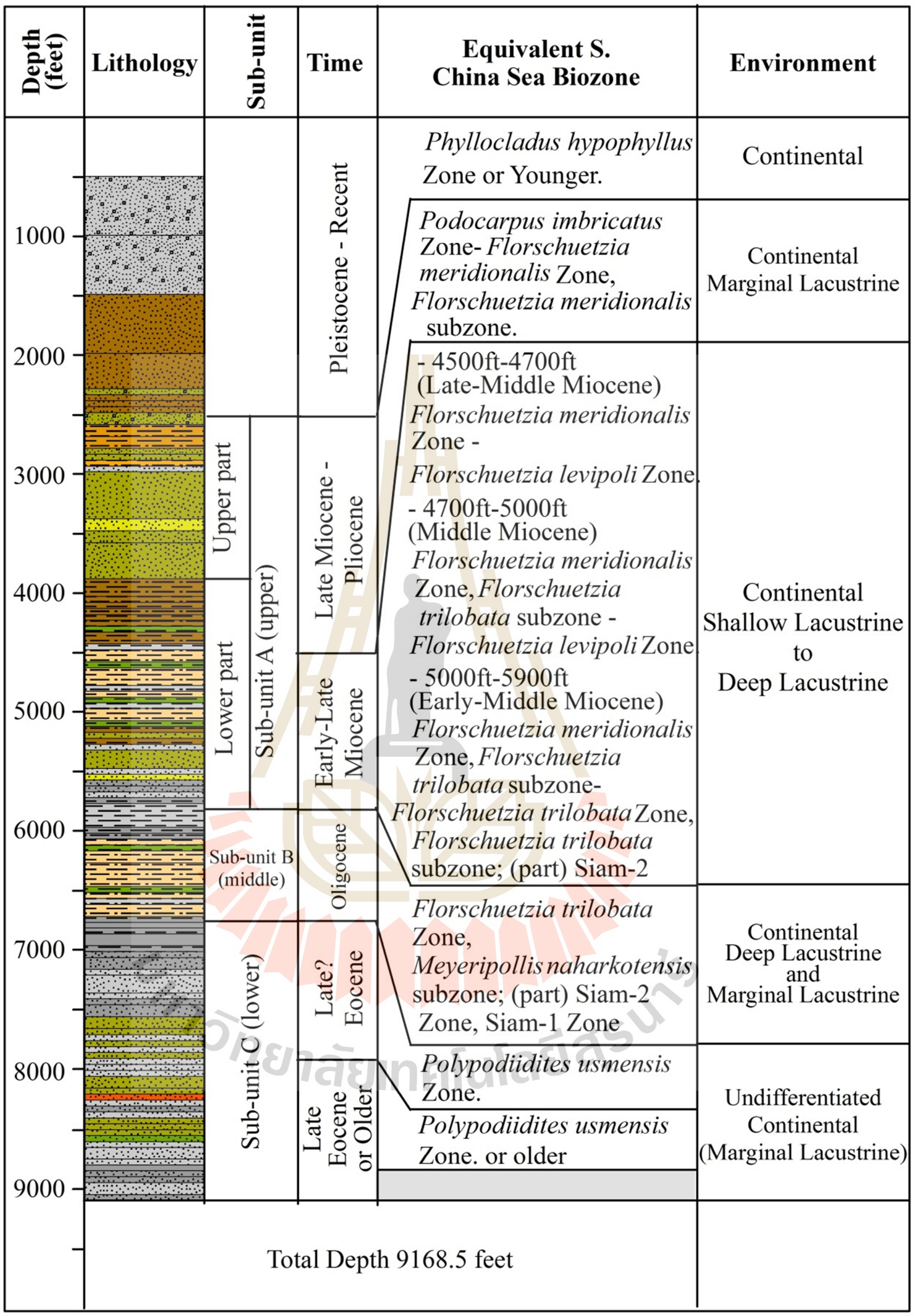

Figure 4.10 Biostratigraphic data from Well FA-SS-35-04 and interpretation of the age and paleoenvironment.

4.3 Structural Evolution

The San Sai oil field is one of many oil fields in the Fang Basin. The development of the Fang Basin can be divided into three stages of tectonic events base on interpretation of 2D seismic profiles as shown in Figure 4.11-4.15.

The first stage or the initial stage (pre-rift) represent an early extensional rifting phase formed by north to south in the Late Eocenecene (Figure 4.16(A)). The basin is accumulated in sandstone of fluvial environment at the basin margin and claystone at the basin center.

The secondary stage (syn-rift) represented a rapid subsidence phase in the Oligocene to Pliocene (Figure 4.16(B)). The basin accumulated mainly the lacustrine shale facies.

The third stage (post-rift) represent a slow subsidence stage in the Pleistocene (Figure 4.16(C)). The basin accumulated mainly the alluvial facies after the syn-rift stage including the semi-consolidated sediments of gravel sand silt and clay.

4.4 Petroleum system

All geochemical data, such as, the total organic carbon content (TOC), rock-eval pyrolysis and visual kerogen of the petroleum source rock of the Mae Sod Formation of Well FA-SS-35-04 from the depth of 2,500 feet to bottom hole (9,100 feet), were analyzed. Vitrinite reflectance (%Ro), Tmax, production index (PI), hydrogen index (mg HC/g TOC) and oxygen index (mg HC/g TOC) are used for interpretation of its petroleum potential. All petroleum source rock properties can be summarized in Table 4.2. The petroleum system of the Fang Basin can be summarized as illustrated in Figure 4.38.

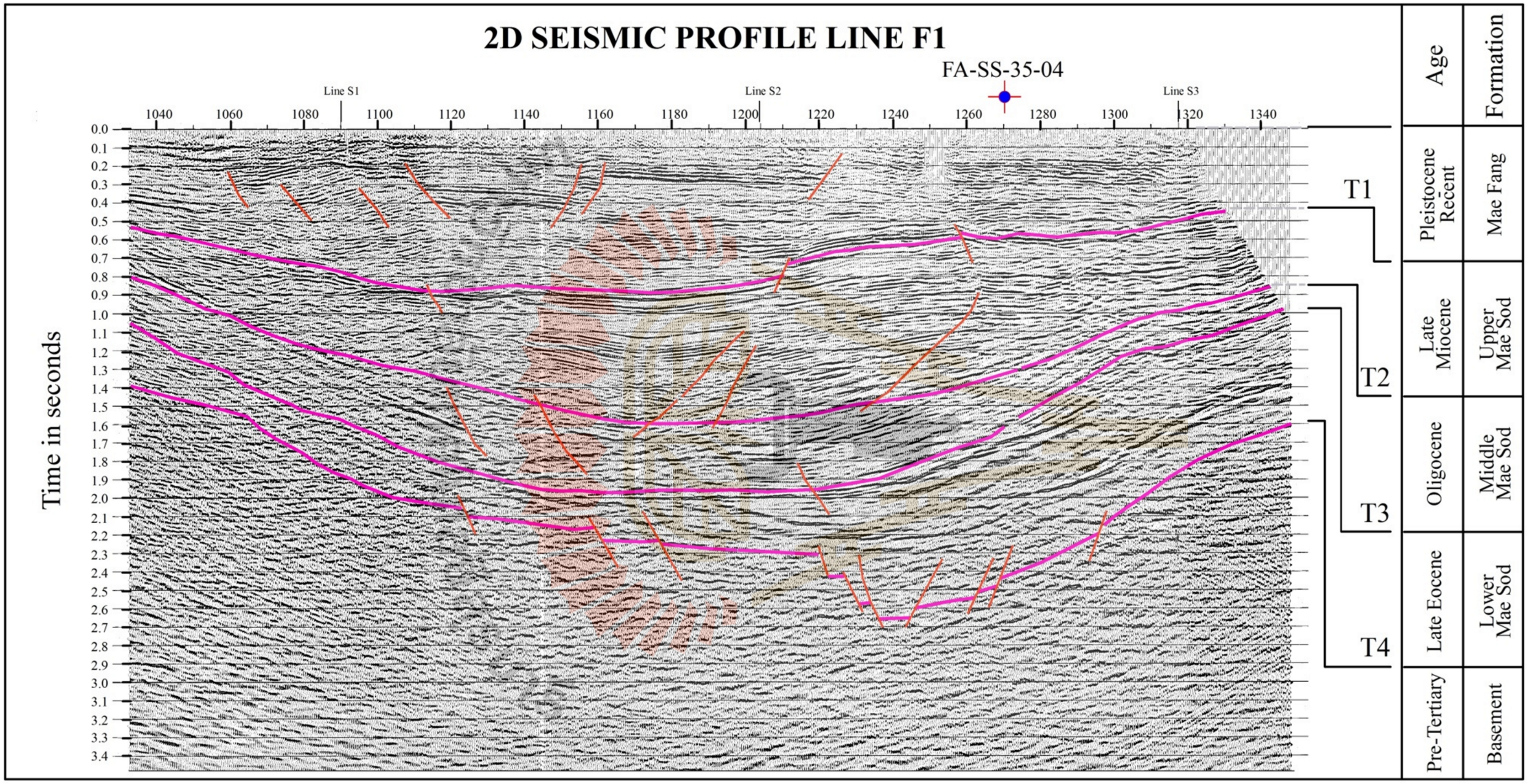

Figure 4.11 Interpretation of 2D seismic profile line F1 (after Defence Energy Department, 1990).

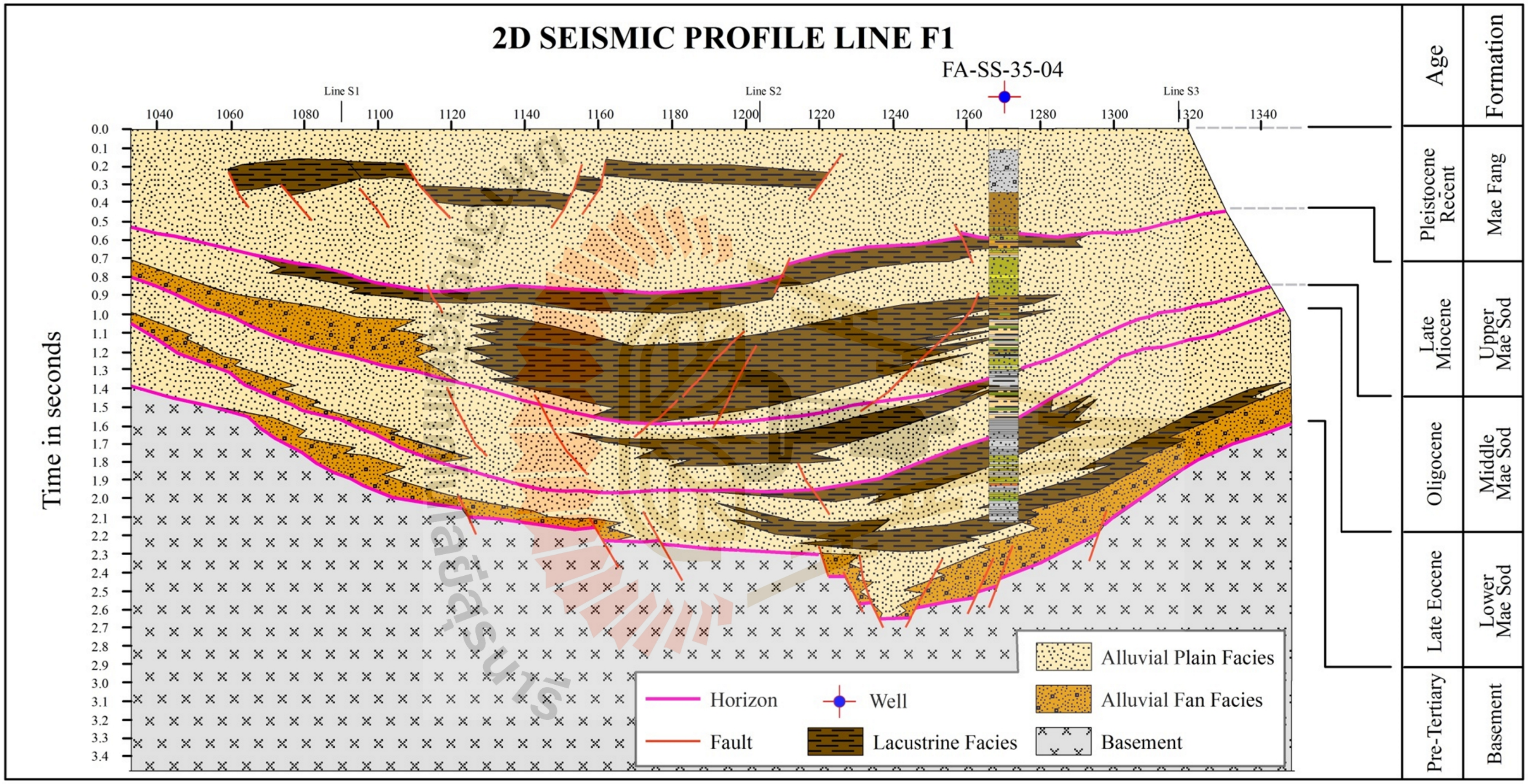

Figure 4.12 Facies interpretation from 2D seismic profile line F1.

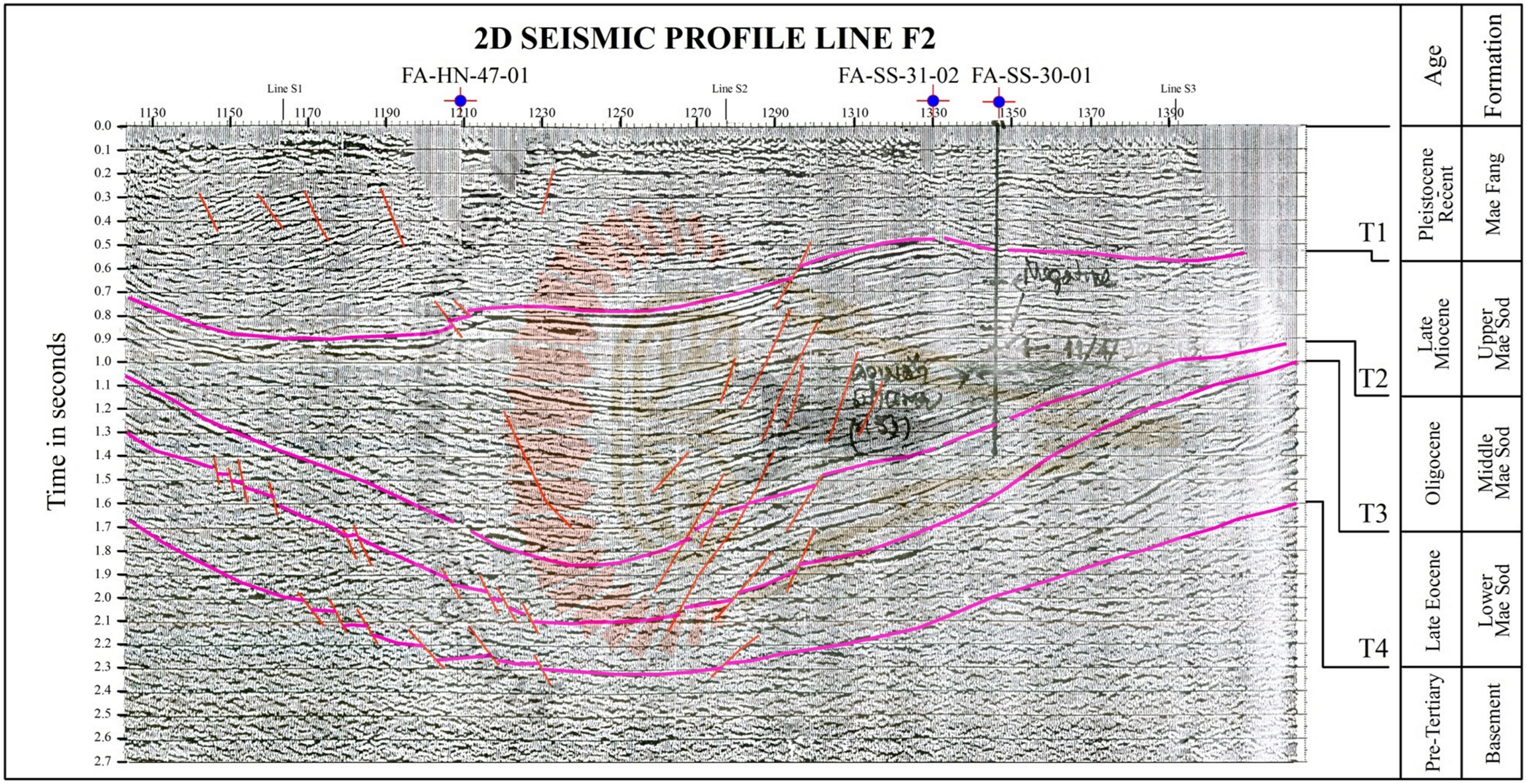

Figure 4.13 Interpretation of 2D seismic profile line F2 (after Defence Energy Department, 1990).

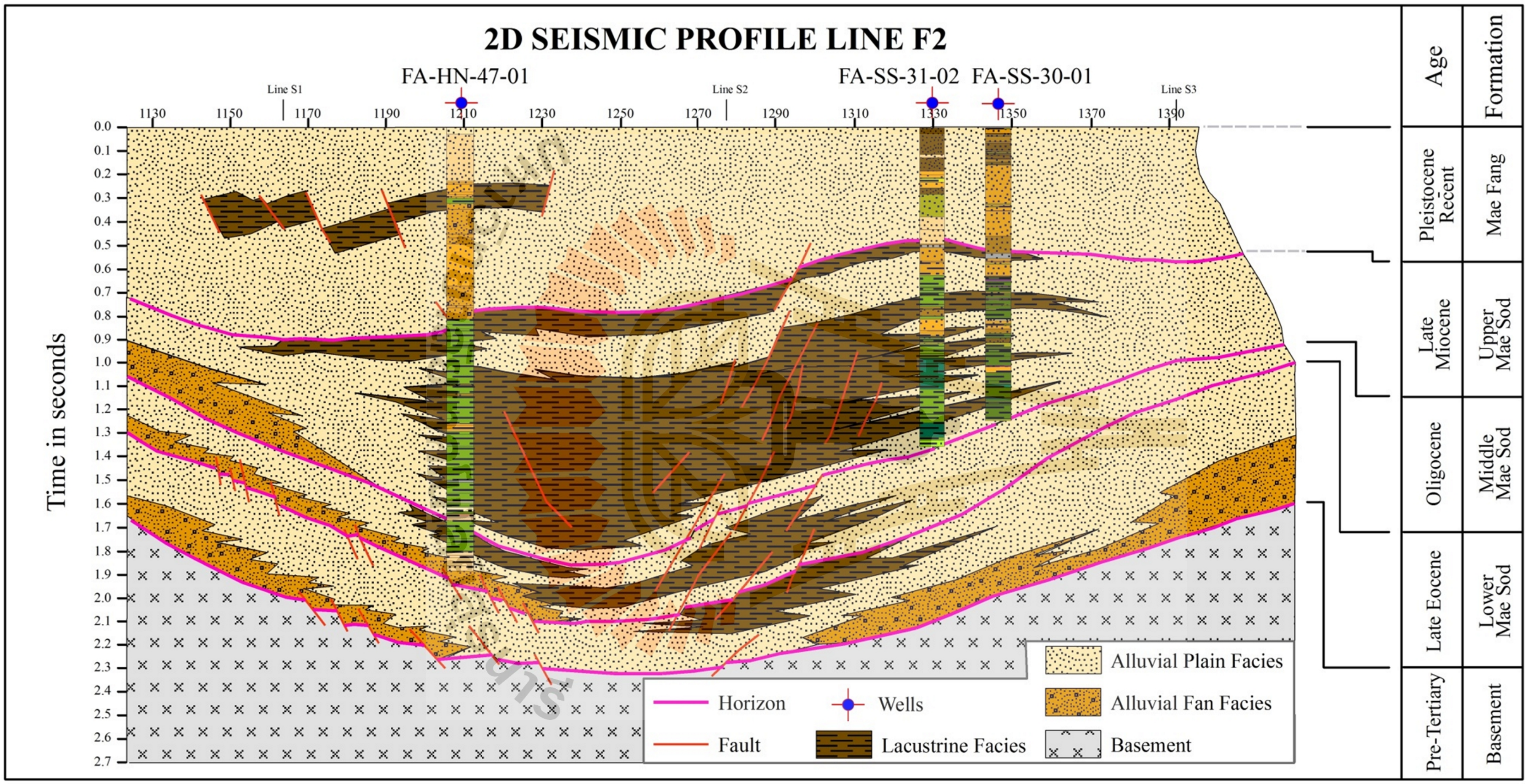

Figure 4.14 Facies interpretation from 2D seismic profile line F2.

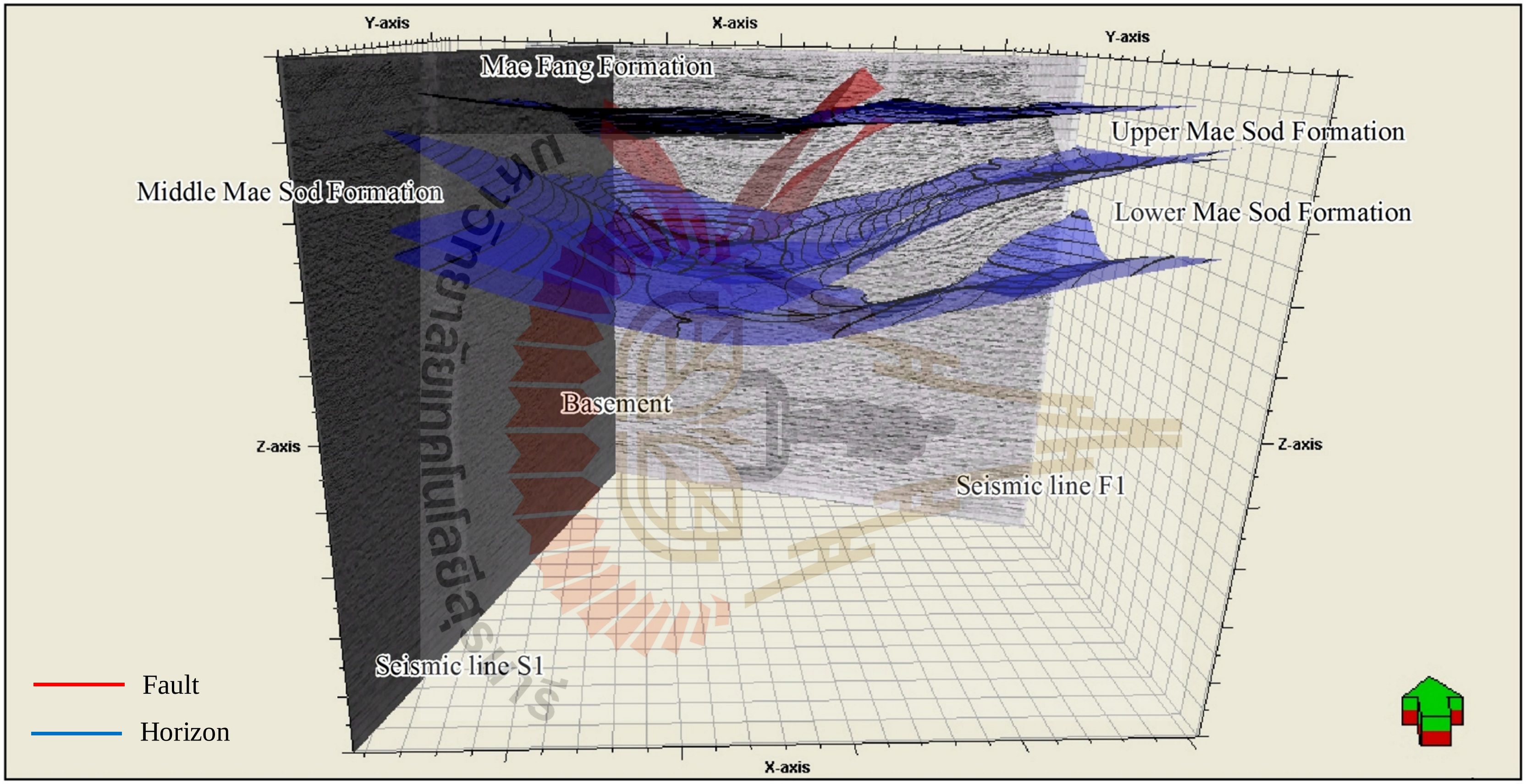

Figure 4.15 Interpretation of 3D seismic diagram based on 2D seismic data.

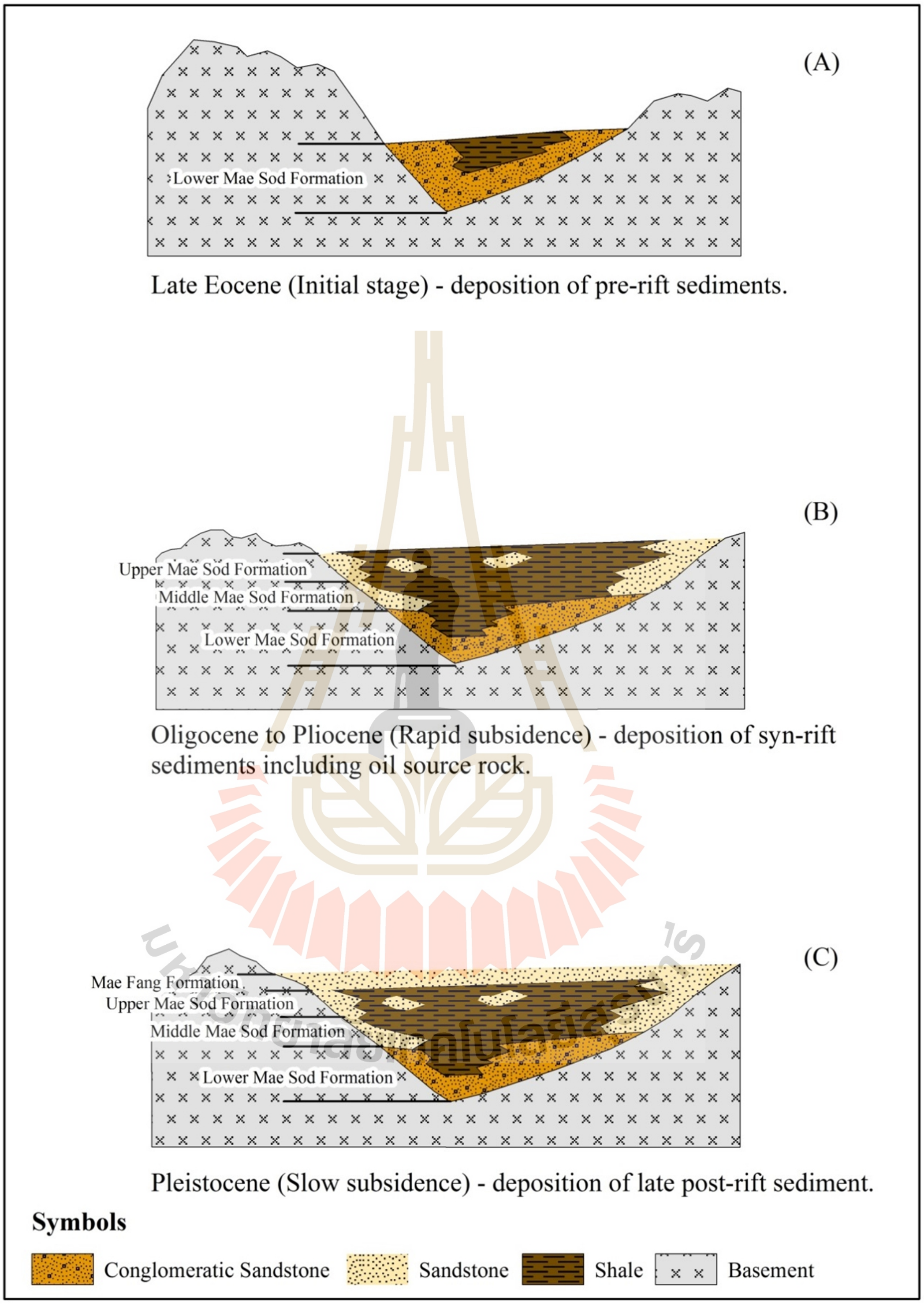

Figure 4.16 Basin evolution and sedimentary facies of the Fang Basin.

4.4.1 Petroleum source rock

4.4.1.1 Organic matter content

The whole section of Mae Sod Formation below the depth of 2,500 feet was analyzed for it total organic carbon content (TOC). It is divided into three parts based on its age from Late Eocene, Oligocene and Late Miocene – Pliocene.

The values of TOC of upper Mae Sod Formation, at depth of 2,500 to 5,900 feet, are in the range of 2.05 – 4.27%. The values of middle Mae Sod Formation, at depth 5,900 to 6,700 feet, are in range of 1.78 – 3.13% . The values of lower Mae Sod Formation, at depth of 6,700 to 9,100 feet, is in the range of 2.05 – 39.07% (Figure 4.17).

According to the headspace gas analysis as shown in Figures 4.18(a) and 4.18(b), the result is consistent with the TOC values which are fair to excellent. It indicates that the potential of the whole section of Mae Sod Formation is a good source rock.

4.4.1.2 Organic matter type

The modified Van Krevelen diagram comparing hydrogen index (mg HC/g TOC) and oxygen index (mg HC/g TOC) data obtained from rock-eval pyrolysis analysis is the standard practice for indicating the kerogen types of the source rock. The result of Mae Sod Formation indicates that the organic matter of the upper Mae Sod Formation is type I/II oil prone (Figure 4.19) and the middle and lower Mae Sod Formations are type II/III mixed oil and gas prone kerogen (Figure 4.20-4.21).

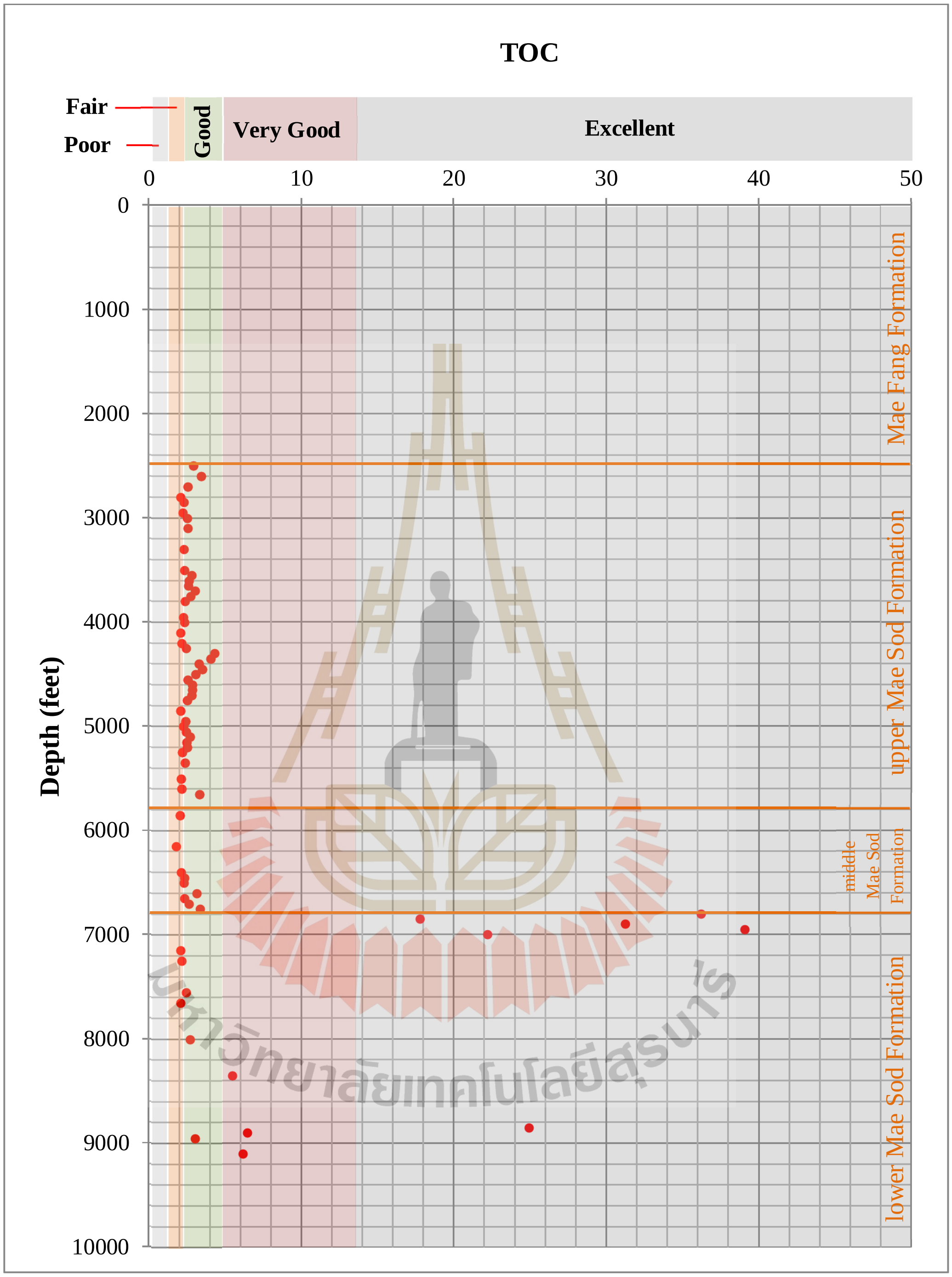

Figure 4.17 Total organic carbon content (TOC) in %wt. of the Mae Sod Formation.

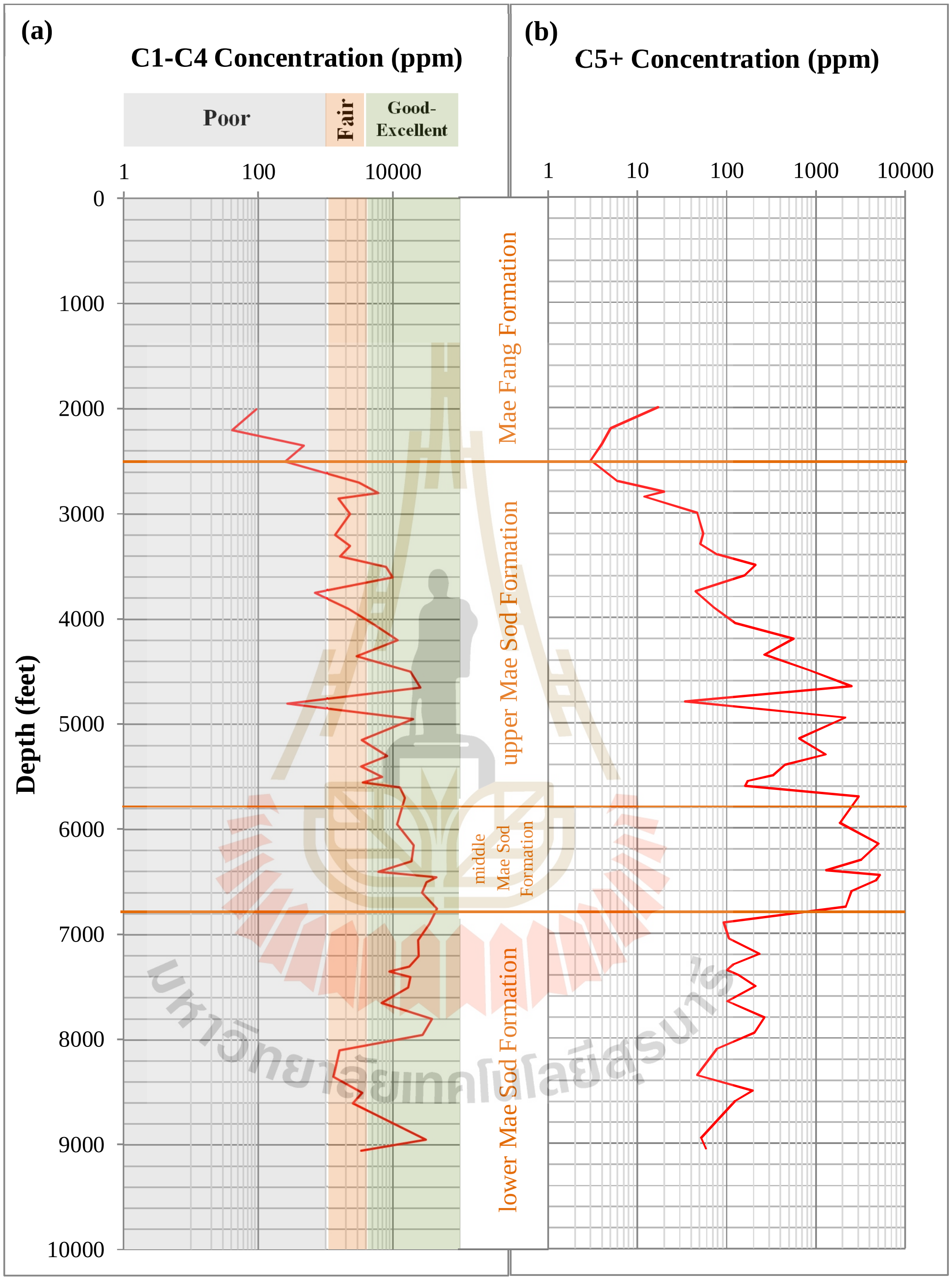

Figure 4.18 Headspace gas analyses of the Mae Sod Formation (a) C1-C4 concentration and (b) C5+ concentration.

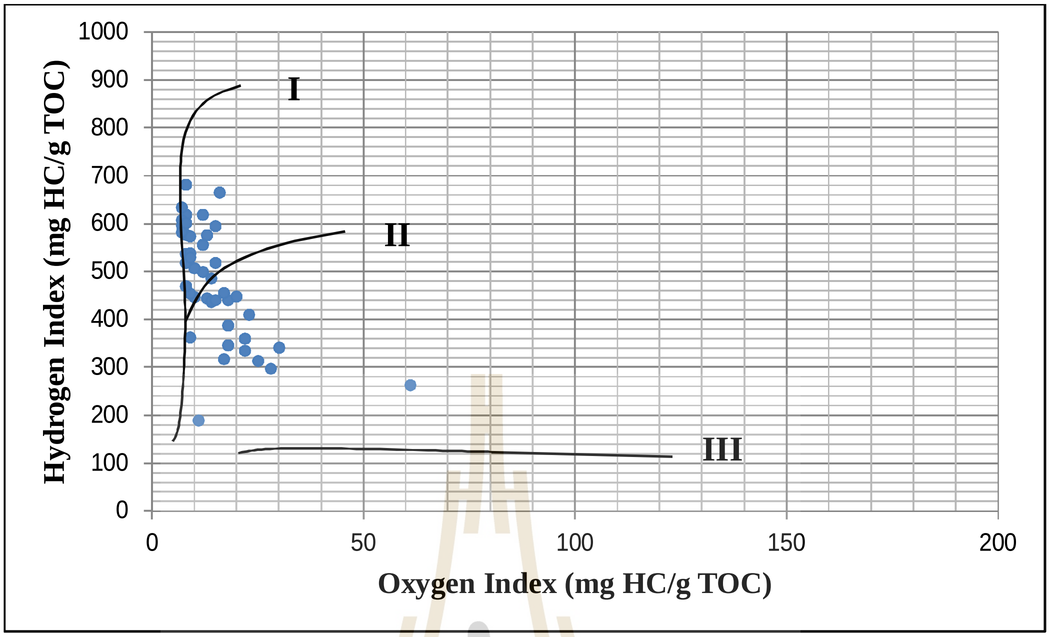

Figure 4.19 Plot of hydrogen index (HI) versus oxygen index (OI) of upper Mae Sod Formation.

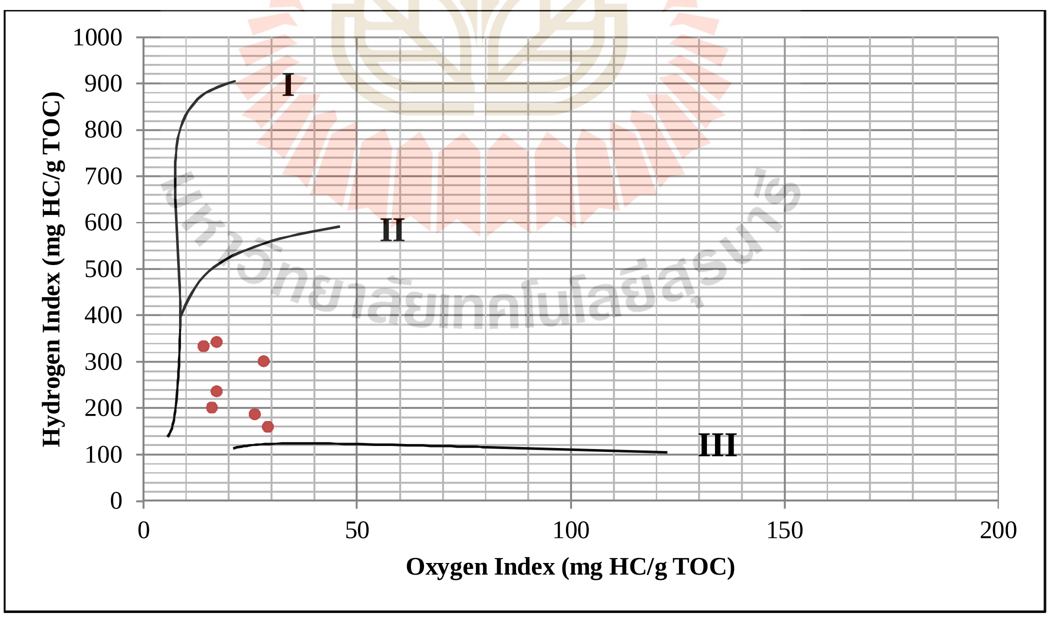

Figure 4.20 Plot of hydrogen index (HI) versus oxygen index (OI) of middle Mae Sod Formation.

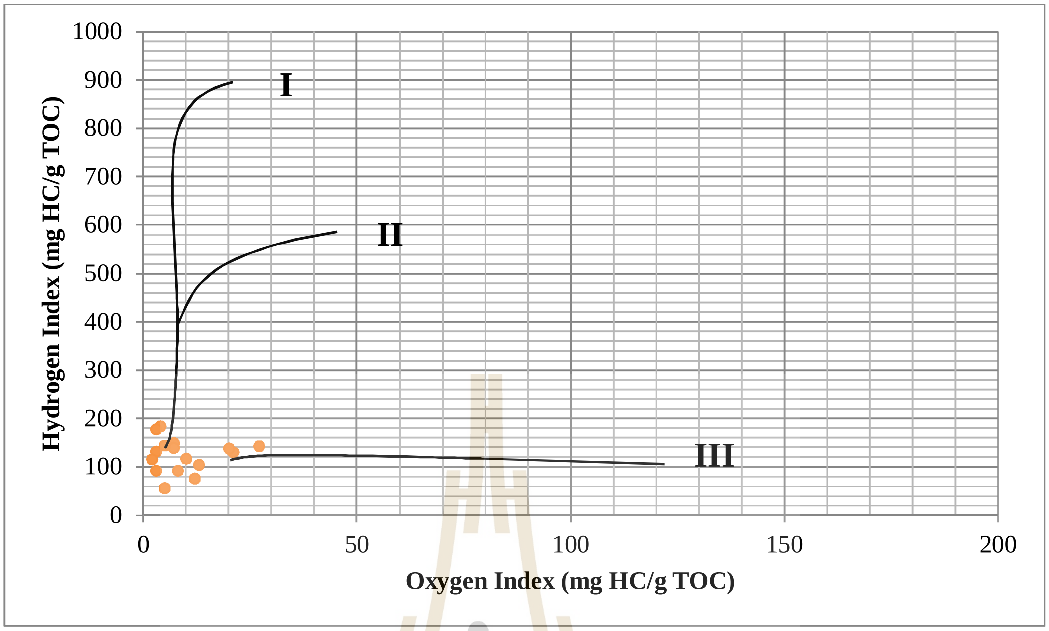

Figure 4.21 Plot of hydrogen index (HI) versus oxygen index (OI) of lower Mae Sod Formation.

4.4.2 Thermal maturation

There are many methods to indicate the thermal maturity level of source rocks, such as, vitrinite reflectance (%R_o) (Figure 4.22(a)), rock-eval pyrolysis (Figure 4.22(b)) and headspace gas analysis methods (Figure 4.23(a)), iC4/nC4 ratio (Figure 4.23(b)) and Production Index (Figure 4.24(a)).

The upper Mae Sod Formation has Ro in the range of 0.31 - 0.61%, Tmax has values in the range of 428° – 447°C, PI values in the range of 0.01 – 0.1. The middle Mae Sod Formation has Ro value in the range of 0.67 – 0.76, Tmax in the range of 447° – 458°C and PI in the range of 0.09 – 0.25. The lower Mae Sod has Ro value in range of 0.81 – 1.31%, Tmax 448° - 491°C and PI 0.04 - 0.17.

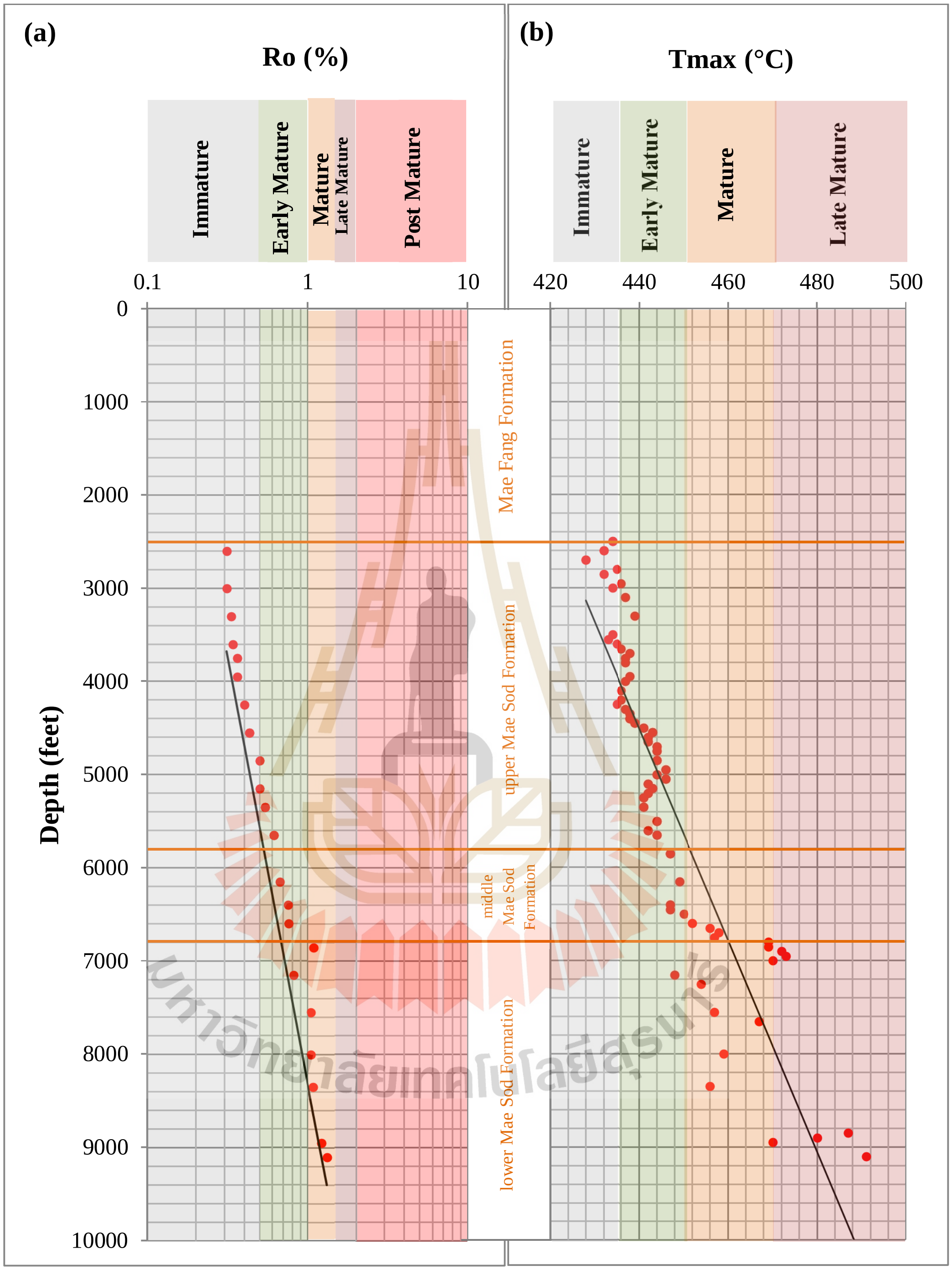

Figure 4.22 Maturity of source rock of Mae Sod Formation. (a) Ro (%) and (b) Tmax (°C).

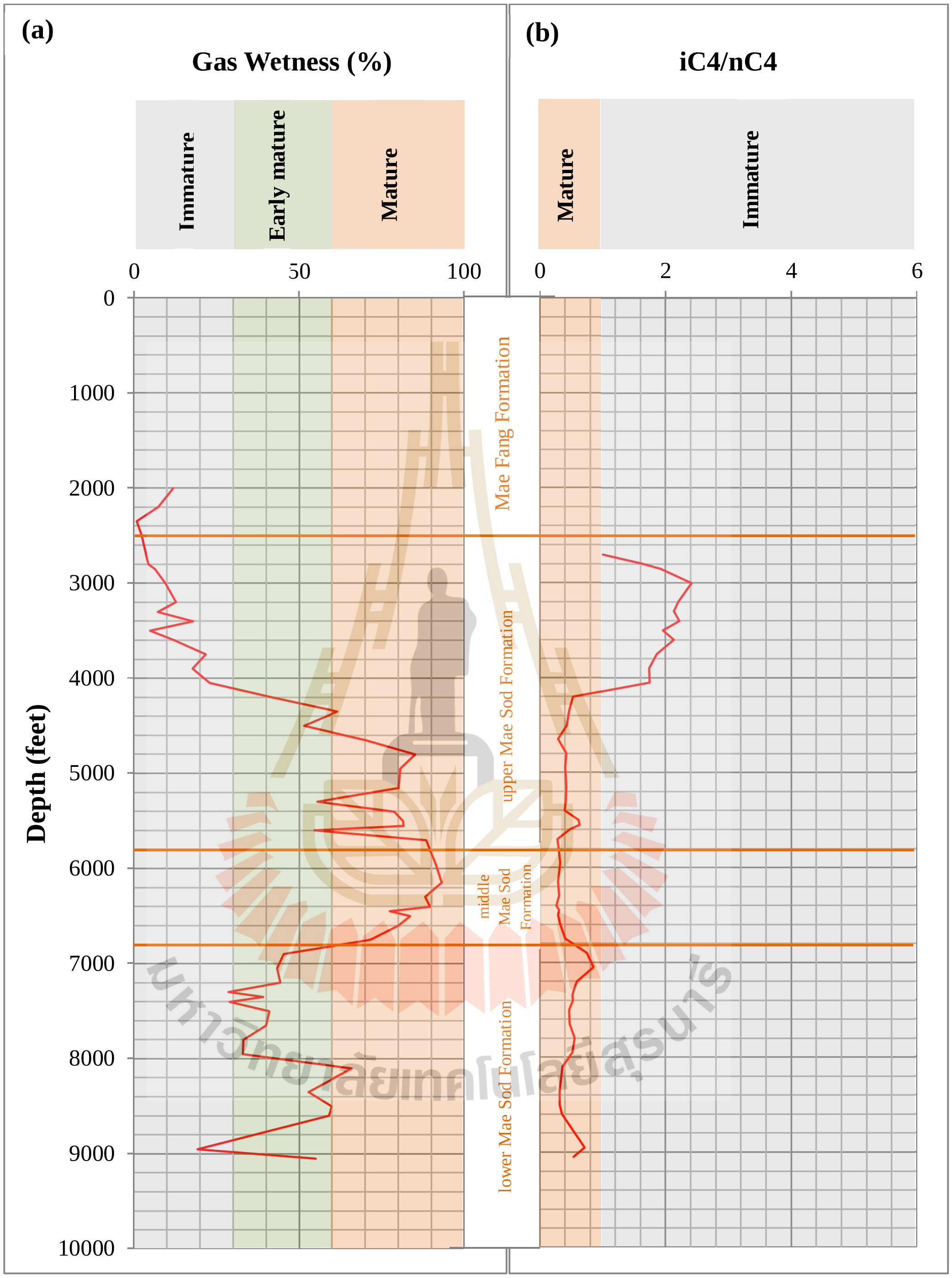

Figure 4.23 Headspace gas analysis for hydrocarbon maturation indicator (a) from gas wetness. (b) from of iC4/nC4 ratio.

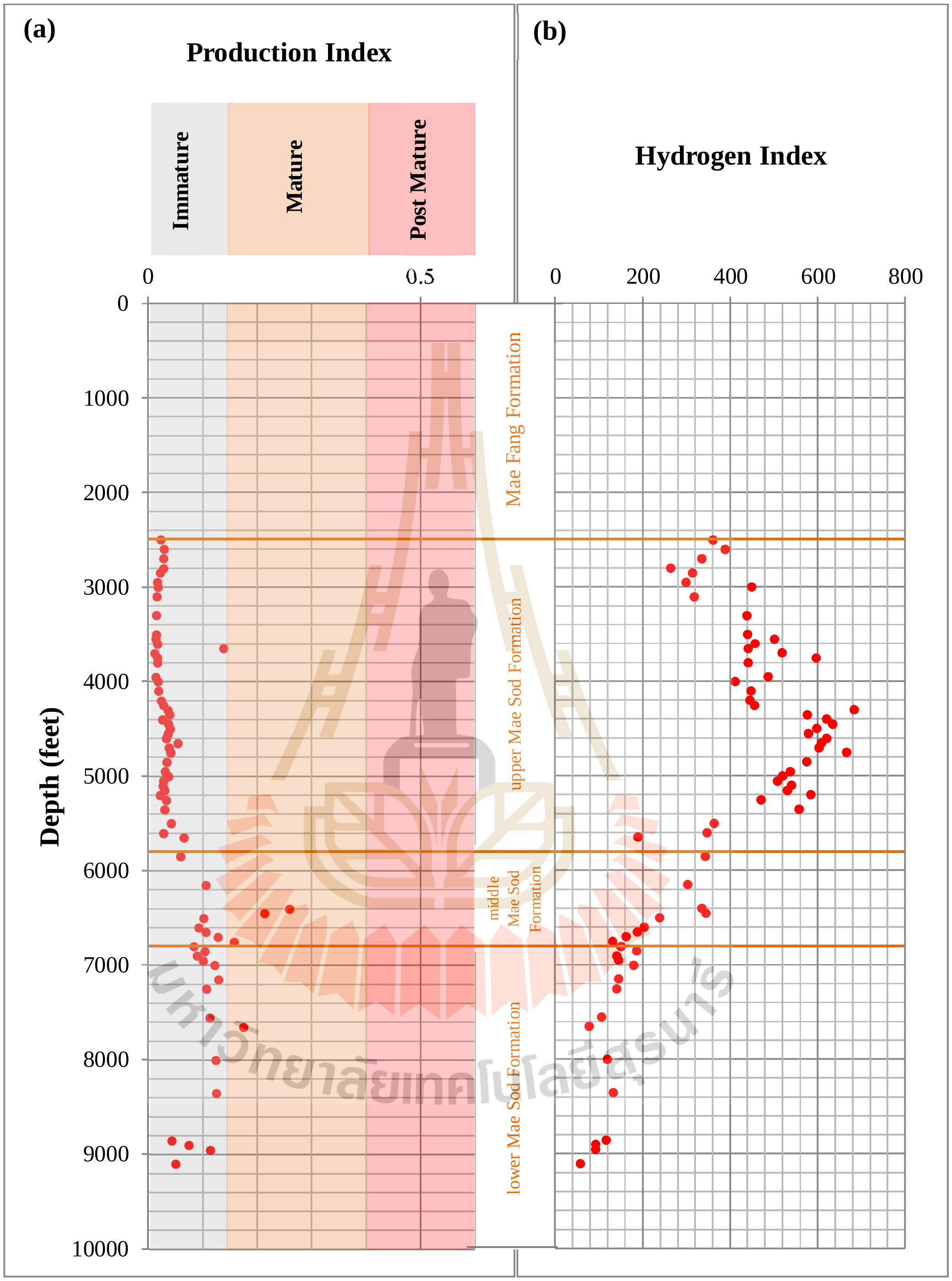

Figure 4.24 (a) Maturity of source rock of Mae Sod Formation from production index. (b) hydrogen index.

In conclusion, the result of Ro indicates the source rock is early mature at a depth of 5,600 to 8,300 feet and mature below 8,300 feet.

The result of Tmax indicates that the source rock is early mature at a depth of 4,000 to 4,700 feet, mature at 4,700 to 7,900 feet and late mature below 7,900 feet.

The result of PI indicates that most of source rock is immature and some samples below 6,400 to 7,600 feet are mature. PI (Production Index) value in a range of 0.15 – 0.40 indicates that the source rock is mature for hydrocarbon generation (Peters and Cassa, 1994).

The result of gas wetness indicates that the source rock is early mature between a depth of 4,160 to 4,600 feet, mature at 4,600 to 6,800 feet deep and late mature at 6,800 feet to total depth.

Finally, the result of iC4/nC4 ratio indicates that the source rock is mature below a depth of 4,180 feet to total depth.

Table 4.1 Summary of organic richness, thermal maturity and kerogen type of source rock of the Mae Sod Formation.

<table>
<tr><th colspan="4">Defense Energy department (2006)</th><th colspan="4">This study</th></tr>
<tr><th>Depth (ft.)</th><th>Organic richness</th><th>Thermal maturity</th><th>Kerogen type</th><th>Depth (ft.)</th><th>Organic richness</th><th>Thermal maturity</th><th>Kerogen type</th></tr>
<tr><td>500 - 2,500</td><td>Poor</td><td>Immature</td><td>III/IV</td><td>500 - 2,500</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td rowspan="2">2,500 - 5,900</td><td rowspan="2">Good to Very good</td><td rowspan="2">Immature</td><td rowspan="2">I/II</td><td>2,500 - 5,600</td><td>Good to very good</td><td>Immature</td><td>I/II</td></tr>
<tr><td>5,600 - 5,900</td><td>Good</td><td>Mature</td><td>II/III</td></tr>
<tr><td>5,900 - 6,700</td><td>Good to very good</td><td>Early mature</td><td>II/III</td><td>5,900 - 6,700</td><td>Fair to good</td><td>Mature</td><td>II/III</td></tr>
<tr><td rowspan="2">6,700 - TD</td><td rowspan="2">Fair to good</td><td rowspan="2">Mature</td><td rowspan="2">III</td><td>6,700 - 7,900</td><td>Good to excellent</td><td>Mature</td><td>II/III</td></tr>
<tr><td>7,900 - TD</td><td>Good to excellent</td><td>Late mature To Over mature</td><td>III</td></tr>
</table>

4.4.3 Thermal maturity modeling

The study of time and temperature model for the San Sai oil field follows the Lopatin’s method or TTI by using PetroMod11.1D software. The lithological data from Wells FA-SS-35-04 and FA-HN-47-01 are used in the modeling.

The required data for basin modeling were obtained from two wells, including Well FA-HN-47-01 and Well FA-SS-35-04. The geochemical data required for PetroMod11.1D modeling are list in Table 4.2. The results were burial history, Time Temperature Index (TTI), hydrocarbon generation, temperature profile and thermal maturity.

The result of modeling from Well FA-SS-35-04 indicates that the source rock is mature in middle Mae Sod Formation (Oligocene) below 5,900 feet and over mature at lower Mae Sod formation below 6,800 feet (Figure 4.29).

The result of modeling from Well FA-HN-47-01 indicates that the source rock is mature in lower of upper Mae Sod Formation below 5,500 feet (Figure 4.30).

Table 4.2 Geochemical analysis data used in the modeling.

Well	**TOC% (average)**	**Geothermal Gradient (°C/100m)**	**Kerogen type**			**Source type**	**Potential Petroleum source rock**
			I	**II**	**III**		
FA-HN-47-01	2.48	1.73		X	X	Oil/Gas prone	Good
FA-SS-35-04	5.56	4.32		X	X	Oil/Gas prone	Good

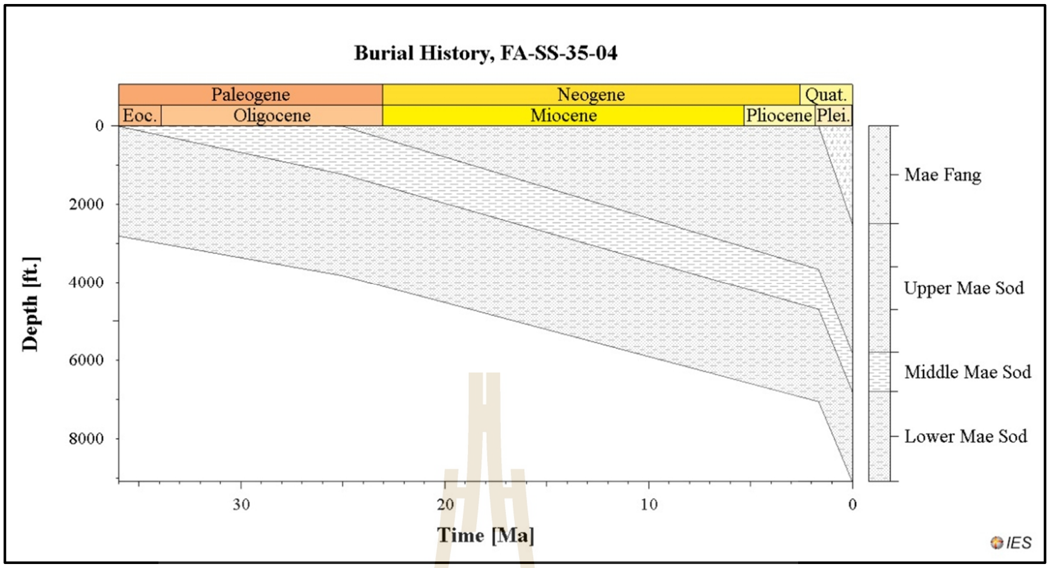

Figure 4.25 Burial history of Well FA-SS-35-04.

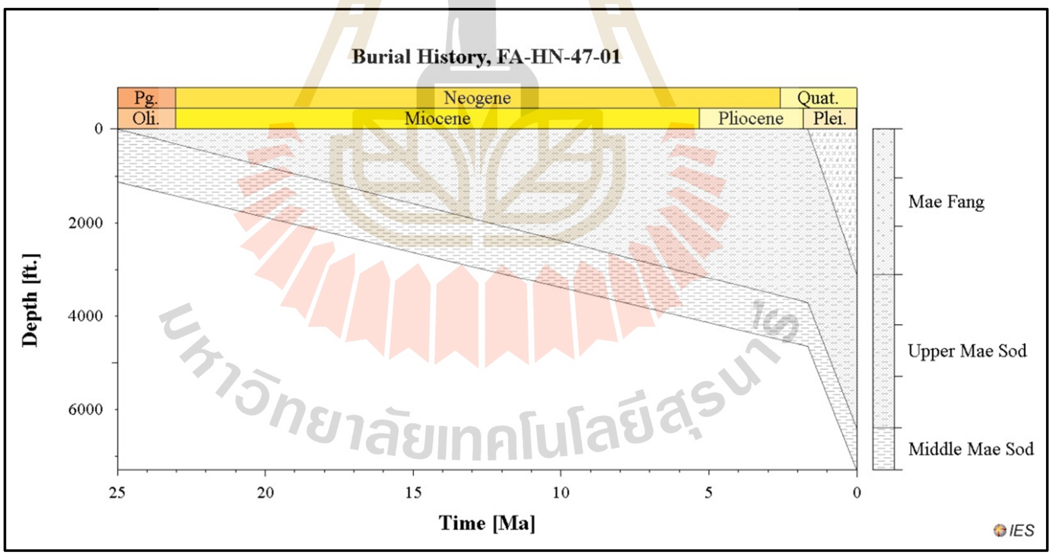

Figure 4.26 Burial history of Well FA-HN-47-01.

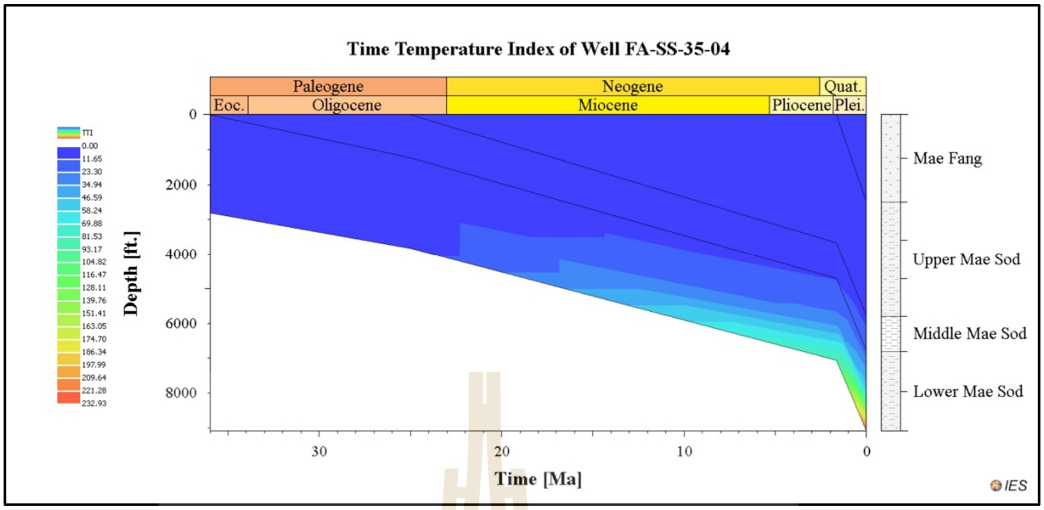

Figure 4.27 Thermal maturity model (TTI) of Well FA-SS-35-04.

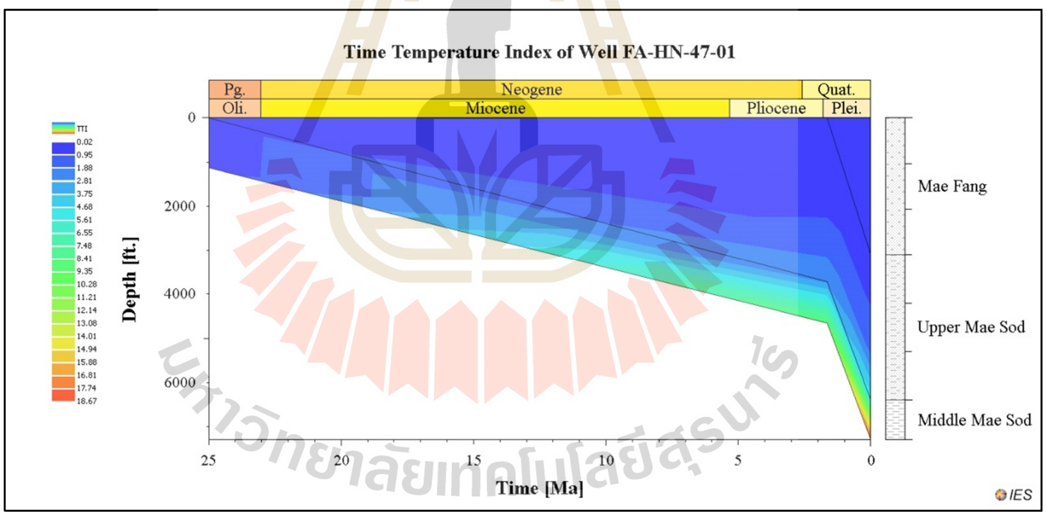

Figure 4.28 Thermal maturity model (TTI) of Well FA-HN-47-01.

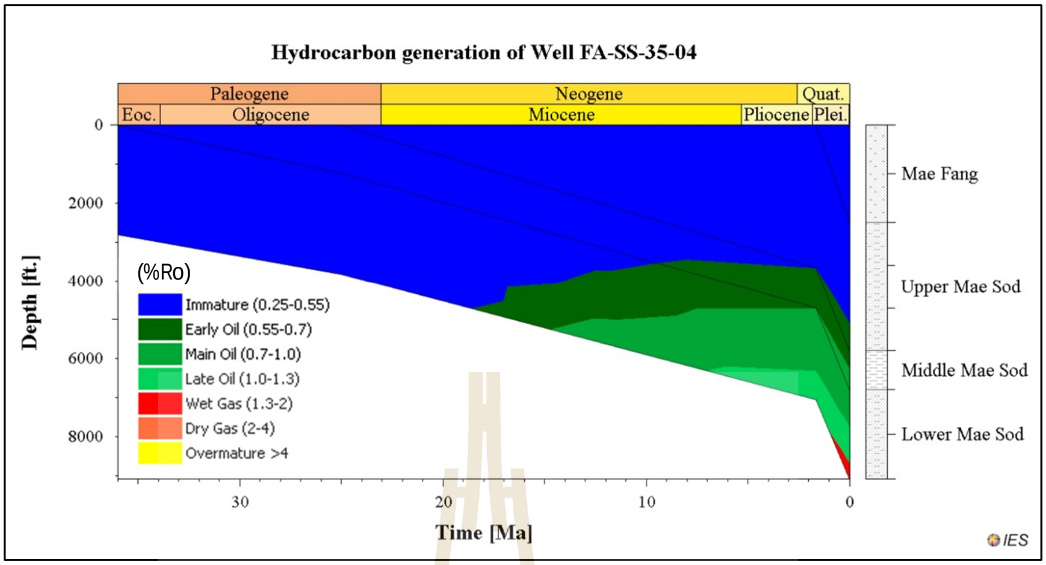

Figure 4.29 Hydrocarbon generation model of well FA-SS-35-04.

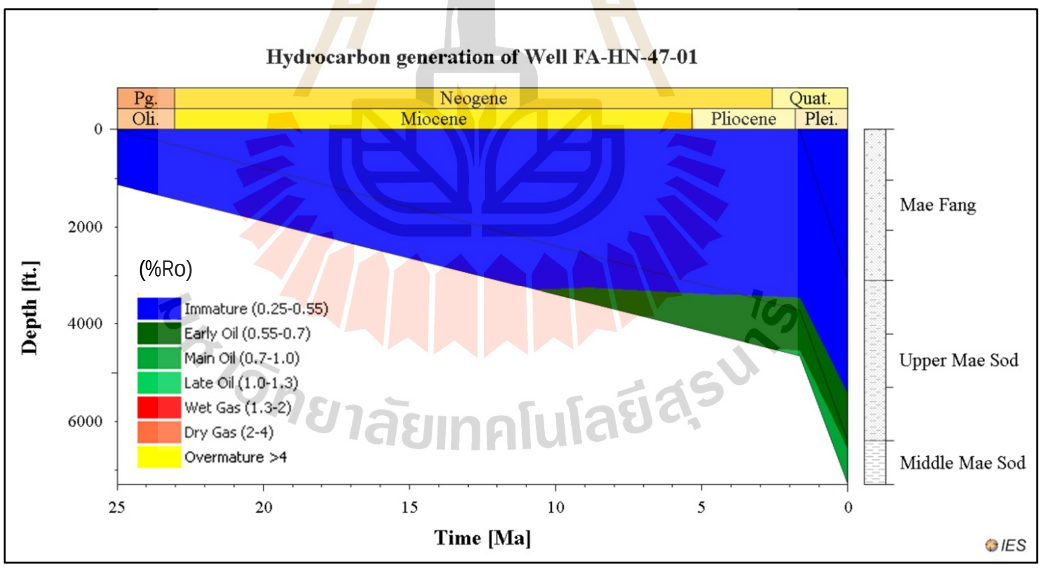

Figure 4.30 Hydrocarbon generation model of well FA-HN-47-01.

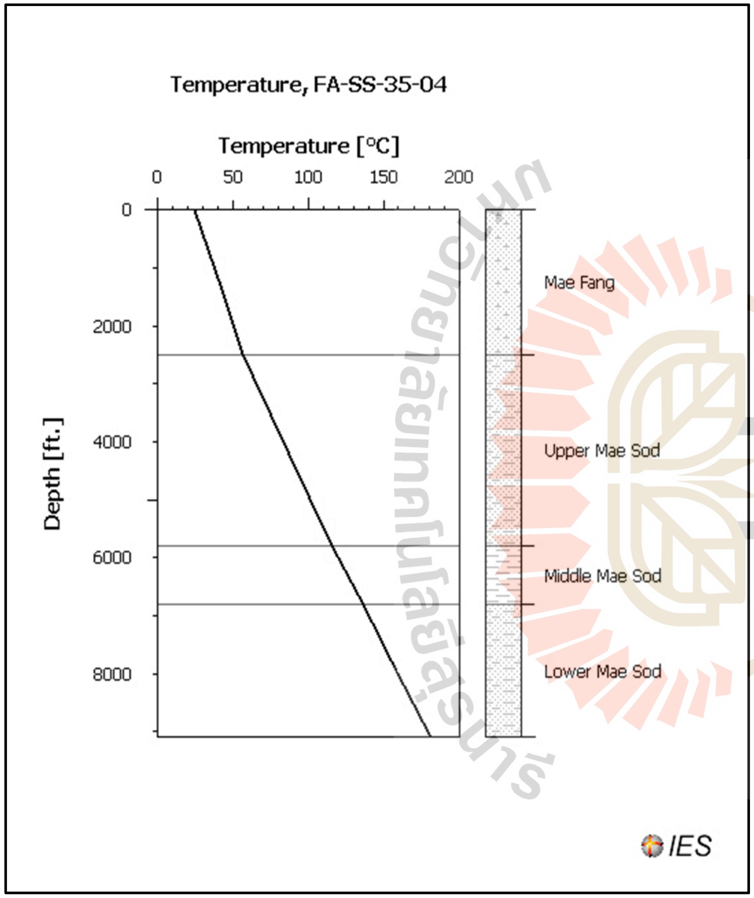

Figure 4.31 Temperature profile of Well FA-SS-35-04.

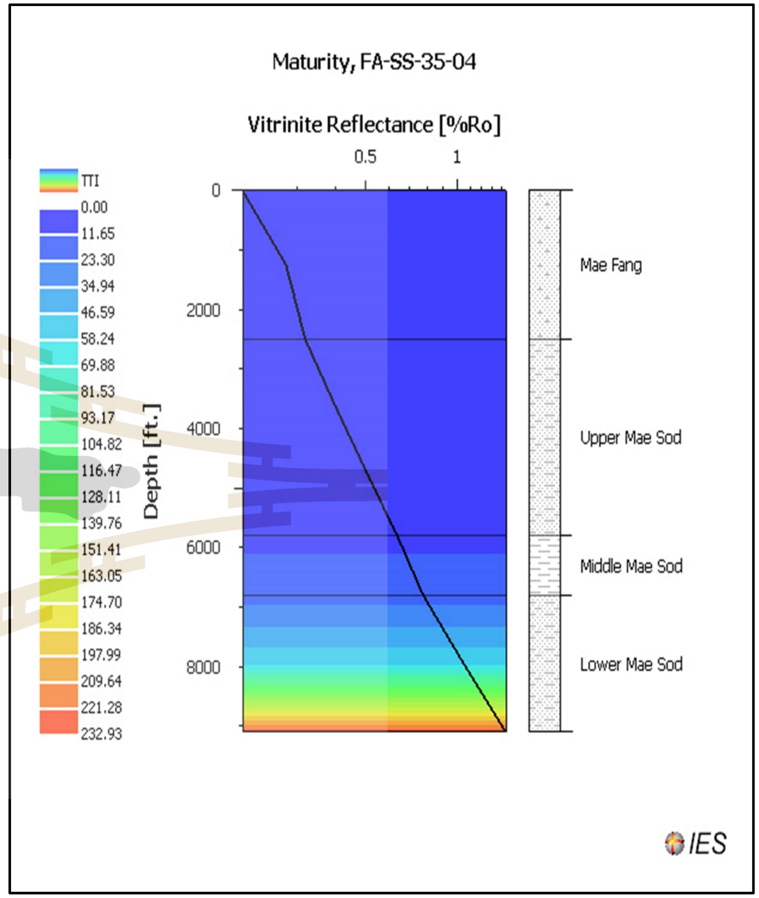

Figure 4.32 Overlaying of Ro with TTI of Well FA-SS-35-04.

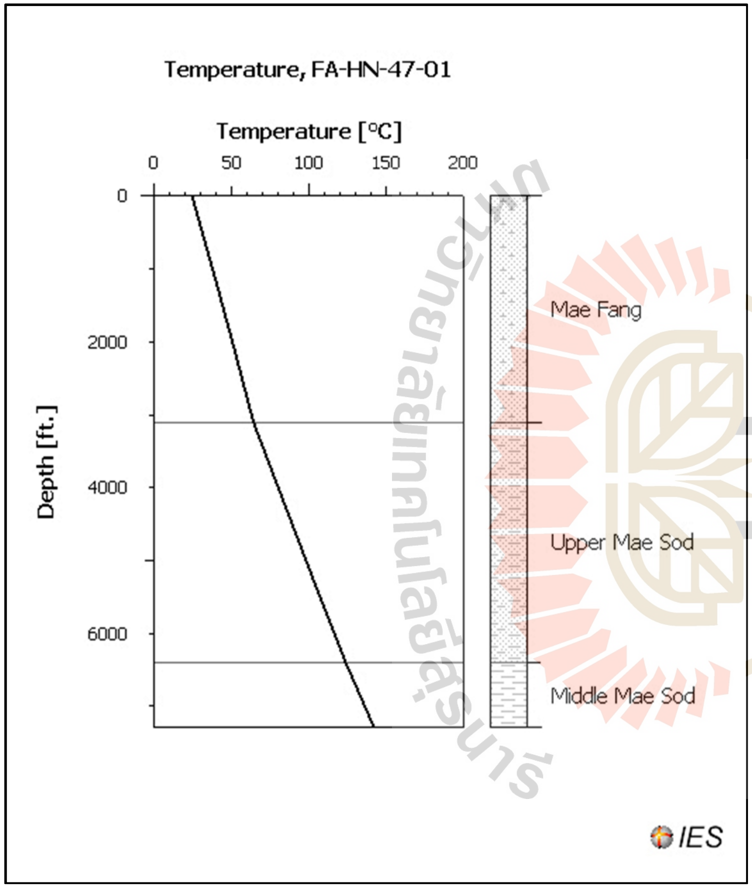

Figure 4.33 Temperature profile of Well FA-HN-47.-01.

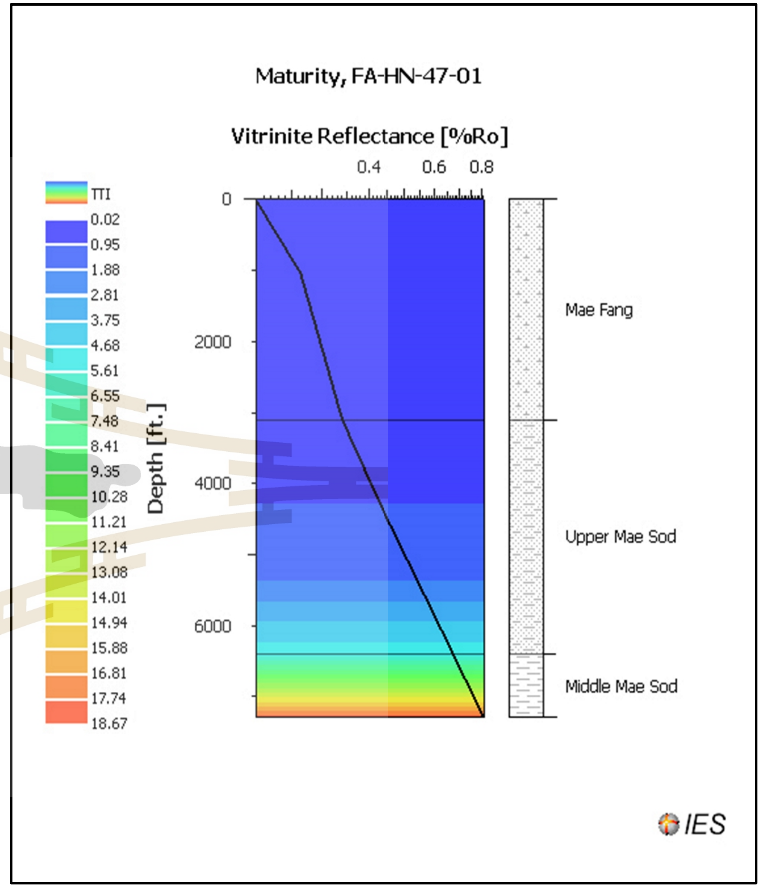

Figure 4.34 Overlaying of Ro with TTI of Well FA-HN-47-01.

4.4.4 Reservoir and Accumulation

4.4.4.1 Reservoir

The meandering fluvial facies of upper Mae Sod Formation is the main reservoir of the San Sai oil field. The analysis of reservoir rock from Core Laboratory International (1987) from Well FA-SS-33-03 indicates that the average porosity between 3,695-3,707 feet is 22.7%. This interval consists of coarse- to very coarse-grained sandstone. The well FA-SS-30-01 (located west of Well FA-SS-33-03) comprises fine- to medium-grained sandstone of similar average 22% porosity.

4.4.4.2 Migration pathway

Petroleum migration results from buoyancy force which is the main driving force. The migration pathway of the San Sai Oil field from the kitchen areas (approximately 7.7 km^2.) to the reservoir rock is shown in Figure 4.35. In 3D view as shown in Figure 4.36, it demonstrates that the hydrocarbon migrates through fault zone to the reservoir rock (Figure 4.37). The San Sai oil field traps are usually a combination trap of fault and stratigraphic traps.

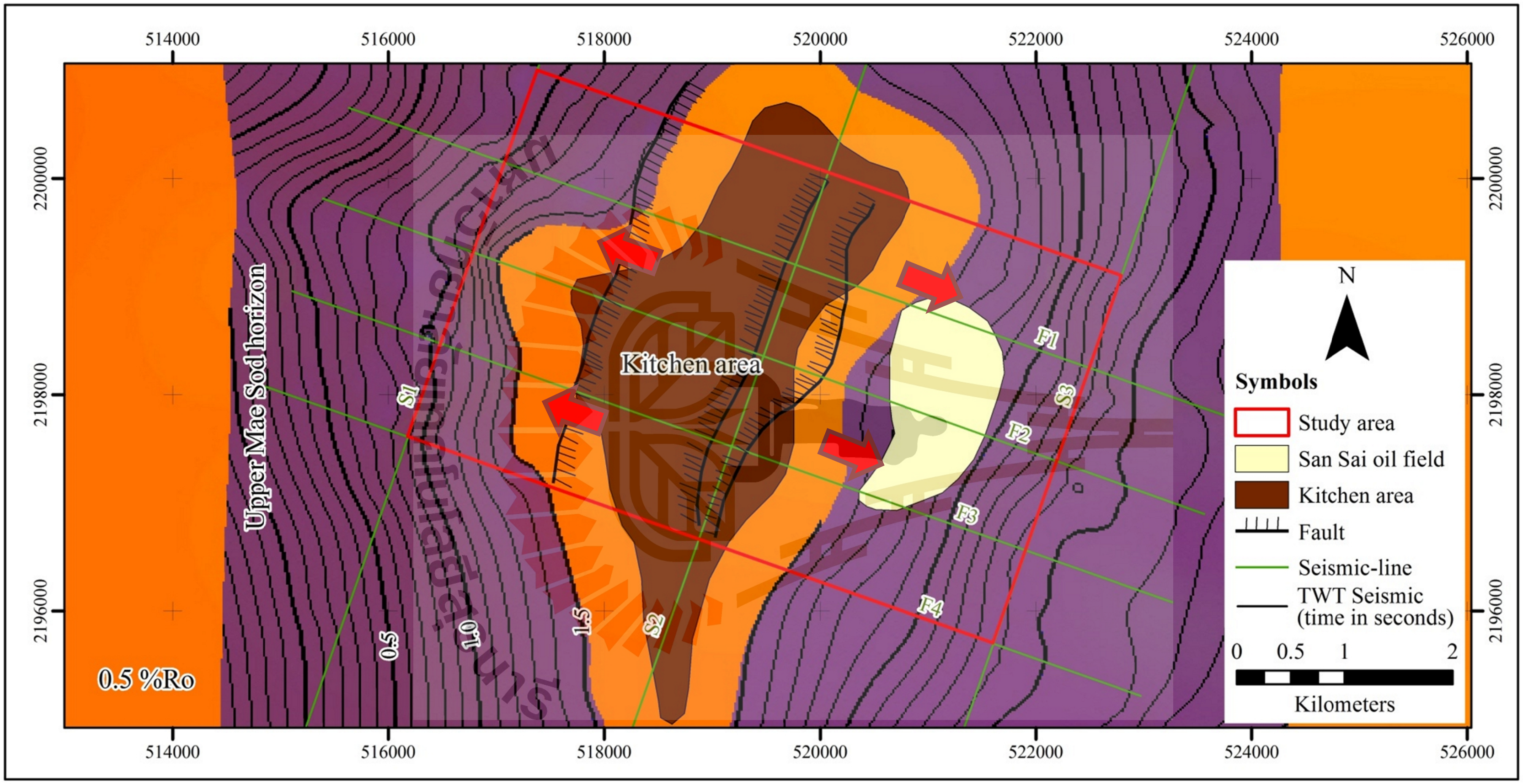

Figure 4.35 Top view of hydrocarbon migration pathway from mature source rock of San Sai oil field.

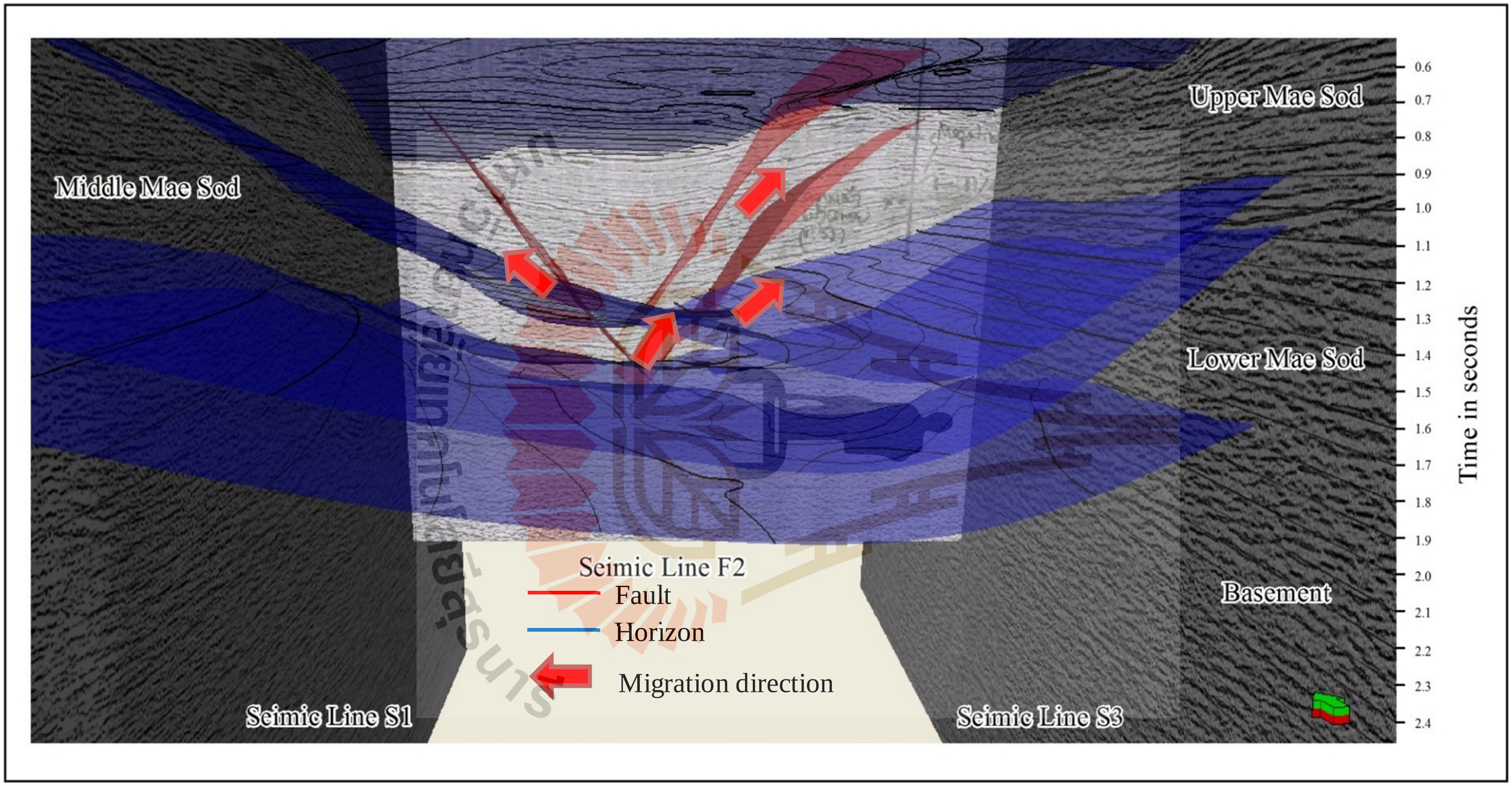

Figure 4.36 3D Cross section (based on 2D seismic interpretation) of San Sai oil field, showing hydrocarbon migration pathway from mature source rock.

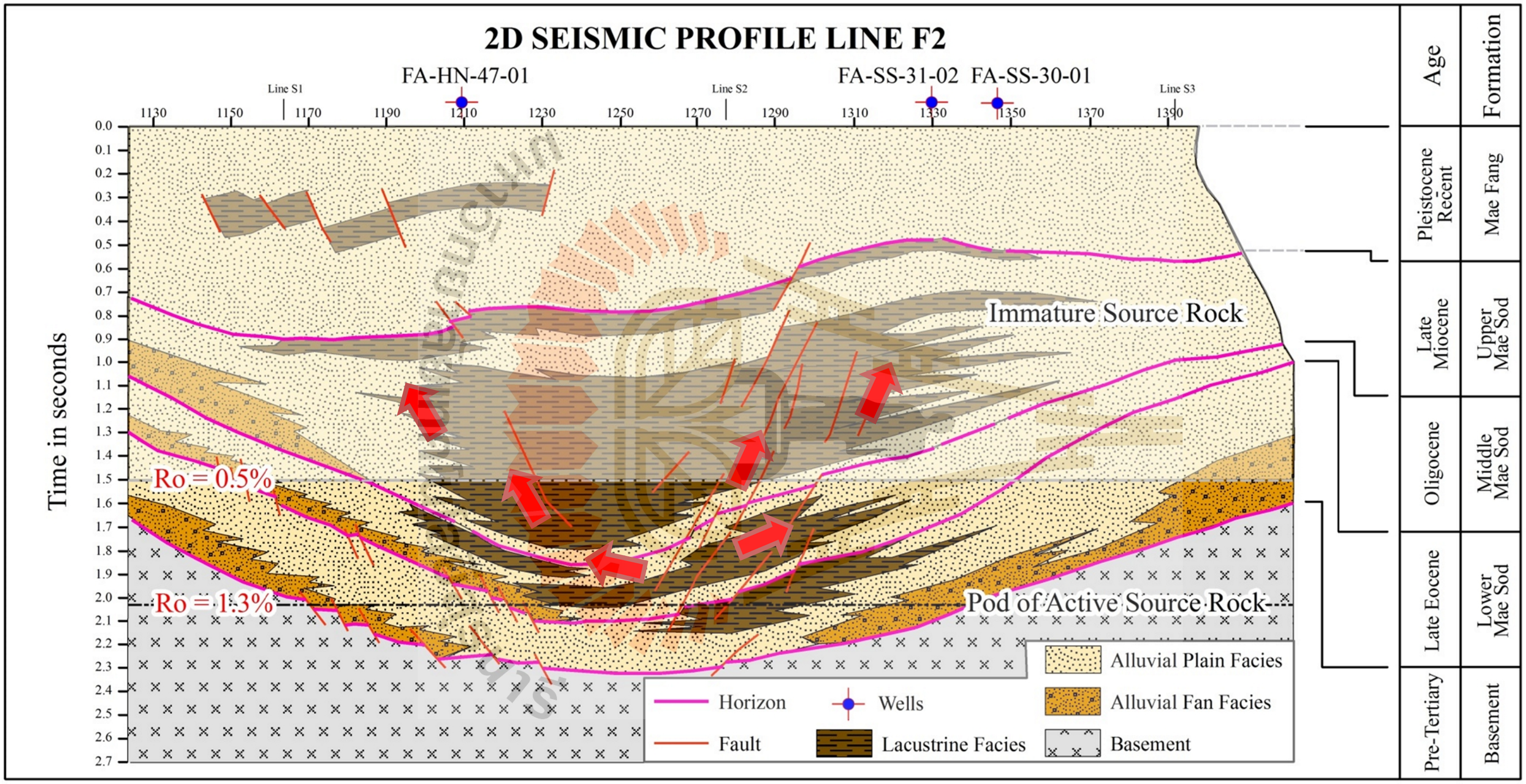

Figure 4.37 Cross section of the San Sai oil field showing the migration pathway and oil accumulations.

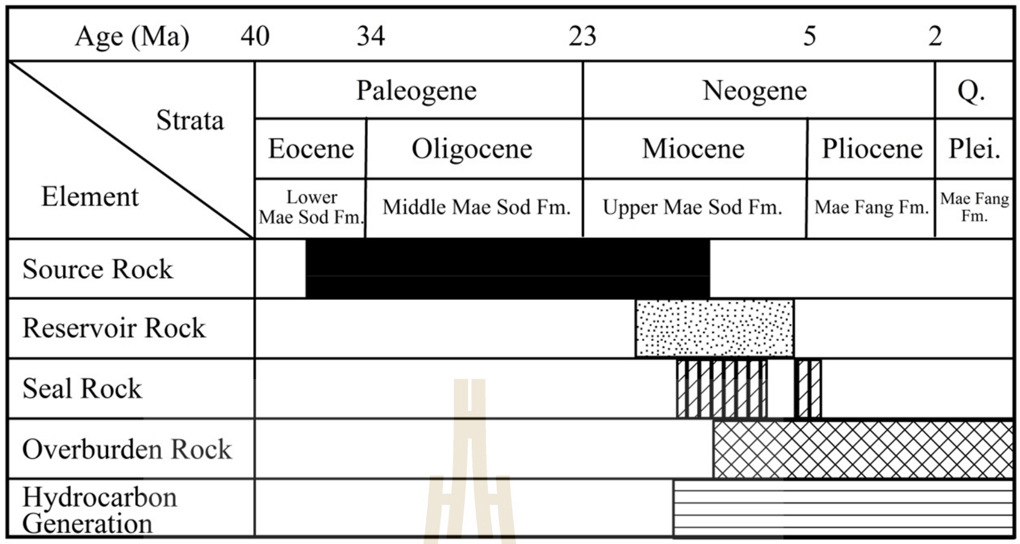

Figure 4.38 Event chart of the petroleum system of the San Sai oil field, Fang Basin.

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

This study interpreted the sedimentary facies, basin evolution and petroleum potential of the San Sai oil field by using the available well and analysis. The facies analysis determined its basin evolution sedimentary accumulation and environment of deposition. Petroleum potential assessment was performed based on data from seven wells and seven lines of 2D seismic profiles to simulate the subsurface model. The petroleum geochemical properties are interpreted from the result of laboratory testing to determine petroleum source rock property including organic richness, organic matter type, level of maturation and hydrocarbon generation.

5.1.1 Sedimentary facies and Basin evolution

The sedimentary facies of the San Sai oil field can be divided into two formations. The upper part is Mae Fang Formation and the lower part is Mae Sod Formation. These two formations comprise five associated environment of deposition. The Mae Fang Formation (Pleistocene to Recent in age), 2,500 feet thick, is composed mainly of clay, coarse- to very coarse-grained sandstones, gravel and carbonized woods which were deposited in fluvial environment. It overlies unconformably on the Mae Sod Formation. The Mae Sod Formation, overlying unconformably on pre-Tertiary basement, can be divided into three parts which comprise four depositional environments. The upper Mae Sod Formation is divided into two environments and represents the reservoir rocks and traps. The upper part, 1,400 feet thick, is composed mainly of shale interbedded with medium- to very coarse-grained sandstones. It represents a marginal lacustrine environment (Late Miocene to Pliocene in age). The lower part, ranging up to 1,000 feet, is composed mainly of thick shale interbedded with fine-grained sandstone. It indicates a shallow to deep lacustrine environment (Early Late Miocene in age). The middle Mae Sod Formation, 800 feet in thickness, is composed mainly of dark grey shale, fine-grained sandstone and coal. It indicates a marginal and deep lacustrine environment (Oligocene in age). These strata are the main source rocks for petroleum. The lower Mae Sod Formation, 2,500 feet thick, comprises mainly thick shale and sandstone interbedded with coal in the lower part. It indicates a marginal lacustrine environment (Late Eocene in age).

5.1.2 Petroleum system

5.1.2.1 Petroleum source rock

The upper Mae Sod Formation is a good to very good source rock based on the high TOC (2.05-4.27%wt TOC). Rock-eval pyrolysis was performed and the result indicates a very good kerogen quality and hydrocarbon generation below level of 5,600 feet. Hydrogen and oxygen indices indicate type I and type II oil prone kerogen. This section is immature to early mature for hydrocarbon generation.

The middle Mae Sod Formation is a fair to good (1.78 – 3.13 %wt. TOC) source rock. Hydrogen index is tending towards a mixed oil-prone and gas-prone assemblage. Visual kerogen typing has revealed mixed type II and type III. The section is thermally mature for hydrocarbon generation.

The lower Mae Sod Formation in general the organic richness is considered to be good source rock with occasional excellent richness in the coal bed. Hydrogen and oxygen indices show predominantly gas prone kerogen. This section is thermally mature to late mature.

5.1.2.2 Petroleum accumulation

The hydrocarbons migrated from the kitchen areas which are mostly located in the basin center. The amount of hydrocarbons that had been generated from mature source rocks and then migrated to accumulate in the traps through cracks and faults were limited. The San Sai oil field traps are usually a combination of fault and stratigraphic trap. Hydrocarbon generation occurred mainly in Middle Miocene after main traps were formed.

5.2 Recommendations

The study of basin analysis and petroleum system of this study contained a limited available data, it may have some errors. More data i.e. 3D seismic profiles and new well data should be obtained for more accurate identification of potential reservoir and migration pathway. Moreover, the new geochemical data should be obtained, it is very importance for evaluation of the petroleum potential in the future.

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