DETECTING AND PREDICTING THE DISTRIBUTION OF UNPRODUCIBLE RESERVOIR SANDSTNES IN BONGKOT FIELD, GULF OF THAILAND

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การค้นหาและการทำนายลักษณะการกระจายตัวของชั้นหินทรายกักเก็บ
ที่ไม่สามารถผลิตปิโตรเลียมบริเวณแหล่งบงกช อ่าวไทย

นางสาววัชรี เกลี้ยงกลม

รายงานนี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิทยาศาสตร์บัณฑิต
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(Dr. Kruawan Jankaew)

Advisor

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บทคัดย่อ

แหล่งบงกชตั้งอยู่ในแอ่งมาเลย์บริเวณพื้นที่อ่าวไทย ภายใต้การสำรวจและผลิตของบริษัท ปตท.สำรวจและผลิตปิโตรเลียม จำกัด (มหาชน) โครงการวิจัยนี้จัดทำขึ้นเพื่อศึกษาลักษณะและการกระจายตัวของชั้นหินทรายกักเก็บที่ไม่สามารถผลิตปิโตรเลียมได้ทั้งในแนวราบและแนวดิ่ง โดยอาศัยข้อมูลความดัน ข้อมูลผลบันทึกโคลนเจาะและข้อมูลหยั่งธรณีหลุมเจาะจำนวน 35 หลุม การกระจายตัวของชั้นหินทรายกักเก็บที่ไม่สามารถผลิตปิโตรเลียมจะแสดงลักษณะที่แย่ที่สุดของชั้นหินทรายกักเก็บในแต่ละบริเวณ โดยมีการศึกษาและรวบรวมข้อมูลทำให้สามารถแบ่งคุณภาพของชั้นหินทรายกักเก็บที่ไม่สามารถผลิตปิโตรเลียมได้ออกเป็น 3 ประเภท ดังนี้ คือ ชั้นหินทรายกักเก็บคุณภาพดี ปานกลาง และแย่ ซึ่งพบว่าการกระจายตัวตามแนวราบบริเวณ Greater Bongkot North เป็นบริเวณที่มีการเปลี่ยนแปลงของชั้นหินทรายกักเก็บที่สามารถผลิตปิโตรเลียมได้ซึ่งอยู่ทางตอนเหนือไปยังทางตอนใต้ของพื้นที่ที่ชั้นหินทรายกักเก็บที่ไม่สามารถผลิตปิโตรเลียมได้กระจายตัวอยู่ ทั้งนี้มีลักษณะการกระจายตัวในแนวดิ่งบริเวณชุดหิน 2C ซึ่งเป็นบริเวณศึกษาที่ตื้นที่สุด มีชั้นหินทรายกักเก็บที่สามารถผลิตปิโตรเลียมได้และชั้นหินทรายกักเก็บคุณภาพดีกระจายตัว แ ต่ในหมวดหิน 1 ซึ่งเป็นบริเวณศึกษาที่ลึกที่สุด มีการกกระจายตัวของชั้นหินทรายกักเก็บที่ไม่สามารถผลิตปิโตรเลียมได้คุณภาพปานกลางและแย่กระจายตัว ทั้งนี้ความแตกต่างของคุณภาพของชั้นหินทรายกักเก็บที่กระจายตัวในแนวราบน่าจะมีผลมาจากชุดลักษณ์ (facies) และหรือโครงสร้างทางธรณีวิทยา ทั้งนี้การกระจายตัวในแนวดิ่งน่าจะมีผลจากความแตกต่างจากการก่อตัวใหม่ของแร่เกิดกับที่ การอัดแน่นและการเชื่อมประสาน

Title (English) : Detecting and predicting the distribution area of unproducible reservoir sandstones in Bongkot field, Gulf of Thailand

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Abstract

Bongkot field is located in the Malay basin, Gulf of Thailand under a concession of PTT Exploration and Production Public Company Limited. The main purposes of this project are to characterize unproducible reservoir sandstones and map horizontal and vertical distribution areas of these unproducible reservoir sandstones in the Bongkot field by using the RFT (pressure, mobility and porosity), mud log and well log data from 35 wells. Unproducible reservoir sandstones are those with the worst reservoir characteristic (porosity and permeability-as reflected by mobility) are reported to be present in the Bongkot field. From this study, the unproducible reservoir sandstones can be classified into three classes; good, moderate and poor reservoirs owing to their mobilities and porosities. The result of horizontal distribution of reservoir sandstones shows that the greater Bongkot North is a transitional zone from producible of North Bongkot to unproducible reservoir sandstones of the South Bongkot. Vertical distribution of reservoir sandstones reveals that unit 2C contains producible and a good class of unproducible reservoir sandstones. Formation 1 composes of only unproducible reservoir sandstones (of moderate and poor classes). The difference in reservoir quality horizontally is thought to be due to facies and/or structural controls while vertically it is thought to be due to a difference in diagenesis (formation of authigenic minerals, compaction and cementation) effects.

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CHAPTER 1

INTRODUCTION

1.1 General Statement

At present, the gulf of Thailand is the main target for exploration and production of petroleum. Bongkot field is located on the northwestern part of the Malay basin, gulf of Thailand under the concession of PTT Exploration and Production Public Company Limited. Although this field is in the production phase, in some of this area the reservoir sandstones cannot produce petroleum. Therefore, the main purpose of this project is to detect and map distribution area of the unproducible reservoir sandstones by using pressure, mud log and well log data from 35 wells in Bongkot area. The result of this study may help in production planning and in evaluating petroleum reserves.

1.2 Problem Defined

Many reservoir sandstones in the Bongkot field have a good potential to produce petroleum but some of these sandstones cannot produce petroleum, even though they posses similar characters as the producible ones.

1.3 Hypothesis

Most of reservoir sandstones at level below 7,000 feet are unproducible. This may be caused by their low permeability relating to depth of burial. Pressure, mud log and well log data may be used to detect these unproducible sandstones.

1.4 Objective

1. Study the horizontal and vertical distribution area of unproducible reservoir sandstones.
2. Identify characteristic of unproducible reservoir sandstones.

1.5 Term Defined

1. **Unproducible reservoir sandstones**: reservoir sandstones that have very low mobility (less than 10 millidarcy per centipoises)

1.6 Literature Review

Campbell (2009) summarized that in Australia, they were not interested in tight gas industry. Nowadays, many countries are successful in explorating and producing natural gas from tight gas reservoir. Thus, it will be interesting and challenging to study. Tight gas is gas which is immobile and hence does not flow to another area. Tight gas has low permeability reservoirs that generally do not flow gas at commercial rates. The reservoirs should be stimulated by using many techniques for helping their reservoirs gas to flow effectively. The areas which have performing reservoirs are known as "sweet spots", they are controlled by the increase in porosity, permeability and fracturing.

In this study, there are many characteristics of reservoir under studied such as single, isolated and stacked reservoirs. Reservoir permeability ranges from 0.1 to 0.0001 millidarcies (md).

Holditch (2006) proposed that tight gas is referred to low permeability (<0.1md) reservoirs that produce dry natural gas. The best definition of tight gas reservoir is a reservoir that cannot produce at economic flow rates. The well is stimulated by a large hydraulic fracture treatment, by a horizon wellbore, or by use of multilateral wellbore. A tight gas reservoir can be deep or shallow, high or low pressure, high or low temperature, blanket or lenticular, homogenous or naturally fractured, and can contain a single layer or multiple layers.

Interest in tight gas reservoirs around the world increased during the 1990s. In many countries, tight gas is defined by flow rate and not by permeability. To evaluate and develop a tight gas sand play; the data from geology, reservoir connecting, regional tectonics, reservoir layers, log data, core data, mechanical properties, permeability distribution and vertical profile should be considered. By using the correlations and open hole logs, the engineer must design the optimum well completion and stimulation treatment. Normally, a layered reservoir description is needed for the reservoir and P3D fracture models to determine where to perforate and what kind of a fracture treatment is optimal.

Shaun (2009) Saudi Arabia has very large structural geology which is suitable for the exploration of petroleum. However, it is starting to study unconventional resources, especially tight gas reservoirs.

The unconventional resources are the Lower Paleozoic siliciclastic succession which has source rock is shale of Middle of Silurian age and the reservoir in Lower Paleozoic, is always below 20,000ft and is distinctly tight.

The tight gas sandstones is referring to the sandstones which do not allow petroleum to flow at commercial rates by using the Saudi Aramco's standard drilling, completion and stimulation procedures. Generally these sandstones have <12% porosity and <1md permeability.

From the result, this research is the key to the development of (1) understand the lower Paleozoic succession; (2) identify few reservoirs; and (3) Confirmation that late Ordovician sandstone contains untapped hydrocarbon resources.

Yang et al. (2008) studied in Sulige gas field in central Ordos Basin are the largest gas fields in China, which cover about 500 square kilometers and have reserves of 860.7 billion cubic meters (bcm). The Upper Carboniferous – Lower Permian deltaic sandstones and Upper Permian lacustrine mudstones deposited in a cratonic and formed an effective petroleum system. Tight lithological seals were developed from reservoir sandstones because of poorly sorted and diagenesis nears the detrital source.

Typically, gas reservoirs in this area range from 3,200 to 3,400 m in burial depth, averaging 5-20 meters in thickness. Their porosity is about 7-15% and their permeability is about 0.5-20md. The reservoirs show three types of lithology; quartzarenites, sublitharenites and litharenites. There are comprised of medium to coarse grained and poor sorted sublitharenites with 60-90% quartz grains, 10-25% rock fragments and 2-8% feldspar grains. The rock fragments consist of metamorphic grains and volcanic grains that were formed with the sedimentation and the feldspar grains have been altered to kaolinite. Pore fillings are filled by matrix (argillaceous hydromica, kaolinite and authigenic chlorite) and cements (calcite, clays, chlorite and silica).The pore type can be classified into 5 types based on the estimation of grain size, sorting, chemical composition, the amount of cements and the size and distribution of pore throats.

Generally, the gas reservoir can be classified in to four types by using the pore type, production tests and log analysis as follows (1) Type I and II rocks can produce natural gas without natural fracturing; (2) Type III rocks can produce natural gas with artificial fracturing; and (3) Type IV rocks are too tight to produce at commercial rates.

Yin (2003) reported that most gas-bearing, upper Cretaceous sandstones in the Rocky Mountain region are tight and overpressured (>9,000ft depth) contain a large number of gas reserves. Samples were collected and thin sections from the Almond, Frontier and Lance sandstone were made.

There are consisted of chemical composition as follow;

(1) The Almond sandstones contain up to 58% lithic fragments, 26% detrital feldspar grains and detrital grains of chert up to 6%.

(2)The Lance sandstones contain up to 59% lithic fragments, 6% feldspar grains and detrital grains of chert up to 48% (a big proportion of the detrital grains).

(3)The Frontier sandstones contain up to 48% lithic fragments, 50% feldspar grains and detrital grains of chert up to 24%.

Matrix and authigenic clays are the causes decreasing of porosity and permeability reduction in these buried tight sandstones. From the thin sections, clay content in the Lance sandstones ranges from 10 to 25%. In the Almond sandstones, matrix content is up to 5%, with carbonate and quartz cements in the intergranular pores which cause them to become very tight sandstones.

The tight sandstones have secondary porosity which ranges from 5 to 8% and result from dissolution of detrital grains and cements. Permeability is less than 1md. Leaching of the detrital grains of the clay in micropores influence porosity but not permeability. Thus, in these sandstones, permeability does not relate with porosity.

The Almond sandstones were deposited in the tide channel and shoreface environments. These sandstones are fine to very fine grained, sublitharenites, litharenites, feldspathic liharenites, and lithic arkoses. Carbonate cementation rapidly reduced porosity and permeability with buried depth. Dissolution of feldspar and lithic grains cause the development of micropores which increase the porosity. At levels below 9,000 ft, the Almond sandstones are tight and gas saturated. There were deposited in a different environment, have a different texture and detrital grain composition, likely difference diagenetic during burial. Thus, the depositional and diagenetic are factors to change in the distribution of porosity and permeability. As a result, the distribution of porosity and permeability under the lithofacies, compaction and cementation factors can be concluded that the tidal channel sandstones have a higher permeability than the shoreface sandstones.

From the Lance Formation cores from the Jonah #2-5 well were studied for physical properties. Clay minerals were analyzed by using XRD and SEM. Porosity and permeability were measured under different pressures. The Lance sandstone was deposited in fluvial channels which ranges thickness from 5 to 30 ft, is comprised of stacked single channel deposits, with siltstone or shale. The sandstones are characterized by massive bedding, cross stratification, wave ripples, and soft deformation. These sandstones are fine to coarse grained litharenites. Clay content ranges from 10 to 25% and carbonate cement up to 23%, with quartz overgrowth and feldspar dissolution.

1.7 The Study Area

Bongkot production field is located approximately 600 km south of Bangkok and 203 km off the coast of Songkhla province. It is located on the northwestern flanks and lies on the western edge of Malay basin in the southern gulf of Thailand. The Bongkot concession consists of five blocks; B15, B16, B17, B13/38 and G12/48, covers area approximately 3,986 square kilometers (see Fig 1.1).

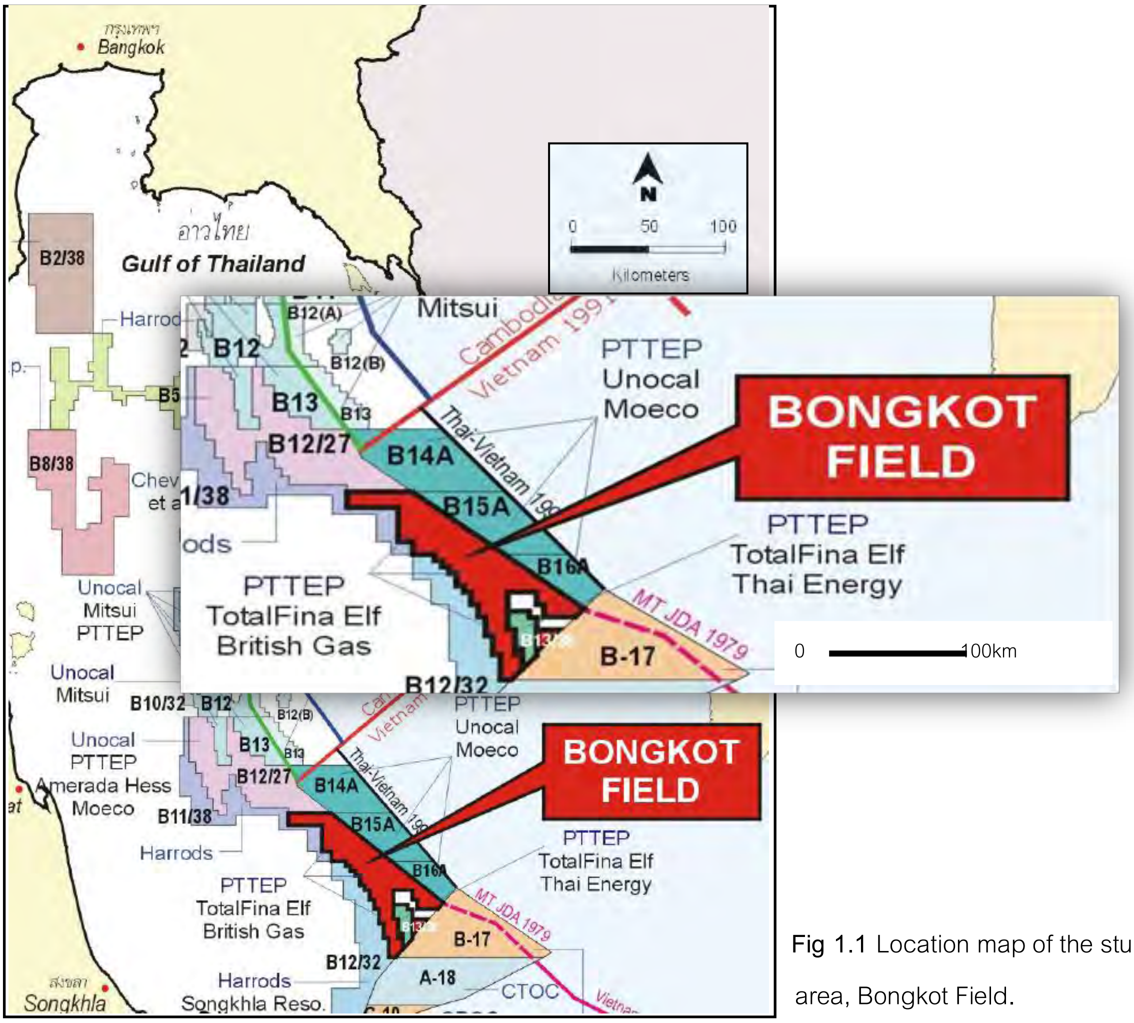


Fig 1.1 Location map of the study area, Bongkot Field.

1.8 Methodology

In this project, there are three disciplinary techniques used for studying the unproducible reservoir sandstones distribution area. These techniques are pressure technique, mud log technique and well log technique. Pressure data will be used for collecting porosity and mobility. Mud log data were used in identifying petrophysical characteristic. Well log data can be used to define lithological characteristics which are an important factor in depositional environment study. They provide subsurface geological information while drilling a well, also produces data which allows reasonable mapping and cross-section to be made. The flow chart of this research study is shown in Figure 1.2.

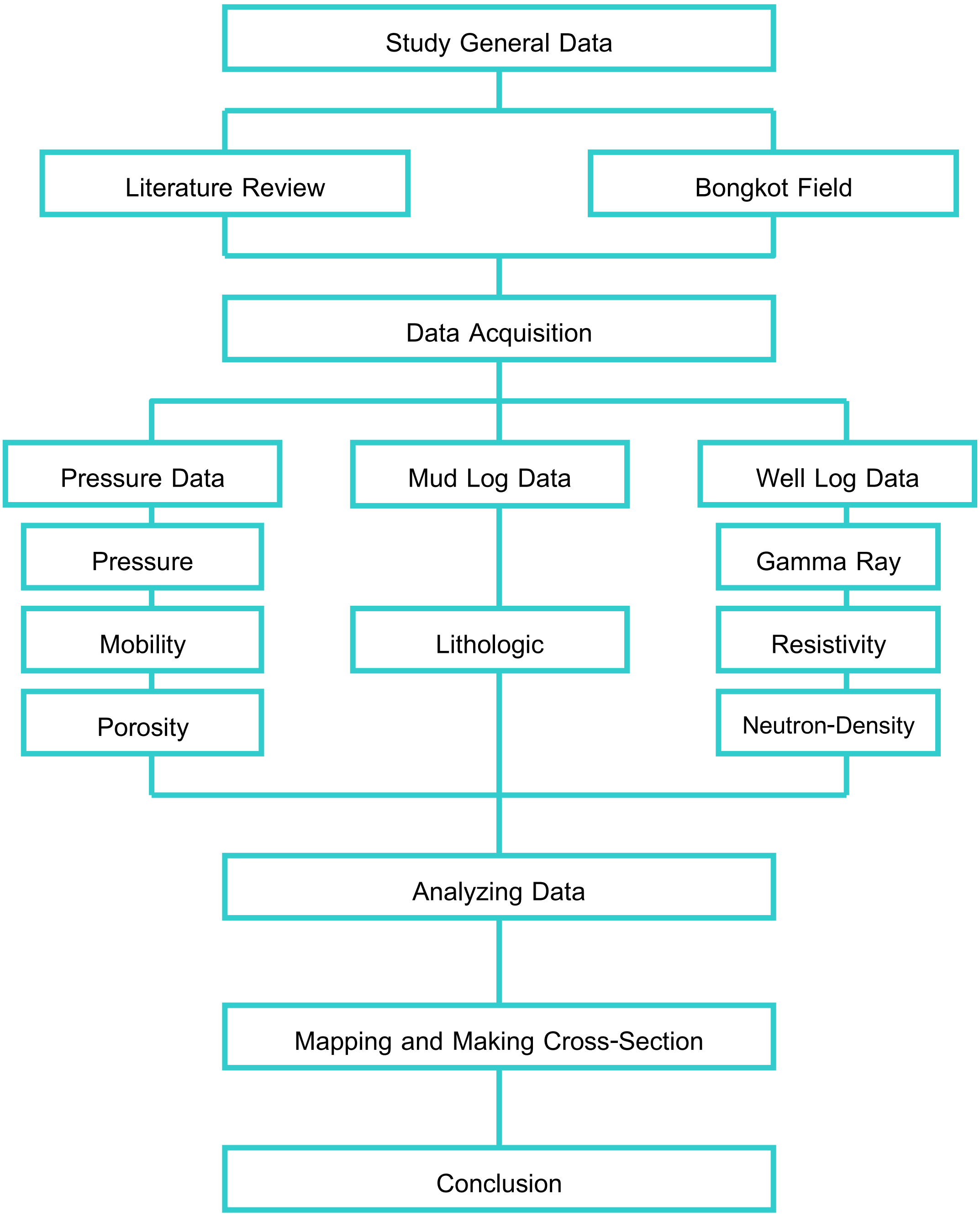


Fig 1.2 Work flow of this project.

1.1 Study general data

- Literature review
- Data relating to Bongkot field include geological setting, regional structure and stratigraphy.

1.2 Data acquisition

There are 35 wells in Bongkot field that data were collected. The data used in this project are pressure, mud log and well log data.

- Pressure data: This process involves rapidly screening from the statistical RFT data which is necessary in comparing the basic performance of each reservoir. Repeat Formation Tester (RFT) is a device measuring the reservoir pressure, mobility and porosity data (comparing with well log).
- Mud log data: Advanced screening from mud-logging data provides subsurface information especially the lithologic description of each reservoir.
- Well log data: Well log data which consists of gamma ray, resistivity, neutron and density logs are studied to identify sandstone depositional environment. Combination of neutron and density logging tools are related to cross plot technique which can be identified gas zone.

1.3 Analyzing data

Unproducible reservoir sandstones are classified by using the data (pressure, mud log and well log data).

1.4 Mapping and cross-section

Mapping the distribution area and making cross-section of unproducible reservoir sandstones by using the classification.

1.5 Conclusion

1.9 Expected Output

1. The distribution area map of unproducible reservoir sandstone in Bongkot field.
2. Identify the specific features of unproducible reservoir sandstone in Bongkot field.

CHAPTER 2

GENERAL GEOLOGY IN BONGKOT FIELD

This area is characterized by a major northwestern to southeastern strike slip central fault zone associated with en echelon fault systems which form several horsts and grabens. (Crumeyrolle, PH. and Druesne, D. 1993)

The basin-fill consists of a very thick Oligo-Miocene siliciclastic series. In the Bongkot field area, the prospective Miocene section has been subdivided from bottom to top into three main lithological units; Formations 1, 2 and 3. These formations comprise several groups of facies which were laid down into fluvio-deltaic depositional environment. Sandy reservoirs correspond to channels and bars interbedded into red or grey to black organic-rich shales. Some marine shaly intervals were also encountered. Coal beds, common in formations 2 and 3, can be picked as major seismic events and/or well-log markers. (Crumeyrolle, PH. and Druesne, D. 1993)

- Formation 1 is the lowermost section and consists of relatively thick (around BK Q) channelized sandy reservoirs interbedded with red clay.
- Formation 2 comprises several channel and bar reservoirs.
- Formation 3 is predominantly shaly with sporadic fine sands.

Previous laboratory studies on cores and cuttings clearly show the deltaic origin of formation 1 and 2. Based on marine fauna, marine influences were noticed in the upper part of units 2A and 2C (giving an Upper Middle Miocene age for 2C unit). The marine fauna content increases abruptly in formation 3.

2.1 Stratigraphic Intervals and Their Depositional Environments

- Formation 1

It consists of fluvial deposits with thick coarse-grained sandy channels interbedded with red oxidized delta plain clay. The top of this formation has been defined while drilling by the first occurrence of red clay (see Fig 2.1). Formation 1 presents a characteristic low frequency higher velocity sonic curve compared to the formations above. On seismic lines, Formation 1 is characterised by the occurence of strong low frequency discontinuous seismic events. The uppermost 200 to 500m of the Formation 1 have often been drilled and encountered amalgamated and isolated sandy reservoirs.

- Formation 2

It is the thickest and the most prospective interval. It has been subdivided into 5 lithostratigraphic units (A through E). Depositional environments range from delta plain to delta front (see Fig 2.1). These units are from bottom to top:

Unit 2A

Unit 2A consists of fine to medium crevasse splay and channel sands which were deposited in delta plain environment. Distributary channels are interbedded in delta plain brown to grey clay. Coal beds are abundant and some such as M 2010 and M 2040 (H50) are widespread. Top 2A unit is defined by a continuous coal bed occurring below the widespread lower sands of the 2B unit.

Unit 2B

Unit 2B is predominantly sandy and consists of several vertically stacked thick coarse grained channels. These amalgamated channels form a seismic event called S41. The occurrence of thick vertically stacked channels is related to a change in sediment supply or/and subsidence rate; as sand shale ratio increase, channel interconnections are more frequent than in the other units. Top 2B is defined by a radioactive peak on G.R. pattern which is related to a group of organic rich shale beds occurring a few meters below H40 seismic marker. H44 seismic horizon corresponds to the top of the lower 2B widespread channel sand.

Unit 2C

In the studied area, is predominantly shaly but the middle part is more sandy. Reservoirs occur mainly as bars. However several channelized sandbodies have been recognized. Coal beds are abundant and some such as M 1455 (H33) and M 1600 (H37) are widespread. The S38 seismic event, in the eastern part of the north 3D, is characterized by a large channelized system with a probable complex infill. It can be interpreted as an incised valley-fill occurring at the base of the more sand prone middle 2C interval. In the upper part of the 2C unit, several widespread delta front bars occur and change vertically into a muddy marine interval. Top 2C was previously defined by a widespread channelized reservoir (S31) which erosive base corresponds to a probable sequence boundary. However this sand is not present everywhere; thus the top of an underlying tight bar sequence which has a characteristic well-log signature has been used as a practical marker to define Top 2C in the present study.

After Upper 2C shaly marine section, more terrestrial conditions prevailed during 2C deposition of 2D and 2E units.

Unit 2D

This unit is regressive with respect to 2C and comprises channelized sandy reservoirs associated with coal and organic rich delta plain shale. A group of coal beds above reservoir 14-05 (S31) corresponds to H30 horizon. Above, as channel sands occur, they seems more amalgamated and coalescent (S17 meander belt) and correspond to a rapid change in depositional pattern well defined on amplitude maps; this could be due to a modification of the river profile equilibrium in relation with a relative sea level fall (i.e. sequence boundary).

Unit 2E

Unit 2E is sand dominated and consists of amalgamated fluvial to deltaic channels. This later unit and Formation 3 are considered as secondary objectives rarely gas bearing and were not studied.

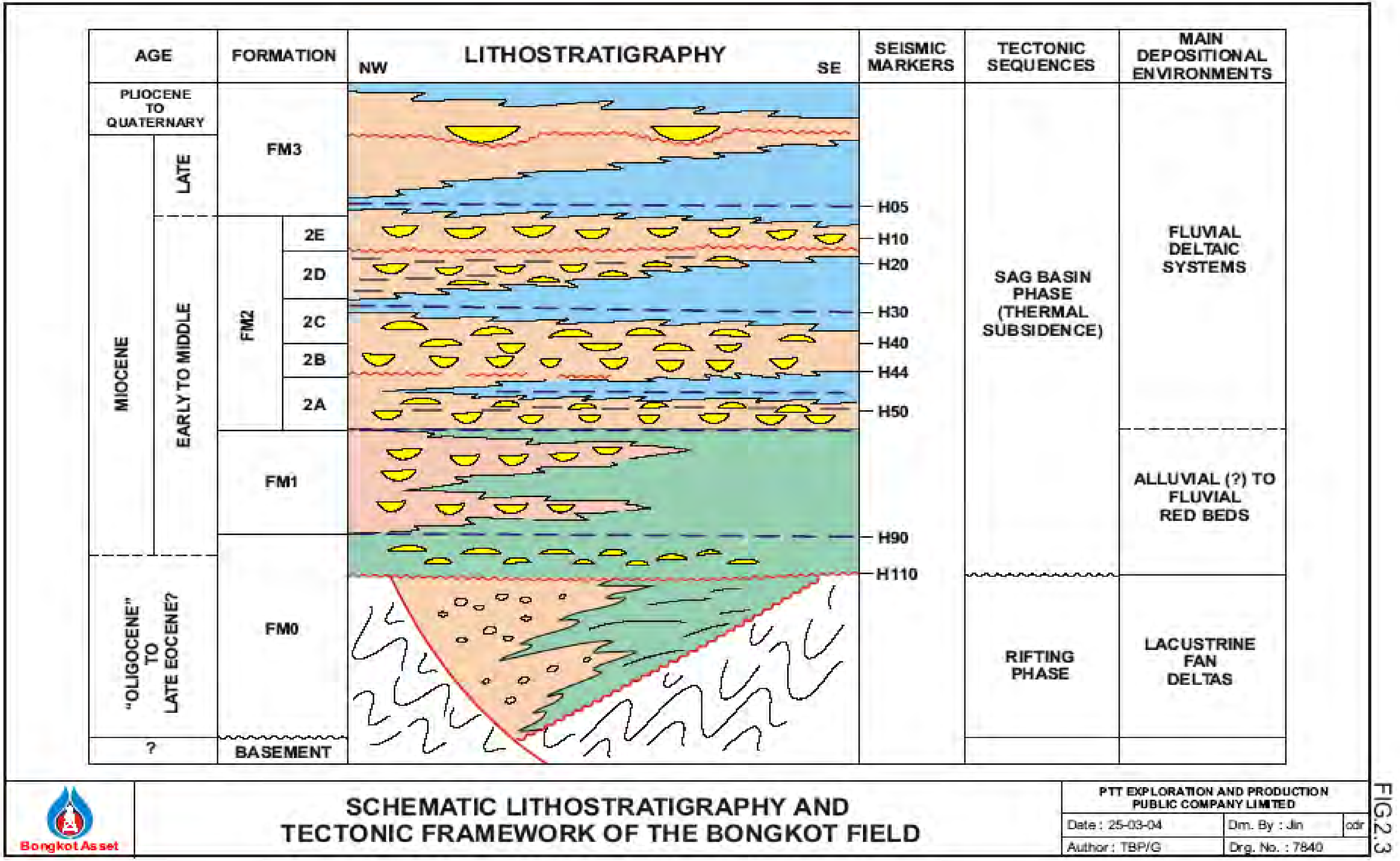


Fig 2.1 Schematic lithostratigraphy and tectonics framework of Bongkot field (PTTEP).

2.2 Remarks on Sequence Stratigraphy

Most of the lithological units defined on the Bongkot field area are group of genetically related deposits which were laid down in the same depositional environment. These units are bounded by widespread coal beds which are main geological and geophysical markers. As it is well known that sea level changes during Tertiary play a key role in vertical and horizontal distribution of sediments, the major coal beds can be interpreted as the landward equivalent of flooding surfaces and associated seaward with transgressive deposits. However sequence boundaries have a poor lithological expression compare to these flooding surfaces and/or their coal bed equivalent and cannot be picked on the seismic. Some of the large channelized systems, only recognized with amplitude maps, can be interpreted as incised valley-fills. In a rapidly subsiding area such as this part of the Malay basin, more than 1,000 of sediments were deposited during Upper Miocene; thus the expression of sea level changes is overwhelmed by high subsidence rate. (Crumeyrolle, PH. and Druesne, D. 1993)

2.3 Evolution of the Gulf Thailand in Relation to the Northern Malay Basin

The tectonic evolution and stratigraphic sequence in the Gulf of Thailand began to evolve since the Indian Terrain collided with the Eurasian Terrain in Cretaceous to early Tertiary. In the early period of evolution, continent around the Gulf of Thailand subsided widely. Sediments deposited in land before rifting. After that this area has influenced by extensional tectonic regime, causing the rift and basin. Prosser (1993) divided the evolution of the basin into four major periods, each of which is characterized by its own style of sedimentation.

Phase 1 the rift initiation phase

The rift initiation phase is characterized by small initial uplifts on the shoulders of the incipient half-grabens. Increasing accommodation space near the bounding faults focuses fluvial processes along these fault traces and results in axial elongated sand fairways near the bounding fault traces. At this time there is not enough relief to result in significant alluvial processes along the basin edge and finer grained sediments will lap out toward the passive flank. Phase 1 sediments are represented by lower-most Formation 0 sediments in the North Malay Basin.

Phase 2 the rift climax phase

The rift climax phase is characterized by raid vertical uplift of the active basin margins creating accommodation space faster than it can be filled by sediments. The resulting high topographic relief facilitates abundant alluvial processes along the hanging wall margin and marked on lap towards the passive margin. Isostatic processes result in the footwall shoulder being rotated such that dip (and drainage) is away from the basin margin. Relative sediment “starvation” can occur in the basin center during this phase. If the basin is structurally open, though-flowing fluvial systems will develop down the basin axis near the bounding faults. If the basin is structurally closed (as is commonly the case) extensive lacustrine systems can develop. Alluvial, fluvial and fluvial/lacustrine-deltaic processes will be present in these situations. Phase 2 sediments are represented by the majority of Formation 0 in the North Malay Basin.

Phase 3 the early post-rift thermal subsidence phase

The early post-rift thermal subsidence phase is also known as early sag phase. It is characterized by cessation of uplift and the subsequent rapid erosion of the basin shoulders resulting in a flood of coarse clastic sediments coming into the basin and eventually in moderately low relief of the basin shoulders. The flood of coarse clastics into the basin is facilitated by the fact that isostatic forces are becoming less dominant and drainage patterns become increasingly focused into the basin. The lower topographic relief during this phase suggests that alluvial processes will not be as important as in Phase 2, but can still occur along major faulted margins. Formation of lakes during this phase, particularly early on, can be much more widespread than during Phase 2 when many of the individual fault basins can be quite isolated. In the North Malay basin, Phase 3 sediments are initially widespread lacustrine deposits giving way upwards to dominantly fluvial sedimentation. Sediments representing this phase are uppermost formation 0 and all of Formation 1 in the North Malay Basin.

Phase 4 the late post-rift thermal subsidence phase

The late post-rift thermal subsidence phase is characterized by low topographic relief as the last of the rift shoulders are buried. The sedimentary section is dominated by fine grained, low gradient, fluvial processes or marine processes depending on basin configuration and/or eustatic sea level. Phase 4 sediments are represented by Formation 2 in the North Malay Basin. It should be noted that marine incursions can enter the basin at any phase during its development depending on the structural/topographic setting of the basin and its proximity to a marine coastline.

CHAPTER III

DATA ACQUISITION

The data sets were provided by PTT Exploration and Production Public Company Limited. The data is a combination of pressure data which comprised of porosity, mobility and pressure, mud log data which defied the lithological characteristic, well log data (which consisted of gamma ray log, resistivity log, density log and neutron log) and company internal reports. There are 35 wells that were provided within the study area. The 35 wells can be classified into 3 types; development wells, delineation wells and exploration wells. There are 23 development wells; BK A, BK B, BK C, BK D, BK E, BK F, BK G, BK H, BK I, BK J, BK K, BK L, BK M, BK N, BK O, BK P, BK Q, BK R, BK S, BK T, BK U, BK V and BK W. Seven delineation wells include DEL AA, DEL BB, DEL CC, DEL DD, DEL EE, DEL FF and DEL GG. There are 5 exploration wells; PK AX, TK B, TR AXA, TNY AX and TSN B. The wells are distributed around the study area especially in the western part of greater Bongkot north area (see Fig 3.1).

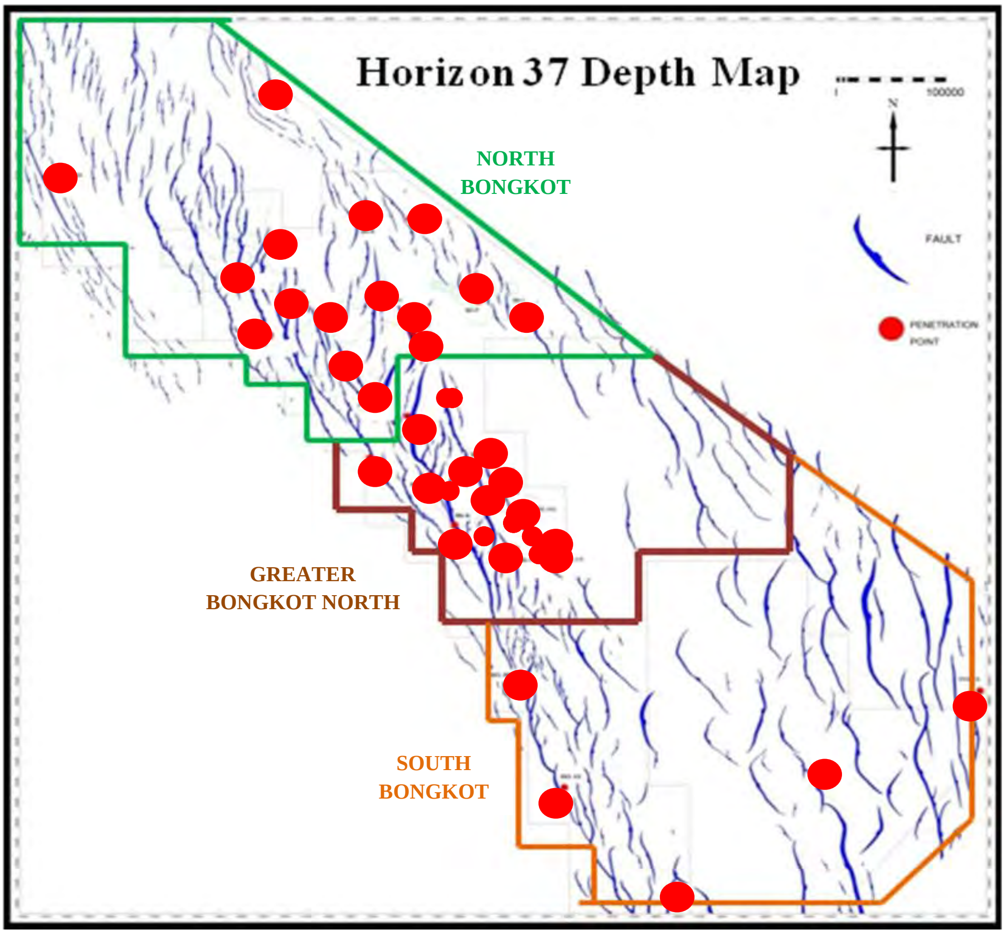


Fig 3.1 Location of well studied, most of them locate in the western part of main Bongkot area.

3.1 Pressure Data

The formation pressure can be measured by probe which is called the “Repeat Formation Tester (RFT)”. This device measures the vertical pressure distribution in the reservoir along open hole well. The probe was inserted into the formation pass through the mud cake. Volume of fluids are fixed when the pressure drawdown rapidly. Then, pressure will build up with a surface record gauge, known as “Pre-test”.

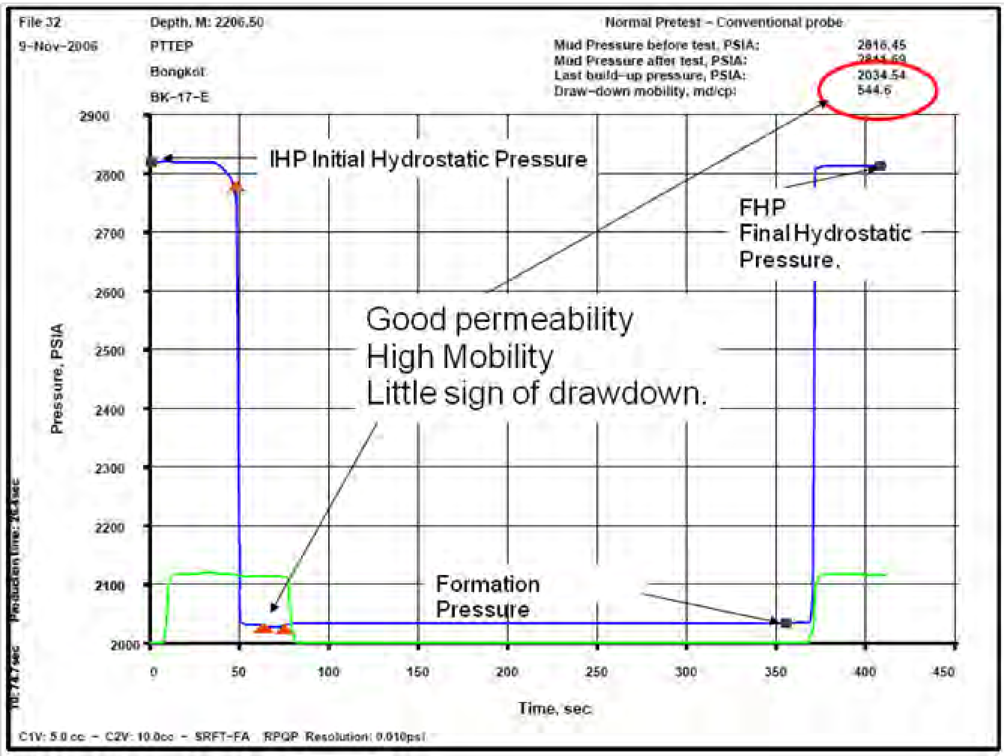


Fig 3.2 An example of pre-test record in normal case (PTTEP).

In normal case, the probe detects reservoir pressure, should be build up in short time, about 10 seconds to increase to more than 200psi (see Fig 3.2). if the pressure is very low, there will be no build up. This could be due to (1) dry test and (2) tight test (see Fig 3.3). Dry test could be causes by (1) the probe which is a point measurement device contacts the grain (especially quartz) directly; and (2) clay minerals or fine grains block up the probe. Tight test, result from the formations having very low permeability and then spend long period to build up the pressure.

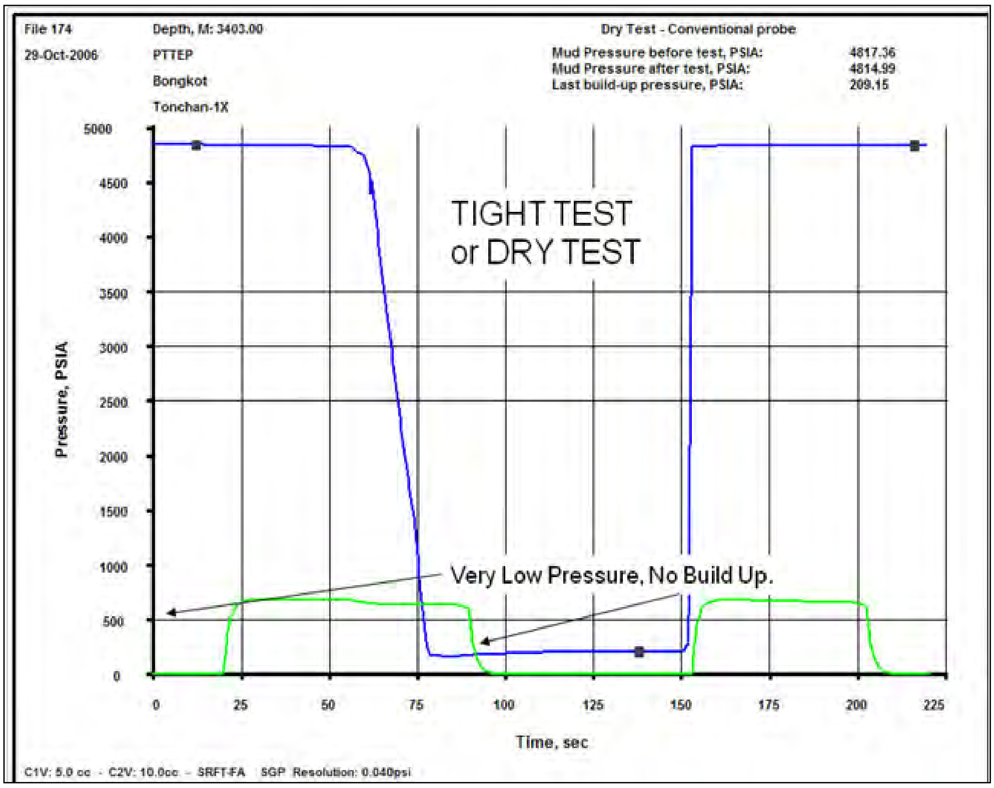


Fig 3.3 An example of pre-test record in abnormal case; dry test or tight test (PTTEP).

In an abnormal case, although the probe can detect the reservoir pressure and builds up for short time, the pressure does not stabilize. Thus, pre-test cannot record the reservoir pressure, and is called “unstabilized” which results from the formation having high porosity and low permeability. The pore spaces are not connected to flow easily.

In some case, the probe can detect the extra reservoir pressure. The possible causes of this case are overbalance as mud filtrate leaks into formation and the probe measured mud cake pressure.

The collected reservoir pressure data consisted of well name, sand name, true vertical depth from mean sea level (TVD MSL), porosity (Phi), permeability (K), water saturation (Sw), pressure (Pi), mobility (mob) and remark. All of which can be separated by formations. The RFT data of studied reservoirs in unit 2C, unit 2B, unit 2A and Formation 1 are shown in Tables 2.1, 2.2, 2.3 and 2.4 respectively.

Table 3.1 Reservoir pressure data of studied reservoir sandstone in unit 2C.

Well Name	TVD MSL (m)	Phi (%)	K (md)	Sw (%)	Pi (psia)	Mob (md/cp)	Remark
TNY AX	2101.5	16	2.21	39	4567.9	4.5	OVER P.
BK J	1783.3	18	5.8	65	x	x	DT
DEL DD	1834.5	12	0.32	58	x	x	T
BK I	1711.7	17	3.58	48	2497.8	0.4	U
DEL BB	2053.4	10	0.12	52	x	0.1	SUPERCH+DT
DEL DD	1870.7	12	0.32	52	x	x	T
BK V	1928.2	16	2.21	70	2906.4	1.8	U
BK V	1941.1	17	3.58	63	3055.9	1	U
BK I	1774.2	18	5.8	54	x	x	DT
BK J	1783.3	19	9.38	44	2988.8	0.9	U
BK W	1697.2	22	39.69	73	x	x	T
DEL BB	2113.4	13	0.52	39	x	8.5	DT
DEL DD	1908.6	16	2.21	27	3521.4	0.6	U+LOW K+T
BK L	1739.9	20	15.17	38	2634.1	6.7	U
BK A	1557.1	15	1.37	63	x	x	T
BK A	1564	16	2.21	69	x	x	T
BK L	1755.9	23	64.21	31	2694.9	2.2	U
BK J	1985.3	17	3.58	51	x	x	DT
DEL BB	2163.7	12	0.32	43	X	0.1	SUPERCH
BK I	1829	16	2.21	66	x	x	DT
BK L	1779.9	19	9.38	42	2698.3	9.6	U
BK V	2048.1	12	0.32	62	3521.6	0.2	T+U
DEL DD	2017.3	21	24.54	44	3710.9	4.9	U
BK J	2133.6	22	39.69	53	3410.4	1.2	U
BK J	2138	22	39.69	53	3414.7	5.3	U
BK J	2140.4	21	24.54	70	3420.1	0.8	U
BK J	2144.4	21	24.54	70	3423.5	12.2	U
BK D	1615.5	18	5.8	65	2287.9	0.6	DT

U is unstabilized, DT is dry test, T is tight test, SUPERCH is super charged, Over P is over pressured and x is no data.

Table 3.2 Reservoir pressure data of studied reservoir sandstone in unit 2B.

Well Name	TVD MSL (m)	Phi (%)	K (md)	Sw (%)	Pi (psia)	Mob (md/cp)	Remark
BK A	1772.1	12	0.32	72	x	x	T
DEL BB	2413	13	0.6	53	x	0.7	DT
DEL BB	2424.3	14	1.1	51	x	x	DT
DEL BB	2430.1	15	2.02	47	x	0.9	U
BK T	2294.2	16	3.72	78	2776.5	0.5	U
DEL AA	1825.1	14	1.1	68	x	x	DT
DEL BB	2465.8	13	0.6	36	x	1.7	DT
DEL GG	2370.9	15	2.02	35	4062	0.9	SUPERCH
DEL GG	2377.4	16	3.72	36	4064.4	0.1	SUPERCH
DEL GG	2383.4	17	6.84	34	4063.9	0.6	DT
BK V	2235.5	14	1.1	61	x	x	T
BK W	2026.5	17	6.84	50	x	2.1	T
BK V	2266.9	15	2.02	67	3839.1	0.3	U
DEL 18C	2650.7	14	1.1	89	6139.3	0.3	U

U is unstabilized, DT is dry test, T is tight test, SUPERCH is super charged, Over P is over pressured and x is no data.

Table 3.3 Reservoir pressure data of studied reservoir sandstone in unit 2A.

Well Name	TVD MSL (m)	Phi (%)	K (md)	Sw (%)	Pi (psia)	Mob (md/cp)	Remark
BK W	2096.3	16	10.19	63	x	x	T
DEL AA	1925.6	12	1.5	83	x	x	DT
DEL GG	2509.8	11	0.93	35	4280.5	5.4	DT
BK T	2436.6	15	6.31	77	3844.3	0.6	U
BK R	1936.3	14	3.91	75	2875	x	T
DEL AA	1955.5	11	0.93	59	x	x	DT
DEL DD	2292	17	16.44	29	3680	1.5	U
BK I	2215	16	10.19	29	3438	0.3	U
DEL EE	2073	14	3.91	32	3282.9	0.2	SUPERCH
BK I	2247.1	12	1.5	47	x	x	T
DEL AA	1995.3	12	1.5	74	x	x	DT
BK D	1900.9	17	16.44	47	2684.1	0.3	DT
BK J	2527.1	13	2.42	64	4209	x	V.LOW PERM.
BK J	2528	13	2.42	64	x	x	DT
BK K	1828.6	23	x	69	x	x	T
BK W	2200.1	17	16.44	72	x	x	DT
DEL CC	2753	10	0.58	57	X	x	T
BK B	1884.3	20	69.18	75	2687.2	5.3	DT
DEL AA	2025.6	15	6.31	67	x	x	DT
DEL DD	2382.1	12	1.5	29	3557.6	0.5	LOW K
DEL DD	2384.5	10	0.58	31	x	x	T
BK O	2334.6	14	3.91	44	x	x	DT
DEL AA	2068.5	13	2.42	69	x	x	DT
BK J	2609.2	14	3.91	53	x	x	DT
BK O	2371.2	14	3.91	58	x	x	DT
BK I	2378.1	12	1.5	69	x	0.1	U
BK J	2627.5	13	2.42	59	x	x	DT

Table 3.3(cont') Reservoir pressure data of studied reservoir sandstone in unit 2A.

Well Name	TVD MSL (m)	Phi (%)	K (md)	Sw (%)	Pi (psia)	Mob (md/cp)	Remark
BK U	2381.8	17	16.44	48	3893.1	3.4	T
DEL GG	2727.2	9	0.36	40	X	x	DT
DEL BB	2852	12	1.5	36	X	x	DT
BK D	1987.6	13	2.42	60	X	x	DT
BK M	1712.6	19	42.85	73	X	x	T
BK A	2144.7	14	3.91	59	X	x	T
BK D	2006.5	14	3.91	39	x	x	DT
BK A	2150.4	14	3.91	69	X	x	T
DEL DD	2473	13	2.42	44	X	1.3	T
DEL 18C	2954	11	0.93	76	5189.9	0.5	U
DEL BB	2889	11	0.93	47	X	x	DT
DEL 18C	2963	11	0.93	60	5097	0.4	U
DEL EE	2269.2	14	3.91	25	X	0.6	DT
DEL BB	2909	12	1.5	51	X	x	DT
BK A	2180.2	12	1.5	69	X	x	T
DEL DD	2517.2	11	0.93	23	X	2.5	T
BK I	2488.1	14	3.91	61	X	x	DT
BK J	2752	15	6.31	73	X	x	DT
DEL AA	2203.1	15	6.31	74	x	x	DT
DEL 18C	3042.1	12	1.5	86	5067.8	0.1	U

U is unstabilized, DT is dry test, T is tight test, SUPERCH is super charged, Over P is over pressured and x is no data.

Table 3.4 Reservoir pressure data of studied reservoir sandstone in Formation 1.

Well Name	TVD MSL (m)	Phi (%)	K (md)	Sw (%)	Pi (psia)	Mob (md/cp)	Remark
BK A	2262	20	389.4	80	3221.2	2	T
BK B	2096.4	14	16.9	49	x	x	DT
BK Q	2324.5	16	48.08	68	3326.4	1.7	U
BK U	2574.8	17	81.11	50	x	x	T
BK J	2830.7	15	28.5	70	3983.3	x	U
BK B	2161.4	14	16.9	63	3076.5	0.3	DT
BK J	2933.4	13	10.02	72	x	x	DT
DEL EE	2489.2	11	3.52	41	x	x	DT
BK J	2970.3	13	10.02	72	x	x	DT
BK U	2698.7	13	10.02	51	3824.3	6.8	T
BK P	3119	18	136.84	56	x	x	DT+T
DEL DD	2819.3	15	28.5	64	3722	1	U
BK M	2109.7	19	x	76	x	x	U
BK K	2327.8	13	10.02	63	x	x	T
BK Q	2634.6	16	48.08	75	3739.9	9.8	U
BK M	2258.5	16	48.08	84	x	x	U
BK M	2283.9	14	16.9	56	x	x	DT
BK E	2408.4	13	10.02	46	x	x	DT
BK E	2415	13	10.02	100	x	x	DT
BK M	2363.8	15	28.5	62	x	x	DT
BK M	2671.1	13	10.02	66	x	x	U
TR AXA	2260.2	14	16.9	69	3131.1	0.9	U,SUPERCH,DT
TR AXA	2288.7	16	48.08	84	3794.4	x	DT
TR AXA	2372.4	15	28.5	67	3287.8	1.5	SUPERCH+DT

U is unstabilized, DT is dry test, T is tight test, SUPERCH is super charged, Over P is over pressured and x is no data.

3.2 Mud Log Study

Mud-logging provides critical subsurface information. The mud log provides depth, lithology percentage, formation gas, rate of penetration (ROP) and the formation description (see Fig 3.4).

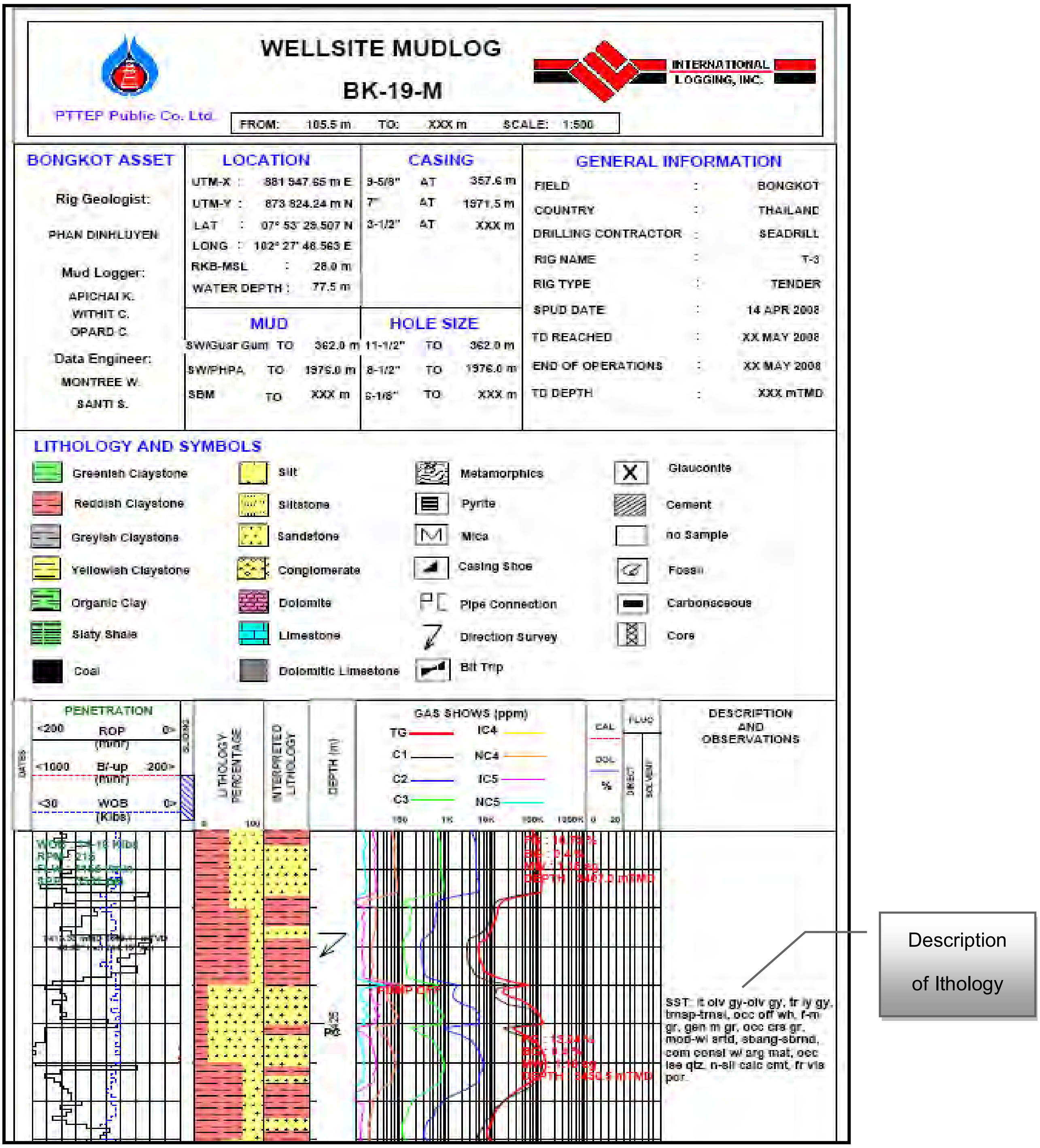


Fig 3.4 An example of mud log data related to lithologic description (PTTEP).

The collected mud log data consisted of well name, sand name, true vertical depth from mean sea level (TVD MSL) and lithologic description. These data can be separated by formations. The mud log data of studied reservoir sandstones in unit 2C, unit 2B, unit 2A and Formation 1 are shown in Table 2.5, 2.6, 2.7 and 2.8 respectively.

Table 3.5 Lithologic description of studied reservoir sandstones from mud log data in unit 2C.

Well Name	TVD MSL (m)	Lithologic Description
TNY AX	2101.5	X
DEL 18B	2041.1	X
BK J	1783.3	CLYST: dk gy-gr gy, sbblky-blky, sft-m hd, slty i/p, non calc
DEL DD	1834.5	CLYST: olv-yel gy, sft, slty, sbblky-blky, n calc
BK I	1711.7	X
DEL BB	2053.4	CLYST: brn-blk, sft-m hd, sbblky-blky,
DEL DD	1870.7	SILTST: yel-gr gy, fri-brit, arg. Grad vf slty sst
BK V	1928.2	SST: lt olv gy-wh,vf-f gs,m-w srtd,ang-sbrnd,arg mtx,tr lse qtz,tr carb mtx
BK V	1941.1	X
BK I	1774.2	X
BK J	1940.8	CLAYSTONE-SILTSTONE
BK W	1697.2	CLYST: olv gy, sbblky-blky, fri-m hd, sft, slty, tr carb mtx, tr org sh
DEL BB	2113.4	SST: wh, yelsh gy, calc cmt, arg mtx, f-vf gs, m srtd, grad arg siltst
DEL DD	1908.6	CLYST: olv-yel-brn gy, sft, sbblky-blky
BK L	1739.9	X
BK A	1557.1	X
BK A	1564	X
BK L	1755.9	SST: lt gy, f-vf gs, sbang-sbrnd, m srtd lse qtz, tr carb mtx, calc
DEL 1	1347.3	X
BK J	1985.3	SST: wh, med-crse gs, sbang-sbrnd, p-mod sft, dolo cmt, lse qtz
DEL BB	2163.7	CLYST: brnsh-olv gy, sft, sbblky-blky, m calc
BK I	1829	X
BK L	1779.9	CLYST: lt gy-gy, fri-m hd, sbblky-blky,tr carb mtx, slty calc
BK V	2048.1	CLYST:olv gy-olv blk,org mtx,sbblky-blky,tr plty,fri-m hd,carb mtx,grad sltst
DEL DD	2017.3	CLYST: pred gy-blk, m hd, srnd, vf sdy, carb
BK J	2133.6	FINE SANDSTONE
BK J	2138	FINE SANDSTONE
BK J	2140.4	FINE SANDSTONE
BK J	2144.4	FINE SANDSTONE
BK D	1615.5	SST: f-m gs, sbang-abrnd, lse qtz, no vis cmt

X is no data.

Table 3.6 Lithologic description of studied reservoir sandstones from mud log data in unit 2B.

Well Name	TVD MSL (m)	Lithologic Description
DEL 3	2000	SST: l brn, f-m gs, sbang-sbrnd, m srtd, lse qtz, arg cmt
DEL 22	2355.9	CLYST: dk yel brn, m hd, sbblky, sbplty, n calc
DEL 3	2041.8	CLYST: brnsh gy-li gy, fri-m hd, sbblky-blky, slty.carb mtx, org clyst
BK A	1772.1	CLYST: yel-gr, brn-gr, coal-rc lami
DEL BB	2413	SST: vf gs, m hd, m cpct, grad siltst
DEL BB	2424.3	SILTST: olv gy, hd cpct, arg, grad slty clst
BK N	1702.4	CLYST: brnsh gy, fri-m hd, sbblky-blky, carb mtx, org rc
DEL BB	2430.1	SST: vf-f gs, uncons qtz, mod srtd, arg mtx
BK T	2294.2	CLYST: olv gy-blk,sbblky-blkt,fri-m hd,slty i/p,grad slst,tr carb mtx, n calc
DEL AA	1825.1	X
DEL BB	2465.8	CLYST: olv-gr gy, m hd-fri, sbblky, slty i/p
DEL GG	2370.9	SST: brnsh gy, sbang-sbrnd, f-m gs,m srtd, m hd-hd, lse qtz
DEL GG	2377.4	SST: brnsh gy, sbang-sbrnd, f-m gs,m srtd, m hd-hd, lse qtz
DEL GG	2383.4	SST: brnsh gy, sbang-sbrnd, f-m gs,m srtd, m hd-hd, lse qtz
DEL 3	2094.4	SST: dk brn gy, vf-f gs, sbrnd-rnd, w-m srtd, arg cmt
BK V	2235.5	SST: vf-f gs, m-w srtd, sbang-sbrnd, arg mtx, tr lse qtz, tr carb mtx
BK W	2026.5	CLYST: lt olv gy-gy, sbblky-blky, fri-m hd, grad sltst, tr carb mtx,
BK V	2266.9	SST: lt olv gy-wh,vf-f gs,m-w srtd,sbang-sbrnd,arg mtx,tr ls qtz,tr carb mtx
DEL FF	2650.7	SST: yelsh brn, f-m gs, sbang-sbrnd, m srtd, m hd, lse qtz, carb mtx

X is no data.

Table 3.7 Lithologic description of studied reservoir sandstones from mud log data in unit 2A.

Well Name	TVD MSL (m)	Lithologic Description
BK W	2096.3	X
DEL AA	1925.6	CLYST: slty sft
DEL GG	2509.8	CLYST: yel-brn, sft-m hd, blky-sbblky
BK T	2436.6	CLYST: olv gy-brnsh blk, sbblky-blky, fri-m hd, slty i/p, grad sltst, tr carb mtx
BK R	1936.3	SILTST:olv gy-brnsh gy,fri-m hd,sbblky-blky,arg mtx,tr carb mtx,grad vf sst
DEL AA	1955.5	X
DEL DD	2292	CLYST: gy-olv gy, m hd, grad slty sh,
DEL 18B	2800.4	SST: brn, f gs, fri, sil cmt, arg mtx, m srtd
BK I	2215	LIGNITE: blk, sft-m hd, brit, sbblky-blky
DEL EE	2073	SILTST: yelsh brn, m hd, m cpct, sbblky-blky, grad vf gs arg sst
BK I	2247.1	SST: lt brn, f gs, m srtd, sbang-sbrnd, p cpct, arg, tr carb mtx, tr lig
DEL AA	1995.3	CLYST: slty sft
BK D	1900.9	SILTST: dk gy-gy, mod hd-hd arg cmt
BK J	2527.1	SANDSTONE
BK J	2528	SANDSTONE
BK K	1828.6	CLYST: dk gy-gy, lt brnsh gy, fri-m hd, sbblky-blky, slty, tr carb mtx, lse qtz
BK W	2200.1	SST: lt olv gy-gy,f-m gs,m-w srtd,sbrnd-rnd,arg mtx,tr carb mtx,coal,calc
DEL 4A	2198.5	LIME: wh, fri-m hd, dolo
DEL CC	2753	SST: yel-brn gy, arg mtx, sil cmt, f-m gs, m srtd, scrnd-sbang, qtz
BK B	1884.3	SITLST: med gy, fri-mod hd, w-m cmt, arg mtx, grad to vf sst
DEL AA	2025.6	X
DEL DD	2382.1	CLYST: olv gy, m hd, grad slty,sh
DEL DD	2384.5	CLYST: olv gy, m hd, grad slty,sh
BK O	2334.6	CLYST: org-rc
DEL 4A	2230.4	CLYST: brn gy, v sft, blky, 30-40org, slty
DEL 18B	2936.9	SST: f-m gs, subang-subrnd, m srtd, lse, arg mtx, sil cmt
DEL AA	2068.5	ORG CLYST: blky, cpct
BK J	2609.2	SILTST: lt brn-brn, brn gy, fri-mod hrd, blk-sbblk, arg,non calc
BK O	2371.2	X
BK I	2378.1	SST: l brnsh gy, f-m gs, m srtd, sbrnd, lse

Table 3.7(cont,) Lithologic description of studied reservoir sandstones from mud log data in unit 2A.

Well Name	TVD MSL (m)	Lithologic Description
BK J	2627.5	SST: f-mod gs, sbrnd-m, m-w strd, lse qtz, tr of cmt
BK U	2381.8	SST: olv gy,fri-m hd,tr crs gs,m-w srtd,ang-sbrnd,arg mat,lse qtz,carb mtx
DEL GG	2727.2	SST: yel-org gy, vf-m gs, ang-sbrnd, p srtd, arg mtx, fri,
DEL GG	2730.2	SST: yel-org gy, vf-m gs, ang-sbrnd, p srtd, arg mtx, fri,
DEL BB	2852	ORG-RCH CLYST: olv brnsh blk, sft, org siltst
DEL BB	2857	ORG-RCH CLYST: olv brnsh blk, sft, org siltst
BK D	1987.6	SST:med-crse gs, sbrnd, no vis cement
BK M	1712.6	DOLO: yel brn, m hd-hd, blky, tr arg
BK A	2144.7	X
BK D	2006.5	X
BK A	2150.4	SST: lt-gy to olv gy, vf-m gs, m-w srtd, sbrd-rd, calc&arg cmt
DEL DD	2473	CLYST: olv-brn gy, m hd, grad slty, sh, org-rc
DEL F	2954	SST: gysh brn, vf-f gs, m-w srtd, ang-sbrnd, tr calc cmt, arg mtx, grad sltst
DEL BB	2889	CLYST: olv-yel gy, sft, sbblky, slty i/p, calc, m hd, grad arg siltst
DEL FF	2963	X
DEL EE	2269.2	CLYST: olv-grnsh gy,fri, grad f slty clyst,h arg siltst,10-15org,sbblky-sbplty
DEL BB	2909	CLYST: olv-grnsh gy, sft-m hd, sbblky, grad arg siltst
BK A	2180.2	CLYST: it-gy, non calc
DEL 18B	3077	CLYST: prd-olv gy, blky-sbblky, sft, fri, org rc
DEL DD	2517.2	X
BK I	2488.1	X
BK J	2752	SST: wh, rdsh brn, m-hd, arg, org-rc sbblky-blky
DEL AA	2203.1	SANDSTONE
DEL FF	3042.1	X
DEL DD	2309.8	sst: wh-gy, vf-f gs, sbang,sbrnd, mod srtd, arg
DEL FF	3002.1	SH: pred blk-dk gy, sbblky-blky, sbplty, fri-m hd, slty-v slty, carb mtx

X is no data.

Table 3.8 Lithologic description of studied reservoir sandstones from mud log data in Formation 1.

Well Name	TVD MSL (m)	Lithologic Description
BK A	2262	X
BK B	2096.4	SST: crse-vcrse gs, mod hd, m-p strd, dol cmt, arg mtx
BK Q	2324.5	SST: yel gr-lt gr,lse qtz,vf-f gs,tr crs gs,sbrnd-rnd,m-w srtd,calc cmt,arg mtx
BK U	2574.8	CLYST: dk rdsh brn,sbblky blky,sft-fri hd,tr sbfis,sltsr,grad sltst,tr carb mtx
BK J	2830.7	X
BK B	2161.4	X
BK J	2933.4	CLYST: gy-dk gy, brnsh gy, slty, dolo arg, sbblky-blky,
DEL EE	2489.2	CLYST: oly gy, sft-m hd, sbblky-sbplty
BK J	2970.3	
BK U	2698.7	CLYST: rdsh brn-dk brn,sbblky-blky,fri-m hd,sbfis,sltsr,grad sltst,tr carb mtx
BK P	2470	SST: lt gy-wh, sbrnd-rnd, fri-m hd, w srtd, lse qtz, tr slt
DEL DD	2819.3	SILTST: gr-brn-gy lbk, cmpt, fri, sbblky-sbplty, mica, rr arg
BK M	2109.7	CLYST: lt brnsh gy, fri-m hd, sbblky-blky, tr slty&f qtz sst, tr carb mtx, calc
BK K	2327.8	CLYST: pred gy, rdsh brn, fri-m hd, blky, slty, calc, tr lse qtz, tr carb mat
BK Q	2634.6	SST: lt brn gy, lse qtz, vf-f gs,crs gs, sbang,sbrnd, m srtd, calc cmt, arg mtx
BK M	2258.5	CLYST: dk gy-gy, lt brn-blk, m hd-hd, sbblky-blky, slty, calc
BK M	2283.9	X
BK E	2408.4	SILTST: rdsh brn-brn, mod hd-hd, fri, non calc
BK E	2415	X
BK M	2363.8	CLYST: rdsh brn-m brn, brnsh gy-gy, fri-m hd, sbblky-blky, slty, tr vf sst
BK M	2671.1	X
TR AXA	2260.2	CLYST: yel-rd brn, fri-m hd, sbblky-blky
TR AXA	2288.7	X
TR AXA	2372.4	SST: pred lse qtz, l brn, f-m gs, m srtd, sbang-sbrnd,

X is no data.

3.3 Well Log Study

Well log tool is one of the necessary methods in studying the subsurface formations. Well log tools used in this study include gamma ray, resistivity, density and neutron logs.

Gamma Ray Log

Gamma ray logging tool is a device which can be identified formation lithology by detecting the natural radioactive emission. Three radioactive elements are Potassium (K), Thorium (Th), and Uranium (U) which can be emitted the natural radiation. Potassium is generally main composition in clay minerals which founded in shale. Thus, gamma ray can be separated shale and non-shale. The measuring unit was be used in this tool is API Gravity.

Resistivity Log

Resistivity log is used to evaluate fluids in formation and can be identified fluids type. Hydrocarbon does not conduct electricity, but water does, which is a principle for resistivity logging tool. Electrical resistivity was measured in unit ohm-meter.

Furthermore, resistivity log used to study the water saturation by considering the porous formation which saturated by water. There should be low electrical resistivity.

Density Log

Bulk density is an important formation characteristic which can be identified of some lithology and determinate porosity. Gamma ray source (cesium or cobalt 60) was transmitted into the formation. Backscattered gamma ray from the formation was recorded by detector. Backscattered gamma ray depends on the electron density of the formation. In case high electron density, gamma ray collides with electron. Gamma ray will lose energy. Many effects on density log are borehole, hydrocarbon, shale and pressure.

Neutron Log

Neutron log is a device which can be identified porous zone of formation. The device measures hydrogen concentration. The principle for this device is transmitting neutron from source (radium-beryllium, plutonium-beryllium and americium-beryllium) into formation. High energy neutrons lose high energy when collide with atomic nuclei. Hydrogen atoms are the most effective in the neutron lose energy because their mass are nearly equal the neutron.

Density/Neutron Combination

Density and neutron logs are the porosity measurement devices which have average porosity value is closely true porosity. Another advantage of density-neutron log is “gas effect”. Natural gas, has less density and hydrogen concentration than oil. Both logs are displayed on compatible scales, they will show gas effect. Thus, both curves are displayed cross-over and shown the gas effect, in case the formation has porous and full filled by natural gas.

Density and neutron combination logs can be identified gas zone. A difference spreading crossover of both logs is a difference efficient of gas saturation zone. The density-neutron combination logs data of studied reservoir sandstones are divided into 6 scales by using the spread of crossover (see fig 3.5). The combination logs data of unit 2C, unit 2B, unit 2A and Formation 1 are shown in Table 2.9, 2.10, 2.11 and 2.12 respectively. This process can be used in only the same reservoir.

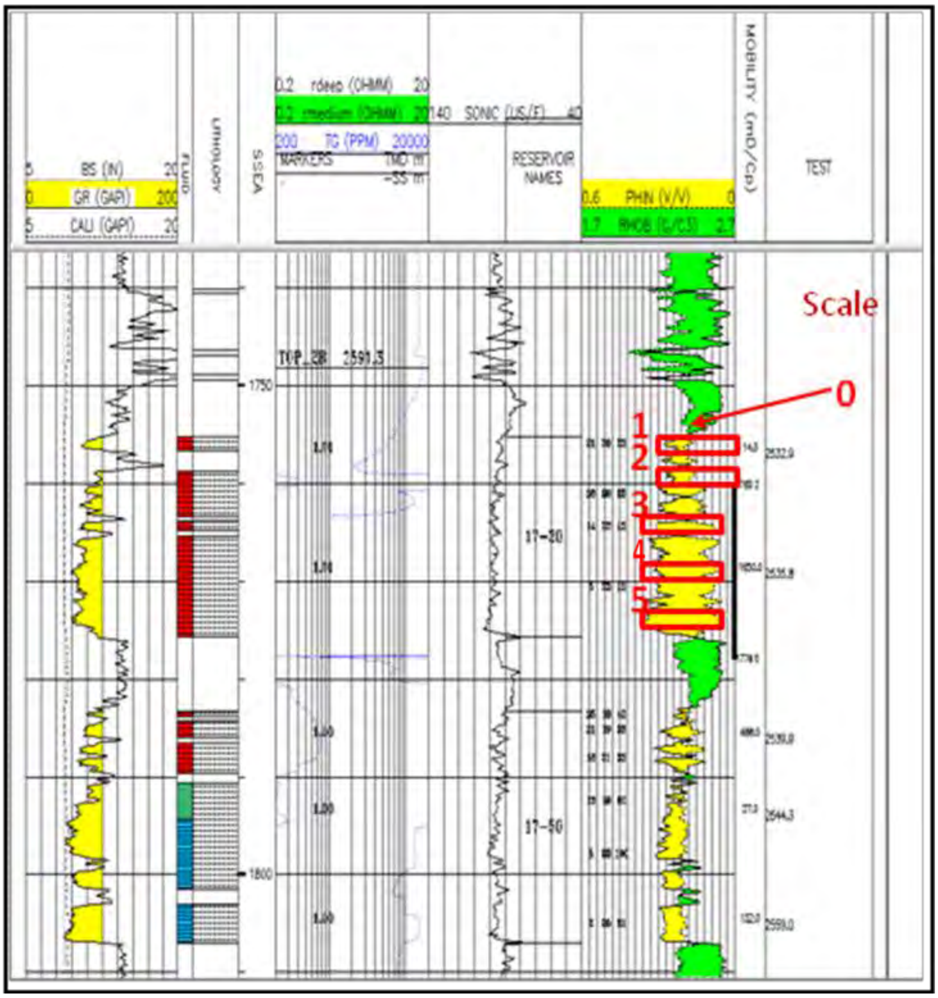


Fig 3.5 Scale of gas effect (PTTEP).

Explanation of gas effect scaling

5	Excellent gas zone quality
4	Good gas zone quality
3	Moderately gas zone quality
2	Fair gas zone quality
1	Poor gas zone quality
0	No gas zone

Table 3.9 Gas effect of studied reservoir sandstones from density-neutron combination logs data in unit 2C.

Well Name	TVD MSL (m)	Gas Effect
TNY AX	2101.5	X
DEL 18B	2041.1	X
BK J	1783.3	3
DEL DD	1834.5	1
BK I	1711.7	1
DEL BB	2053.4	2
DEL DD	1870.7	1
BK V	1928.2	3
BK V	1941.1	3
BK I	1774.2	1
BK J	1940.8	2
BK W	1697.2	2
DEL BB	2113.4	2
DEL DD	1908.6	1
BK L	1739.9	3
BK A	1557.1	0
BK A	1564	0
BK L	1755.9	3
DEL 1	1347.3	X
BK J	1985.3	1
DEL BB	2163.7	3
BK I	1829	1
BK L	1779.9	3
BK V	2048.1	0
DEL DD	2017.3	2
BK J	2133.6	4
BK J	2138	2
BK J	2140.4	3
BK J	2144.4	3
BK D	1615.5	0

Table 3.10 Gas effect of studied reservoir sandstones from density-neutron combination logs data in unit 2B.

Well Name	TVD MSL (m)	Gas Effect
DEL 3	2000	x
DEL 22	2355.9	x
DEL 3	2041.8	x
BK A	1772.1	0
DEL BB	2413	3
DEL BB	2424.3	1
BK N	1702.4	4
DEL BB	2430.1	2
BK T	2294.2	2
DEL AA	1825.1	0
DEL BB	2465.8	1
DEL AA1	2370.9	3
DEL AA1	2377.4	3
DEL AA1	2383.4	2
DEL 3	2094.4	X
BK V	2235.5	1
BK W	2026.5	1
BK V	2266.9	1
DEL 1BK H	2650.7	1

X is no data. 2 is fair.
5 is excellent. 1 is poor.
4 is good. 0 is no gas effect.
3 is moderate.

Table 3.11 Gas effect of studied reservoir sandstones from density-neutron combination logs data in unit 2A.

Well Name	TVD MSL (m)	Gas Effect
BK W	2096.3	4
DEL AA	1925.6	0
DEL AA1	2509.8	3
BK T	2436.6	1
BK R	1936.3	0
DEL AA	1955.5	0
DEL DD	2292	1
DEL 18B	2800.4	X
BK I	2215	3
DEL EE	2073	2
BK I	2247.1	1
DEL AA	1995.3	1
BK D	1900.9	4
BK J	2527.1	0
BK J	2528	0
BK K	1828.6	1
BK W	2200.1	3
DEL 4A	2198.5	X
DEL CC	2753	3
BK B	1884.3	2
DEL AA	2025.6	1
DEL DD	2382.1	2
DEL DD	2384.5	2
BK O	2334.6	2
DEL 4A	2230.4	X
DEL 18B	2936.9	X
DEL AA	2068.5	1
BK J	2609.2	2
BK O	2371.2	3
BK I	2378.1	3

Table 3.11 (cont') Gas effects of studied reservoir sandstones from density-neutron combination logs data in unit 2A.

Well Name	TVD MSL (m)	Gas Effect
BK J	2627.5	1
BK U	2381.8	5
DEL AA1	2727.2	2
DEL AA1	2730.2	1
DEL BB	2852	3
DEL BB	2857	3
BK D	1987.6	0
BK M	1712.6	1
BK A	2144.7	1
BK D	2006.5	2
BK A	2150.4	0
DEL DD	2473	4
DEL 1BK H	2954	2
DEL BB	2889	4
DEL 1BK H	2963	2
DEL EE	2269.2	2
DEL BB	2909	2
BK A	2180.2	1
DEL 18B	3077	X
DEL DD	2517.2	1
BK I	2488.1	5
BK J	2752	2
DEL AA	2203.1	2
DEL 1BK H	3042.1	1
DEL DD	2309.8	1
DEL 1BK H	3002.1	0

X is no data.	2 is fair.
5 is excellent.	1 is poor.
4 is good.	0 is no gas effect.
3 is moderate.	

Table 3.12 Gas effect of studied reservoir sandstones from density-neutron combination logs data in Formation 1.

Well Name	TVD MSL (m)	Gas Effect
BK A	2262	X
BK B	20€96.4	3
BK Q	2324.5	4
BK U	2574.8	4
BK J	2830.7	2
BK B	2161.4	0
BK J	2933.4	2
DEL EE	2489.2	2
BK J	2970.3	5
BK U	2698.7	2
BK P	2470	X
DEL DD	2819.3	5
BK M	2109.7	3
BK K	2327.8	1
BK Q	2634.6	2
BK M	2258.5	2
BK M	2283.9	1
BK E	2408.4	5
BK E	2415	2
BK M	2363.8	1
BK M	2671.1	5
TR 1XA	2260.2	5
TR 1XA	2288.7	2
TR 1XA	2372.4	1

X is no data.	2 is fair.
5 is excellent.	1 is poor.
4 is good.	0 is no gas effect.
3 is moderate.	

CHAPTER IV

RESULT AND ANALYSIS

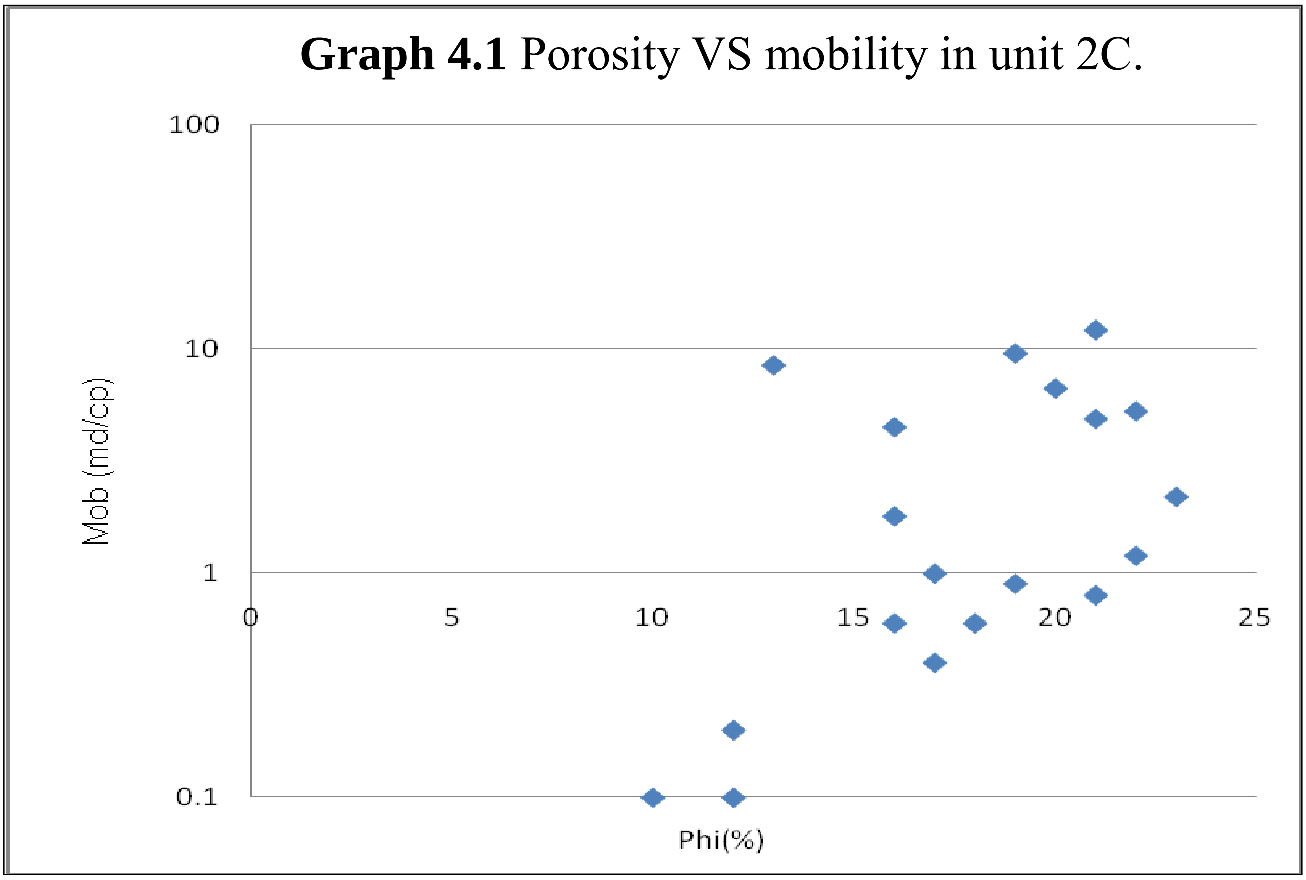
4.1 Result

4.1.1 Pressure Data

The collected reservoir pressure data influence the mobility measurement. During fluids flow surrounding the probe, there are movements in spherical direction as follow by spherical flow equation:

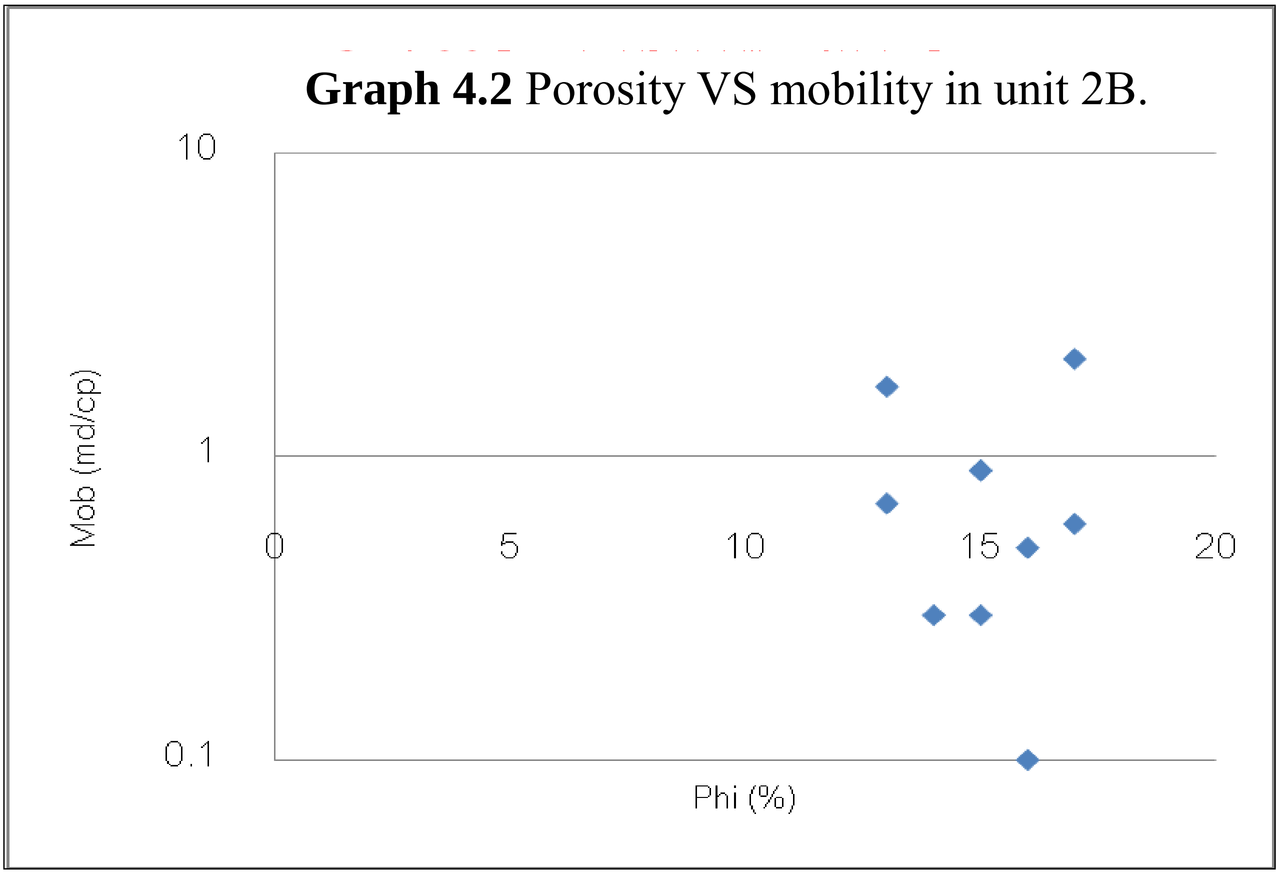
$$\left(\frac{k}{\mu}\right)_{dd} = \frac{C\,q}{\Delta p_{steady-state}}$$

We can calculate mobility automatically, if the drawdown is clear. Permeability is converted from porosity of each formation. However, this is not a reliable data in this project. Thus, relationship between permeability and porosity are not interested. In the contrary, the relationship between mobility and porosity of each formation are interesting. The relationship of these data for unit 2C, 2B, 2A and Formation 1 show in graphs 4.1, 4.2, 4.3 and 4.4 respectively.



Result

Graph 4.1 shows the relationship between porosity and mobility of unit 2C, which has porosity ranging from 15 to 23% and mobility is about 1 to 10 md/cp. There is no clear relationship between porosity and mobility.

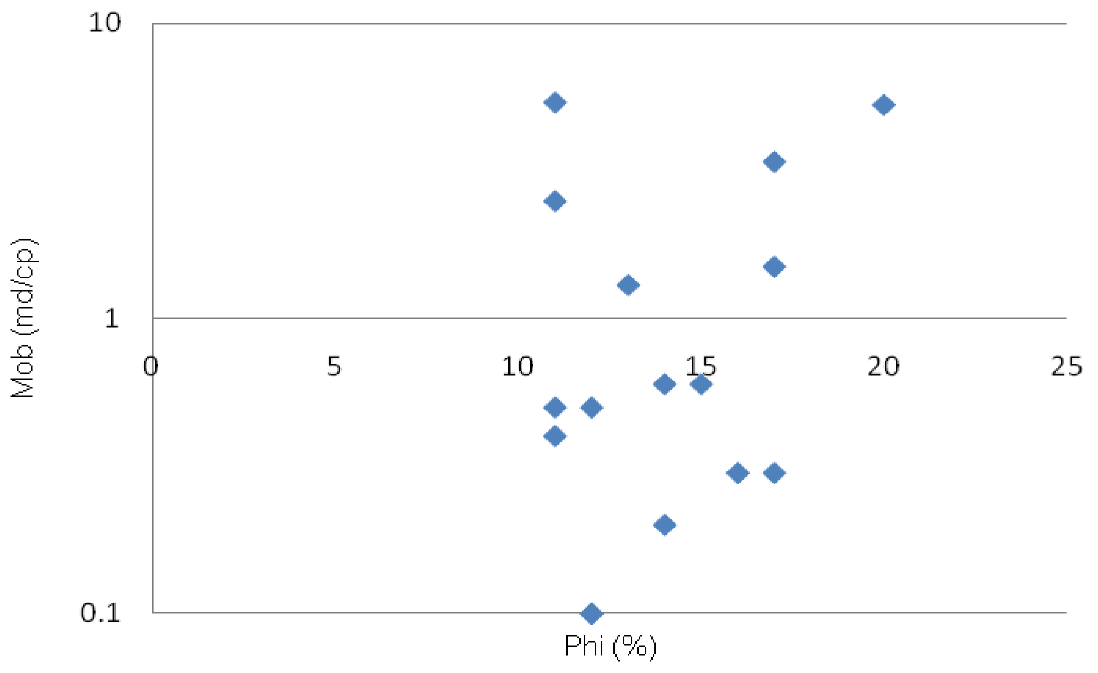


Graph 4.2 Porosity VS mobility in unit 2B.

Result

From graph 4.2, the relationship between porosity and mobility of unit 2B, which has porosity ranging from 13 to 17%. Although the porosity in this unit is lower than the upper unit (2C), its mobility varies from 0.1 to 1md/cp. There is no clear relationship between porosity and mobility.

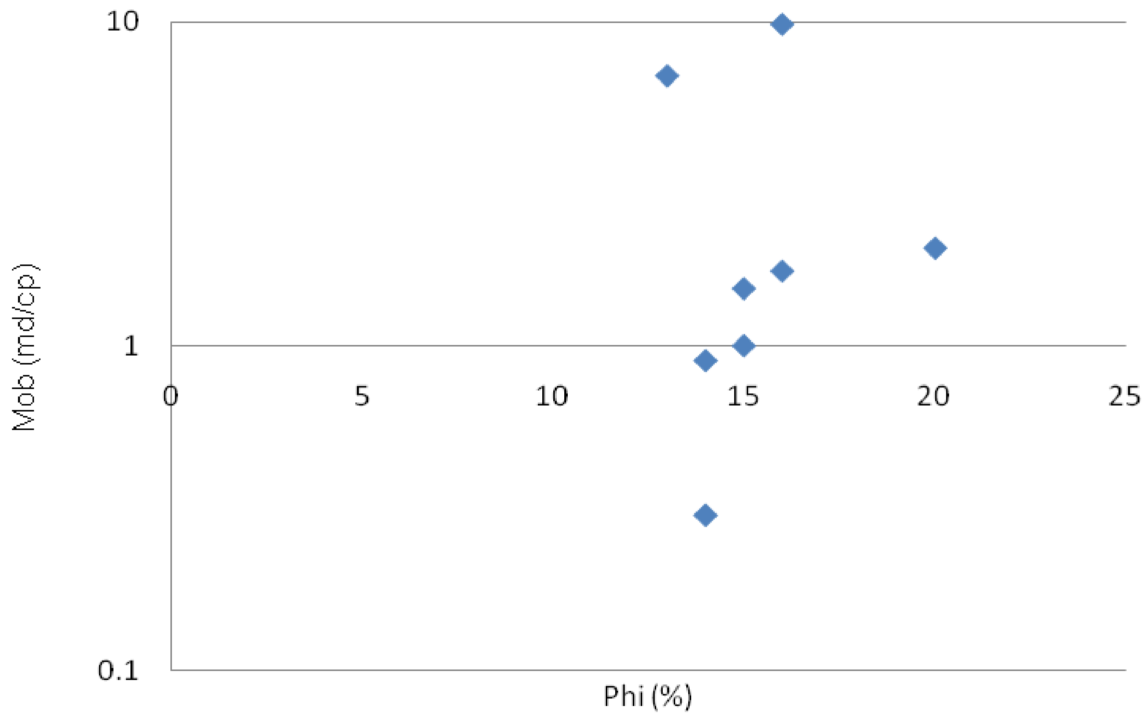
Graph 4.3 Porosity VS mobility in unit 2A.



Result

Graph 4.3 shows the relationship between porosity and mobility of unit 2A, which has porosity ranging from 11 to 17% while mobility ranges 0.1 to 10md/cp. It does not show any relationship between porosity and mobility.

Graph 4.4 Porosity VS mobility in Formation 1.



Result

Graph 4.4, the relationship between porosity and mobility of Formation 1, which has porosity ranging from 13 to 16% which is decreasing and mobility of about 1 to 3md/cp. There is no clear relationship between porosity and mobility.

Graph 4.1, 4.2, 4.3 and 4.4, there are no relation between porosity and mobility because the reservoir pressure data (especially mobility) is not enough plotting a graph.

Summary RFT data from sandstones under studied in table 4.1 below. The table shows the formation name, porosity range, mobility ranging and remark, which shows the number of studied pressure points.

Table 4.1 Summary of RFT data from well studied.

Formation	Porosity (%)	Mobility (md/cp)	Remark
Unit 2C	15-23	1-10	20 from 30 pressure points
Unit 2B	13-17	0.1-1	14 from 18 pressure points
Unit 2A	11-17	0.1-10	22 from 46 pressure points
Formation 1	13-16	1-3	8 from 16 pressure points

4.1.2 Mud Log Study

The collected lithologic description from mud log data can be concluded and separated by formations as follow:

Unit 2C

There are 30 pressure points in this unit, but only 20 pressure points have mud log data and can be classified into 3 types as;

1. Sandstone

    1.1 Fine sandstone: moderately sorted, subangular to subrounded, calcareous and carbonate matrix, argillaceous.

    1.2 Medium to coarse sandstone: subangular to subrounded, poor to moderately sorted, dolomitic cement.

2. Claystone

    2.1 Non-calcareous claystone: subblocky to blocky, soft to moderately hard.

    2.2 Carbonate matrix claystone: subblocky to blocky, friable to moderately hard.

3. Siltstone: brittle, argillaceous, graded to silty sandstone.

Unit 2B

There are 19 pressure points in this unit, however only 18 pressure points have mud log data and can be classified into 3 types as;

1. Sandstone
    1.1 Fine to very fine sandstone: moderately to well sorted, moderate roundness, argillaceous and carbonaceous matrix.
    1.2 Medium to coarse sandstone: subangular to subrounded, moderately sorted, moderately hard, carbonaceous matrix.
2. Claystone: subblocy to blocky, friable to moderate hard, carbonaceous matrix.
3. Siltstone: hard compacted, argillaceous.

Unit 2A

There are 56 pressure points in this unit, but only 46 pressure points have mud log data and can be classified into 4 types as;

1. Sandstone: vary in grain size, matrix, cement, subangular to subrounded, moderate sorted, subblocky to blocky, graded to siltstone.
2. Claystone: organic rich, subblocky to blocky, friable-soft, graded to argillaceous siltstone.
3. Siltstone: friable to moderately hard, subblocky to blocky, argillaceous matrix, graded to very fine sandstone.
4. Others: shale, lignite, dolomite and limestone.

Formation 1

There are 24 pressure points in this formation, but only 16 pressure points have mud log data and can be classified into 3 types as;

1. Sandstone: vary in grain size, moderately to well sorted, subrounded, calcareous cement, argillaceous matrix.
2. Claystone: friable to moderately hard, subblocky to blocky, carbonaceous matrix, subplaty.
3. Siltstone: micaceous (subplaty), friable.

4.1.3 Well Log Study

Gamma ray logging tool can be identified the lithology of formation. We can conclude the shape of curve and interpret depositional environment of each formation (see Table 4.2).

Table 4.2 The characteristic shape of gamma ray curve and interpreted depositional environment of each formation.

Formation	Shape of Curve	Deposition Environment
Unit 2C	Funnel and Cylinder (serrated)	Distributary channel (delta front bars)
Unit 2B	Cylinder	Large stack channel (incise valley)
Unit 2A	Funnel (Serrated)	Distributary channel (delta plain)
Formation 1	Serrated	Fluvial channel

Density-neutron combination logging tool can be detected gas saturation zone. The separation between curves is qualitatively related to gas saturation. From this study, most of studied reservoirs in unit 2C, 2B, 2A and formation 1 have moderate, fair and poor gas saturation zone.

4.2 Analysis

Pressure, mud log and well log data are integrated for analyzing. There are classified into three types of unproducible reservoir sandstones as follow by the table 4.3.

Table 4.3 Classification of unproducible reservoir sandstones in Bongkot field.

Class	Pressure Data		Mud Log Data	Well Log Data	
	Mobility (md/cp)	Porosity (%)	Lithology Description	Gamma Ray Curve Shape	Gas Effect
Good	1-10	≥18	Sandstone: 1. Very fine to fine grain sized, matrix, moderately to well sorted, subrounded to rounded. 2. Medium to coarse grain sized, matrix, cement, moderately to well sorted, rounded. Claystone: moderately hard to hard, matrix.	Cylinder , bell (smooth)	3-5
Moderate	1-5	13-18	Sandstone: 1. Very fine to fine grain sized, matrix, cement, moderately sorted, subangular to subrounded. 2. Vary in grain sized, matrix, cement, moderately sorted. Claystone: friable to moderately hard, matrix, cement, argillaceous, graded to silty. Siltstone: friable to moderately hard, matrix, graded to sandstone.	Funnel, cylinder (serrated)	2-3
Poor	0.1-1	≤13	Sandstone: very fine to medium grain sized, matrix, cement, argillaceous, poor to moderately sorted, angular to subrounded. Claystone: organic rich, graded to siltstone, shale interbeded, platy minerals. Siltstone: friable, matrix, cement, argillaceous.	Funnel, bell, cylinder (serrated)	0-1

CHAPTER V

DISCUSSION AND CONCLUSION

5.1 Discussion

5.1.1 Reservoir Distribution Map

Based on the classification (Table 4.3), the unproducible reservoir sandstones distribution in unit 2C, 2B, 2A and formation 1are shown in figures 5.1, 5.2, 5.3 and 5.4 consecutively. From the maps, green color represents the area which has producible reservoir sandstones distribution. Yellow, orange and violet colors represent the areas which are distributed by good, moderate and poor classes of unproducible reservoir sandstones. There are those with the worst reservoir characteristic in the area.

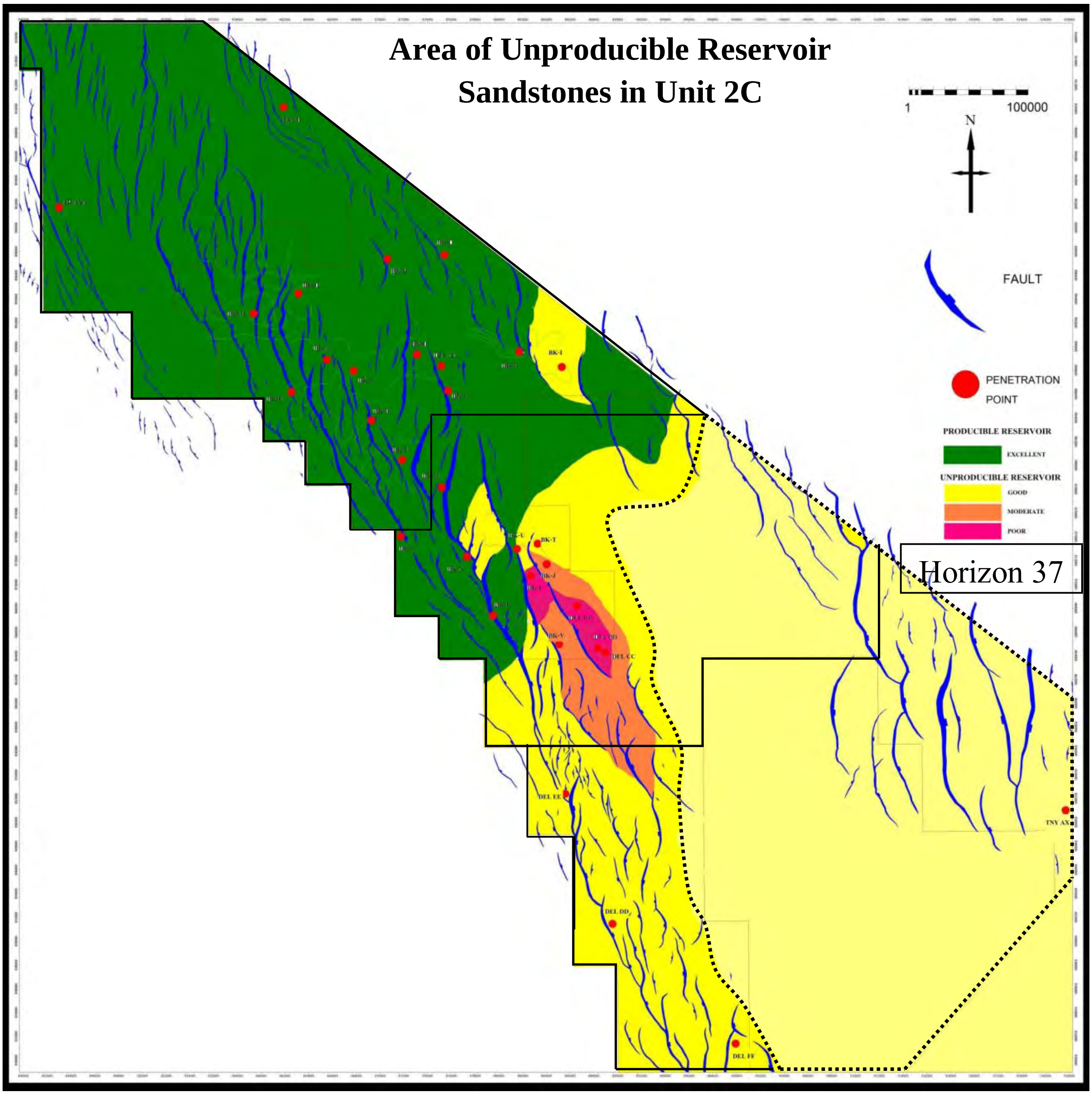


Fig 5.1 Map showing area of unproducible reservoir sandstone obtained by overlaying depth map base of unit 2C (Horizon 37) onto the reservoir quality.

Figure 5.1 shows the unproducible reservoir sandstones distribution area in unit 2C. The producible reservoir sandstones distributes around north Bongkot area. Greater Bongkot north area is distributed by producible in the north and unproducible reservoir sandstones (good class) in the south. In the central and western have poor and moderate classes which distribute along fault block. Good class distributes around the south Bongkot area

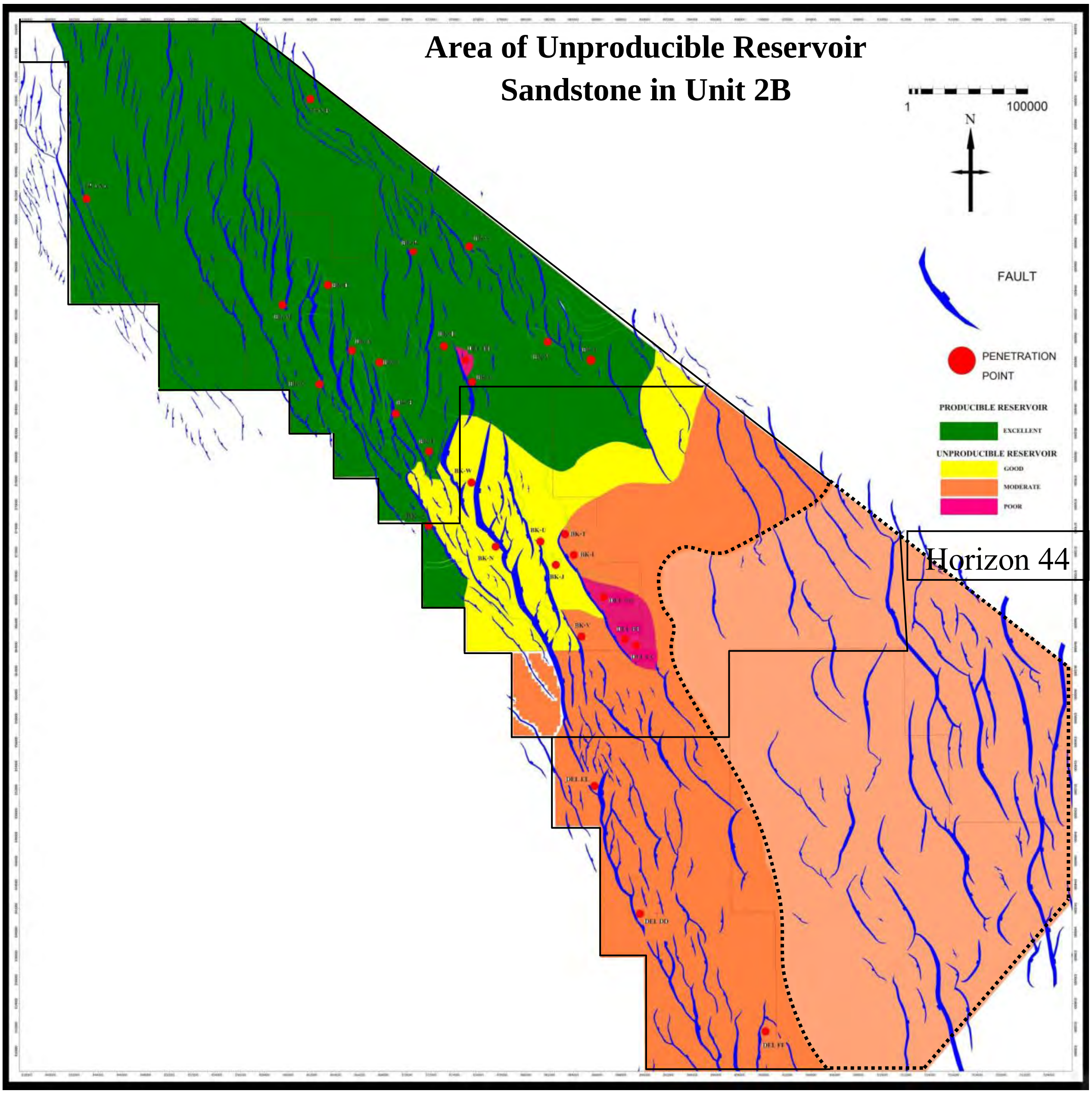


Fig 5.2 Map showing area of unproducible reservoir sandstone obtained by overlaying depth map base of unit 2B (Horizon 44) onto the reservoir quality.

Figure 5.2 is showing the unproducible reservoir sandstones distribution area in unit 2B which has the producible reservoir sandstones distribution around north Bongkot. Good and moderate reservoirs distributes around greater Bongkot north. One fault block in this area is distributed by poor class of unproducible reservoir sandstones.

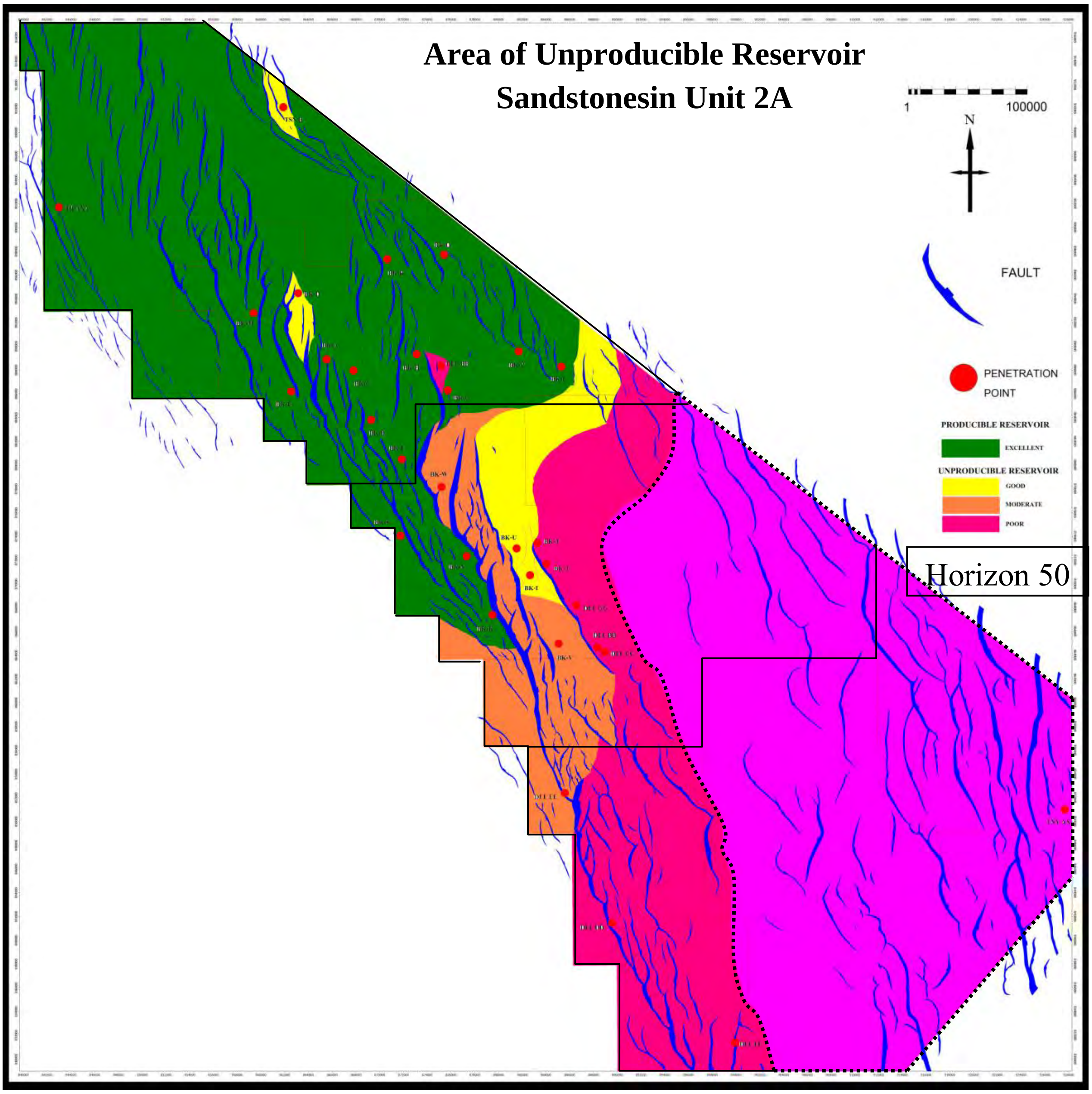


Fig 5.3 Map showing area of unproducible reservoir sandstone obtained by overlaying depth map base of unit 2A (Horizon 50) onto the reservoir quality.

Figure 5.3, showing the unprodcible reservoir sandstones distribution area in unit 2A, which has good class distributes in some part of north Bongkot and most of the area is distributed by producible reservoir sandstones. Greater Bongkot north is distributed along fault block by three classes of unproducible reservoir sandstones. South Bongkot is the area which has poor class distribution.

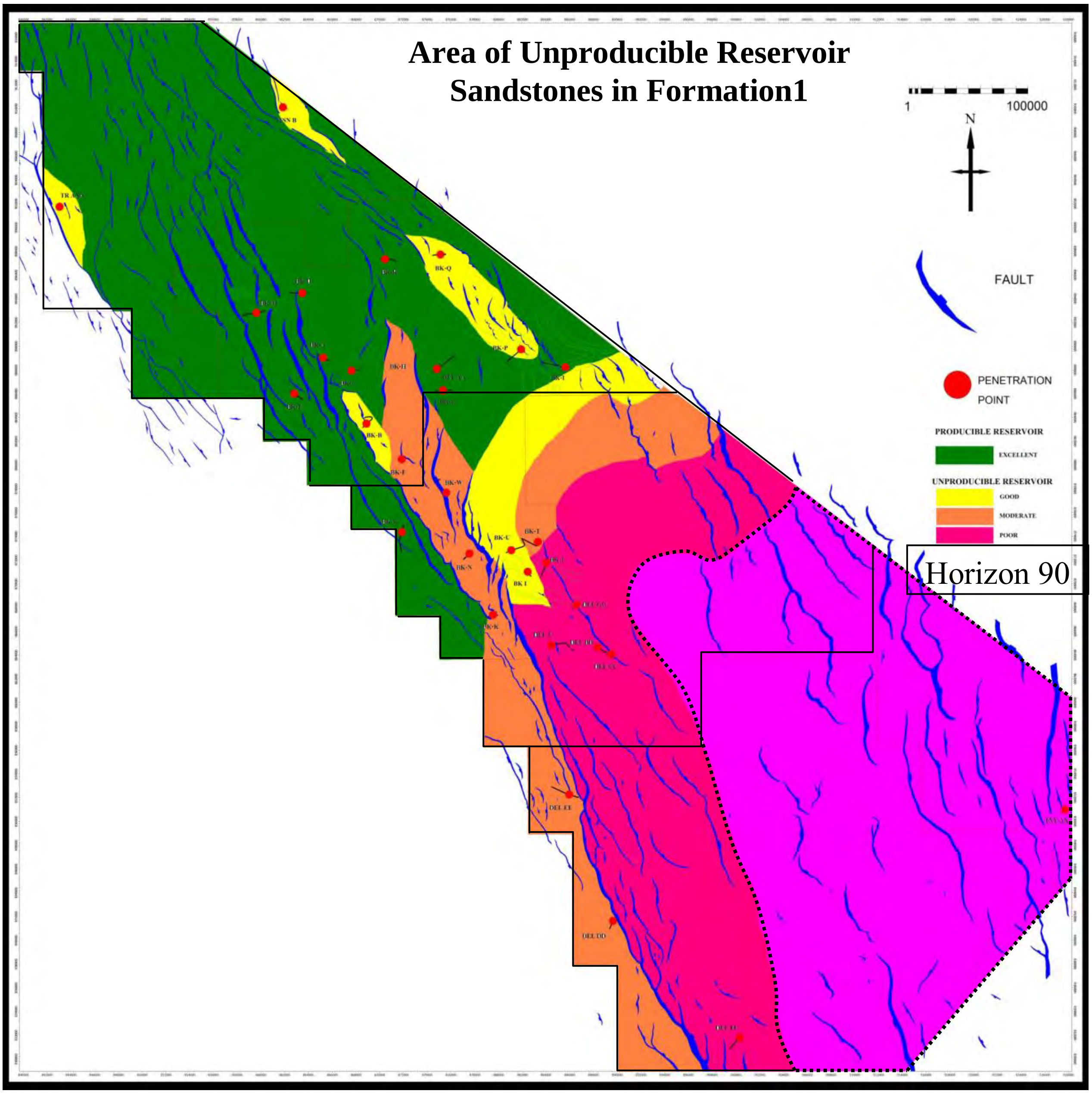


Fig 5.4 Map showing area of unproducible reservoir sandstone obtained by overlaying depth map base of Formation 1 (Horizon 90) onto the reservoir quality.

Figure 5.4 presents the unproducible reservoir sandstones distribution area in formation1. Although unproducible reservoir sandstones distributes in some area of North Bongkot, the producible reservoir sandstones distributes around the area. Greater Bongkot north and south Bongkot are the area which distributed by unproducible reservoir sandstones.

5.1.2 Cross-Section

Two cross-sections were made; first line (line A) is in north-south direction, another line (line B), is in northwest-southeast direction (figure 5.5). Line A passed through 12 wells which comprise of TSN-B, BK-D, BK-P, BK-W, BK-O, BK-U, BK-V, DEL-BB, DEL-GG, DEL-EE, DEL-DD AND DEL FF. Another passed through 10 wells; TR-AXA, BK-M, BK- E, BK-P, BK-G, BK-U, BK-J, DEL-BB, PK-AX and TK-B.

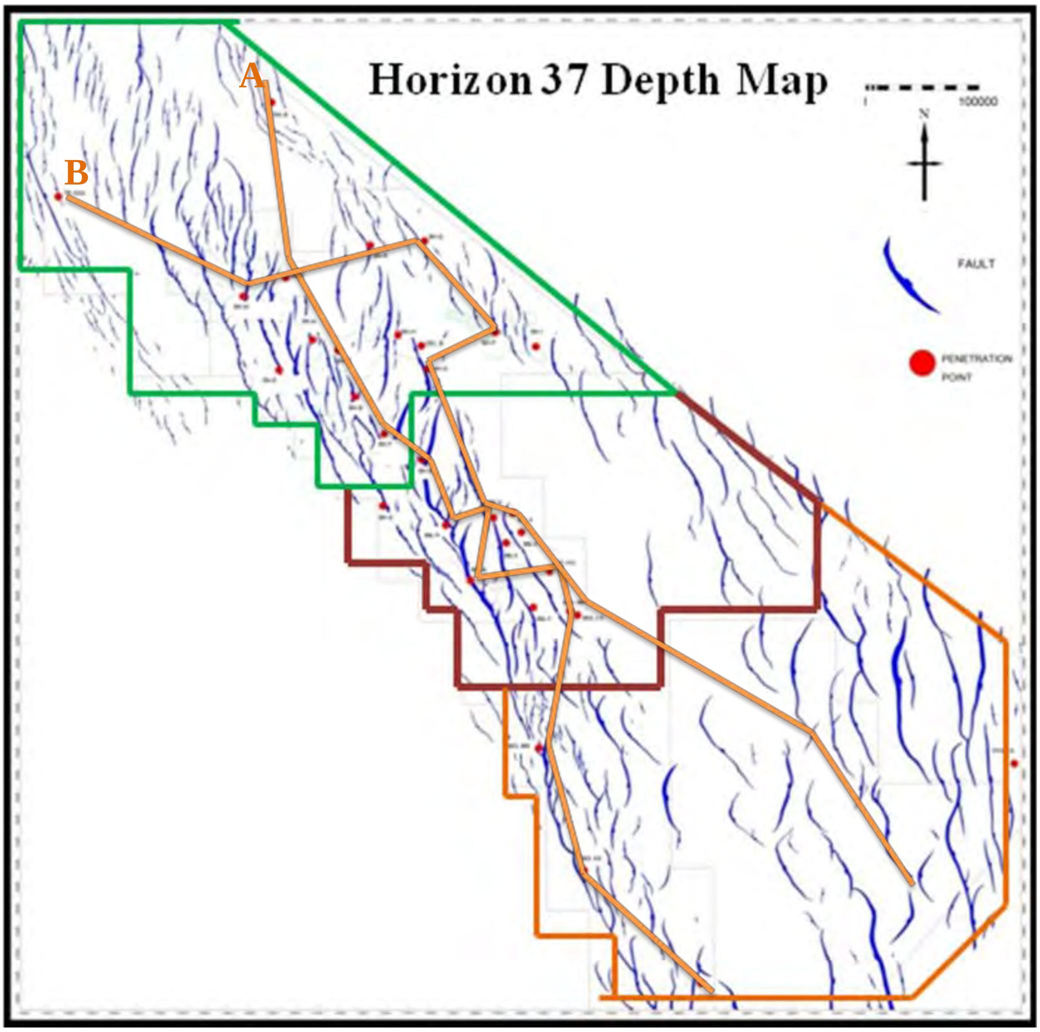


Fig 5.5 Two arbitrary lines were selected for making cross-section.

The vertical distribution area of first line (north to south line) and another (northwest to southeast line) is shown in figure 5.6 and 5.7.

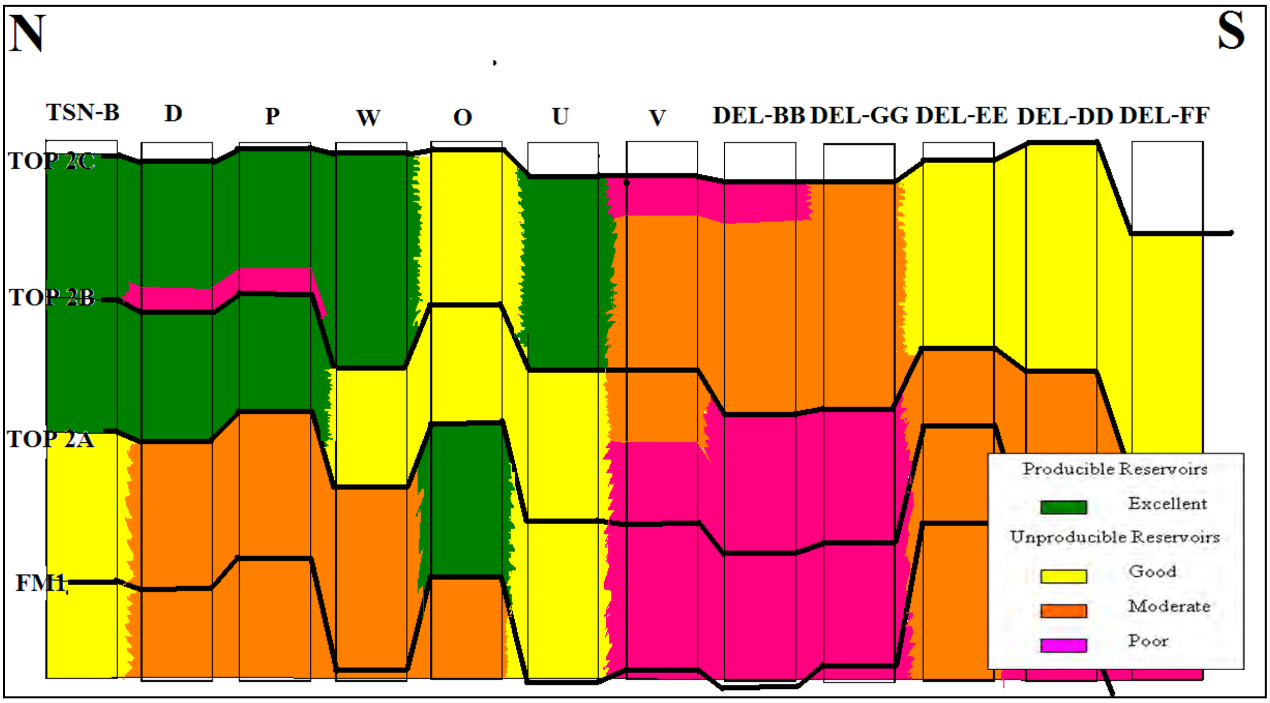


Fig 5.6 Cross-section A through several wells showing the sections of unproducible reservoir sandstones.

Figure 5.6 shows the vertical distribution area of unproducible reservoir sandstones of line A. Although some part of the shallow area has poor class of unproducible reservoir sandstones distributed, the shallower area has better reservoir quality than the deeper of each well.

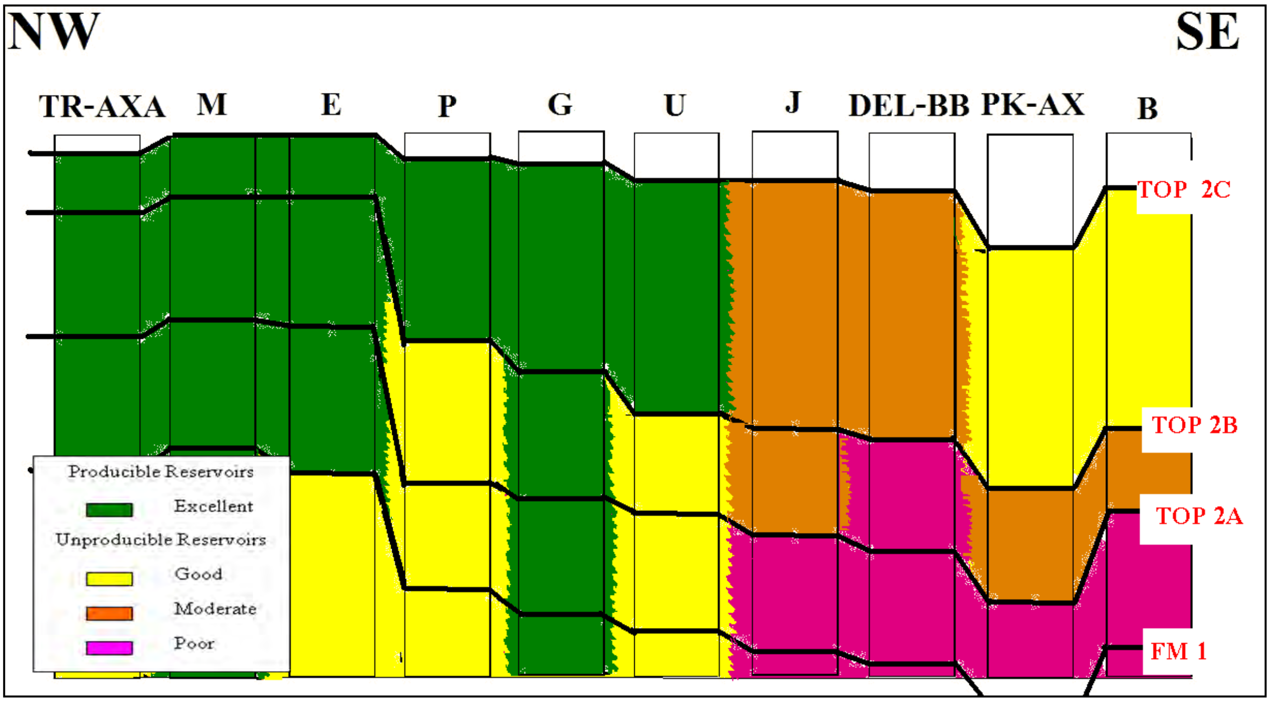


Fig 5.7 Cross-section B through several wells showing the sections of unproducible reservoir sandstones.

Figure 5.7, showing the vertical distribution area of unproducible reservoir sandstone of line B. A better quality reservoir distributes in the shallow unit. Poor and moderate classes are distributes in the deeper unit especially in the southeast.

5.2 Conclusion

RFT data are of little use in classifying unproducible reservoir sandstones because there appears to be no clear relationship between porosity and mobility data. Hence, the detailed lithology from mud logs and wireline logs (NPHI and RHOB) are used to help in identifying areas of different reservoir quality, including different classes of unproducible reservoir. The reservoir distribution maps and cross-sections produced in this study are only preliminary results and should be re-interpreted with more data, should it be available in the future. However, from the maps and cross-sections the horizontal and vertical differences in reservoir quality over the Bongkot field can be observed. The difference in reservoir quality horizontally is thought to be due to facies and/or structural controls. Unit 2C, the shallowest reservoir unit, has better reservoir quality than the deeper rock units, though some poor class reservoir is also contained in the shallow unit. Therefore, diagenetic processes (formation of authigenic minerals, compaction and cementation) is believed to be the cause of differences in reservoir quality vertically.

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