Diagenesis and Porosity-Reducing Mechanism in Moragot Field, Pattani Basin, Gulf of Thailand

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Abstract

Lower to middle mid-Miocene sandstones are the petroleum reservoirs in Moragot Field, southern part of Pattani Basin, Thailand. These sandstones were deposited in continental, transitional and marine environments. This study combined wireline logs, thin section and scanning electron microscope to enhance the understanding of the diagenesis and porosity-reducing mechanisms in this area.

In general, porosity decreases with depth due to increasing overburden. A combination of cementation with a high clay content and poor sorting contributed destroying porosity. In contrast, quartz overgrowths have a positive correlation with porosity. Moreover, except quartz cement, dissolution of framework grains and cement also recovers porosity lost by diagenesis. The reservoir interval of Moragot Field is stratigraphically deeper than other areas plus the depositional environment changes to a transitional clay-rich environment.

Keywords: Diagenesis, Wireline logs, Thin section, Scanning electron microscope and Porosity-reducing mechanisms.

1. Introduction

Moragot Field is part of Pailin Operation Area which is located in southern part of Pattani Basin, Gulf of Thailand (Figure 1). The depositional environments are fluvial to marginal marine. Recovery efficiencies of this field are frequently lower than initial prediction. Although geologically similar, the production histories of several wells have lower production than estimated due to poor reservoir porosity and permeability.

In general, petrophysical analysis has used the average value of porosity, clay content or water saturation. Small change in lithology may not be detected on logs. As well as internal low permeability may not be observed on log curve. This could be cause of inconsistency of flow path and reduce fluid flow. A proper understanding of reservoir properties is necessary for the more accurate prediction of fluid flow and for more accurate reserves prediction.

The main objective is to determine the main control porosity and permeability by integrating petrographic data from percussion sidewall core sample and log characterization from wireline logs.

Data of this study obtained from Chevron Thailand Exploration and Production Company which consist of Moragot-02, Moragot-09 Exploration Wells and all Moragot Producing Wells. Sixteen and eleven percussion sidewall core samples were collected from Moragot-02 and Moragot-09 Wells, respectively. All samples of Moragot-02 Well were thin sectioned but only 6 samples were analyzed as X-ray diffraction and scanning electron microscope techniques. Nevertheless, all Moragot-09 samples were examined by X-ray diffraction techniques and 6 samples were done scanning electron microscope analysis.

These data are plotted for analyzing electrofacies classification and log response by using Interactive Petrophysic Program. Combining GR values, density neutron, resistivity and sonic log provide improved understanding lithology, reservoir properties especially its porosity and permeability. As well as cross plot from many curves were compiled to better identify lithology.

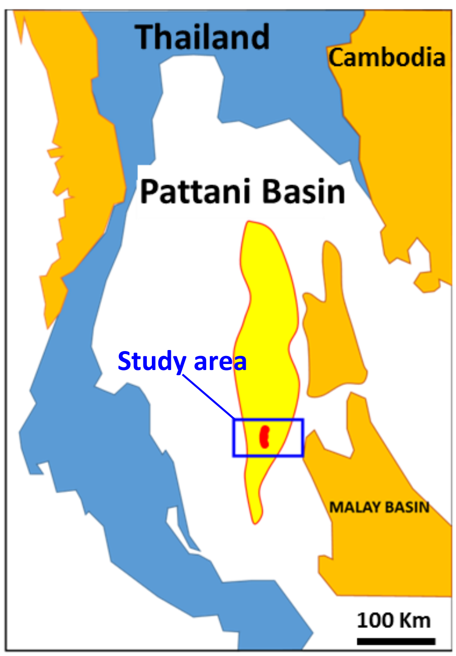

Figure 1. The location map of Moragot Field, Gulf of Thailand.

2. General geology

The Pattani Basin is characterized as a major north-south trending extensional basin, which is approximately 450 Km in length and 100 Km in width. The basin opens into the Malay Basin to the south east where a board structural saddles mark a major change in structural in orientation of major faulting and also marks a change in facies and depositional environment (Crossley, 1990).

The basin morphology is controlled by a series of en-echelon listric faults that bound basin-deep half-graben in a linear belt running the length of trough. These major faults relate to the initial failed Oligocene rifting phase. Additionally, the basement block-faulting created a series of en-echelon horst and graben trends which characterize the structure of the basin. The graben trends have developed syn-depositionally throughout the Miocene to the present.

3. Petrographic analysis

3.1. Sedimentary composition and texture

Sandstones from Moragot-02 contain a broad compositional range which were classified based on thin section analysis, text used Folk's classification, (1974) as quartzarenites, litharenites, feldspathic litharenites, sublitharenites and lithic arkoses (Figure 2). The lithic content of the sandstones decreases from the top to the base of the cored interval and maturity of the sandstone increases with depth. The sandstones have a wide range of grain size (very fine to coarse- grained sand, averaging 0.062 to 0.82 mm), with angular to sub-rounded grains, that are poorly to well sorted.

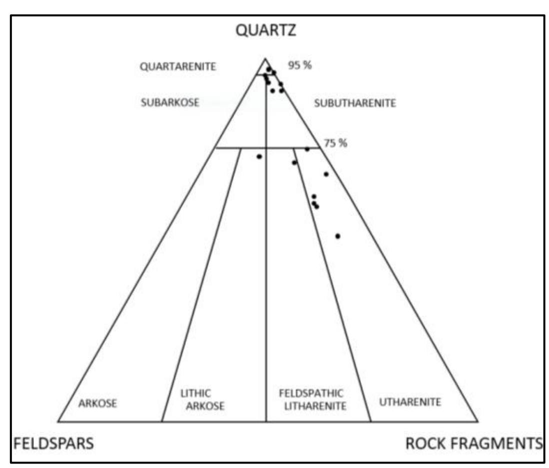

Figure 2. Sandstone classification of Moragot-02 (Folk, 1974) modified from Davies, 1992.

3.2.Mineral framework grains

Quartz is the most abundant mineral and consist of two types of framework grains; monocrystalline and polycrystalline quartzes. Rock fragments are the second most abundant component in the sands. These fragments are composed of several rock types which are dominated mainly by sedimentary and metamorphic and minor igneous clasts. The major abundant sedimentary fragment are mudstone, dolostone and some chert. Metamorphic is the second domonant clasts including schist and phyllite/argillite which acts as mudstone fragments to reduce porosities. Fragments of igneous rock are less significant than sedimentary and metamorphic rocks.

Feldspars consist of two types; potassium feldspar and plagioclase. Potassium feldspar occurs only in the shallowest sample. Plagioclase feldspar is more common than potassium feldspar, although its content decreases with increasing depth due to partial grain dissolution.

3.3.Cementation

The most abundant cementing agents in the sandstones are euhedral silica overgrowths, dolomite, and authigenic clay. Clay mineral identified within these sandstones include illite, illite/smectite, kaolinite and chlorite. Calcite, pyrite, siderite, and carbonate overgrowths (on detrital carbonate grains) are less abundant cements. Iron-rich calcite is noted in one sample (2,703 m.).

Cementation history and diagenesis can be summarized in Figure 3.

4. Electrofacies classification

Electrofacies classification based on density-neutron against gamma ray and density-sonic against gamma ray crossplots gives five electrofacies including 1) gas bearing sandstones, 2) low porosity, water wet sandstones and siltstones, 3) claystone, 4) highly radioactive claystones or organic-rich clay, and 5) coal.

Gas bearing sandstones are recognized by low gamma-ray log values with low to moderate density and very low neutron density values. Water wet sandstones, low porosity sandstones and siltstones generally have higher density values with high gamma-ray value but neutron porosity is similar. Claystone is recognized by high density, high neutron and high gamma ray. Highly radioactive clay or organic-rich claystone is defined by a very high gamma ray (> 200 API) compared to normal claystone, density is lower than normal claystone, neutron and interval transit times are higher. Coal intervals are recognized by low gamma-ray with low density values, high neutron porosity and very high interval transit times (Figure 4).

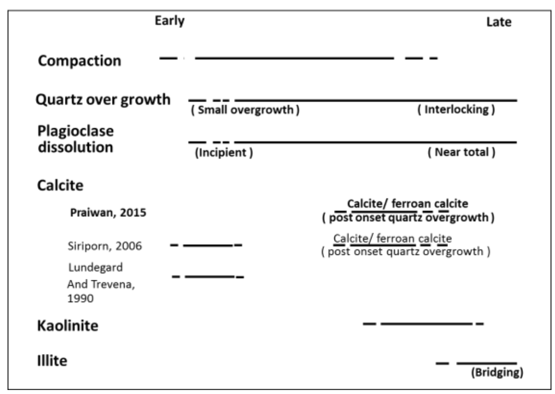

Figure 3. Cementation history of the study area combined with carbonate cementation history of Lundegard and Trevena, 1990 and Siriporn, 2006.

5. Controls on porosity and permeability

5.1 Compaction

Compaction is the major process which destroyed porosity and permeability of sandstone in this study. This relationship can be observed from cross plot between porosity and depth of Moragot-02 well (Figure 5). The plot shows that porosity and depth have inverse relationship, porosity values decrease with increasing depth. The reason would be from mechanical and chemical compaction. The first stage of pore space modification in sands results from simple repacking of grains to form more dense arrangement. Continued mechanical compaction forces grain to grain contact, with continued burial the contacts change from point-to-point contacts to long contacts and to convex-concave contacts. This process called pressure solution or chemical compaction. The chemical compaction does not only destroy porosity by decreasing amount of pore space, but also produces a relatively high dissolved silica concentration in pore water which will precipitate as quartz overgrowth.

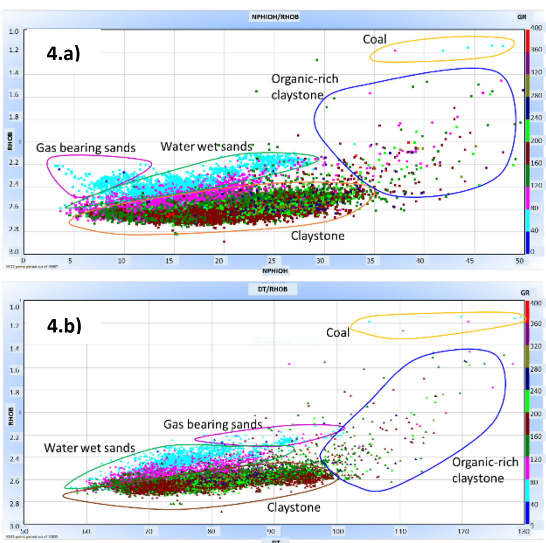

Figure 4. Electrofacies classification a) density and neutron against gamma ray b) density and sonic against gamma ray. Both crossplots give five groups of data that are interpreted as gas bearing sand, low porosity sand and siltstone, claystone, highly radioactive claystone or organic-rich claystone and coal.

5.2 Clay content

Clay minerals, both detrital and authigenic play major roles in decreasing porosity in the sandstone in this study. The most common clay minerals are observed from this study including kaolinite, smectite, minor of illite and chlorite. Detrital clay in matrix of poorly sorted sandstones was deformed and compressed between framework grains during compaction causing pore throats to become plugged. A thin section sample at depth 2777 m. shows obviously deformed detrital clays or mudstone clasts which coat the quartz grains and clog the flow path ways or permeability (Figure 6). In addition, clay minerals can also be induced by breakdown of unstable framework grains such as feldspar. One product of feldspar dissolution is authigenic kaolinite which is observed in thin sections as well as observed on scanning electron microscope.

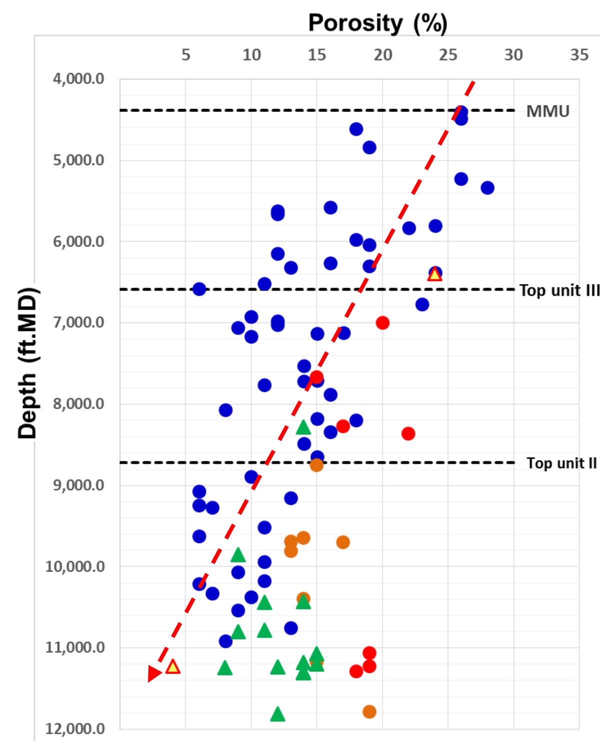

Figure 5. Plot of porosity vs depth of Moragot-02 Well shows decreasing of porosity with depth.

5.3 Grain size and sorting

Relationship between porosity and grain size is shown as Figure 7. Increasing grain size corresponds to increasing of porosity. However, correlation coefficient value of the plot is quite low value (R^2 = 0.5901). This could imply that the grain size is controlling porosity-depth trend together with other properties.

In general, well sorted sedimentary rock provide higher porosity and permeability because it contains narrow range of grain sizes, so it provides high pore space between intergranular. On the other hand, poorly sorted sand contains a wide range of sizes, and fine grains can clog pore space that can reduce porosity and permeability.

Roundness and sphericity are also used to determine sediments in this study. High porosity values can be found from angular to roundness shape or high sphericity to low sphericity that could imply that these two properties have less significance on the porosity trend.

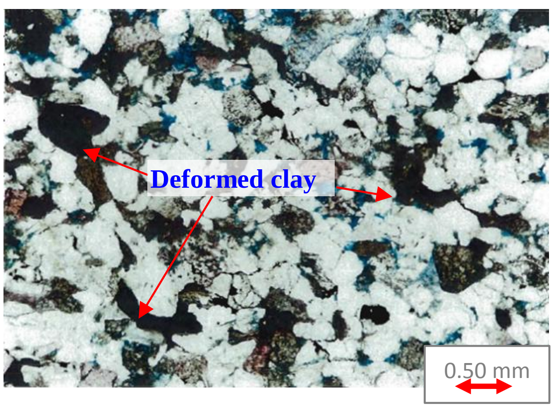

Figure 6. Detrital clays deformed and compressed between framework grains causing pore throats to become plugged (Sample depth 2777 m. with 9% porosity), prepared by Davies, 1992.

5.4 Dissolution

In general, porosity deceases with increasing depth, but diagenetic dissolution can significantly enhance porosity from effects of compaction and cementation. Dissolution of unstable grains such as feldspar and carbonate clasts can be observed from some points which deviate from porosity trend to the right side (Figure 5).

Dissolution does not only develops through unstable framework grains, but also cements and/or matrix especially carbonate cement. Interaction between hydrocarbons and aqueous pore water can produce fluids that are corrosive to calcite and dolomite cements.

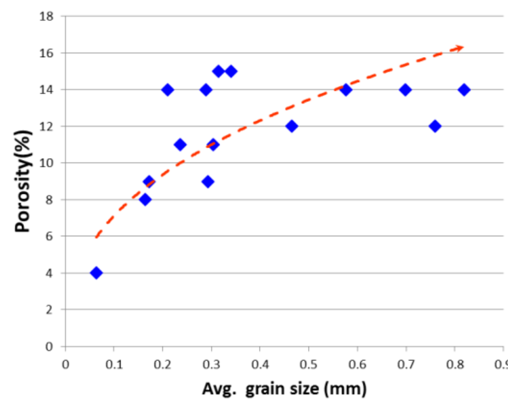

Figure 7. Increasing of average grain size could be one reason that enhance porosity value of reservoir rocks (porosity values and average grain size derived and measured from thin section point count).

5.5 Cementation

Cementation is also a part of the diagenetic process which plays as major control on the porosity but less significant than compaction and clay content. Cementing agents of this area include mainly quartz overgrowth, pore-lining clay and carbonate cement. However, there are some minor other cements such as pyrite and illite which play a less significant control on porosity.

5.5.1 Quartz overgrowth

Quartz overgrowth is the major cementing material which can be observed from the shallowest-depth sample no.01 at 1803 m. (unit 4) down through the deepest–depth sample no.16 at 2994 m. (unit 2). It occurs as well-developed syntaxial overgrowth on detrital quartz grains which can be recognized by their euhedral crystal faces and underlying clay rims.

Quartz overgrowth is the only cementing agent that results in retaining of porosity. From the plot between numbers of quartz overgrowth versus porosity, the relationship of porosity increases with increasing of quartz overgrowth with relationship coefficient equivalent R^2 = 0.7535 as Figure 8.

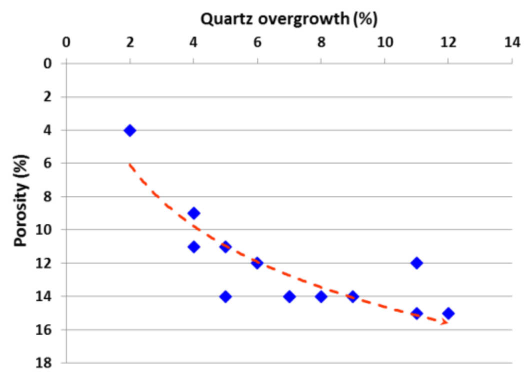

Figure 8. Increasing of quartz overgrowth retain significantly porosity value of reservoir rocks (porosity values and quartz overgrowth derived and measured from thin section point count).

5.5.2 Carbonate cement

Based on thin section study of sample at 2703 m. which illustrates calcite cement coats on the polyhedral crystal faces of the quartz overgrowth. This evidence indicates that the calcite cement precipitated after the quartz overgrowth.

Siriporn, (2006) suggested that carbonate cement can be divided into two stages; early siderite cement related to flood plain deposits and late stage calcite cement related to fluid flushing at greater burial depths in sandstone in Pailin Field. These carbonate cements filled pore space and reduced porosities of the sandstones (Figure 9).

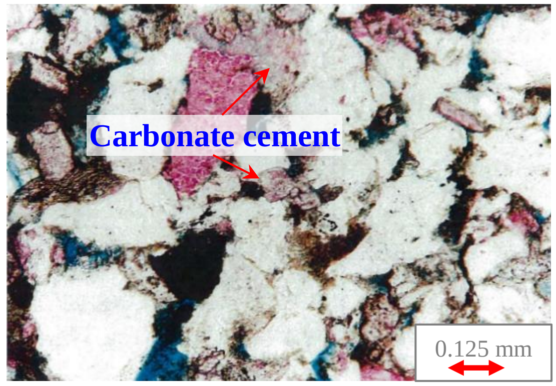

Figure 9. Carbonate cement filled pore spaces and reduced a number of porosities of the sandstones (sample at depth 2582 m. with 9% porosity).

5.5.3 Kaolinite cement

Kaolinite cement normally contain microporsity inside, SEM photo shows the book-like structure of kaolinite and needle-like illite, which fill the pore. It normally fills pore space in the sand, and consequently reduces porosity, which may be either primary porosity or secondary porosity (Figure 10). Even though a number of porosities were induced by secondary porosity, occupying of kaolinite in the pore reduces efficiency of porosity and permeability.

5.5.4 Illite cement

Illite and illite/smectite are recognized by Scanning Electron Microscope and XRD techniques (Davies, 1992). SEM photo shows needle-like illite, which fills pore space in the sandstones, and consequently reduces porosity.

5.5.5 Pyrite cement

Pyrite could be formed in the sulphate reduction zone with little free oxygen, beneath the water-sediment interface. Generally, it forms very early before quartz overgrowth, but from the thin section study, it shows unclear relationship with other cementing agents

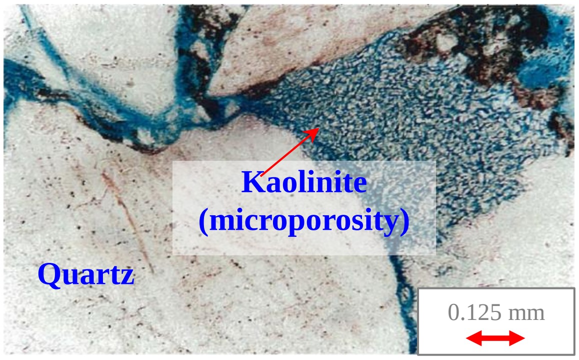

Figure 10. Kaolinite cement contain microporosity (sample at depth 2858 m. with 14% porosity).

except quartz overgrowth. Pyrite cement can be found in 2 samples (2581, 2700 m.), thin section shows that pyrite cement formed after quartz overgrowth. Even though pyrite cement can be observed, the amount of this cement is too small to reduce porosity in the reservoir. It is a minor effect.

5.6 Mineral composition

Rigid grains such as quartz, feldspar and chert fragments enhance the ability to hold compaction force when buried deeply. Inversely, increasing of soft grains such as mudstone clast, volcanic clast, mica minerals, enhance compaction buried. Because these grains are more flexible deformation when deeply buried. However, original composition can be changed during undergoing diagenesis. Because when these sediments were buried deeply then some unstable minerals breakdown to be stable minerals such as feldspar. In contrast, some minerals do not change such as quartz. From this point, unstable minerals decrease with depth. Moreover, increasing with depth sandstone composition became more mature as present of quartzarenite. This could support high porosity still remains in the deep zone.

6. Discussion

6.1 Porosity variation

Porosity in this area is not simply controlled by only diagenesis but also by a combination of several factors, as can be observed from the plot between porosity with depth Figure 5. The overall trend of porosity is decreasing with depth. However, this trend exhibits highly variable porosity values.

Compaction and clay content acted together to destroy reservoir quality in this area. Increasing depth corresponds significantly to decreasing porosity plus increasing clay content reduces porosity. In poorly sorted sands, the wide range of sedimentary grain size enhances the ability of fine grains and/or clay to clog interganular pore spaces. Moreover, increasing of grain size supports high porosity in the sandstones. These four factors are the major processes that destroyed porosity values in the sandstone reservoirs in this area.

However, cementation controls are less significant than the previous factors. Even if quartz overgrowth, carbonate cement and pore-lining clay (authigenic clay) are the major cements, they have negligible effect on porosity. However, quartz overgrowth acts as enhancing-porosity factor while the others are reducing-porosity factors. The second most abundant cementing agents are kaolinite and carbonate cements. The amount of calcite and dolomite cement is too low (≤ 3%) to affect porosity values. Even when this cement contains microporosity, it is non-effective porosity.

6.2 Porosity in Moragot Field

There are other factors that might affect porosity of this field which including;

1. The unit 4 (reservoir interval), which is a red bed interval, changes to predominantly grey shale below the

Mid-Miocene Unconformity, indicating a change in environment from flood plain to delta plain in the northern Malay basin, which generally contains more fine-grained sediment and a low net-to-gross of sand that makes it easily more compacted.

2. The reservoir of Moragot Area is stratigraphically deeper than other areas to the north, this can cause a bigger overburdened force than other field which act as the major factor destroying porosity.
3. The deeper stratigraphy is not only affected by the overburden but also higher temperatures which can induce chemical reaction that destroys reservoir quality.

7. Conclusions

A study of the sandstone reservoirs in Moragot Area concludes following.

1. The sandstones are dominantly sublitharenites, litharenite, with minor quartzarenites, subarkose, lithic arkose and feldsparthic litharenite. Quartz is the major granular constituent and range from 32% to 70%. Lithic fragments are more common than feldspar and decreases with depth. Feldspar content varies between 1% and 6% with plagioclase dominating over K-feldspar. The dominant types of cement are quartz overgrowth, carbonate cements, and authigenic kaolinite.
2. Net to gross maps can be generated by extracting low frequency amplitudes within the zone of interest. The reservoir quality of Moragot-02 resulted from a combination of several factors. The major influences are compaction, grain size, clay content as well as sorting and dissolution. Cementation is minor influence. Grain and cement dissolution and quartz overgrowth cause porosity enhancement while the others cause porosity reduction.
3. Moragot Field is stratigraphically deeper than other fields which contributes more overburden that acts as the major porosity destroying factor, as well as higher temperatures which induce chemical compaction.

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