PALEOGENE SEDIMENT COMPLEX - GEOLOGICAL FACTORS IMPACTING ON ITS RESERVOIR QUALITY AND HYDROCARBON POTENTIAL

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Summary

The Paleogene reservoir complex has diverse facies which change rapidly both laterally and vertically. Its depositional environments are determined as alluvial, deltaic, tidally affected lacustrine and, rarely, with a shoreline. The variety in sedimentary facies and lithological heterogeneity are the main causes for the anisotropy in porosity and permeability of the Paleogene reservoirs, thus reducing field exploration and development efficiency as well as the application of secondary exploitation in order to increase the oil recovery.

Reservoir quality has resulted from the combined effects of primary diagenetic elements and secondary alteration. Secondary deformation has a bidirectional influence on the reservoir quality, reducing the primary porosity but also forming secondary porosity. Dual porosity is one of the important properties of the Paleogene reservoir that should be considered in production management.

Secondary fractures could potentially increase the flow in the tight Paleogene reservoirs.

The production from Paleogene reservoirs is still small, not corresponding to the potential of Paleogene formations as rich source rocks. The Late Eocene-Oligocene reservoir, therefore, needs to be investigated and sufficiently evaluated as a potential hydrocarbon bearing play in order to enhance production and reserves.

1. The lithology of the Paleogene reservoir complex and its heterogeneous character

In the Cuu Long basin, wells are concentrated on structural uplifts, thus encountering only the upper strata of Paleogene age, mainly those of of Late Eocene-Oligocene age.

The Late Eocene-Oligocene assemblage was found in many locations with a full or partial section and showing high facies heterogeneity (Fig.1):

- The underlying Tra Cu formation of Late Eocene - Early Oligocene age, corresponding to the seismic sequence E, is composed mainly of fine- to coarse-grained sandstones interbedded with siltstone, shale, and thin layers of coal and intraformational conglomerate;

- The overlying Tra Tan formation of Late Oligocene age, equivalent to seismic sequences D and C, is characterised by finer-grained sedimentary rocks, mostly shale and siltstone intercalated with thin layers and lenses of sandstone.

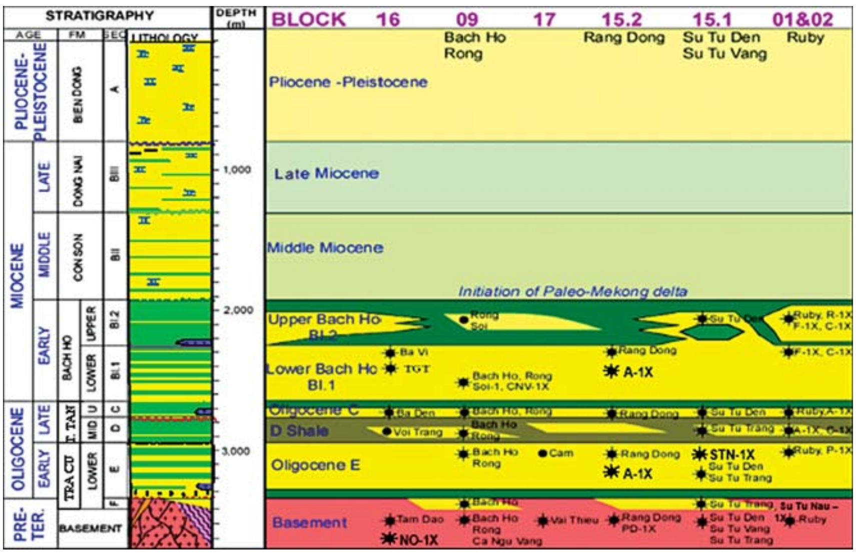

***Fig.1.** Stratigraphic column of Tertiary formation - Cuu Long basin*

The Paleogene sandstones are hydrocarbon reservoir with low flow rate due to low permeability. However, some wells yield high flow, at times reaching 2 - 3 thousand barrels per day, such as at North Bach Ho, and Southeast Rong…

1.1. The sandstone of Sequence E, (Fig.2) grey and light brown colored with cross-bedding, blocky shape, and the grain size of 0.25 - 1mm, is overlain by fine- to coarse-grained sandstones intercalated with siltstone, coal bearing argillite, and shaly schist with thin coal layers. Sandstones are polymictic with compositions varying from arkose, lithic arkose to litharenite, feldspar litharenite, and with increasing tendency for the presence of rock fragments to the Northeast of the basin (Block 01-02, 15), where they were formed plausibly in a terrestrial environment of high energy, close to the supply source. The facies changes rapidly from proluvium, channel bar to alluvial plain and swamp facies laterally, towards the depositional centre, and stratigraphically upwards.

Fig.2. *Fine to medium-grained sandstone oil-saturated moderately sorted with cross-bedding point bar facies - Early Oligocene - BH-10 well - 4,054m*

Tab.1. *Distribution of clays minerals in Miocene - Oligocene reservoir rocks in Bach Ho field*

Unit	Clay (%)					
	Smectite	Kaolinite	Illite	Chlorite	Mixed minerals	Zeolite
Early Miocene						
23	36	40	11	8	5	-
24	19	66	6	8	1	-
Late Oligocene						
I	-	13	39	36	12	-
II	-	5	35	43	15	2
Early Miocene						
VI	-	4	39	40	14	3
VII	-	-	20	53	27	-
VIII	-	-	28	55	12	5
IX	-	2	30	52	6	10
X	-	-	28	58	3	10
XI	-	-	10	80	-	10

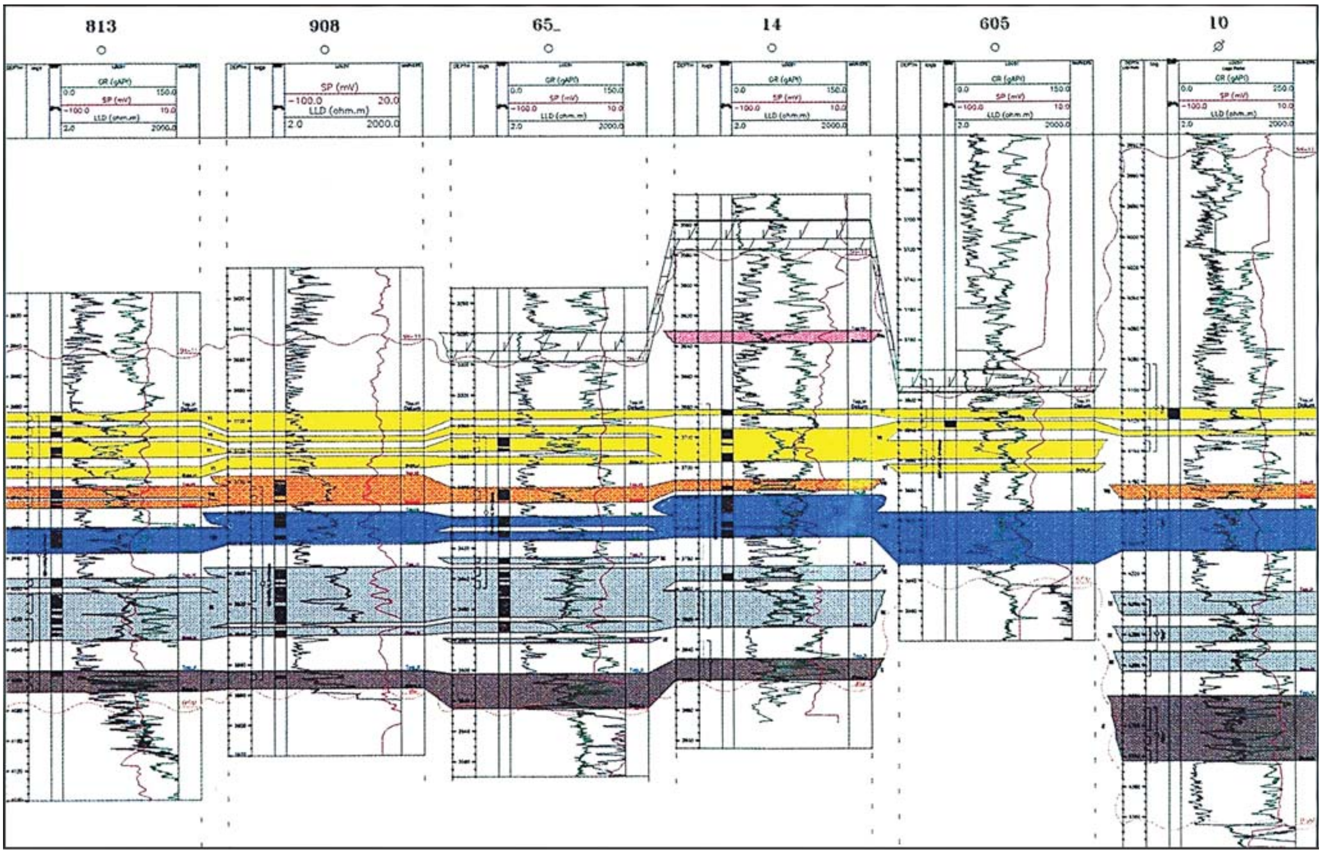

Fig.3. *Interfingering character of stratigraphic arrangement in the Early Oligocene section - Bach Ho field*

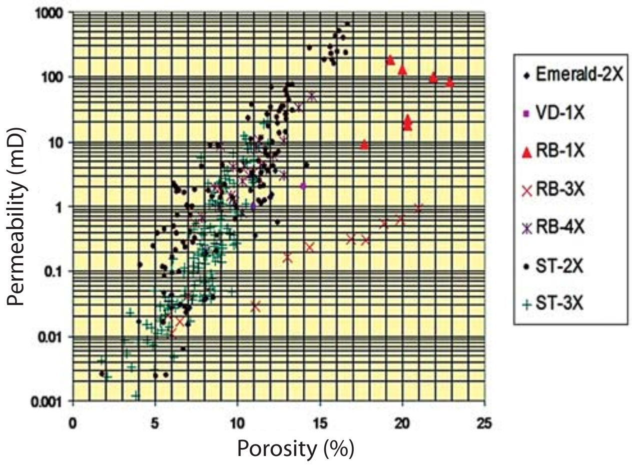

Fig.4. *Porosity - Permeability relationship of Oligocene reservoir in Cuu Long basin*

The high concentration of feldspar (plagioclase) and the presence of unstable, ductile minerals in the cement composition, such as albite, zeolite, illite, chlorite, and hydromica, as well as compaction and secondary alteration had reduced the size and volume of primary porosity. An abrupt increase in the zeolite and decrease in kaolinite contents has been recorded in the 3,700 - 4,400m interval (SH VI-IX) (Tab.1). This phenomenon is observed in a number of wells in the Bach Ho, Rong and Rang Dong structures.

Facies-lithological studies indicate that the E sequence consists of fluvial, partly lagoon-deltaic clastic sediments deposited in sub-grabens. Dominant facies are fluvial bars of braided and meandered rivers, alluvial fans and coastal sediments bordering sparsely distributed lagoons.

Alluvial fans were deposited under the influence of strong currents, which flowed in multi-direction streams. Shale laminae between sand lenses are confining and do not play the role of a seal. The evidence of desiccation cracks and bioturbation by burrowing organisms shows that the water was shallow and occasionally receded or evaporated.

Lithologic heterogeneity due to facies variation has resulted in the interfingering character of stratigraphic arrangement in the Early Oligocene section (Fig.3).

The average porosity of the Early Oligocene sandstone is 12 - 14%, and 18% in some places; while permeability ranges from 1 - 50mD. Permeability tends to be better in the upper part of the section and decreases rapidly with depth, while porosity is normally below 10 - 12% at 4,000m, where strong quartz overgrowth and chloritisation occurred… The quality of that sandstone reservoir is normally poor with low flow rate, but sometimes the flow could reach several hundreds of tons of oil per day as in Bach Ho and Southeast Rong, or condensate gas in Emerald and Su Tu Trang fields (Fig.4).

1.2. The rocks comprising sequence D in the Late Oligocene Tra Tan formation are mainly bituminous shale, coaly shale, lignite and siltstone with intercalated sandstone lenses of various thicknesses, in which clastic components include quartz, feldspar and rock fragments. The amount of orthoclase outweighs that of plagioclase - that is a significant property compared to sequence E's sandstone. The sandstone belongs to the arkose and lithic arkose clan, medium to coarse-grained, medium sorted and of poor roundness. Authigenic minerals include quartz and calcite, whilst secondary clay minerals are illite and chlorite. The content of zeolite increases with a decrease in the composition of kaolinite. A high variety of rock texture was observed such as fine cross-bedding, planar bedding and massive. The depositional environment is determined to be a meandering river and low deltaic plain environment of medium energy. The sequence D is considered as the regional source and seal of the Oligocene assemblage although it contains a certain amount of sandstone layers, the latter are of small in quantity and are normally thin and confining. On the basin boundary, where shale facies is changed into sand facies, the sandstone layers, especially in the lower part of sequence D, become a target of interest.

1.3. Sequence C in the Late Oligocene Tra Tan formation is commonly composed of shale, coaly shale rich in organic matter, thin coal layers, and siltstone interbedded with thin sandstone lenses. Yet, in several structures such as Diamond, Ruby, Su Tu, Rang Dong, and Bach Ho fields, flow of high charge is found in areas where the number and thickness of these sandstone layers increase. Sandstones are polymictic and belong to the arkose and lithic arkose type with a content of quartz (40 - 62%), feldspar (30 - 50%), and rock fragments (9 - 13%). Particularly, in the Su Tu area, the litharenite and feldspar litharenite are dominant with the rapid increase of rock fragments ratio (40 - 50%) while the content of feldspar decreases to 5 - 15%. Sandstones are medium- to coarse-grained with medium sorting and good roundness. Cement is composed of authigenic quartz and secondary clay minerals such as chlorite and illite. The amount of illite is recorded as increasing rapidly and becoming dominant below 3,300m with a decrease in kaolinite content. The rocks are cross bedded and rippled.

Porosity ranges between 12 - 21% with an average of 14%. Permeability is 2 - 26mD, and reaches 50 - 60mD in certain places. The depositional environments were swamps, floodplains, and anoxic tidal plains affected by sporadic sea ingression from the Northeast.

The facies variety and lithological heterogeneity are the main causes for the anisotropy in porosity and permeability of the Paleogene reservoir, reducing field exploration and development efficiency as well as limiting the application of EOR methods.

2. Geological factors impacting on the reservoir quality of Paleogene formation

Many factors of different origins could affect the reservoir quality. However, reservoir quality is a combination of the effects of primary elements and secondary deformation during diagenesis. The quality of Paleogene reservoirs is generally low.

2.1. Sedimentary lithology and reservoir characteristics

Such primary elements related to the sedimentary lithology as rock texture (grain size, sorting, and roundness), rock type (clastic and cement, clay minerals), sand-shale ratio, reservoir thickness and distribution significantly affect the porosity and permeability of the Paleogene reservoir complex, especially that of the Eocene - Early Oligocene sequence E.

- There is a relationship between porosity and permeability, which tends to decrease with depth due to loading compaction. The visual porosity is normally less than 18%. The effective porosity of sandstone is usually less than 10% with permeability less than 10mD. The granular porosity is less than 4% below 4,350m in Bach Ho field (Fig.5).

- The values of porosity and permeability are functions of grain size, sorting, abrasion, clastic components and textural arrangement. The porosity of medium- and coarse-grained sandstone is generally low because the clasts are poorly sorted and poorly eroded; the development of clay minerals in the cement composition such as illite/chlorite and zeolite indicates the level of secondary alteration and the ability to fill up primary

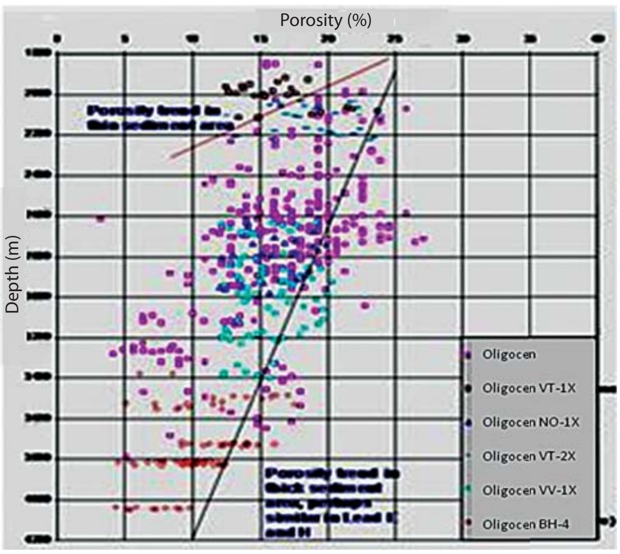

Fig.5. *Functional relation between porosity versus depth of Miocene/Oligocene reservoir rocks*

Fig.6. *Non-uniform character of oil contamination of Oligocene reservoir - Bach Ho field*

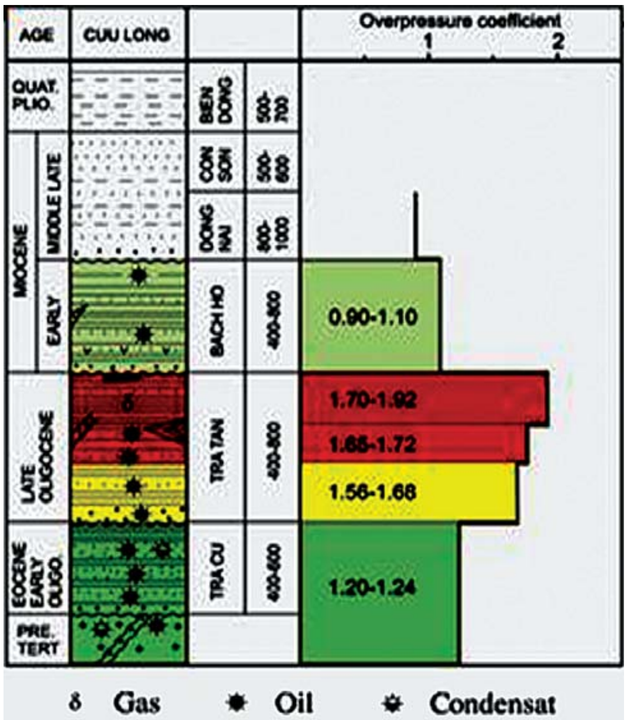

Fig.7. *Distribution of overpressure zones with depth in Cuu Long basin*

pores, thus reducing the Oligocene reservoirs' porosity and permeability.

- In terms of clastic composition, the Oligocene sandstones are mostly polymictic. They are classified as arkosic and lithic arkosic sandstones with high contents of unstable fragments, such as feldspar (20 - 40%) and particularly fragments of acidic extrusive rocks, granitoid and shaly schists (7 - 25%). Such high concentration of unstable rock fragments is one of the factors that have reduced the reservoir quality of this terrigeneous sediment.

- Another critical factor is the cross-bedding of the reservoir rocks. Analysing the cross-bedded reservoir rocks for intergranular porosity, the vertical variation is firstly investigated, while laterally the reservoir is considered homogeneous at least in the extended space between correlated wells. The discrepancy in reservoir quality is complicated, especially in cross-bedded strata. Cross-bedding has a direct influence on the porosity-permeability (K-φ) relationship. At the same porosity, a reservoir rock has maximum permeability and thus yields the maximum flow in the direction parallel to that of the crossbedding, while in the perpendicular direction, the permeability and flow have their minimum values. The difference is recorded to be tens of times. Fig.6 shows that the oil contamination is not uniform but depends on sorting, grain size and texture of the reservoir rocks.

- Abnormal overpressure is another factor that influences the distribution of reservoir porosity and permeability. Abnormal overpressure greatly affects the petroleum system, including trap seal integrity, reservoir quality, timing of maturation of the source rock, as well as the timing and the direction of hydrocarbons' primary migration (Fig.7).

Reservoir quality is closely related to the ability of clastic rocks to lose porosity under mechanical loading compaction, which increases with depth. However, abnormal overpressure could reduce, and at times stop the mechanical compaction, preserving the porosity in sandstone reservoirs interbedded with or underlying overpressured shale. Abnormal overpressure could also retard diagenesis. Abnormal overpressure was commonly present in the center of the basin where thick shale was deposited. In the proximal part of basin the grain size becomes coarser, the thickness of shale decreases, and the overpressure phenomenon disappears.

Abnormal overpressure is always a favorable condition for both lateral and upward vertical migration of hydrocarbon within reservoir rocks while interbedded with overpressured shale, but the pressure differentiation could also create migration to underlying reservoir sequences.

2.2. Bidirectional influence of the secondary deformation on the reservoir quality

Paleogene, especially Eocene-Early Oligocene, sediments were deeply buried and are distributed below 3.5 - 4.5km. Under the high pressure of loading compaction and high temperature, the Paleogene sediments have undergone vigorous secondary deformation, changing to the late catagenesis - early metagenesis stage, which is manifested in two opposite processes that result in a reduction of the primary porosity and the formation of secondary porosity.

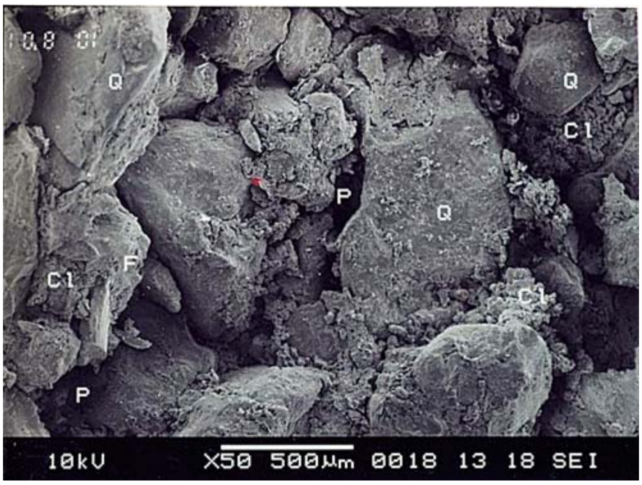

Fig.8. *Pore spaces infilled by clay minerals, but still with good connectivity (ST-3X well)*

Fig.9. *Early Oligocene sandstone highly fractured - Bach Ho field fractures filled by secondary minerals*

- The cementation process, especially quartz cementation and the formation of secondary minerals to content of more than 20%, sometimes 25 - 30%, causes the infilling of primary pores and reduction of the intergranular porosity (Fig.8). According to the field statistics from Blocks 01-02, 09, 15, and 16, with the content of secondary minerals more than 30%, the primary reservoir porosity should be reduced to less than 5%, equivalent to the level of deformation from late catagenesis to early metagenesis, which occurs at the 4,200m depth. At this depth, oil has low mobility and usually loses its flow ability, particularly in the case of medium - heavy oil (29 - 35°API) with low GOR (300 - 350scf/stb).

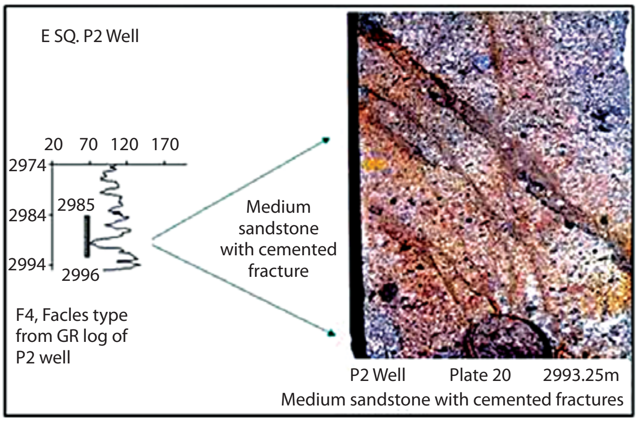

Fig.10. *Core at 2,993.25m in E sequence of Rang Dong field*

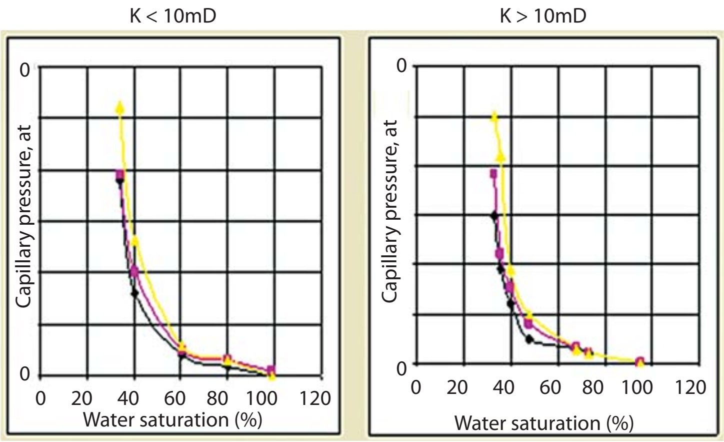

Fig.11. *Relation between P_c and S_w of the Late Oligocene reservoir - Bach Ho field*

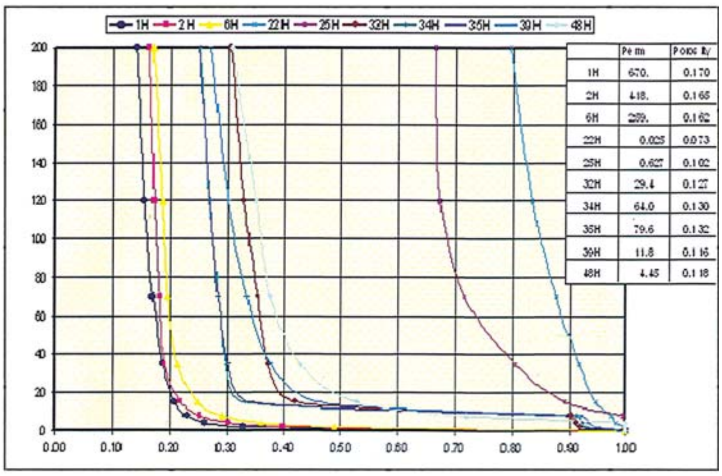

Fig.12. *Relation between P_c and S_w of the Early Oligocene reservoir (E sq.- ST field)*

- Contrary to the above trend, secondary deformation can also generate secondary pore spaces, an important factor that helps increase the porosity and permeability of Paleogene clastic sediments. The appearance of microfractures and micropores during late diagenesis, especially when changing from late catagenesis to early metagenesis due to dissolution, chemical solution on the pore walls, and volumetric contraction due to the formation of secondary minerals, had initiated the generation of secondary porosity and permeability. The lithological analysis reveals the existence of vuggy porosity with radius of 0.2 - 0.35mm; and microfractures with apertures up to 1mm mostly filled with secondary minerals (Figs.9 and 10). For reservoir rocks of early catagenesis the intergranular porosity plays a critical role, while for clastic sediments in the late catagenesis - early metagenesis stage, secondary pores (vuggy pores, fractures) become the potential hydrocarbon migration pathways.

- However, besides the ability of late diagenesis to form secondary deformation which increases the reservoir quality, differential fracturing of brittle clastic rocks in the intercalated sand/shale reservoir sequence, formed during the folding and faulting period of Late Oligocene tectonic compaction and inversion, could also form secondary porosity and permeability in both structural and stratigraphic traps.

Secondary fractures could potentially increase the flow of the tight Paleogene reservoirs

The influence of fractures, which are always present in clastic rocks, in improving low fluid flow rates has not yet been as sufficiently investigated as in fractured basement reservoirs. The impact of the presence of fracturest is also demonstrated by the abrupt change on the capillary curves of reservoir rocks with different values of permeability (Figs.11, 12 and 13).

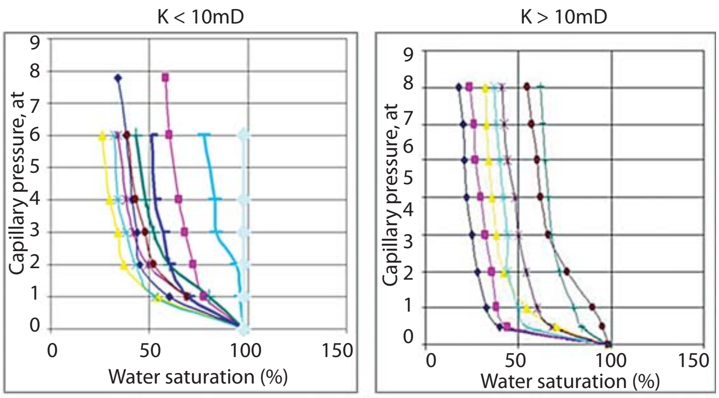

Fig.13. *Relation between P_c and S_w - Early Oligocene reservoir Bach Ho field*

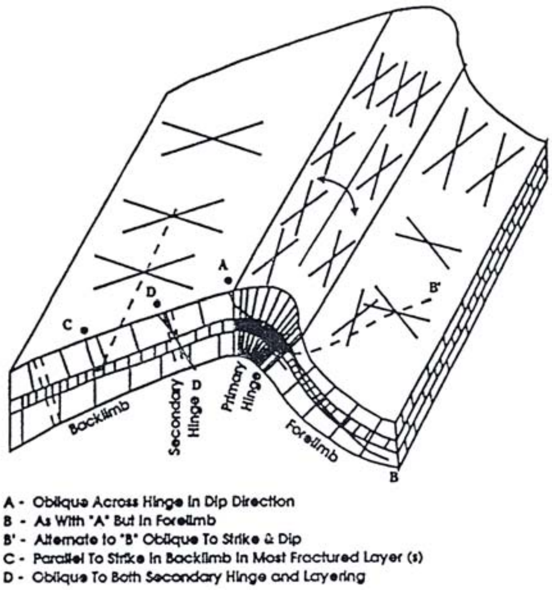

Fig.14. *Fracture distribution on a folded anticline trap [4]*

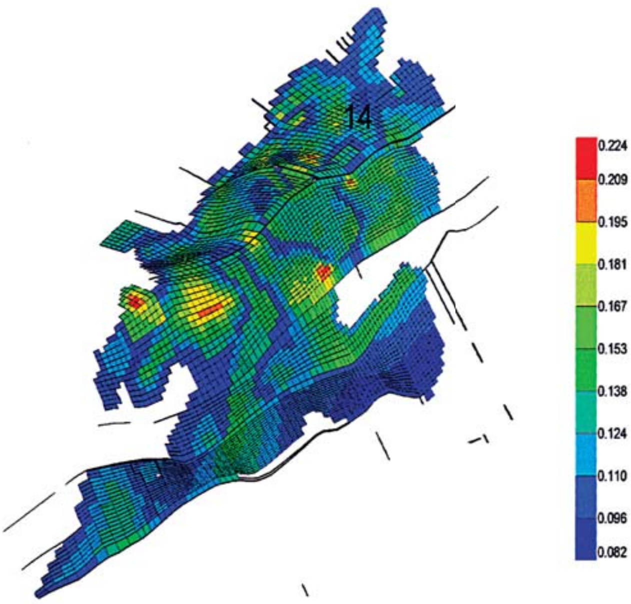

Fig.15. *Map illustrating the distribution of total porosity in Early Oligocene sequence of Bach Ho field (data VSP)*

Thus, the characteristics of fracture distribution need to be analysed in order to identify at what location and when the fracture system would dynamically increase the flow. In the case of fractured basement, the density and connectivity of the fractures system network depend upon the stress field's attributes and its intensity while in the stratified clastic reservoir, the fracture intensity, spacing and fracture width depend upon: (1) lithology, (2) grain sizes, (3) rock texture, (4) porosity, (5) reservoir thickness and (6) the location of fractures on the folded structures.

The study results indicate that:

- Rocks with a high content of ductile minerals have denser fracture distribution, but narrower fracture width as comparing to those of brittle composition. This could explain the fact that high flow reservoirs in the Cuu Long basin are normally quartz arkose sandstones, quartz polymictic, litharenite of high brittle clastic and low feldspar ductile contents. Fracture width and connectivity become better.

- In general, there is a relationship between a decrease in grain size and an increase in fracture density, probably due to the fact that fine-grained layers are more thinly-bedded as compared to the thickly-bedded and blocky coarse-grained layers.

- Rocks of the same composition and texture, but of high tightness and low porosity, will have sparse fracture networks, but open fractures possibly become wider.

- With respect to all lithological and sedimentary characteristics, given the same compaction condition, thin sand layers tend to be more fractured with closer spacing.

- The fracture intensity depends upon the stress field formed during the folding and faulting tectonic deformation. The role of faulting in stratified traps is investigated for sealing capacity rather than fracture extent. Moreover, with the multi-staged property of the fault system in the Cuu Long basin, the closure of the Late Oligocene seal, containing thin shale strata, is still a big risk. Therefore, the possibility for the fracture system to act as a factor to increase the porosity and permeability of the Paleogene reservoir is only related to the folding movement, and in the case where the covering Late Oligocene shale as a regional seal was not destroyed. The fracture system is usually very complicated and is extrapolated from surface field studies. The variation in fractures' location and intensity depends upon the shape and origin of the folds. Their trend and plunge could either be parallel or perpendicular to the bedding surface. Despite their diversity and complexity, fractures of high dip tend to be concentrated in the apex and along the axis of the folds, and sparsely extended on the two limbs. The strike of fractures is usually parallel to the fold axis (Fig.14).

This trend is very critical to locating the exploration and production wells in clastic traps such as those of Paleogene age.

- Also, the abrupt change on the relation curve between capillary pressure P_c and saturation S_w possibly indicates the presence of the dual porosity character of the Paleogene reservoir: the fracture porosity as open conduit of high permeability and the matrix intergranular porosity having lower permeability.

Though the relationship between fracture distribution and the porosity character of the Paleogene reservoir of Bach Ho field has not been fully investigated, some correlation can be observed between the porosity distribution and the location of the apex zone of the anticlinal axis, and also partially with faults (Fig.15).

2.3. Hydrocarbon potential distribution in the Paleogene reservoir formation

Commercial oil production from the Oligocene rocks is identified systematically at Bach Ho field of Cuu Long basin. The oil potential Oligocene formation is developed mainly in the Northern part of Bach Ho field and overlapped the Mesozoic intrusive granite basement. The oil trap structure is complicated, of multilayered character and isolated mostly by faults and lithological barriers (Fig.16).

In general, the Oligocene reservoir complex could be grouped into Late and Early Oligocene productive formations with different reservoir properties. Up to now the Early Oligocene reservoir is the main production target for Vietsovpetro.

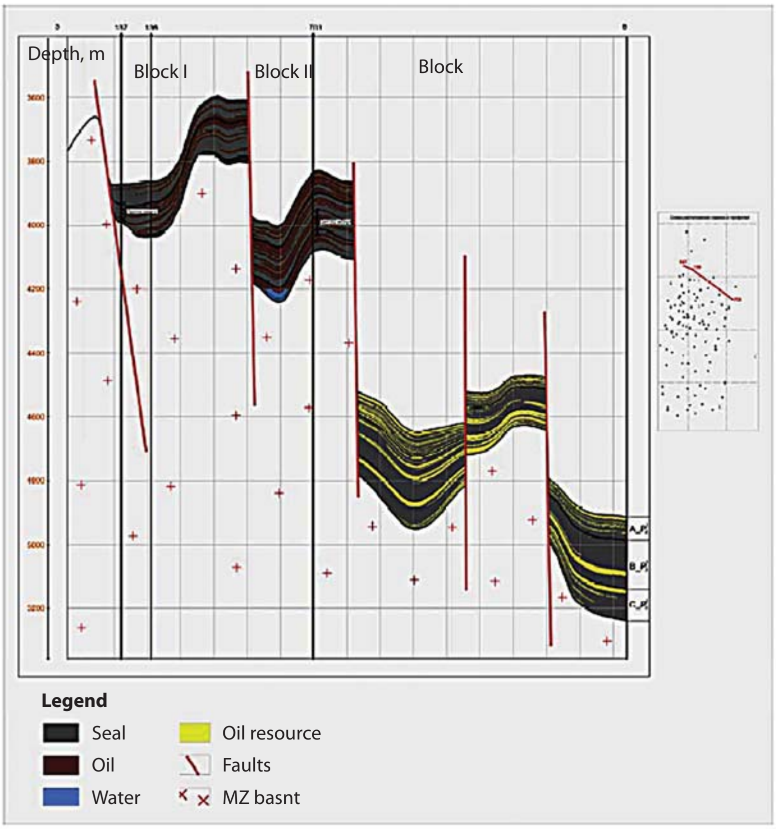

Fig.16. *Multi-layered character of Early Oligocene reservoir - Bach Ho field (VSP data)*

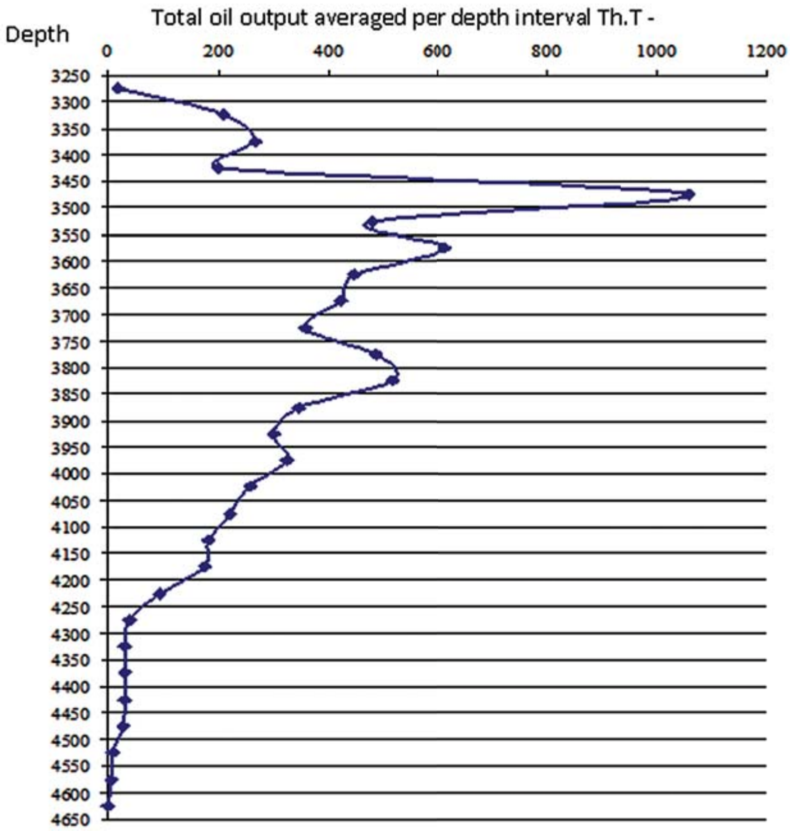

Fig.17. *Distribution of hydrocarbon potential with depth (data VSP)*

Some common trends in reservoir quality can be recorded:

- Oil bodies are discontinuous and heterogeneous in reservoir quality. They are separated by faults, and sealed by tectonic and lithological barriers.

- The highest block is less compacted and the western part, more impacted by faults is better qualified in reservoir quality.

- High heterogeneity of poro-permeability with both area and depth and poor hydrodynamic connectivity between wells, negatively affected the result of waterflooding.

- Exploitation is performed mainly by the displacement mechanism of water drive with local gas solution drive.

- High productivity seems to be related to the apex zone of the block anticline and partially to the fractured zone close to faults where the reservoir quality is plausibly better.

- In most of the wells, the production index varied weakly, but tends to decrease with time.

- For exploitation, high interbedding and reservoir heterogeneity, negatively affect the reliability of reservoir petrophysic parameters and consequently the assessment of reserves and oil distribution in each block and every productive unit, and also the design of offshore facilities.

- Averaging the production in Oligocene producer wells by depth intervals (data to 2006), the output capacity of the Oligocene reservoir is estimated (Fig.17):

- Reserves recovered at depth 3,450 - 3,500m are the highest with the oil output of about 1,056 thousands tons, taking 20% of total oil production from Oligocene reservoir.

- The most effective producing interval is at depth 3,300 - 4,250m.

- Production capacity decreases with depth.

3. Conclusions

- The lacustrine-delta facies complex which developed in rift basins during the Paleogene period, particularly in the Cuu Long basin, has a great hydrocarbon potential.

- The Paleogene reservoir rocks have diverse facies, which varied rapidly in both horizontal and vertical directions, but those of high production are underlying the sequence D's shale (seal) or thinly interbedded in the D and C sequences. They were formed in the environment of alluvial plain, lacustrine delta or coastal plains regularly affected by tidal influx.

- The variety in sedimentary facies and lithological heterogeneity, the great variation of net to gross sand ratios and interbedding coefficient in lateral and vertical direction are the main causes of the anisotropy in porosity and permeability of the Paleogene reservoirs, reducing field exploration and development efficiency as well as the application of secondary exploitation in order to increase the oil recovery.

- Being deeply buried and having undergone the effects of loading compaction and high temperature, the Paleogene reservoir rocks, particularly of the F and E sequences, are usually tight, cemented, and subject to a high level of diagenesis and secondary deformation (from late catagenesis to early metagenesis). The reservoir quality of these strata is usually low.

- The values of porosity and permeability depend upon grain size, sorting, roundness and clastic composition.

- The porosity and permeability quality tends to increase in the overlying part of the cross section and rapidly decrease with depth. Due to strong zeolitisation and chloritisation, porosity is normally less than 5% at 4,200m and below.

- Another critical factor is the cross-bedding of the reservoir rocks. Cross-bedding has direct influence on the porosity-permeability (K-φ) relationship. At the same porosity, reservoir rock has the maximum permeability and thus yields maximum flow in the direction parallel to that of the crossbeds, while in the perpendicular direction, the permeability and flow are minimum at a minimum.

- The abnormal overpressure developed in the shale of the Paleogene sequence D affects the distribution of porosity and permeability. Abnormal overpressure always creates favourable conditions for lateral and vertical fluid migration in the reservoir sequence.

- Fractures are always present in the clastic rocks. The differential fracturing of brittle clastic rocks formed in the reservoir formation comprising interbedded shale and sandstones during the folding-faulting process in the

Late Oligocene tectonic compression and inversion could generate secondary porosity and permeability in both structural and stratigraphic traps.

- The density and spacing of secondary fractures depend upon: lithology, grain size, porosity, reservoir thickness, and location of the fracture system on folded structures.

- Secondary fractures are a potential factor that could increase the flow in tight Paleogene reservoirs. The intensity of fractures with high dip tends to be concentrated on the structures crest and along the axis of the folds, and decreases on the two fold limbs. The strike of fractures is usually parallel to the fold axis. This trend is very critical to locating the exploration and production wells in clastic reservoirs.

- Dual porosity is one of the important properties of the Paleogene reservoir that should be considered in production management.

- The high flow rate in the Oligocene-Late Eocene reservoir is possibly related to: firstly, the secondary fractures, that were associated with inversion folding at Late Oligocene; secondly, the low viscosity light oil, or gas and condensate. The oil viscosity and density plausibly affect the flowing capability of high rate.

- Up to now about 300 million tons of oil have been produced in Vietnam, but the production percentage from Paleogene reservoirs still does not exceed 7%, and does not correspond to the potential of Paleogene formation as source rock.

- The Late Eocene-Oligocene reservoir needs to be investigated and sufficiently evaluated as a potential hydrocarbon-bearing play in order to enhance the production and hydrocarbon reserves of Vietnam.

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