The Natural Fracture Evaluation in the Unconventional Tight Oligocene Reservoirs - Case Studies from CuuLong Basin, Southern Offshore Vietnam

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Abstract

The Oligocene Formation in CuuLong Basin, Southern offshore Vietnam, is predominantly fluvial-lacustrine sand and shale sequences deposited above the pre-Tertiary granite basement. The reservoir sands are usually tight with average porosity about 10%, and variable but mostly low permeability. In many wells targeting the granite basement, significant oil shows have been detected when drilling through the Oligocene section. However, it is usually difficult to get a well to flow naturally from this section due to the tight matrix. Therefore, the Oligocene sands were rarely paid much attention.

With commercial discoveries of both oil and gas made in several fields in the CuuLong basin recently, reassessment of the potential for the Oligocene sands has been brought back to the agenda. Natural fractures or faults are among the most important aspects to evaluate when assessing this tight formation. This paper presents a few recent case studies on fracture characterization for the Oligocene reservoirs. The data used includes core, borehole images, conventional open-hole logs, mud logs as well as DST dynamic data. Natural fractures including both open and mineralized ones are quite common in the tight Oligocene formation even though the fracture density and type might vary from one well to another depending on the structural location of the well, proximity to faults and depth in the vertical sequence. It is believed that the naturally open fracture or fault plays an important role in enhancing the reservoir permeability for potential natural flow in a well. The healed fractures, on the other hand, might block the lateral reservoir communication. Locating the fractured zones is also important for perforation decision and frac job design, if stimulation is required for a well.

Introduction

Oil exploration and production in the CuuLong Basin (Fig. 1) were started in the 1980’s. An early commercial discovery was made in the pre-Tertiary granite basement in the White Tiger Field. Since then most of the drilling activities have been focused on evaluating and developing the basement. Little attention was paid to the Oligocene formation above the basement. The Oligocene sequences (Fig. 2), deposited in fluvial-lacustrine settings, are comprised of sand and shale successions overlaying the pre-Tertiary granite basement. The Formation has been sub-divided into “C”, “D”, “E” and “F” sequences (see Fig. 2) with a thickness in the range of 100m to 1000m. Many wells are drilled through the Oligocene Formation due to basement exploration and development. Some brief evaluation of the Oligocene was also made with pessimistic results in general due to low permeability, which makes the wells hard to flow naturally. A few surprising commercial discoveries of both oil and gas were made in the CuuLong basin recently and therefore reassessment of the potential of the Oligocene sands has been brought back to the agenda for many operators. This paper aims to provide some preliminary evaluation for the natural fracture aspect of Oligocene based on the limited data available, which is believed to be important for assessing the potential of this tight formation.

Oligocene Matrix Porosity

- Oligocene “C” and “D”

The Oligocene “C” and “D” usually have reasonable matrix properties. The reservoir can potentially produce naturally even without natural fractures or stimulation. An example from Field B is shown in Figure 3. The average porosity for a “C” sand is in the range of 18-20%.
small zone of 4-m from xx09-xx13m was tested and produced about 4000bbls/d without any stimulation. Therefore, it is important to understand the matrix properties for "D" and "C" reservoirs for perforation and completion decisions.

- **Oligocene “E” & “F”**

The Oligocene “E” and “F” sands are usually much tighter than the “D” sands. The average porosity for a typical “E” and “F” sand is in the range of 8-10% and the permeability can be variable but is mostly low. Sands with good porosity and permeability in the “E” and “F” sequences have been detected in places but seem to have a limited extent so far. In addition, further studies are required to understand the proper facies, depositional settings and possible distribution for those better quality sands in a particular field.

**Fracture Evidence on Core**

Is the Oligocene rock in the CuuLong basin naturally fractured? There is no straight answer to this question yet as there has been little fracture evaluation work carried out to date. In order to access the potential fractures in Oligocene sands, geologists would logically start by reviewing core data if outcrops are not available in the nearby area. Fortunately, core has been cut in several wells drilled in field A.

Figure 4 shows a 3-meter whole core from the Oligocene “E” sands. There are 17 fractures interpreted as highlighted by the dashed yellow lines. Some of the fractures have quite high dip angle (sub-vertical) and some of them have medium dip angles. The fractures appear to be mostly open.

Figure 5 shows another 4-m of whole core from the Oligocene “E” sands. There are 12 fractures interpreted and highlighted in yellow dashed lines. Some of the fractures have high dip angle (sub-vertical) and some of them have medium to low dip angles. The fractures appear to be mostly open. A fault is interpreted on the 2nd core from the left (Fig. 5) as highlighted in dash purple line. The fault has low dip. Bed boundary is also visible on core as indicated by green lines.

An additional core example is provided in Figure 6 where another 4 meters of whole core from the Oligocene “E” sands is shown. The section seems less fractured with 9 fractures and 1 fault interpreted. Again, fractures include both high angle and medium dip and appear to be open or partially open.

In summary, there is evidence that natural fractures and faults exist based on the very limited core observation. Fracture density seems to vary significantly as both high (up to 10 fractures/m, Fig. 4) and low fracture density or non-fractured zones are all observed. In addition, it seems that a minimum of three fracture sets exist – low, medium and high angle. They might be generated by different stages in the CuuLong basin deformation history. Obviously, so far it has been difficult to evaluate the fracture density distribution in the vertical Oligocene sequence due to the limited data.

**Fracture Characterization Based on Borehole Images**

Borehole images provide a good alternative data set to characterize natural fractures and sub-seismic faults for the entire Oligocene formation in a cost effective manner. Unfortunately, little image data has been acquired in most of the wells in the Oligocene in the past due to two main reasons. First of all, the Oligocene formation has rarely been a drilling target. Secondly, it was not known that natural fracture exist in the Oligocene. In recent years with some commercial discoveries of both oil and gas in the Oligocene, some image data sets have been acquired.

- **Fractures on Oil-based mud images**

Oil-based mud micro-resistivity image was acquired in well Y, Field A drilled with oil-based mud. Figure 7 shows an example of the images from a 3-m sand/shale interval. There are 12 resistive fractures (white traces) interpreted within the 3m as shown in tracks 3 and 4. The fractures show a strong NW-SE strike trend with a minor set striking NEE-SWW (track 6). One needs to bear in mind that an open fracture appears as a resistive trace (similar to fractures healed with resistive minerals) on oil-based images due to the resistive drilling fluid. This is different from an open fracture response on images logged in water-based mud. It is beneficial to add the Ultra-Sonic images (Li, et al, 2009) in order to be able to differentiate open fractures from healed in a well drilled with oil-based mud.

- **Fractures on Water-based mud images**

Micro-resistivity images were acquired in well Z in Field B drilled with water-based mud. Figure 8 shows an example of images from a 4-m sand interval. There are a total of 12 fractures including 1 continuous conductive fracture (dark trace), 6 discontinuous conductive fractures and 5 resistive fractures (white traces) interpreted within the 4m as shown in tracks 2 and 3. The continuous conductive fracture is defined as the one with a dark trace more or less crossing the entire wellbore while the discontinuous ones as those partially crossing the wellbore. The conductive fractures are usually interpreted as open while...
the resistive fractures as healed. The conductive fracture sets show a dominant N-S (or sub-N-S) striking trend (tracks 5 & 6) while the resistive set has a NWW-SEE strike (or sub-E-W) (track 7). The sub-E-W healed fracture set can be interpreted as an earlier set than the sub-N-S open set from the same interval.

- **Sub-seismic faults on micro-resistivity images**

Sub-seismic faults can also be interpreted on borehole images based on either direct evidence for displacement or fault indications including structural dip trend change across a fault, breccias, increased fracture density near a fault, lithology change across a non-bedding plane etc. Two examples are presented in Figure 9. Two faults are interpreted in the example given in Plot A, Figure 9 where bedding termination in both faults observed indicating obvious block displacement crossing the fault planes (track 2). One fault is picked in the example given in Plot B where both bedding termination and bedding dip trend changed above and below the fault. The two faults in Plot A show E-W strike while the one in Plot B gives N-S strike trending. Likely they are different fault sets from different timing in history.

- **Fracture distribution in the vertical Oligocene sequence**

The continuous borehole image logs provide a good opportunity to evaluate the fracture and fault distribution for the entire Oligocene sequence near the wellbore. A detailed case study from well Z, Field B is given in Figure 10. Borehole images were acquired within the entire Oligocene section which is subdivided into “D”, “D1” and “E1” in this particular field. There are three types of fractures presented including conductive fractures, resistive fractures and faults. The conductive fracture set represents those obvious ones including all continuous conductive and some high confidence discontinuous conductive fractures for the purpose of extracting the representative dip and striking trends. There are 18 sub-seismic faults picked within the Oligocene formation in this well as shown in track 4 of Fig. 9. The fault dip angle has a range from low to high (see fault summary in the upper right). The fault strike has a dominant NWW-SEE set with a few other minor sets like NNE-SSW, NE-SW, NW-SE, N-S and NEE-SWW. The faults are distributed in all sub-formations – 7 in sequence “D”, 6 in “D1” and 5 in “E1”. The strike trend variation in different sub-formations can be viewed in the lower right plots. The conductive fracture set shows a dominant NW-SE strike trend with a minor trend at NWW-SEE (Fig. 9) and medium-high dip angles. It was observed mainly in the Oligocene “D1” with NW-SE strike mostly and “E1” where there is NW-SE dominant strike set with NWW-SEE, E-W and NE-SW minor sets. Healed fractures are seen in all sections. There are three main sets – N-S, NE-SW and NEE-SWW with two minor sets – NW-SE and E-W based on strike orientation. The dip angle has a wide range from low to high for healed fractures (upper right plot, Fig. 8). In Oligocene “D”, healed fractures seem dominantly striking NE-SW. There are two distinguished sets of healed fractures in “D1” – N-S and E-W. In “E1”, healed fractures seem having a few more sets – N-S, NEE-SWW, NW-SE and E-W.

In summary, both fractures and sub-seismic faults are well developed within the Oligocene “D” and “E” sequences in this well. Fracture clusters seem to be associated with faults (left plot of Fig. 9). Fracture intensity also indicates a general trend of increasing downwards. In other words, the older or deeper “E1” is more fractured than the younger “D1” and “D” sections. Fracture set analysis also shows that there are more fracture sets observed in the “E1” than younger rock above. The fracture development might be related to faulting, rock mechanical properties and rock relative age. The “E1” rock is tighter than the “D” and “D1” above (see RHOB variation in the track 2, left plot of Fig. 9) and likely to be more brittle, which is easier for fracture development. The older “E1” might have a better chance for experiencing more tectonic deformations or more opportunity for fracture development.

**Fracture Impact on Permeability Enhancement for the Tight Oligocene Sands**

There is obvious evidence presented in the above sections from core and borehole image observations in the Oligocene formation. However, knowing the formation is fractured is only a first step for fractured reservoir evaluation. Fracture impact on reservoir permeability or production enhancement has to be assessed next in order to gain better understanding of the importance of natural fracture in the Oligocene. Owing to the fact that the Oligocene formation has been paid little attention in the past and therefore, there is no full set of data (i.e. borehole images/PLT/DST as a minimum) needed for evaluating natural fracture impact on production. Alternatively, mud logs and limited DST data along with borehole image logs have been used in this study for assessing the potential fracture impact.

- **Fracture impact based on mud losses**

Two examples are given in Figure 11 showing fracture and mud losses from wells X and Y, Field A. In plot A (Fig. 11), mud losses at a rate of 32 bbls/hr was recorded in a small zone in an “E” sand where there are a few fractures interpreted on image logs, indicating those fractures are...
open with enhanced permeability to the tight sand and probably the main contributor to the mud losses. In plot B, more significant mud losses at a rate of 48bbls/hr observed in a small interval as indicated by blue box. It is suspected that there is a fault at that depth as indicated by the RHOB and NPHI log anomalies. Unfortunately there is no image log acquired in this well to validate the existence of fault or fractures.

- Fracture impact based on gas shows

An example from Well Y, Field A is given in Fig. 12, showing increased gas shows in places where fractures were also interpreted based on image data. The zone is mostly shaly with only one sandy interval in the lower section highlighted in yellow shading (Fig. 12). Obviously no increased gas show would be expected in such shaly zones in general without natural fractures. In other words, the interpreted fractures on images are believed to be the main permeability provider which caused the rising gas shows.

- Fracture impact based on DST

DST was performed in well W, Field A. Plot A in Figure 13 shows one of the perforated zones in the Oligocene “F” where the matrix is tight (high end porosity in the range of 7-10% and perm 1-5md). However, the DST result shows quite good production rate for gas at 8.7 mmmscf/d and oil at 1086 bbls/d. This is an unexpected production rate for a tight “F” sand which is often hard to flow naturally. Limited core was taken in the upper portion of the perforation and fractures are observed as shown in the right of the Fig.13. Some more natural fractures and/or faults are highly likely in the rest of the perforated zone but unfortunately there is borehole images acquired in the zone to verify.

Production Stimulation for Oligocene Formation

Natural fractures have been observed in all level within the Oligocene sequences. However, there are some non-fractured sands as well without any doubt. For those non-fractured but hydrocarbon bearing sands, there are opportunities for stimulation to make a well flowing. Figure 14 shows an example from well Z, field B where fracturing was applied in a small interval of 5-m with much enhanced production.

Implications

The Oligocene formation is naturally fractured and some of the fractures are open providing potential permeability enhancement to the tight reservoirs for possible natural flow. The implications for the above findings can be summarized as following. First of all, the Oligocene in CuuLong basin probably has much better hydrocarbon potential than what was thought in the past. The zones with naturally open fractures and faults can be potentially flow naturally or flow with minimum stimulation. Secondly, this tight but fractured zones (particularly for “E” and “F”) need to be treated as unconventional reservoirs with proper data acquisition, drilling and completion strategies. For instance, fracture data (i.e. borehole images) along with some dynamic data (i.e. PLT/DST or Dual-Paker MDT*) need to be part of the future data acquisition package in order to have the right data set to pick up the fractured zones for perforation decision, evaluating the fracture impact on permeability enhancement and also for potential stimulation design. In the drilling and completion aspects, it is important to drill through productive natural fractures and complete the fractured zones with minimum damage. Selecting proper drilling fluid with subsequent acid for clean up, drilling underbalanced and open-hole completion for the fractured zones, if possible, should be considered. Thirdly, faulted and structural crest areas are expected to be better targets for the tight sands as fractures can be better developed there. Also deviated wells with trajectory designed to intersect more open fracture sets is recommended once the dominant open fracture set orientations are fully understood in a field.

Conclusions

On the basis of core and borehole image data analysis in this study, it has been demonstrated that the Oligocene formation is naturally fractured even though the fracture density and type might vary from one well to another depending on the structural location of the well, proximity to faults and depth in the vertical sequence. It is believed that the naturally open fracture or fault plays an important role in enhancing the reservoir permeability for potential natural flow in a well based on the assessment from limited dynamic data like mud losses, gas shows and DST. The healed fractures which also exist in places, on the other hand, might block the lateral reservoir communication and gives more heterogeneity to the already complex reservoirs. Locating the fractured zones is also important for perforation decision and frac job design, if stimulation is required for a well. In future Oligocene exploration and appraisal drilling, it is recommended to target those faulted and structural crest areas with deviated wells aimed at intersecting more open fracture sets for potential natural flow from the tight Oligocene reservoir. Borehole images, production logs and DST need to be acquired as the minimum data set for more comprehensive fracture evaluation of these fractured unconventional clastic reservoirs.

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Fig. 3. An example shows a typical Oligocene “C” formation with good porosity in the range from 18-20%.
Fig. 4. Natural fractures in the Oligocene sands, core images from Field A. Bedding and fractures are highlighted in green and yellow dashed lines respectively.

Fig. 5. Natural fractures in the Oligocene sands, core images from Field A. Bedding and fractures are highlighted by green and yellow dashed lines respectively. There is also a low angle fault (purple dashed line).
Natural fractures & fault in the Oligocene sands, core data from Field A, CuuLong Basin

Fig. 6. Natural fractures in the Oligocene sands, core images from Field A. Bedding and fractures are highlighted in green and yellow dashed lines respectively. There is also a low angle fault (purple dashed line).

Fig. 7. Natural fractures interpreted on oil-based mud images. Example from Oligocene “F” sand, Field A. Track 1 – depth in meter, track 2 – static images, track 3 – fracture dip tadpole plot (scale 0-90 degrees), track 4 – dynamic images with fracture trace picks, track 5 – GR and track 6 – fracture strike plot.
Fig. 8. Natural fractures interpreted on images. Example from Oligocene “E” sand, Field B. Track 1 – depth in meter and GR, track 2 – dynamic images with fracture trace picks, track 3 – fracture dip tadpole plot (scale 0-90 degrees), track 4 – static images, track 5 – Continuous conductive fracture strike plot, track 6 – Discontinuous conductive fracture strike plot and track 7 – healed fracture strike plot.

Fig. 9. Plot A – Borehole image examples showing two faults in a 2-m short interval from Oligocene “E” in well Z, Field B. Track 1 – depth in meters and GR, track 2 – dynamic images with fault and bed trace picks, track 3 – fault and bed dip tadpole plot (scale 0-90 degrees) with fault strike plot (purple), track 4 – static images. Plot B – Another image example of fault from the same well.
Fig. 10. A case study on fracture distribution within the Oligocene sequence in well Z, Field B based on image data. Left plot: track 1 – GR, depth (MD), calipers, track 2 – RHOZ & NPHI, track 3 – static images, track 4 – fault tadpole, track 5 – fracture tadpole, track 6 – formation tops. Right plot: Upper – fracture statistics summary for entire well, Lower – fracture statistics by sub-formations.

Fig. 11. Plot A – mud losses recorded in a small zone in the sand package (well Y, Field A) indicate the fractures interpreted on oil-based mud images in that zone are open and enhance the reservoir permeability. Plot B – high rate mud losses also occurred in a shale zone in well X from the same field indicating the zone is likely fractured or faulted. No images acquired in this well to confirm the existence of fractures or a fault.
Fig. 12. An example from well Y explains how gas show peaks indicate the fractures interpreted on oil-based mud images are probably open and give positive impact on reservoir permeability enhancement.

The tight zone produced gas at rate of 8.7 mmscf/d with oil at rate of 1086bbls/d.

Fig. 13. Plot A – a perforated tight zone (Well W, Field A) in Oligocene “F” with very high productivity.
Fracturing was applied for the 5-m short zone with oil production of 500 bbl/day. No natural open but a few healed fractures interpreted on FMI in the zone.

Fig.14. An example of a 5-m stimulated zone with fracturing applied with much enhanced production. No natural open fracture but a few healed fractures observed in the zone on image logs. The example is from Well Z, Field B.