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Fractured Reservoir in Baong Formation, North Sumatra Basin, Indonesia

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Abstract

Fracture reservoirs are becoming a major issue throughout the entire world both old and new fields. Many newly discovered oil and gas fields happen to be fractured and their development constitutes a real challenge for E&P industry. North Sumatra Basin (NSB) is one of Indonesia's most profilic sedimentary basins. Baong Formation in NSB is one of the main rocks in the NSB with total content of shale hydrocarbon gas of 4,450 Mmboe and for oil 2,230 Mmbo. Despite of Baong Formation as a source rock in majority of field in NSB, The AR gas reservoir are hosted by fractured Middle Baong Sandstone (MBS) units.

The understanding how naturally fracture can develop in MBS is interested to discuss to expand the exploration in the NSB. This study provides an integrated subsurface data (well log, seismic, drilling report, etc) from several field, outcrop data analogue, and regional literature study. Based on this study fractured MBS can caused inversion tectonic activity, regional uplift in the Middle Miocene was observed by the reactivation of older horst and grabens in NSB and widespread erosion led to regional unconformities. The fracture play in MBS led us to the new exploration view in North Sumatra Basin.

Introduction

North Sumatra Basin is believed to have a good potential of hydrocarbon accumulation and remain challenging for exploration. Although conventional reservoirs dominate the North Sumatra Basin, a new type of sandstone reservoir also exists in the on shore are that has a low matrix porosity (tight) in which natural fractures govern both permeability and porosity.

Although fractures are present at some large scale in all reservoirs, it is only when they have sufficient spacing and length that their effect on fluid flow becomes important. Fractures not only enhance the overall porosity and permeability of many reservoirs, they also create significant permeability anisotropy In order to assess the role of fractures on hydrocarbon production and reservoir permeability an isotropy, characterization of naturally fractured reservoirs has focused primarily on the distribution and orientation of fractures and fluid-flow properties of individual representative fractures in a given reservoir volume.

The occurrence of fractured reservoirs over the world is well acknowledged. A quite significant proportion of world oil reserves is commonly assumed to lie in fractured reservoirs, for instance Firoozabadi (2000) gives an estimation of more than over 20%. Although not or less reported, the proportion is probably equivalent or higher for fractured gas reservoirs if one considers their higher depth in average, often involving a higher occurrence of diagenesis and fracturing phenomena.

The AR gas reservoir are hosted by fractured Middle Baong Sandstone (MBS) units. AR Field is a simple anticlinal structure having about 5 Km long and 1.5 Km wide. Gas was logged to the base of the reservoir at –2,985 meters (-9,653 ft) and the structure may fill to spill point at –2,985 meters (9,790.8 ft). The closure is about 5 kilometers long and 1.5 kilometers wide. AR field penetrated the gas accumulation in the Middle Baong Formation made up of sandstones containing some clay minerals. Two wells were drilled in this field.

Data and Method

Geological analysis from well log and seismic interpretation conducts a comprehensive analysis in this study to compare the characteristic of Baong Formation in another area. The analysis of tectonic regime in NSB combine with proven area of fractured gas reservoir, we get some criteria to analyze another potential area to be reviewed as a potential field that contain fractured sandstone reservoir in Baong Formation.

Some of seismic section was performed as a foundation of a structural style trap that indicate hydrocarbon accumulation. Seismic sections of a proven area in AR field guide us to identify the same situation of another area around the AR field. We also do petrophysical calculation from AR well in order to confirm the presence of the fracture in a proven gas reservoir

Result and Discussion

Regional Geology & Tectonic Review

The North Sumatra Basin, one of the three Sumatra back arc basins, is bounded on the southwest by the Barisan Mountain Front, on the southeast by the Asahan Arch, on the northwest by the Andaman Sea, and on the northeast by the Malacca Platform. The basin exhibits a dominant Northwest/Southeast and Northeast/Southwest structural trend.

Located in tectonically active area within the western margin of Sibumasu continent, NSB underwent several tectonic episodes controlling the basin development. Furthermore, these are also widely recognized from the structural orientation, regional lineaments as well as from the corresponding sedimentary sequences that are observed in outcrop and wells.

Davies (1984) modeled the NSB structural evolution as a product of interactive plate movements during the Tertiary. Major rotational and translational plate movements are responsible for the complex NSB setting and structures.

Daly et al. (1987) and Sosromihardjo (1988) defined that the tectonic model of NSB is principally controlled by the dextral Sumatran coupling fault system forming a major pull-apart basin (Pase sub-basin) bounded by Sigli and Tampur Platforms to the west and east respectively. Both Davies (1984) and Sosromihardjo (1988) agreed that Sumatra underwent rotational movements that modify the structural kinematics during the Tertiary despite their different understanding about the rotational direction of Sumatra.

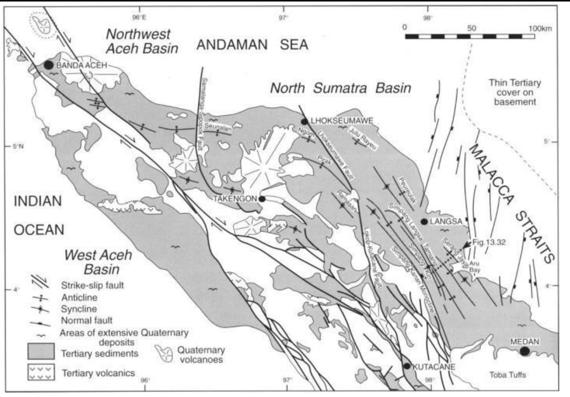

Fig. 1 Active Sumatra Tectonic System

Primary folds and faults of active Sumatra tectonic system are oriented Northwest-Southeast (Figure 1). Compressional or transpressional structures with the deformation intensity are decreasing to eastward across the coastal plain. Convergence subduction of the lithospheric plates between Australian Plate and Asia Plate is oblique resulting in right-lateral offset along Bukit Barisan strike-slip faults.

This Sumatra compressional tectonics overprint an earlier extensional regime, reactivating some pre-existing normal faults as high angle reverse faults and causing structure inversions. Rifting began in the Oligocene, following Eocene and earlier periods of tectonic quiescence. This period of normal faulting controls the distribution of deep gas reservoirs in the Peutu Formation. The intervening Middle Baong gas/condensate sand at AR field was affected by early tensional and later compressional regimes.

Oligocene extension segmented Sumatra into elongated through and horst blocks separated by broad, intervening basins. The upthrown north-south blocks trends are bounded by high angle normal fault systems. Movement on the faults persisted into the Miocene and the uplifts supported reef growth in the Lower Miocene Peutu Formation.

Entering Lower Miocene, the rifting decelerates, and subsequent transgression occurred, submerging the paleohigh and marked the post-rift episodes in NSB (Davies, 1984; Banukarso et al., 2013). Massive deposition of the Peutu limestone and Belumai sandstone equivalent occurred within the highs meanwhile the basinal carbonate and shales were deposited within the lows and submerged platforms (i.e., Matang-Pergidatit area). The transgression endures until Lower Middle Miocene, marked by backstepping carbonate deposition towards the Mallaca Platform (Alexander and Nellia, 1993). The latest tectonic activity occurred starting since Middle Miocene to Present is characterized by predominant compression, uplift, basin shoaling and reversal of sedimentation direction.

Despite the quite established subdivision of NSB tectonic phases from various researchers (rift, post-rift and syn-tectonic/inversion), some discrepancies remain, pertinent on the timing of tectonic events, age of sedimentary sequences and basin definition (Figure 2). Different area of study between researchers and variety of data coverage is accountable to this disagreement. In addition to that, among number of authors, only few of them extended the interpretation towards the Barisan Mountain by taking advantage of surface geology, which made significant differences of regional point of view (e.g., timing of Barisan uplift and southwestward extension of the basin).

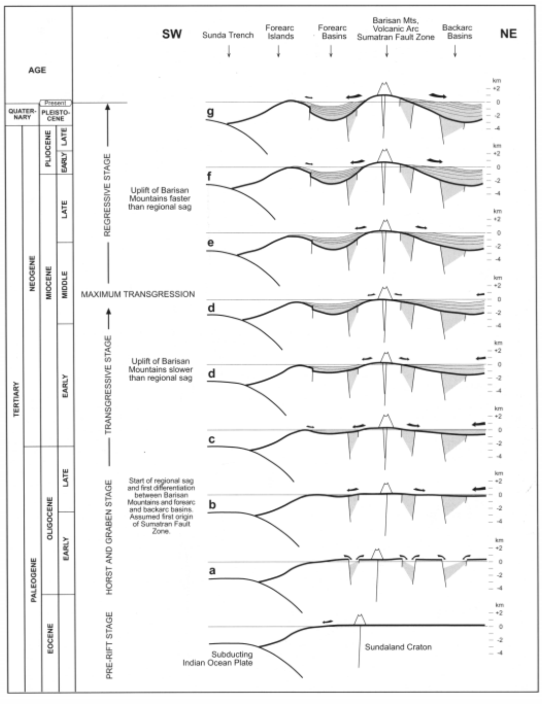

Fig. 2 Palinspastic cross-sections across Sumatra from SW to NE (Barber et al.,2005)

Barber et al. (2005) interpreted that the development of forearc and backarc basins are separating by the Barisan Mountains, which occurred in the latest Oligocene to the earliest Miocene. The starting regional sag resulted in the gradual submergence of the Barisan Mountains and the deepening of the basins in both the forearc and back-arc areas. Marine transgression extended until the Mid-Miocene when the Barisan Mountains still rose above sea level. The Barisan Mountains were uplifted and eroded from the Mid-Miocene onwards, accompanied by marine regression and dextral movements on the Sumatra Fault System, until Sumatra gradually took on its present outline.

In The Middle Miocene, Turbidite sandstone formations started to infiltrate the basins in the back-arc region from the Barisan Mountains until the Pliocene. The fractured turbidite sandstone may occur by the period of the regressive stage when uplift Barisan mountain faster than regional sag.

These movements coincided with the inversion of basin sediments, where the reactivation of faults, the folding of basin sediments, and the development of unconformities in the sequence transpired.

Characteristic of Baong Formation

Sedimentation & Facies

Baong Formation is divided into three sequences, Lower-Middle-Upper Sequence. The lower part of this formation is Baong Shale. A major transgression followed sedimentation of the Peutu Formation. The change from paralic environments in the Peutu limestone to bathyal deposits of the overlying Baong shale reflected a change in tectonic regime as well as a rise in relative sea level. The plate collision along the Sumatra trench became a dominant factor in regional tectonics resulting in reactivating and inversion of pre-existing extensional faults, development of major dextral transcurrent faulting, and compressional folding.

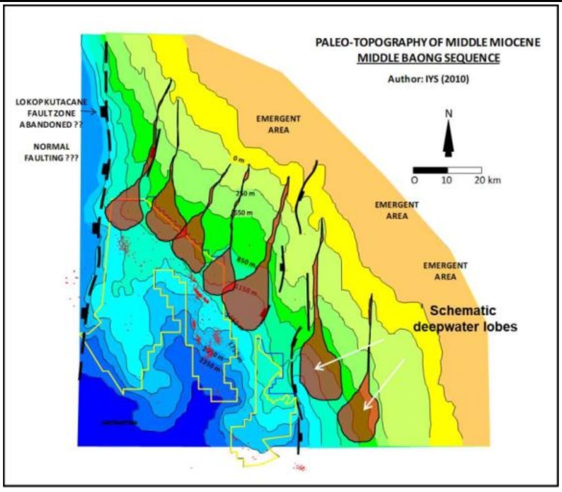

Fig. 3 Provenance of Baong Formation, Northeastward Direction

Regional subsidence accompanied these changes and formed a deep, extensive foreland basin that eventually filled with Baong shale. These basinal shales are onlap pre-existing structural high, including Peutu reefs. This unit consists predominantly of bathyal shale, with local concentrations of planktonic foraminifera forming thin, muddy limestone beds. Foraminifera zones for the Lower Baong vary from zones N-8 to N-11 in the Lower to Middle Miocene.

The middle part of Baong Formation is called Middle Baong sand due to the formation dominantly sandstone. Sands along the eastern basin margin indicate a major low-stand event near zone N-13. The sands derive from the Malacca Platform to the northeast, and they extend southwest. In eastern Block A, the Middle Baong sand is fine-grained and glauconitic. It occurs in three members, but only the second member, the MBS-II sand at AR, has significant hydrocarbon shows.

Middle Baong sedimentation ended with another period of tectonic quiescence. Erosion of pre-existing structural highs resulted in a widespread unconformity within zone N-14. Except for thin local sands above the unconformity, the overlying upper Baong consists of clay-rich mudstone. Paleoenvironment deepened again to bathyal depths, followed by gradual shoaling upward into paralic sands of the overlying Keutapang Formation. These sand prograded northeastward from source terrain in the rising Barisan Mountain (Figure 2).

Middle Baong Sandstone (MBS) in the research area is a member of Baong Formation, in lithostratigraphic dominated by deep sea shale facies. While in the Middle Baong Sandstone contain intercalated with shale. This caused by changing of water depth from bathyal to middle neritic caused by tectonic activity and drop of sea level present at the time of deposition (Situmorang et al, 1994).

Log Analysis & Fracture Indication

The MBS reservoir in AR field includes two sands separated by 11 meters (36.08 ft) of shale break. The upper MBS-IIA Sand is 11 meters (36.5 ft) thick, and the lower MBS-IIB Sand is 218.5 ft thick MBS-IIA has 11.5 % porosity, 1.43 mD and 35.8 % water saturation, while the MBS-IIB has 11.1 % porosity, 0.52 mD and 33.3 % water saturation, respectively. The typical log and the summary of the log analysis are presented in Figure-2.15 and Table-2.4. The porosity of both zones may be slightly underestimated due to formation damage. Sidewall core petrography characterized both MBS-IIA and MBS-IIB as fine to very fine grained argillaceous marine sandstone.

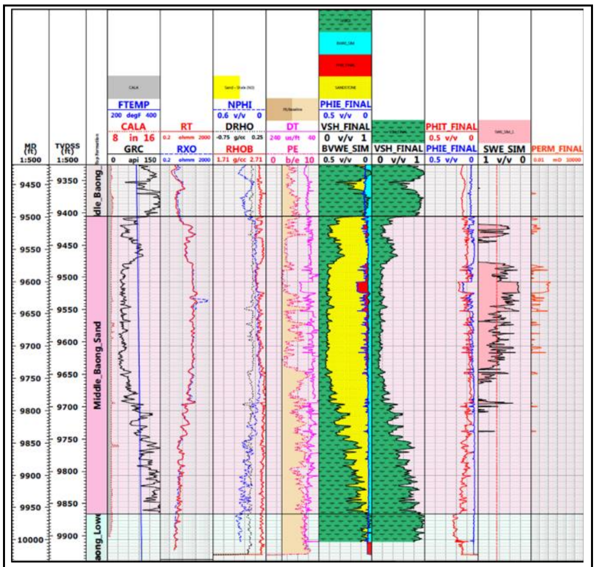

Fig. 4 Petrophysical Calculation Result of AR-1 Well

Based on petrophysical result of Middle Baong Sandstone in AR Field it has to be difficult to perform a good fluid flow with porosity range 8-10% and permeability range 07-1.4 mD. The property shows a low value. In the other hand, we have drilled 2 wells targeted in MBS reservoir and in those intervals dynamic loss occurred several times during 8.5 inch. After logging, we spotted a different pattern of the DT and PEF in MBS interval, although not whole body of sandstone. The fractured interval was expected from relatively high DT and PEF log value

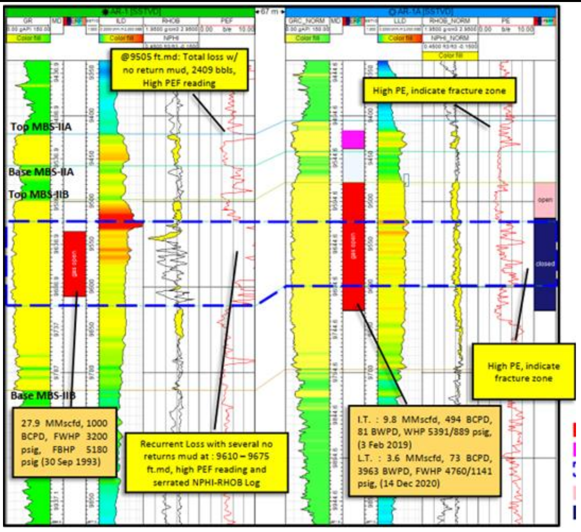

Fig. 5 Well Correlation and Potential Fracture Interval from Log Data

The test of an upthrown, east-west trending fault the closure found 75 meters of gas column in the Middle Baong sand. The sand is over-pressured with an effective mud weight equivalent to approximately 14.1 pounds per gallon. Extensive fracturing resulted in numerous drilling problems with lost circulation followed kick. Multiple cement squeezes and larger volumes of loss circulation material were pumped into the formation to cure lost return.

Seismic Data Review & Interpretation

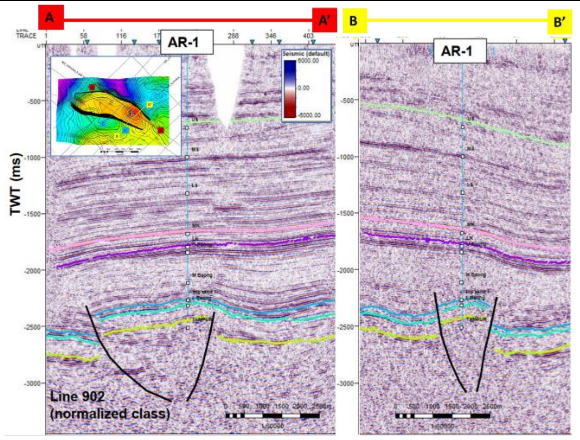

Fig. 6 AR Field Seismic Section

The seismic section from AR field was interpreted to determined structural trap, faults and horizon of a reservoir. The AR field is a simple anticlinal structure, the structure trending west-northwest and east-southeast and it was cut by thrust and normal faults trending northwest-southeast following the structural trend. These are high angle reverse faults and the feature maybe a positive flower structure associated with deeper strike-slip movement. A shallow syncline separates the eastern flank from structurally higher area to the southeast.

From seismic interpretation there is no indication a specific fracture feature from the Formation contain. Tampur until Middle Baong Formation in B-B' section shows some chaotic feature. The intense of chaotic feature are getting more visible in deeper area. It may cause from the tectonic activity in middle Miocene which reactivated the previous rift horst-graben product to build a trap in AR field. These activities are indicated as a period that fracture developed in some Formation with relatively more brittle.

Development Area

Another lead and prospect (figure xx) with same regional tectonic framework in NSB particularly near research area is considered to be the next development. The issue that can be raised related to the tectonic model in the NSB is due to the ranges of existing structural model and evolution. These issues can be broken down into two main categories, the first being related to Paleogene extensional system where different approaches of rifting mechanism have been introduced by various authors (Davies et. al., 1984; Daly et. al., 1987; Sosromihardjo, 1988; Collins et. al., 1996). Secondly, related to subsequent Neogene basin evolution where many researchers pinpoint basin inversion and potential foreland mechanism to explain basin regressive period (Davies, 1984; Daly et al., 1987; Fuse et al., 1996; Banukarso et al., 2013).

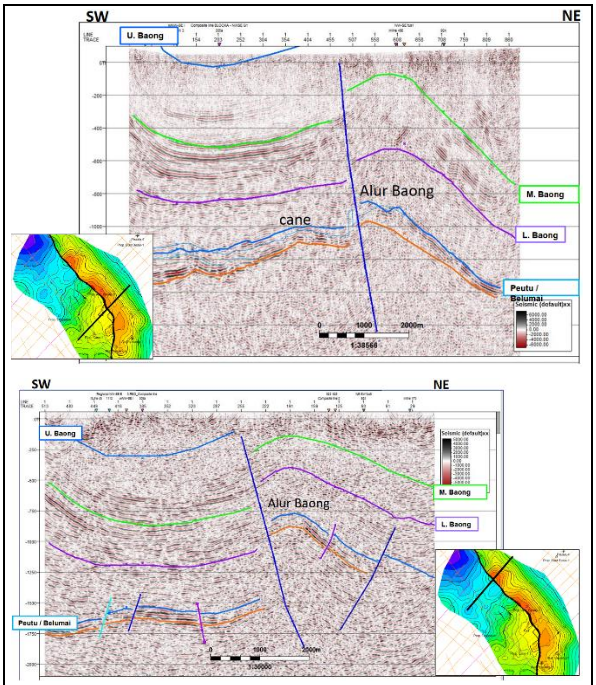

Fig. 7 Seismic Section of Alur Baong Field (Potential Field Area for Baong Formation)

Conclusions

- Fracture is one of the most important geological phenomena that affect the production of hydrocarbon compounds in broken sandstone reservoirs. However, fracture controlling factors must be combined with well data to achieve accurate fracture modeling.

- The occurrence of fractured reservoirs possibly from latest tectonic activity occurred starting since Middle Miocene to Present which characterized by predominant compression, uplift, basin shoaling and reversal of sedimentation direction.
- In The Middle Miocene, Turbidite sandstone formations started to infiltrate the basins in the backarc region from the Barisan Mountains until the Pliocene. The fractured turbidite sandstone may occur by the period of the regressive stage when uplift Barisan mountain faster than regional sag. These movements coincided with the inversion of basin sediments, where the reactivation of faults, the folding of basin sediments, and the development of unconformities in the sequence transpired.
- The Middle Baong Sandstone have been a proven reservoir in North Sumatra Basin. Based on this study fractured Middle Baong Sandstone have a good reservoir quality for future development
- Middle Baong Sandstone in North Sumatra Basin can be alternated host of fracture reservoir in North Sumatra Basin.
- This study indicates that there is possibility of fractured reservoir developed not only on the research area but also on another research area with high tectonic activity after the Baong Formation deposited.
- The fractured classification in MBS reservoir is very essential to develop the potential of AR field. It's suggested to core some interval in fracture section or run the image log to get a better understanding of fracture behavior.

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