ISSN (Online): 2581-6187

Structural Analyses and Evolution and Its Implication for Petroleum System and Exploration Play Concepts of Offshore North Sumatra Basin

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Abstract— *The Offshore North Sumatra Basin is part of the profilic North Sumatra Basin, which has experienced a complex tectonic history since the Eocene, including rifting, wrenching and compression phases. Historical exploration efforts in NSO have focused on the post-rift basin-fill stratigraphy: carbonate build-ups of the Early & Middle Miocene Peutu and Baong Formations and faulted structures with Late Miocene turbidite objectives (Keutapang Formation). The stratigraphy of the Offshore North Sumatra Basin composes a series of Oligo-Miocene up to Pliocene sediments overlaying unconformably the pre-Tertiary basement complex. Structure analyses indicated an N-S and NW-SE trending horsts and grabens developed within the study area. The basinal lows were filled by continental clastics (Parapat Formation?) and deep marine shales and sands (Bampo Formation). Most Exploration wells penetrated the post-rif succession, and one (1) exploration well DYG-1, penetrated the syn-rift succession and has been used to analyze the petroleum system. Another potential is from the Pre-Tertiary Limestone fracture, as indicated by SLM-1 well. Potential hydrocarbon traps consist of fault-bounded two-way and three-way closures. Hydrocarbons are generally from highly profilic terrestrial and marine shales (Bampo and Baong) and charged from deep basinal kitchens adjacent to structural highs. Petroleum will likely have been Type III Middle Baong and Bampo shales. Hydrocarbons are interpreted to have filled structural, stratigraphic or combination traps.*

Keywords— *Offshore north sumatra basin; structure analysis.*

I. INTRODUCTION

The North Sumatra Basin (NSB) is a world-class petroleum province [1]. 1885, the first hydrocarbon discovery was made in the North Sumatra Basin at the Telaga Said field. It was Asia's first significant oil discovery and became the foundation of Shell's global success story. Other significant discoveries followed, such as Rantau in 1929, Arun (the largest gas field in the world at the time of discovery in 1971, and the first liquefied natural gas development in the world, NSO A in 1972, Lhok Sukon A in 1972 and Kuala Langsa in 1992 [2].

Volatile Geopolitical and geological conditions in Aceh led to a steep decline in overall drilling activity, causing flattening of the creaming curve [3].

Administratively, the study area is located in Aceh Province, which covers the Aceh Timur and Aceh Utara Districts (Figure 1). The study area focused on the offshore part of the North Sumatra Basin.

This paper described the subsurface aspects of plays within the Offshore North Sumatra Basin, in which structural analyses and evolution of the area and its implications to the petroleum systems and exploration play concepts.

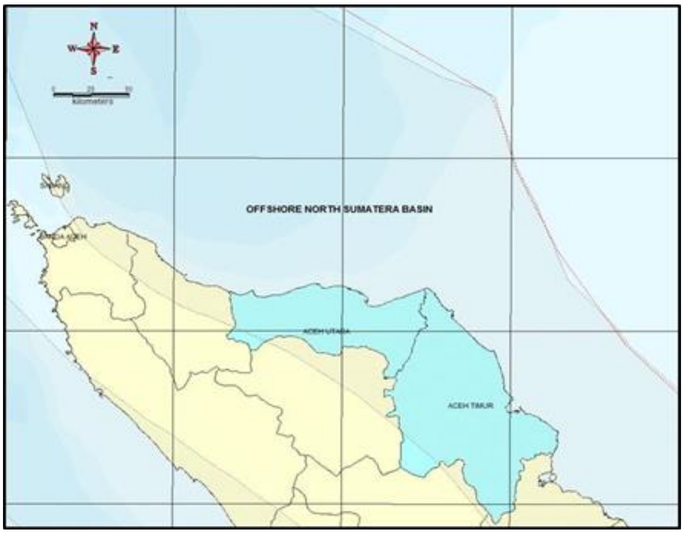

Fig. 1. Location of study area.

II. REGIONAL GEOLOGY

The North Sumatra Basin was subject to four episodes of tectonostratigraphic activity. These stages of basinal evolution provide geological context to the petroleum systems in the offshore part of the basin [3].

- *Eocene – Early Oligocene Rifting*

Early basin formation involved W-E rift-related extension of Paleozoic and Mesozoic metamorphic and granitic basement from the Eocene through Early Oligocene. The rift event formed a series of N-S oriented horst and graben blocks bounded by major dextral shear zones (the Sumatran shear zone to the south and the Lhokseumawe shear zone to the north) (Figure 2).

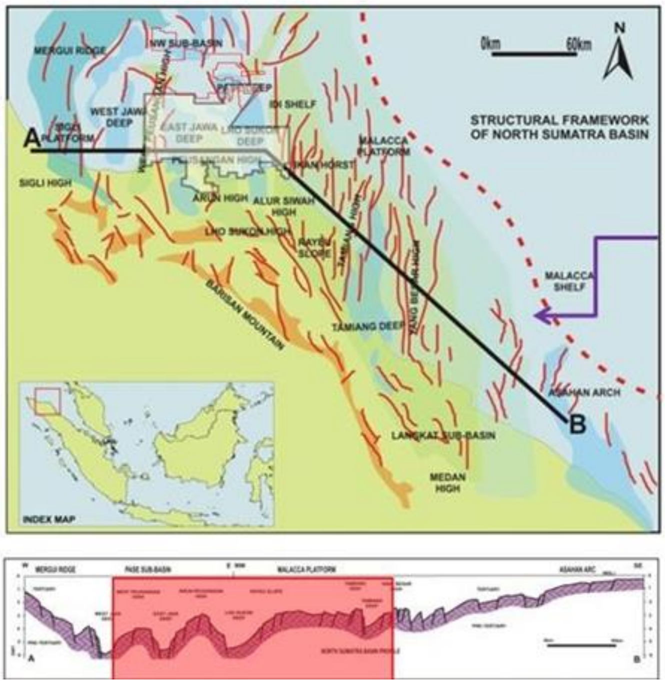

Fig. 2. Tectonic elements map showing N-S and NW-SE trending horst and graben systems (Modified from [4]).

- *Late Oligocene – Early Miocene Post-Rift*

After rifting ceased, the NSB subsided from the Late Oligocene – Early Miocene. Marine conditions dominated over much of the area. Deep marine shale and turbidite sands of the Bampo Formation were deposited. Bampo reservoir sands occur in unconfined turbidite fans. Bampo shales have the potential for gas generation and could become effective seals for reservoirs in the underlying Parapat formations.

The conglomerates and sandstones deposited during this phase comprise the Bruksah Formation, defined by Cameron et al. [5] from field mapping in the Barisan Mountains. Lithologies include limestone conglomerates and breccias, micaceous quartzose sandstones, and silty mudstones. The Bruksah Formation overlays with the Bampo Formation, a locally thick sequence (500 to perhaps 2400 m) of marine black shales, siltstones, and muddily fibre-grained. Stratigraphic relationships indicate that the upper part of the Bruksah is at least partly equivalent in age to the Bampo Formation (Figure 3).

- *Early Miocene – Middle Miocene "Sag"*

During the Early and Middle Miocene, the NSB experienced further subsidence, referred to as "late-stage tectonic sag". Sedimentation was characterized by synchronous carbonate reef growth (Early-Middle Miocene Peutu Formation) and shallow marine clastic deposition (Early-Middle Miocene Belumai Formation), followed by deep marine turbidite deposition (Middle Miocene Baong Formation) (Figure 3). Movement on the N-S trending faults ceased, although back arc subsidence probably continued. This tag was characterized mainly by forced regression (sea level dropping but sediment influx sufficient to cause regression) and basin filling as the central grabens filled. It became shallower, calcareous marine sands, siltstones, argillaceous, and sandy limestones accumulated in the lows. At the same time, the highs remained at least intermittently exposed. These basin-fill deposits comprise the Belumai Formation.

Carbonates of the Peutu Formation developed as reefs, isolated build-ups, and associated platform facies on the flanks and crests of N-plunging basement highs. The Peutu Formation hosts most of the significant discoveries in the North Sumatra Basin, including the super-giant Arun and Kuala Langsa gas fields and the NSO-A complex on the Malacca shelf of Malaysia.

A significant maximum flooding surface separates the low stand and transgressive Peutu and Belumai formations from the overlying fine-grained, deep marine, highstand clastics of the Baong Formation. The sea level rise caused the shoreline to retreat substantially and starved the basin of sandy clastics, which were limited to the basin's margins. Therefore, the thick Baong shales often act as a top seal to reservoirs in the Peutu and Belumai. However, several wells (including DYG-1, NSB C-1, and NSB U-1).

- *Middle Miocene – Pleistocene Dextral Wrenching and Compression*

Toward the end of the middle Miocene, plate tectonic activity caused a reorientation of stresses that initiated a phase of N-S oriented compression and dextral compression on the Lhokseumawe and, especially, the Sumatran shear zones (Figure 2). This phase of tectonic activity has continued to the present day (Figure 3). Regional uplift of the Barisan mountain range occurred SW of the study area, resulting in large amounts of erosion and an influx of coarse-grained clastic material into the NSB (Upper Miocene Keutapang and Seurula formations; Pliocene Julu Rayeu Formation). The onset of uplift and compression is marked by a widespread unconformity that separates the Baong Formation from the overlying Keutapang Formation (Figure 3).

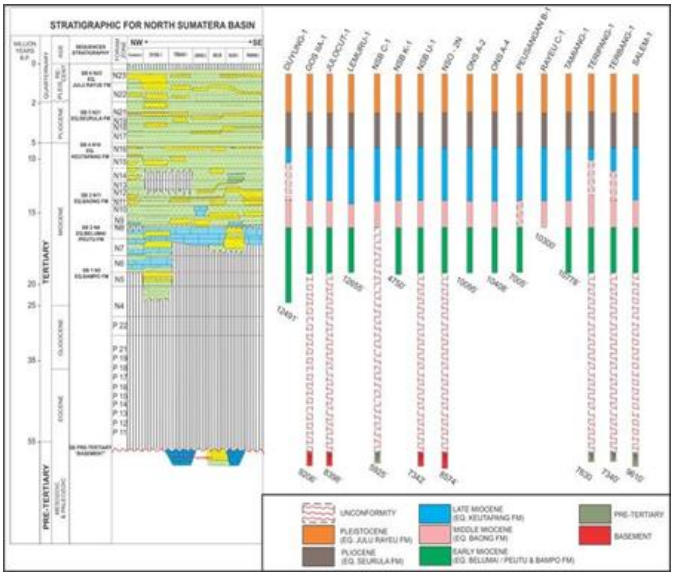

Fig. 3. Chronostratigraphy of study area offshore NSB [6].

The upper contact of the Keutapang is poorly defined in both outcrop and subsurface, and this boundary is both gradational and diachronous. Overlying sediments of the Seuruela Formation contain more shales and weather recessively, forming low, rounded hills. It is early Pliocene in age (N18-N19) and varies in thickness from about 700-900 m.

The Seuruela Formation consists of bluish-grey shales and subordinate fine to medium and locally coarse or conglomeratic sandstones. Both sands and shales are fossiliferous and contain coaly plant fragments. Volcanic clasts are abundant in the sandstones, and shales are described as rarely tufaceous [7].

The Late Pliocene Julu Rayeu Formation consists mainly of coarse clastics. Thin lignites commonly occur in shales interbedded with sandstones and paleoenvironments.

III. Interpretation Methodology

A. *Sequence Stratigraphy Analysis*

The result of sequence stratigraphic analysis to identify several markers such as Sequence Boundary (SB) and Maximum Flooding Surface (MFS) during Eocene to Pleistocene. The data used in sequence stratigraphic determination is GR log with NPHI, RHOB log data assisted and mud log if a well does not have complete GR log data.

The maximum flooding surface is the surface area that indicates the end of the maximum shoreline transgression [8]. In the parasequence set analysis, the maximum flooding surface separates the parasequence set retrogradation at the bottom from the parasequence set of the progradation at the top.

Sequence boundary is a field of unconformity which separates the young sediment from older sediments, where there is an indication of exposed sediments to the surface [9].

The type log is a summary of a well with complete report data, consisting of age zone, biostratigraphy, formation, system tract, lithology description, log pattern, facies, deposition environment, and then determination of stratigraphic sequences.

The lithology that has been identified ranges between sandstone, claystone, limestone, coal, siltstone and dolomite. Based on biostratigraphy analysis, following the biozonation of [10], the DYG-1 well penetrated the stratigraphic sequences of the Early Miocene eq Bampo Fm, Early Miocene eq Belumai/Peutu Fm, Middle Miocene eq Baong Fm, Late Miocene eq Keutapang Fm, Pliocene eq Seurula Fm and Pleistocene eq Julu Rayeu Fm (Figure 4).

The Salem-1 well penetrated stratigraphic sequences of the Pre-Tertiary Limestone, Early Miocene eq Belumai/Peutu Fm, Middle Miocene eq Baong Fm, Late Miocene eq Keutapang Fm, Pliocene eq Seurula Fm and Pleistocene eq Julu Rayeu Fm (Figure 5).

Biostratigraphic data in the critical wells indicate that the sequence stratigraphy can be divided into Complex Basement, SB1 (Early Miocene EQ. Bampo Fm.), SB2 (Early Miocene EQ. Belumai/Peutu Fm.), SB3 (Middle Miocene EQ. Baong Sand), MFS4 (Middle Miocene EQ. Baong Shale), Sb4 (Late Miocene EQ. Keutapang Fm.) and SB5 (Pliocene EQ. Seurula Fm.).

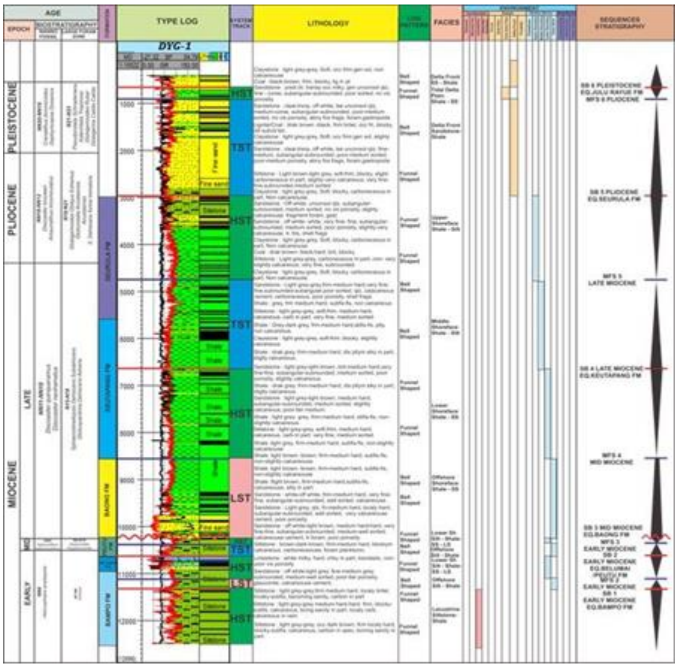

Fig. 4. DYG-1 Well analysis.

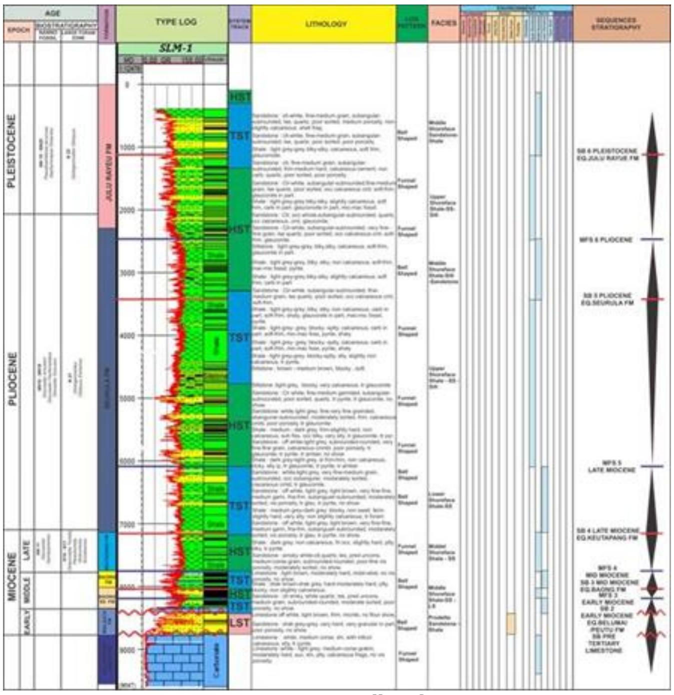

Fig. 5. SLM-1 Well analysis.

B. *Geochemical Analysis*

Regionally, organic matter at the Miocene Baong interval rarely exceeds 1.5% but is widely spread and can achieve adequate thickness to generate substantial hydrocarbon volume [11]. Bampo Formation is synrift to early post-rift source rock sediment exceeding>3% of organic matter. The lateral distribution of the Bampo Formation is primarily limited to graben configuration, but at present, the Bampo Formation is commonly found as a mature source rock.

Geochemical analysis of DYG-1 indicates TOC and Ro data almost covered all well intervals, but pyrolysis data are only available at MFS3(Middle Miocene) to MFS1 (Early Miocene) intervals. Organic Matter at Baong Formation (MF3-SB3) range between 0.5-0.9 wt%; Peutu Formation (MFS2-SB2) range between 0.4-2 wt% and Bampo Formation (MFS1-SB1) range between 0.3-1 wt% (Figure 6).

The kerogen type of Baong Formation and Peutu Formation (MFS3-SB2) is kerogen type III with minor aquatic (alga) influx, which is dominantly potential for generating gas minor oil. The kerogen type of Bampo Formation (MFS11) does not have complete kerogen type data. The data is only available at the MFS3 interval, which is kerogen type III that tends to generate gas. The crossplot between Ro vs Depth indicates that the oil window (Ro=0.6) starts from 10,450ft (SB3 interval).

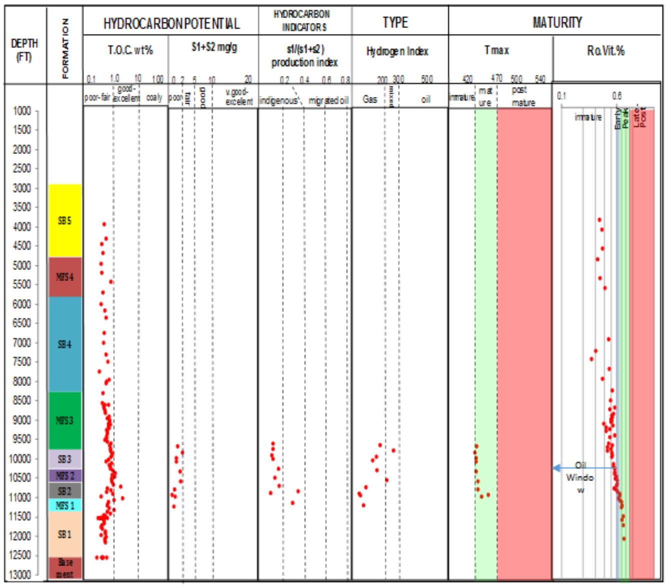

Fig. 6. DYG-1 geochemistry analysis (organic matter richness, kerogen type & maturity).

C. Seismic Analysis

SE-NE seismic sections show the typical rift architecture and the seismic-to-well tie correlating syn-rift stratigraphy and basin stages to seismic events (Figure 7). The early syn-rift interval is characterized by divergent-irregular seismic facies with high amplitude and low frequency. In contrast, parallel seismic facies with low amplitude and low frequency characterize the upper syn-rift interval. The syn-rift stratigraphy lies above a significant tectonostratigraphic sequence boundary and onlaps the pre-rift succession.

Figure 8 shows a structural map of the Top Basement seismic event. The map shows two major structural trends identified in the study area: N-S oriented horsts and grabens. During the Late Miocene, the uplift of Bukit Barisan created a NE-SW-oriented trend as an inversion structure. The rift architecture is less well-defined to the northwest.

The Malacca shelf to the east and the Mergui Ridge to the west appear relatively stable and are interpreted as the primary source of sediment influx into the rifted sub-basins. Several intra-basinal horsts (Peusangan High and Alur Siwah High) may also have acted as local sediment sources into flanking grabens. The Taminag Deep experienced the most subsidence of the grabens and had the thickest sedimentary fill.

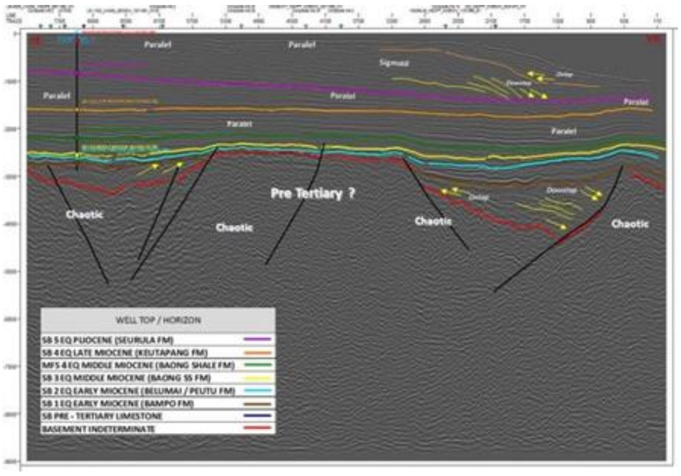

Fig. 7. SE-NW line showing the presence of syn- rift sediment

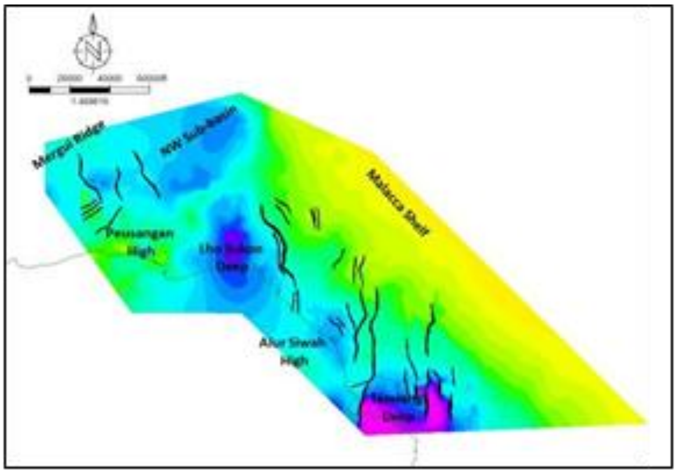

Fig. 8. Structural map of the Top Basement shows a N-S and NW-SE trending horst and grabens

IV. Implications To Petroleum System And Exploration Play Concepts

Essential elements that exert control of the petroleum system development of this area are considered the geometry of the rift grabens, rate of subsidence, and paleogeographical location. The Early Miocene uplift events also impact the productivity of play types. In such geological settings, source rocks, reservoir rocks, and seal presence are related to local structurally controlled depositional environments, and the significance of each element tends to vary through stages of tectonic evolution [12].

Several petroleum systems exist in the North Sumatra Basin [13]: 1). Early Synrift (Early Oligocene); early graben fill of conglomerate & bioclastic limestone. 2). Late Synrift (Late Oligocene); argillaceous deep marine of Bampo primary source rock. 3). Early Postrift (Early-Middle Miocene); Peutu & Belumai formations basinal deeper marine shales & marls with extensive reefoid carbonates build-ups developed on structural high (major reservoir). 4). Late Postrift (Middle Miocene to Pliocene); the argillaceous Baong (in which turbidite sands occur) and the overlying paralic shales, silts and sands of the Keutapang and Seurula formations. In the north, deeper marine facies became shallower towards the southeast, With moderate to good reservoir-quality deltaic sands.

The primary exploration targets in the Offshore North Sumatra Basin range from the Basement complex to Pliocene (Table 1). The occurrence of Oligocene Parapat sediments within the study area raises speculation due to the available wells data no indication. Presence of Pre-Tertiary in Subimasu terrain in Offshore North Sumatra Basin may be proven in SLM-1.

TABLE 1 Petroleum System – Play Type Summaries

Play	Petroleum system (SR-R)	Trapping	Analogue
Eo - Oligocene	Parapat - Tampur (speculative)	Horst-tilted Fault block	SLM-1 well
Early Miocene syn-rift clastic	Bampo - Belumai/Peutu	Build-up carbonate	SLM-1 & LMR-1 wells
Mio-Plio Thrust clastic	Baong - Baong/Keutapang	Thrust Anticline	DYG-1, TRP-1 & NSB C-1 wells

A. *Source Rock*

Syn-rift lacustrine of Bampo and Post rift Baong shale are the primary source rocks are the main source in the study area, with mostly Kerogen type III with TOC< 1%. The earliest timing migration starts from 17ma at the southern part (C, D & E) and 9ma at the northern part (A & B), as seen in Figure 9.

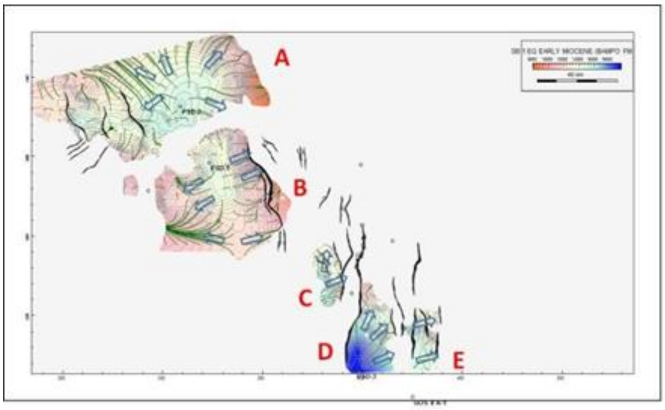

Fig. 9. Bampo source rock with migration pathway

B. *Reservoir Rock*

Core analysis conducted at LMR-1 DYG-1 resulted in a good quality reservoir in the Early Miocene Carbonate of Belumai/Peutu and Middle Miocene of Baong sand. In the LMR-1, one of the central target reserves in the Belumai/Peutu carbonate was proven to be tested as 9 MMSCFD with an average porosity of 9% and Sw of 42%. The other main reservoir target in the Middle Miocene of Baong sand was tested in DYG-1 as 9.5 MMSCFD with an average porosity of 17% and Sw of 60%.

There is also upside potential within the Pre-Tertiary Basement, as seen on SLM-1 well, tested in the Pre-Tertiary Limestone (Tampur?) as 19.48 MMSCFD with an average porosity of 9% and Sw of 30%.

C. *Trap*

The main potential hydrocarbon traps are the Carbonate Build-ups of Belumai/Peutu and frequently faulted 3-way dip closures at Baong Sand with Four-way closures occurring less frequently.

The other potential traps are the Pre-Tertiary Limestone and stratigraphic of syn-rift deposit (Oligocene Parapat?).

D. *Seal*

Potential seal rocks include intraformational shales of the Belumai marl & Baong and Keutapang shales. The thickness of these formations reaches up to thousands of meters, especially in the centre of the rift basins. Few faults cut entirely through the top seal section, so that structural breach can become an issue.

E. *Play Concepts*

Migration Pathways for hydrocarbons in the study area are primarily a lateral up-dip movement via unconformities and/or permeable beds. It is likely that fault planes also provide conduits for migration to shallower reservoirs (Figure 10).

Carbonate build-ups within the Belumai Formation have historically been the principal target for most exploration wells in the basin. Structural traps formed by compression in the Late Middle Miocene to recent times have created the potential for either structural or combined structural stratigraphic traps at several levels.

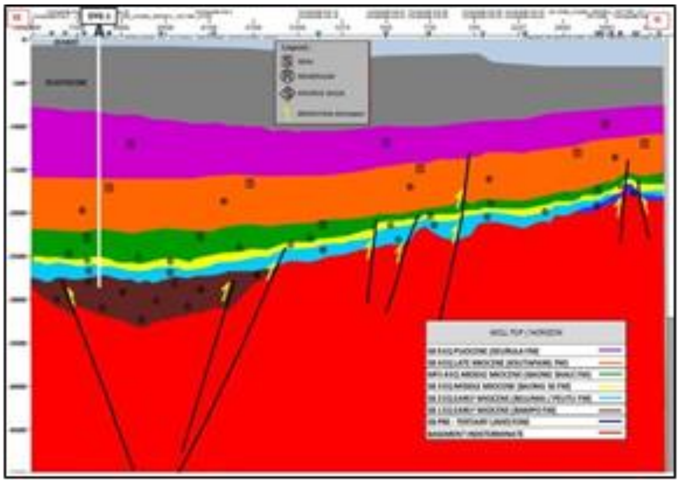

Fig. 10. Typical play concepts in the study area

V. Conclusions

- To date, the offshore North Sumatra Basin has been an exception. Only one significant field (NSO-A) has been found. However, it is essential to realize that the offshore NSB needs to be more explored concerning comparably sized basins.
- Two major structural trends have been identified in the study area: N-S oriented horsts and grabens, and during the Late Miocene, the uplift of Bukit Barisan created a NE-SW oriented trend as an inversion structure.
- Most of the wells data indicated that the Basement occurs at about 2000m with complex lithology in the half-grabens and rises gently towards the east and northeast.
- Geochemical analyses indicate the potential source rocks coming from SB1 EQ. Early Miocene of Bampo Formation & MFS3 Middle Miocene EQ. Baong shale,

with kerogen type III and TOC<1%. Basin modelling shows that the earliest migration timing starts from 17 Ma at the southern kitchen (C, D & E) and 9 Ma at the northern kitchen (A & B).

- The main reservoir is the SB2 Early Miocene EQ. Belumai/Peutu formation & SB3 Middle Miocene EQ. Baong sand, with the upside potential from the stratigraphic trap within the Oligoene Parapat – Early Miocene Bampo and Pre-Tertiary Limestone that tested ar SLM-1 well.

ACKNOWLEDGEMENT

We would like to thank the Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources, along with many others, for giving permission, providing the data, and helping with our study.

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