Hydrocarbon Potential in Sandstone Reservoir Isolated inside Low Permeability Shale Rock
(Case Study: Beruk Field, Central Sumatra Basin)

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Abstract. Upper Red Bed, Menggala Formation, Bangko Formation, Bekasap Formation and Duri Formation are considered as the major reservoirs in Central Sumatra Basin (CSB). However, Telisa Formation which is well-known as seal within CSB also has potential as reservoir rock. Field study discovered that lenses and layers which have low to high permeability sandstone enclose inside low permeability shale of Telisa Formation. This matter is very distinctive and giving a new perspective and information related to the invention of hydrocarbon potential in reservoir sandstone that isolated in low permeability shale. This study has been conducted by integrating seismic data, well logs, and petrophysical data thoroughly. Facies and static model are constructed to estimate hydrocarbon potential resource. Facies model shows that Telisa Formation was deposited in deltaic system while the potential reservoir was deposited in distributary mouth bar sandstone but would be discontinued bedding among shale mud-flat. Besides, well log data shows crossover between RHOB and NPHI, indicated that distributary mouth bar sandstone is potentially saturated by hydrocarbon. Target area has permeability ranging from 0.01-1000 mD, whereas porosity varies from 1-30% and water saturation varies from 30-70%. The hydrocarbon resource calculation approximates 36.723 MSTB.

Keywords: Telisa Formation, low permeability, Central Sumatra Basin, deltaic system.

1. Introduction
Hydrocarbon is one of the primary energy fuels that has been used all over the world. Since the world crude oil price shows declining trend recently, selling price become lower compare to production and operational cost. Therefore, it became economically not-efficient. One of the options to minimize this efficiency problem is by re-evaluate active oil/gas field, to find another reservoir productive layer.

Central Sumatra Basin (CSB) is one of the biggest productive hydrocarbon field in Indonesia. In CSB, main reservoir formations are Upper Red Bed, Menggala Formation, Bangko Formation, Bekasap Formation and Duri Formation. However in Rokan Block (South Balam Sub-Basin), Telisa Formation as reservoir Formation has producing hydrocarbon. Even Telisa Formation dominated by shale regionally (Yarmanto, et al., 2010) it still has potential as reservoir rock.
2. Regional Geology

Central Sumatra Basin is a sedimentary basin which deposited by syn-rift graben that located under a post rift sequence in Central Sumatra (William and Eubank, 1995 in Doust and Noble, 2008). Generally, hydrocarbons accumulated above or close to the synrift graben, caused the accumulation to be shallow and post rift sequence remain immature (Figure 1).

![Tectonostratigraphy of Central Sumatra Basin](image)

Figure 1. Tectonostratigraphy of Central Sumatra Basin (Heidrick and Aulia, 1993)

There are five productive grabens in CSB (Figure 1), including Bengkalis Through, Aman Through, Balam Through, Tanjung Medan Through and Kiri/Rangau Through. The grabens have relatively proximal stratigraphic succession, formed along the trend of the P-Tertiary structure (N-S and WNW-ESE). Those grabens originally are half graben that formed at oblique extension stress regime (William and Eubank, 1995 in Doust and Noble, 2008). The tectonostratigraphy events that form the basin are Early Syn-Rift, Late Syn-Rift – Early Post-Rift, Early Post-Rift and Late Post-Rift.

Early Synrift (Early Eocene - Oligocene) depositioned by Pematang and Kelela Formation that consists of composed by association of alluvial, lacustrine and fluvial deltaic environment, with lithology of laminated shale, silt and sand with coal and conglomeratic rock. Late Synrift - Early Postrift (Late Oligocene – Early Miocene), this sequence equivalent with Sihapas Group, including some of paralic facies which record gradually transgressive event. Menggala Formation deposited at fluvial environs and the upper part at sandy shallow marine environment (Bekasap Formation) and argillaceous (Bangko Formations).

Early Postrift (Early Miocene – Middle Miocene) which deposited by distal marine facies from Sihapas Group, then at the end of the transgressive event, sand and clayin upper delta front facies from Duri Formation are deposited, followed by Tertiary maximum flooding period (shale and silt of Telisa...
Formation). Late Postrift (Middle Miocene - Quaternary), this stage represents the basinfilling process at Late Tertiary, including regressive deltaic and alluvial sediments with some unconformity.

3. Methodology
Data that used in this study are seismic data, well log data, petrophysical evaluation and well report. Well log data of 36 wells (Figure 2.a) consist of gamma ray, caliper, neutron porosity, density, resistivity and sonic. While seismic data is Post Stack Time Migration with 235 seismic line (Figure 2.b).

![Figure 2. Well (a) and seismic (b) basemap](image)

On seismic data especially 2D, amplitude difference often found in process of composites one seismic line to another. Therefore the pattern of reflector must be considerately noticed. Validation of analysis and interpretation of well log data using well report data such as description of core, cutting, mud log and side wall core (SWC) to improve the accuracy of interpretation.

Well to seismic tie using checkshot data and synthetic seismogram was made to determine characters of Top Formation on well log in reflector of seismic. After the seismic well tie done, horizon could be picked to know lateral development and also picking of geological structure.

Petrophysical evaluation was done after analysis and the interpretation of well log data, using deterministic approach. Workflow of petrophysical evaluation is data preparation, determination of shale volume (Vsh), determination of total porosity, determination of water saturation (Sw), determination of permeability (k), determination of cut-off and determination of fluid contact.

4. Results
4.1. Depth Structure Map
The results that obtained from seismic data is depth structure map in Top Telisa Formation (Figure 3.a) and Top Bekasap Formation (Figure 3.b) to observing lateral continuity, depth and thickness of the Formation. The map built by horizon which picked in each of Top Formation that exist in each seismic line, while Top Formation on seismic line obtained from Top Marker in well log with seismic reflector (well-seismic tie). The results of correlation between well-seismic tie is 0.61
Horizon in the seismic still in time domain, to change it into the depth domain required velocity model in each Formation. In this study, velocity model obtained on top of Telisa Formation is 2300 m/s and on top of Bekasap Formation is 2850 m/s. From time to depth conversion, the depth of Top Telisa Formation is 600 - 1200 feet and Top Bekasap Formation located at depth of 1200 - 2000 feet. On the west, present fault zone with N-S trend.

4.2. Well Log Analysis
Lithology interpretation on well validated by cutting and mud log data and some well top obtained from master log from well report, including of Top Formation and "M" Marker. While FS1 - FS10 is the Top of Parasequence marker which interpreted from log pattern (electrofacies), cutting and mud log and the line Shale/Sand FS is the boundary of shale lithology and sandstone in parasequence. The well log divided into 8 parasequences (zones) with coarsening upward pattern (Figure 4.b).

Based on Figure 4.a and facies map, depositional environment of this study located in deltaic system consisting of distributary mouth bar, inter distributary mouth bar, distal delta front and prodelta. Facies
that being the target of this study is distributary mouth bar facies, because the area dominated by sandstone with good enough porosity. Based on lateral distribution of lithology, facies model can be build (Figure 5.a), sand in delta front area may be the distributary mouth bar which have good total porosity and good permeability that isolated between shale which have bad porosity and bad permeability (Figure 5.b).

Based on well log correlation, Zone 1 potential to be hydrocarbon reservoir. Delta fronts sand in this zone also become thicker and widely spread, it shows supply of sediment in this zone has increased. Generally, distributary mouth bar sand in Zone 1 has thickness between 30 - 69 feet and delta front facies which considered as a distributary mouth bar between 35 - 55 feet. In Zone 1, facies gradually thickening from north to south therefore it shows the direction of the sedimentation relatively dominant from north to south.

Zone 1 has crossover between NPHI log (49-59%) and RHOB (1.75 - 1.95 gr/cc). The log response indicate that Zone 1 possible contains hydrocarbon, because crossover RHOB and NPHI log built by high hydrogen atoms medium therefore NPHI values relatively high and RHOB relatively low because bulk density (ρ) of sandstone which contains hydrocarbon tend to have low ρ value. That suspect supported by resistivity log pattern which relatively high between 1.34 - by 2.09 Ωm. In Zone 1 the value of gamma ray is relatively low (59.75 - 72.8 API).

4.3. Petrophysical Analysis
About 50 % value of Vshale is used as cutoff parameter. Petrographic analysis shows that for 50% clay content, porosity value is about 22% (Lemigas unpublished report, 2015). Therefore, 22% value of porosity is used as cutoff parameter. Pickett plot curve were used for determine cementation factor (m), saturation exponent (n) and tortuosity factor (a).

Cementation factor (m) represent the relation between pore connection and water resistivity, usually ranging from 1.7-4.1, where m value for shally sand is 1.33. Exponential saturation (n) potrays the presence of non-conductive fluid at pore space and related with rock wettability. Value of n that usually used is 2 and tortuosity factor (a) used for correcting variety of compaction, structure, and grain size. Water saturation calculated using Indonesia Equation because clay type in the study area is dispersed clay.
Fluid contact obtained from resistivity log trend of Beruk-14 well at depth of 1840 ft, since that depth shows low resistivity trend (1 Ohm.m). Therefore, at depth of 1180 ft interpreted as oil-water contact (OWC) (Figure 6.a). Petrophysical analysis result (Figure 6.a) shows that the study area has porosities ranging from 1-30% (Figure 6.b).

Permeabilities varies from 0.01-1000 mD (Figure 7.a), saturation water varies from 0.3-0.7 (Figure 7.b). Shale permeability value ranging from 0.01-10 mD and classified as low permeability rock (Widarsono et al, 2007), meanwhile permeability of distributary mouth bar sandstone is about 10-1000 mD. Zone -1 as potential zone of study area has hydrocarbon resource approximate 36.723 MSTB based on volumetric calculation.

5. Conclusion
Zone 1 that located at distributary mouth bar facies with gamma ray value varies from 59.75-72.8 API, resistivity varies from 1.34 – 2.09 Ωm, crossover betweenNPHI logwith value varies from 49 - 59 %
and density log with value varies from 1.75 – 1.95 gr/cc. Petrophysical evaluation at zone 1 shows permeability value ranging 1-10 mD, water saturation varies from 30-40% and porosity value varies from 10-20%, with volumetric estimation of 36.723 MSTB. It conclude that Zone 1 of study area has potential as low permeability hydrocarbon reservoir.

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