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RESEARCH ARTICLE

Shale Gas Potential In Jambi Sub-Basin, Indonesia: Insights From Geochemical And Geomechanical Studies

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Abstract

Jambi sub-basin, which is located in South Sumatra, Indonesia has enormous potential of shale gas play. Yet, detailed geological studies are rarely undertaken to understand this relatively new hydrocarbon play concept. This paper presents a combination of geochemical and geomechanical studies with the aim to better understand: (1) the maturity level of source rock; (2) the mechanical properties of shale; and (3) the quality of hydrocarbon source rock. This research began with determination of wells that penetrate the Talangakar and Gumai Formations that have shale in it. Source rock analysis was done by using TOC (total organic carbon), S1, S2, S3, Tmax, and Ro (vitrinite reflectance) data. Geomechanical evaluation was done by using XRD and well logs data. Brittleness index was obtained by using Jarvie et al. (2007) formula, based on the XRD data. S-wave and P-wave are used to calculate the rock strength, Young's modulus and Poisson's ratio with UCS-To methods.Source rock in the Geragai belongs to the of moderate-to-good category because it has more than 0.5% TOC and potentially forms gas because it has a type III kerogen. JTBS-2 well is the only well in the Geragai area which already mature and has been able to produce hydrocarbons, because it passed the oil and gas windows. Source rock in the Betara belongs to moderate-to-good category because it has more than 0.5% TOC potentially forms gas because it has a type III kerogen. Most formations in the Betara are not yet mature based on the value of Ro and Tmax. In wells that have not reached the oil window nor gas windows, the prediction line drawn on the Petroleum Source Rock Summary chart, estimated that they would pass the gas window at Lower Talangakar Formation or Lahat Formation at depth of more than 8000 feet. The results of XRD analysis showed that the Betara had a high brittleness index with an average of 0.809. Talangakar Formation has a higher rock strength values than Gumai Formation, both in Betara high and Geragai deep. The principle that say the rocks which have high TOC values will have a high value of BI can be proven in the study area, the rocks that have high Ro will have a high value of BI, cannot be identified in the study area. With sufficient high value of rock strength and low abundance of clay minerals, the rocks at Talangakar Formation is good for hydraulic stimulation.

Keywords: Gumai Formation, Talangakar Formation, source rock, Young's modulus, Poisson's ratio, brittleness index

1. Introduction

1.1 Background

The Jambi sub-basin is part of the Tertiary sedimentation basin of South Sumatra, which is currently one of the locations for oil and gas exploration. In the Jambi Sub-basin there is a Gumai Formation which is composed of quite thick deep marine shale (Salim et.al., 1995). The opportunity for shale gas exploration requires a better understanding of the geological, geophysical and geochemical aspects to get positive results.Main object for this research are Geragai Deep and Betara Deep, which located in Jambi Sub-Basin. Those two deeps are two of four deeps in Jambi Sub-Basin (Figure 1).

Indonesia has started to develop shale gas since 2009. The potential for shale gas in Indonesia is estimated to reach 574 TCF or greater than coal methane gas (CBM) 453.3 TCF and conventional gas 153 TCF. Indonesia's shale gas reserves are located in Sumatra, Kalimantan, Java and Papua. Studies related to shale gas have been carried out in the North Sumatra Basin and the Central Sumatra Basin.

The purpose of this study is to determine the level of maturity of the Talangakar and Gumai Formations, to determine the mechanical properties of shale both of these formations, and to determine the potential of shale gas from the Talangakar and Gumai Formations.

Table 1. List of abbreviation used in this article

Abbreviation	Meaning
TOC	Total Organic Carbon
PY	Potential Yield
Ro	Vitrinite Reflectance
XRD	X-Ray Diffraction
S_1	The amount of free hydrocarbons (gas and oil) in the sample
S_2	The amount of hydrocarbons generated through thermal cracking of nonvolatile organic matter
S_3	The amount of CO2 (in milligrams CO2 per gram of rock) produced during pyrolysis of kerogen
Tmax	Maximum Temperature when S_2 was obtained
HI	Hydrogen Index
OI	Oxygen Index
Pr	Pristane
Ph	Phytane
nC_{17}	Carbon atom number 17
nC_{18}	Carbon atom number 18
LAS	Log ASCII Standard

1.2 Geological Setting and Stratigraphical Framework

1.2.1 Geology of South Sumatra Basin

The South Sumatra Basin is a northwest-southeast trending back-arc basin bordered by the Barisan Mountains and the Semangko Fault in the southwest, and the Paparan Sunda Pre-Tertiary rocks to the northeast, the Duabelas Mountains and the Tigapuluh Mountains to the northwest separating the South Sumatra Basin with the Central Sumatra Basin; and Lampung High in the southeast that separates the South Sumatra Basin with the Sunda Basin.

Sedimentation that occurred in the South Sumatra Basin took place in two phases (Jackson, 1961):

Transgression phase: Telisa group was deposited in this phase, which consisted of the Lahat Formation, Talangakar Formation, Baturaja Formation, and Gumai Formation. This Telisa group deposited unconformably on Pre-Tertiary source rock (Figure 1).

Regression phase: At this phase the sediment produced from the Palembang group consisted of the Airbenakat Formation, Muaraenim Formation, and Kasai Formation. The rocks that form the base of the basin consist of metamorphic rocks and igneous rocks that are of Mesozoic age (Figure 2).

According to Salim et al. (1995), the South Sumatra Basin was formed during the Early Tertiary (Eocene - Oligocene) when a series of graben developed as a reaction to the angular subduction system between the Indian Ocean Plate under the Asian Continent Plate. According to de Coster (1974) and Salim et al. (1995), it is estimated that there have been three episodes of orogenesis that form the structural framework of the South Sumatra Basin, that is Central Mesozoic orogenesis, Late Cretaceous Late-Tertiary tectonics and Plio – Pleistocene Orogenesa.

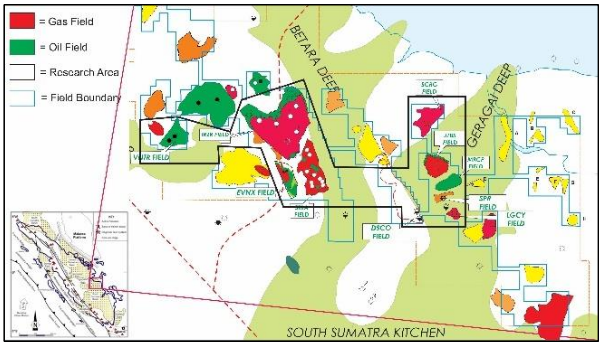

Fig 1. Location of Jambi Sub-Basin

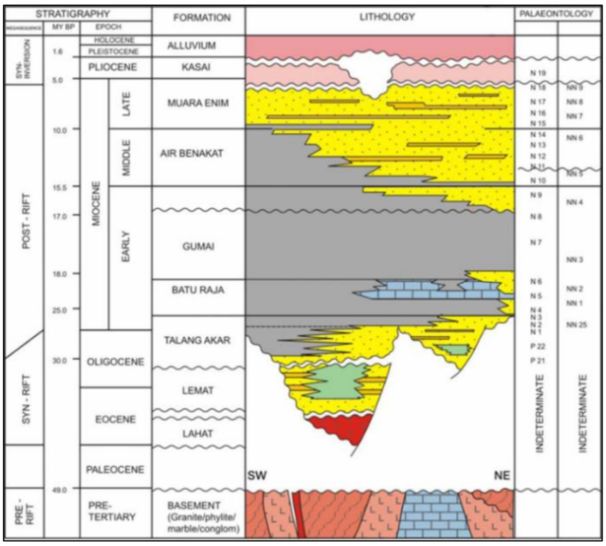

Fig 2. Regional Stratigraphy of South Sumatra Basin (Ginger and Fielding, 2005)

1.2.2 Geology of Jambi Sub-Basin

The Jambi sub-basin is part of the South Sumatra Basin located in the northern part of the South Sumatra Basin. In the northern part of the Jambi Sub-Basin it is bounded by the Dua Belas Mountains and Bangko High, in the south and east are bordered by Ketaling High, and in the west it is bounded by Bukit Barisan.The stratigraphy of the research location is slightly different from the regional stratigraphy, that is the Lemat Formation was not found. At the research location, above the Lahat Formation was deposited the Talangakar Formation (Jabung Regional Study, 2005)

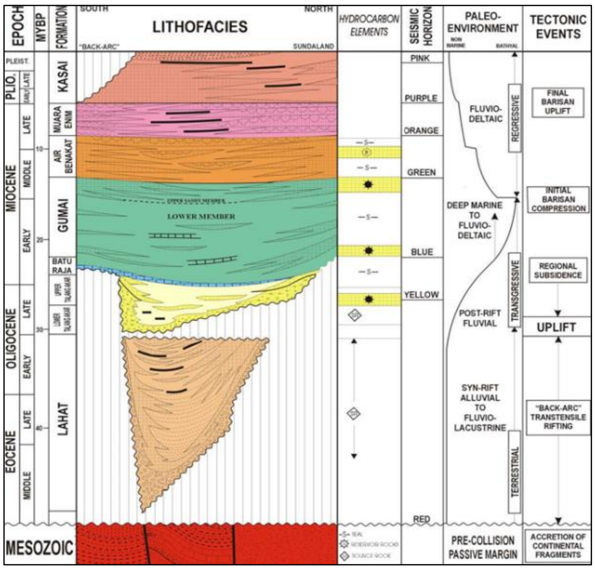

Fig 3. Regional Stratigraphy of Jambi Sub-Basin (Petrochina Jabung, 2005)

Hydrocarbons in the South Sumatra Basin are in the form of oil and gas, which may originated from petroleum migration and followed by gas migration. The source rock comes from the Lahat Formation has a lacustrine depositional environment. In addition to the Lahat Formation, coal and shale in the Talangakar Formation are also a source of hydrocarbons in the South Sumatra Basin (Clure, 2005). The Gumai Formation which is younger than the Talangakar Formation also acts as a source rock with a marine depositional environment, but has a smaller amount of organic material and has a lower maturity compared to some other parts of the South Sumatra Basin (Figure 4).

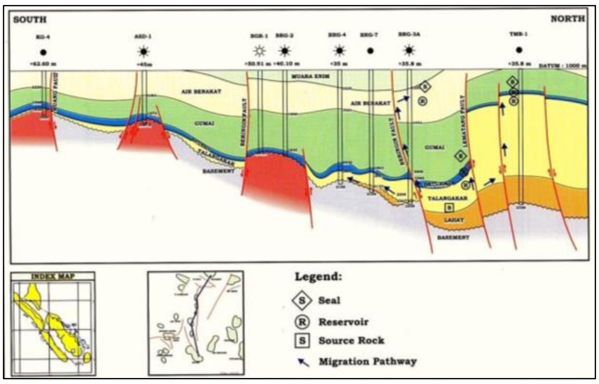

Fig 4. Petroleum System Play of South Sumatra Basin (Patra Nusa Data, 2006)

Lithology in the Lahat and Talangakar Formations is dominated by coal facies and has an excellent source rock potential with a TOC value greater than 3% and a hydrogen index value greater than 300 mgHC / gTOC (Patra Nusa Data, 2006). Potential source rock facies are dominated by type II /

III kerogens produced from higher plant material with a small amount of liptinite, algae, and excitites (Patra Nusa Data, 2006). The mean geothermal gradient in the South Sumatra Basin is 2.89°F per 100 feet, so the average depth of the peak of the oil window is 1700 meters (5500 feet) and the peak of the gas window is 2300 meters (7500 feet).

Hydrocarbon generation in the Lahat and Talangakar Formations began in the Late Miocene which resulted from increased heat flow associated with Late Miocene tectonics and entering the gas window at the age of the Pliocene or Late Pliocene. Early formed hydrocarbons may also have migrated due to the Pliocene-Pleistocene orogenesis.

2. Material and method

The study began with the determination of wells that penetrate the Talangakar Formation and the Gumai Formation which have shale layers in them.

The source rock evaluation was carried out to determine the richness of organic material, the type of kerogen produced and to determine the maturity of the source rock. Richness quality determination used Waples (1985) classification. The data used were obtained using Rock-Eval pyrolysis analysis. In this study, the evaluation of the source rock focused on the Gumai Formation and Talangakar Formation, both the Upper Talangakar Formation and the Lower Talangakar Formation to determine the richness of organic material and maturity in shale lithology. The data used came from the Geragai area, comes from SCRG-1, LGCY-1, JTBS-1, JTBS-2, and DSCO-1 well; as well as from the Betara area are IRZR-1, IRZR-5, EVNX-1, EVNX-2, and VNTR-1 well. Analysis of the quality and quantity of source rock requires data on hydrogen index values (HI), S1, S2, and TOC values which are then plotted into a graph of the relationship between TOC and HI (Figure 5) and graphs of the relationship between TOC and Hydrocarbon Potential values (PY). The PY value is obtained from the sum of S1 and S2 values. Ro vs. depth graph is used to determine rock maturity and gas window limits. Source Rock maturity determination used

Table 2. Source Rock quality based on TOC (Waples, 1985)

TOC Value	Source Rock Implication
< 0.5%	Negligible source capacity
0.5%-1.0%	Possibility of slight source capacity
1.0%-2.0%	Possibility of modest source capacity
>2.0%	Possibility of good to excellent source capacity

Table 3. Kerogen type classification (Peters and Cassa,1994)

Kerogen Type	HI Value (mgHC/gTOC)	Product at Peak Mature
Type I	>600	Oil
Type II	300-600	Oil
Type II/III	200-300	Oil & Gas
Type III	50-200	Gas
Type IV	<50	none

Table 4. Source rock maturity based on Ro (Peters and Cassa, 1994)

Maturity Level	Ro	Tmax(˚T)
Immature	<0.60	<435
Early Mature	0.60-0.65	435-445
Peak Mature	0.65-0.90	445-450
Late Mature	0.90-1.35	450-470
Over Mature	>1.35	>470

The first analysis conducted was the evaluation of the source rock using TOC, S1, S2, S3, Tmax, and Ro data (vitrinite reflectance). From the data of the wells, TOC vs. S1 + S2 and TOC vs HI graphs were made to determine the richness of organic material in rocks, Tmax vs HI and OI vs HI graphs to determine the type of kerogen produced by parent rock.

Sedimentary environment analysis was carried out using data from all wells in the form of GC and GC-MS data. From the well data will be made Pr / nC17 vs Pr / Ph graph to determine the condition of the depositional environment and the type of kerogen produced in the environment, and Pr / nC17 vs Ph / C18 graph to determine the origin of organic material and depositional environmental conditions.

The second analysis was carried out to determine the geomechanical properties of rocks with XRD data and well logs. Unavailability of core rock data and rock analysis, then carried out using the value of the brittlenessindex. The brittleness_index was obtained by the method of Jarvie et al. (2007) based on XRD data. Geomechanical log modeling is done by inputting electrical log data such as gamma ray, resistivity, density, and sonic logs. S-waves and P-waves are used to calculate rock strength, MY and PR by the UCS method (Nations, 1974). The shale geomechanical property obtained from the log analysis, supported by petrophysical analysis, needs to be calibrated with the Brittleness Index previously obtained so that it is considered to represent the true shale geomechanical properties even without drill core data.

Table 5. Availibility data used in this research

Well	Source Rock	XRD	LAS Log			VpVs
			GR	BHC	RT	
SCRG-1	√	-	√	√	√	x
STRA-27	-	√	√	√	√	x
STRA-35	-	√	√	√	√	x
SPRN-1	-	-	√	√	√	x
LGCY-1	√	-	√	√	√	x
MRCP-1	-	-	√	√	√	x
MRCP-13	-	√	√	√	√	x
IRZR-1	√	-	√	√	√	x
IRZR-41	-	√	√	√	√	x
IRZR-42	-	√	√	√	√	x
IRZR-5	√	-	√	√	√	x
IRZR-7	-	√	√	√	√	x
JTBS-1	√	-	√	√	√	√
JTBS-2	√	-	√	√	√	x
JTBS-28	-	√	√	√	√	x
EVNX-1	√	√	√	√	√	x
EVNX-15	-	√	√	-	√	x
EVNX-2	√	√	√	√	√	x
EVNX-9	-	√	√	√	√	x
VNTR-1	√	√	√	√	√	x
DSCO-1	√	-	-	-	-	x
TRVG-1	-	-	√	√	√	√

In this study, a geomechanical evaluation was carried out as an initial review to determine the potential of shale gas that was focused on the Gumai Formation and the Talangakar Formation both in Upper Talangakar and Lower Talangakar. The data used came from the Geragai area, namely wells SCRG-1, SPRN-1, LGCY-1, MRCP-1, MRCP-13, JTBS-1, JTBS-2, JTBS-13, and DSCO-1; and Batara areas namely wells STRA-27, STRA-35, IRZR-1, IRZR-5, IRZR-7, IRZR-41, IRZR-42, EVNX-1, EVNX-2, EVNX-9, EVNX-15, VNTR-41 -1 and TRVG-1. Geomechanical analysis is done by calculating Young's modulus, Poisson's ratio, and UCS values based on VpVs data; and the brittleness index calculation based on XRD data.

3. Result

3.1 Geochemical Evaluation

3.1.1 Geragai Area

In general, the organic material content in the Gumai Formation in the Geragai area classified as moderate to good (Waples, 1985) in shale lithology with values from 0.09% to

1.55% with an average of 0.77%. From the Upper Talangakar Formation the average organic material content is higher than the organic material content of the Gumai Formation which is 1.26% with values from 0.08% to 7.17%. From the samples taken, the Lower Talangakar Formation has the highest average of 1.84%, with values from 0.15% to 8.55%. Samples from the Gumai Formation were obtained from SCRG-1, LGCY-1, and DSCO-1 well, while the Upper and Lower Talangakar Formations were obtained from wells JTBS-1, JTBS-2 and LGCY-1. The JTBS-2 well is the deepest well in the Geragai area, but not yet penetrate the Lahat Formation or bedrock.

Determination of the quality of the source rock can also be seen from the PY value obtained from the total value of S1 and S2. The PY value then plotted into the cross plot of PY and TOC For the Gumai Formation, samples came from SCRG-1, JTBS-1, JTBS-2, DSCO-1, and LGCY-1 well. The analysis shows that the wells have an average PY value from poor to moderate range, with a range of values of 1.11 mg / g in DSCO-1 to 3.39 mg / g in JTBS-2. However, in the DSCO-1 there is no S1 value, so the PY value in the DSCO-1 is less accurate. The lowest PY value after the DSCO-1 well is a sample from the LGCY-1 well with a value of 1.20 mg / g.

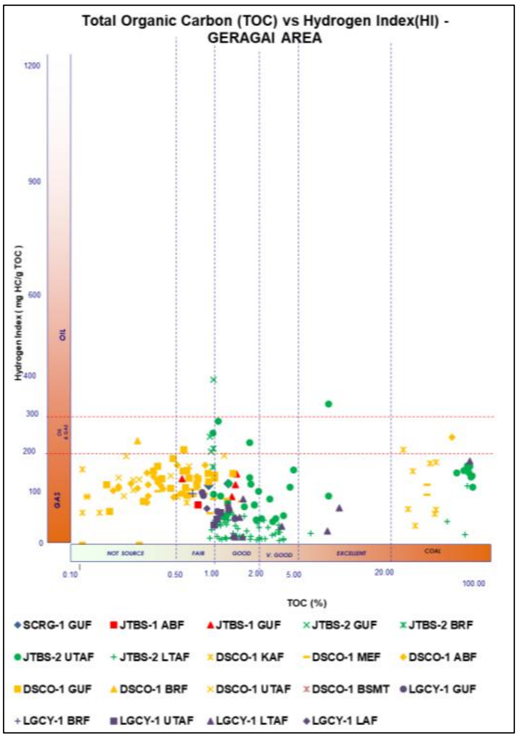

Fig 5. Crossplot of TOC vs HI, showing source rock quality and capability to produce hydrocarbon in Geragai.

Based on the HI value of Gumai Formation at SCRG-1, JTBS-1, JTBS-2, DSCO-1, and LGCY-1 have HI values less than 200 mgHC/gTOC, except for JTBS-2 wells, so based on classification of Peters and Cassa (1994), these wells have the potential to produce gas. In JTBS-2, from all 28 samples, there were only three samples that has HI data. From these three data, samples from JTBS-2 wells have HI values ranging from 264 mgHC / gTOC to 405 mgHC / gTOC, so that rocks in these wells have the capability to produce a mixture of oil and gas. The same results are shown from the results of plotting and reading on cross plots between Tmax and HI values, which show rocks in wells SCRG-1, JTBS-1, DSCO-1, and LGCY-1 produce type III kerogen, which has the potential to form gas. The JTBS-2 well, based on the results of the cross-plot reading, also shows the same result, which has a type II or II / III kerogen that has the potential to generate a mixture of oil and gas (Figure 6).

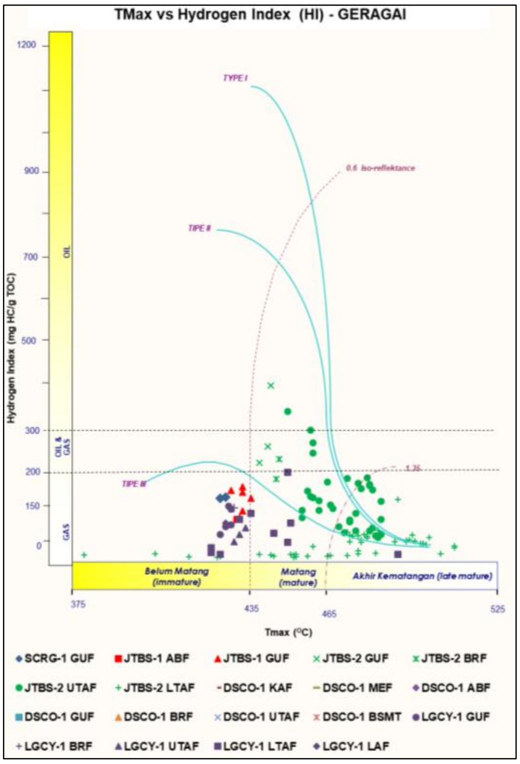

Fig 6. Crossplot of Tmax vs HI to determine kerogen type in Geragai Area.

The source rock maturity can be known from the Tmaks and vitrinite reflectance value, but many samples from Geragai were not analyzed for Tmaks, so to understand the maturity can only be known from the Ro values plotted into the cross plot between Ro values and depth (Figure 7).

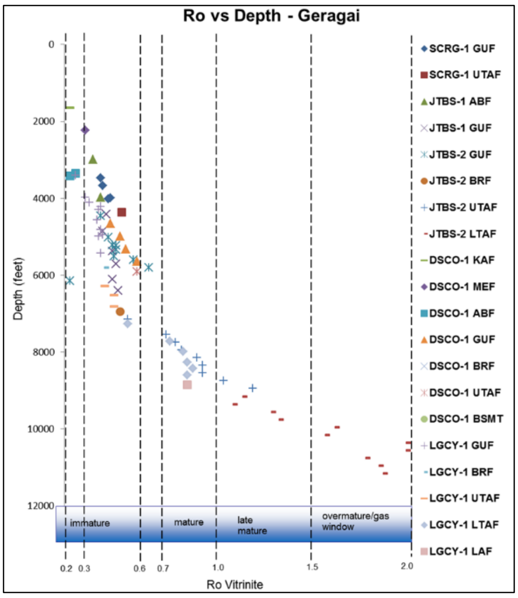

Fig 7. Crossplot of Ro vs Depth to determine maturity level of source rock in Geragai Area.

From the cross plot reading, it is known that only samples originating from Gumai Formation of JTBS-2, Upper and Lower Talangakar Formation of JTBS-2, and Lower Talangakar Formation from LGCY-1 have either matured or did not enter the initial maturity phase. Samples are from

SCRG-1 wells from all formations, JTBS-1 from all formations, JTBS-2 Baturaja Formation, all formations in DSCO-1, and all formations in LGCY-1, except the Lower Talangakar Formation, have not surpass the maturity phase because they have Ro value less than 0.6% (Peters and Cassa, 1994).

Samples from JTBS-2 wells from the Gumai Formation are mostly immature, but from a depth of ± 5790 feet have entered the initial phase of maturity with a Ro value of more than 0.6%. In the Upper Talangakar Formation, most of the samples have matured because they have a Ro of more than 0.7%. At a depth of ± 8750 feet, rocks have exceed the oil window threshold with a value of 1.0% Ro, so that from this depth the source rock is estimated to to produce oil. From the Lower Talangakar Formation, rocks have entered the final maturity phase and at a depth of ± 9950 feet have entered the gas window, so that from this depth the parent rocks have been able to produce gas (Figure 7).

3.1.2 Betara Area

In general, the organic material content in the Gumai Formation is in the poor to excelent (Wples, 1985) category with a range of values of 0.17% - 8.00% with an average of 1.67% which belongs to the good category. The Upper Talangakar Formation has a lower average compared to the Gumai Formation, which is 0.98%, with a range of values of 0.55% - 4.96% (Figure 8), so it categorized as moderate to very good. The Talangakar Bawah Formation has the highest average of the three formations analyzed in the study area at 1.8% TOC, so this formation categorized in the good category. The range of TOC values in the Upper Talangakar Formation is 0.07% - 8.45%, so this formation has the longest TOC range compared to other formations (Figure 8).

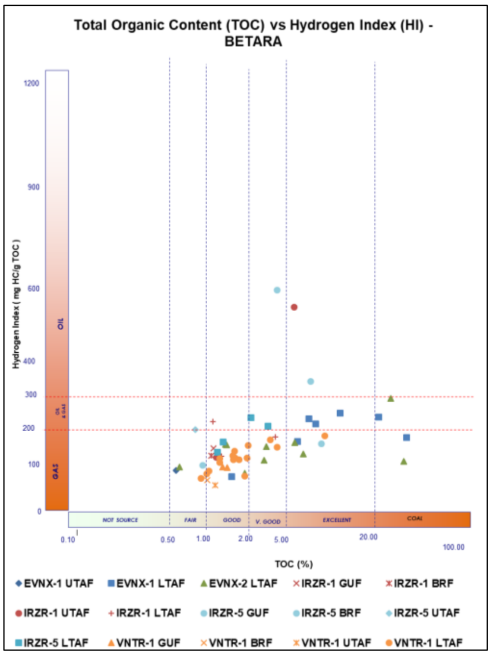

Figure 8. Crossplot of TOC vs HI, showing source rock quality and capability to produce hydrocarbon in Betara Area.

Determination of hydrocarbon quality can also be obtained by calculating the value of PY (Potential Yield) obtained from the total value of S1 and S2. The PY value is then entered into the cross plot of the relationship between PY and TOC. In the Gumai Formation in the Betara area, samples from IRZR-5 well have the highest average PY value of 21.07 mg / g, followed by samples from IRZR-1 well with a value of 2.35 mg / g, and samples from VNTR-1 well have the smallest PY value with a value of 1.84 mg/g. In the Upper Talangakar Formation, PY analysis using samples from wells EVNX-1, IRZR-1, IRZR-5 and VNTR-1, withsamples from IRZR-1 well has the highest average PY value of 15.79 mg / g. The other three wells, including those with poor to moderate hydrarbon potential, have an average PY value of less than 5.0 mg / g. Samples from EVNX-1 well have the smallest average value, which is 0.77 mg /g, then VNTR-1 with an average of 1.02 mg / g and IRZR-5 with an average of 2.15 mg/g.

Determination of the kerogen type for the betara area can be done by plotting and reading the cross plot of Tmaks and HI and the cross plot of OI and HI (Figure 9). Because wells in Betara area have all the data, the determination of the kerogen type can be done with those two cross plots. In general, the five wells analyzed can be divided into three kerogen groups, which is kerogen type III, kerogen type II, and kerogen type II / III (Figure 9).

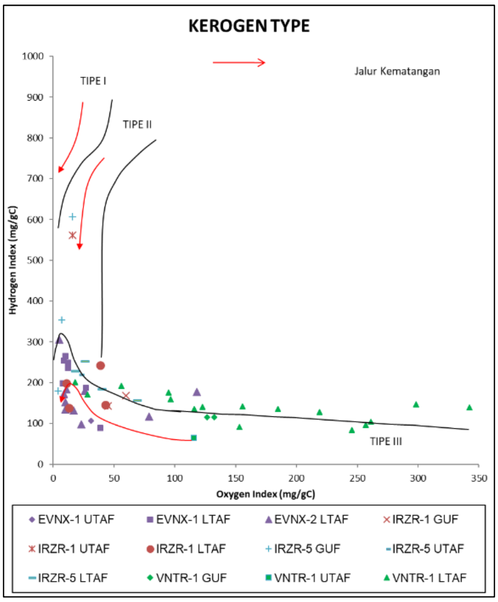

Figure 9. Crossplot of OI vs HI to determine kerogen type in Betara Area.

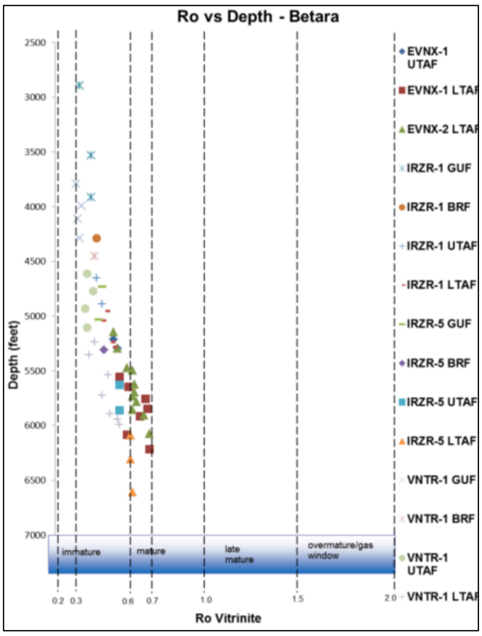

Figure 10. Crossplot of Ro vs Depth to determine maturity level of source rock in Betara Area.

The results of reading the two crossplots, the Gumai Formation and Upper Talangakar Formation samples, from

EVNX-1, EVNX-1, IRZR-1, IRZR-5 and VNTR-1 well have not entered the maturity phase, so the Gumai and Upper Talangakar Formations have not yet produce hydrocarbons. In the Upper Talangakar Formation it looks a bit promising because samples from EVNX-1, EVNX-2 and IRZR-5 have entered the initial phase of maturity as indicated by Ro values greater than 0.6% and Tmaks of more than 435°C (Figure 10). A slightly different case is shown from samples from wells VNTR-1, because the Lower Talangakar Formation in this well has not yet entered the maturity phase, either based on Ro or Tmax values.

3.2 Geomechanics Evaluation

In general, based on the results of BI calculations from 45 samples from nine wells collected from the Gumai and Talangakar Formations, the BI values ranged from 0.417 in the IRZR-42 well in the Lower Talangakar Formation to 0.979 in the STRA-27 well in the Lower Talangakar Formation. The Lower Talangakar Formation has an average BI value of 0.809 which indicates that the Lower Talangakar Formation has a good agility level.

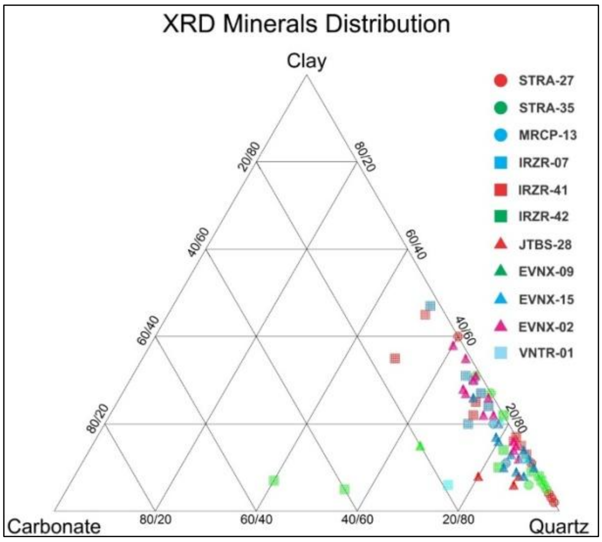

Figure 11. Triangular Diagram of XRD showing mineral distribution.

Based on the XRD analysis in the laboratory which is then plotted into a triangular diagram (Figure 11), it is found that almost all samples have very high quartz content and very low clay and carbonate mineral content. The low clay content and high quartz content indicate that the wells are good enough to do artificial fracturing. High abundance of quartz, and low abundance of carbonates and clays, can occur in rocks that are not pure shale.

Results of cross plot of PR and YM (Figure 12) and YM and UCS (Figure 13), can be seen that the STRA-27, STRA-35, IRZR-07, and EVNX-2 samples have a range of brittleness low to moderate level. PR range from 0.285 to 0.33 and YM values from 7 Gpa to 37 GPa, and UCS values from 17 MPa to 58 MPa. IRZR-41 wells and VNTR-1 wells have the lowest brittleness range (Figure 12 and Figure 13). Among eight wells that have BI calculation, the IRZR-42 well has the longest BI range, from low to high. The highest BI value in the IRZR-42 well is at a depth of 6160 feet. EVNX-9 has the highest brittleness value with PR value ranging from 0.26 to 0.28 and YM from 39.73 GPa to 47.31 GPa (Figure 12).

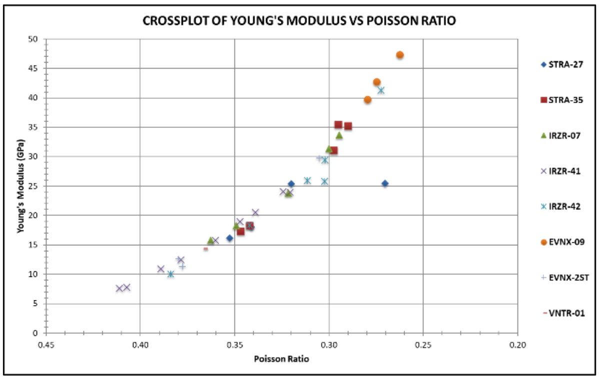

Figure 12. Crossplot of PR vs MY of wells to has BI data.

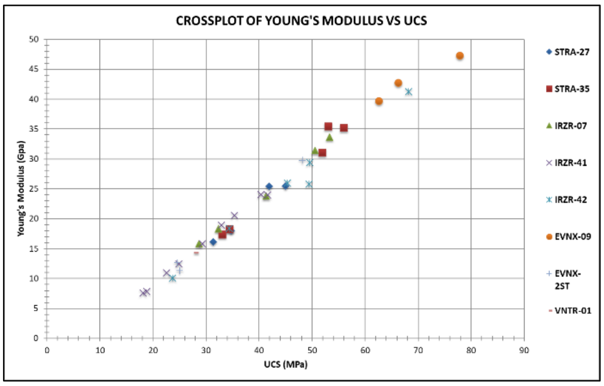

Figure 13. Crossplot of UCS vs My of wells that have BI data.

4. Result

4.1Correlation of Geochemistry and Geomechanics

To understand the correlation of geochemistry, represented by the value of TOC and Ro, and geomechanics, represented by rock strength, can be done by make a cross plot of BI rocks and TOC and BI rock and Ro cross plots. To make the two cross plots, the ideal is to use BI, TOC, and Ro data from the same well. However, this cannot be carried out at the research location due to lack of ideal data. Therefore, the TOC and Ro data are taken from the nearest well or field and the depth is almost the same as the data used for BI values. As the TOC value increased, the rocks become more flexible, or rocks that have high TOC value will have low rock strength. This happens because a high amount of organic material usually exists in clays or shale which make the rock become ductile. In Figure 14 an ideal correlation can be seen between the value of BI and TOC.

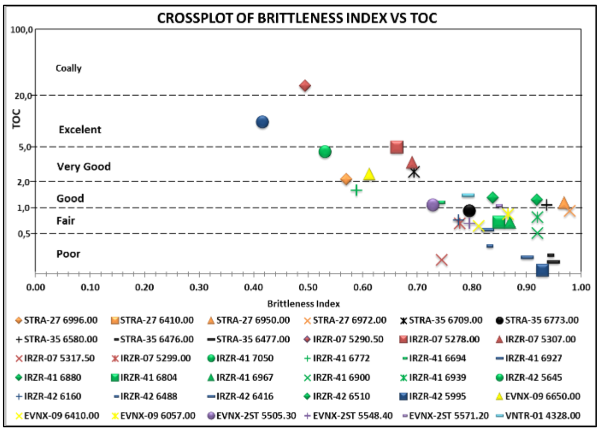

Figure 14. Crossplot of BI vs TOC showing positive correlation of those two parameters.

Rocks that have high Ro value will ideally have a high BI value too or as it become more mature, it will become more rigid. This happens because as the rock become mature, the organic material will be converted into hydrocarbons due to heat and pressure, so the rocks will become denser compared to rocks at early depositional process. Figure 15 shows an ideal relationship, which shows that the more mature the rock, the strength of the rock will also increase, although it is very small.

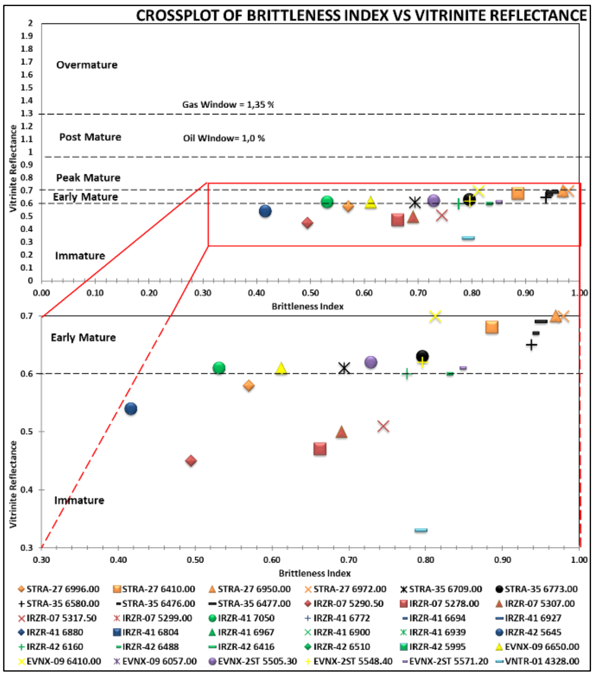

Figure 15. Crossplot of BI vs Ro showing positive correlation of those two parameters.

4.2 Geomechanics Discussion

An Anomaly which shows that the Upper Talangakar Formation has higher rock strength than the Lower Talangakar Formation can happen due to several things, one of which is due to overpressure. Overpressure is a pore pressure condition that is larger than the hydrostatic pressure. According to Swabrick and Osborne (1998), the mechanism for the formation of overpressure is divided into two, due to loading and non-loading.

Overpressure mechanism associated with loading is caused by one or more main strains that work on the sediment. For example is caused by high sedimentation rate. Mechanism associated with non-loading occurs due to increasing in the volume of fluid in the pore with the condition of the fluid can not be release from pore cavity. Clay minerals diegenesis and hydrocarbon generation are examples of non-loading mechanisms. The transformation of smectite into illite and kaolinite to illite causes an increase in the volume of fluid in the rock pore cavity. Transformation of smectite into illite causes changes in the size of clay minerals which contribute to the reduction in the value of effective stress (Katahara, 2006). Water that is bound in the smectite will come out into water that fill pore cavity (Boles and Franks, 1979). Transformation of kerogen to hydrocarbons results in an increasing of fluid volume 75–140% at 70°C, which is the cause of overpressure (Swabrick et al., 2002). Hydrocarbon generation involves two processes, namely the transformation of kerogen into oil and gas, and oil into gas.

Kataren, 2014 stated that in Geragai and Betara there were zones of a non-loading overpressure mechanism in the Upper Talangakar Formation caused by hydrocarbon maturity. Geochemical analysis result support this statement, because source rock in Geragai has surpass phase of maturity. Due to the overpressure zone in the upper Talangakar Formation, this formation has rock strength greater than the lower Talangakar Formation. The Upper Talangakar Formation at Betara high does not experience anomalies like in Geragai, because samples was from high area and not in the Betara Deep, which may not have a zone of overpressure in it because the rocks in the Betara high have not surpass maturity phase.

The inversion in the South Sumatra Basin could have an effect on rock strength. The burial history may affect rock strength because inversion started as the Upper Talangakar deposited. Overburden pressure may also increase after Baturaja and Gumai Formation deposited.

5. Conclusion

1. Source rock in Geragai area have moderate to good category and has the potential to generate gas and a mixture of oil and gas. The JTBS-2 well is the only well in the geragai area that has surpass maturity phase and capable to produce hydrocarbons, because it has exceeded the oil window and gas window phases.
2. Source rocks in the Betara area are in the moderate to good category and have the potential to generate gas, and mixture of oil and gas. Most of the well in the Betara area have not surpass the maturity phase either based on Ro or Tmax values. The EVNX-1 well is the only well in the Betara area that has entered a maturity phase but cannot produce hydrocarbons yet.
3. In wells that have not yet exceed oil window or gas window, maturity can be estimated on average it will surpass the gas window in the Lower Talangakar Formation or in the Lahat Formation with a depth of more than 8000 feet.
4. In general, Gumai and Talangakar Formations at Betara high have lower rock strength values than those in Geragai. The upper Talangakar Formation within the Geragai has higher rock strength compared to the Lower Talangakar Formation due to the influence of overpressure in the Upper Talangakar Formation within the Geragai Formation.
5. The ideal relationship between BI and TOC values that indicate high TOC values will have low rock strength can be proven at the study site. The relationship between BI and Ro shows that the more mature the rock, the less flexible the rock will be, is not proven at the study site because most of the source rock has not yet entered the maturation phase of the hydrocarbon.
6. The Geragai Deep is more potential to produce shale gas compared to the Betara High because the source rock inside Geragai has mature and entered the gas window and the Geragai Deep has a higher rock strength compared to the Betara High.

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