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Shale Plays Characterization of the Talang Akar Formation in the Jambi Sub-Basin, South Sumatra Basin

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ABSTRACT

The Jambi Sub-Basin is part of the prolific South Sumatra Basin which has been proven to produce conventional oil and gas in large quantities. In the basin, Talang Akar Formation (TAF) is believed to be the dominant source rock for commercial hydrocarbons. That means the TAF has potential as shale play resulting oil and gas. Generally, shale plays of the TAF was deposited on littoral-neritic environment during late period of syn-rift until early post-rift at Late Oligocene - Early Miocene. Based on well log analysis, identification characters shale plays of the TAF in the Jambi Sub-Basin have good character as source rock reservoir. Several wells showed that early maturity level happened at depth less than 2000m. Most of TOC, S2 and HI values exist in the range of (1-10) wt %, (0.25 - 10) mg/g rock and (50 - 400) mg HC/ g TOC respectively. Shale plays of the TAF tend to have Type II, II / III and III kerogen. Most of existing wells are not located in the basin center. The geophysical methods such as seismic inversion and seismic attribute can be applied to predict the TOC (Total Organic Carbon) and brittleness index (BI) distributions especially in the basin center. Geologically, the shale plays quality in center of basin was interpreted better than the flank. Age of the shale in the Jambi Sub-Basin is relatively much younger when compared to shale in North America. This fact is suspected to cause the TAF shale play to be relatively less brittle. The data processing result shows that the brittleness index values of shale plays tend to be in the range of 40% - 70%.

Keywords: Shale plays characterization, Talang Akar formation, unconventional oil and gas, Jambi Sub-Basin.

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INTRODUCTION

South Sumatra Basin is one of the mature basins in Indonesia. The South Sumatra Basin is a back-arc basin formed by the interaction between the Indo-Australian and Eurasian Plates in Pre-Tertiary and Early Tertiary time. Over 100 fields have produced oil and gas, where some of which are still producing today. The basin consists of four Sub-Basins, i.e. South Palembang, North Palembang, Central Palembang and Jambi Sub-Basins (Figure 1). Theoritically, not all hydrocarbons in the source rocks migrated to the conventional reservoirs, it is estimated that there is still a significant amount of hydrocarbons left in the source rocks (Jarvie, 2008). In Jambi Sub-Basin, the potential source rocks known as shale hydrocarbons are interpreted to have originated from the Talang Akar and Lemat/Lahat Formations as well as from the Lower Gumai formation in the certain locations.

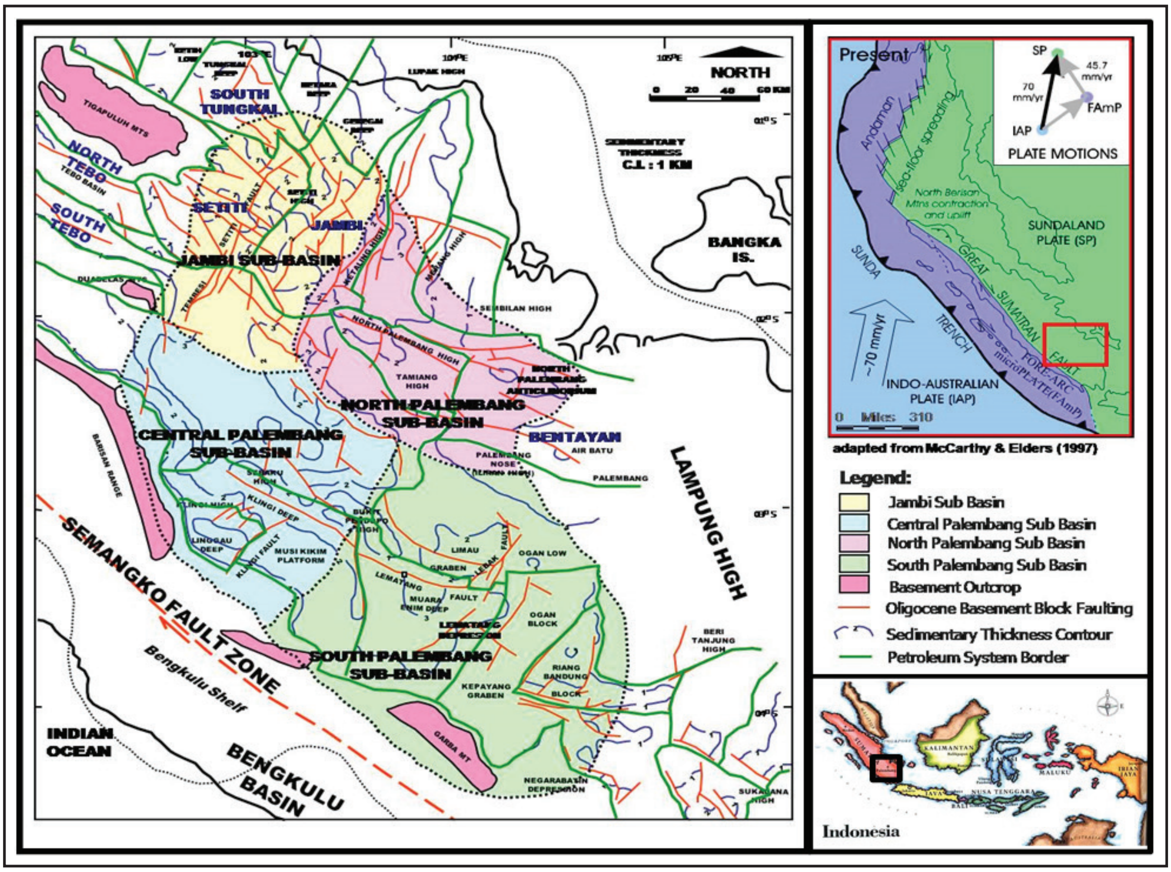

Figure 1
Regional tectonic map of the South Sumatra Basin, Indonesia
(Hadipandoyo, *et al.,* 2006 and McCarthy & Elders, 1997).

The study area is focused on the Jambi Sub-Basin with the Talang Akar Formation (TAF) as shale hydrocarbon target. The formation is believed to be the dominant source for commercial hydrocarbons in the South Sumatra Basin (Ginger & Fielding, 2005). In the unconventional oil and gas case, the shale hydrocarbon play is also known as source rock reservoirs (SRR), the source rocks which also act as reservoir. Generally, distribution of shale plays of the Talang Akar Formation is predicted very wide, therefore shale of the TAF is worthy of being the main target of unconventional oil and gas in the South Sumatra Basin include in the Jambi Sub-Basin.

There are some of deep structures located in the Jambi Sub-Basin, such as Merang Deep, Ketaling Deep, Sungai Gelam Deep, Bajubang Deep, Tempino Deep, Berembang Deep, Kenali Asam Deep. They are predicted as source rock reservoir and expected will to be the potential shale hydrocarbons in Indonesia for next future.

Integrated study is very important to characterize shale plays or shale hydrocarbons of the Talang Akar formation in the Jambi Sub-Basin. To obtain unconventional oil and gas in large quantities, we must have an large sweet spot. A sweet spot is determined by many factors (Sondergeld, *et al.*, 2010). This paper will discuss about 3 main factors, i.e. maturity level, TOC (Total Organic Carbon) and BI (Brittleness Index). To getting a sweet spot area is needed application of the geophysical method, such as seismic inversion and seismic attributes (Chopra, *et al.*, 2013).

The main objective of this study is to characterize the shale play of TAF based on some parameters such as maturity level, TOC (Total Organic Carbon) and brittleness index (BI). The results of previous studies showed that the Jambi Sub-Basin had several deep structures. Most of these deep structures were estimated as a source rock reservoir, especially for the sediments in the synrift - early post rift periods, such as shale plays in the Lemat/Lahat and Talang Akar formations.

METHODOLOGY

The study was supported by lots of wells (about 27 wells) and seismic lines. Not all wells have the same log completeness. About 10 wells having the geochemical data. In addition to subsurface data, this study also utilizes laboratories analysis results (i.e. Sedimentology and Geochemistry laboratories) on rock samples obtained from field geological surveys.

The quality of shale play is determined by many factors. Besides the depth and thickness factors, there are three important factors that must be known, namely maturity, TOC and brittleness index. The three factors will be discussed to determine characterization of the TAF's shale play. Therefore the methodology used includes the following steps:

- To conduct structural and stratigraphic analysis on several existing wells to identify the shale play potential and its age as well as depositional environment.
- To interpret and map distribution of TAF's shale play (seismic interpretation and depth structure map).
- To determine maturity, quality and kerogen type of TAF's shale play based on geochemical data (VR, Tmax, TOC, HI and S2).
- To apply several methods (Multi-Linear Regression, Passey and Neural Network) for predicting the TOC log.
- To apply some methods (such as seismic inversion and seismic attributes) for predicting TOC distribution.
- To calculated brittleness index based on Wang-Gale (1990) and Grieser-Bray (2007).

In this study, TOC data are very limited and there are no TOC data in LAS format, so we need calculating the TOC log for each existing well. We try to use various methods to calculate the TOC log. Passey's Method is very depended by value of baseline and LOM (Level of Maturity). Determination of baseline is very subjective. The other methods, namely MLR (Multi Linear Regression) and Neural Network, make use of other log data (eg gamma ray, density, neutron, sonic) and also AI (Acoustic Impedance) to compute the log TOC.

After calculating a TOC log, we can estimate TOC distribution. From the previous references, TOC distribution can be generated from the acoustic impedance (AI) product. According to Loseth *et al.* (2011), there is good relation between AI and TOC (Figure 2). Therefore, TOC distribution can be obtained based on AI data using a certain equation or applying seismic attributes by Neural Network method. The other authors, such as Crain (2000) and Yenugu, *et al*. (2013), TOC map can be approximated by using density value (Figure 3).

Theoretically, brittleness index (BI) value can be estimated based on: mineral composition (Wang & Gale, 2009), lamdha-rho and mu-rho relations (Goodway, *et al.*, 1997; Mavko, *et al.*, 2009; Perez, *et al.*, 2011) and elastic parameters (Rickman, *et al.*, 2008) such as young's modulus (E) and poisson's ratio [ν]. Brittleness index value is size of rock strength. The greater the value of BI (desired, BI ≥ 50%) indicates if the rock will more easily be cracked. One of the successes of oil and gas exploitation of shale play (hydraulic fracturing) is determined by the brittleness of rocks.

Commonly, formula for calculating BI is obtained from mineral composition. Shale play consists of some minerals, such as clay minerals (illite, smectite, kaolinite, chlorite), other minerals (e.i. quartz, Feldspar, plagioclase) and carbonate minerals (calcite, dolomite and siderite). Quartz mineral has brittle properties and vice versa with clay mineral properties. The formulation of Wang, *et al.*, 2009.

$$BI_{Wang\ (2009)} = \frac{\mathrm{Qz} + \mathrm{Dol}}{\mathrm{Qz} + \mathrm{Dol} + \mathrm{Ca} + \mathrm{Cly} + \mathrm{TOC}}$$

While formula for calculating of BI value from elastic parameters (Grieser & Bray, 2007) is:

$$E_{brittleness} = \frac{E - E_{\min}}{E_{max} - E_{min}}$$

$$\nu_{brittleness} = \frac{\nu - \nu_{min}}{\nu_{max} - \nu_{min}}$$

$$\mathrm{BI} = \frac{E_{brittleness} + \nu_{brittleness}}{2}$$

Young's Modulus (E) and poisson's ratio (ν) can be calculated if known values of Vp (from sonic log of P-wave), Vs (sonic log of S-wave) and ρ (density log).

RESULTS AND DISCUSSION

Structural and Stratigraphy Analysis

The Early Tertiary rocks units were deposited unconformably onto Pre-tertiary (Figure 4). This sediment is typified by series of fining upward sediments; at the lower section is a coarse grain of Lahat and Talang Akar Formations, and then it changes to fine grain Gumai Formation at the upper section, before a regressive sequence and volcanic Kasai Formation and alluvium.

The South Sumatra Basin can be differentiated into 3 (three) tectonic mega sequences. They are Syn-rift (40-29Ma), Post-rift (29-5Ma), and Syn-orogenic and inversion (5 Ma - Present), while evolution of structural elements is shown in Figure 5.

Since Eocene to early Oligocene the Indian Oceanic Plate subducted underneath Eurasian Plate at the west of Sumatra Island. It was created a back arc extension and formed a series of N-S trending horsts and grabens. Because of 15^o clockwise rotation since Miocene, it changed the grabens orientation to NNE - SSW (Hall, 1995).

High rate of subsidence and sea level rise is characterized by a long transgression period until 16 Ma, then it changed to regression period in (16-5) Ma, where rate of deposition was higher than rate of subsidence. In general, the orogeny and uplifting of Barisan Mountain occurred since (5-0) Ma, but locally had been initiated since 10 Ma (Chalik, et al., 2004). This orogeny had created a series of NW - SE

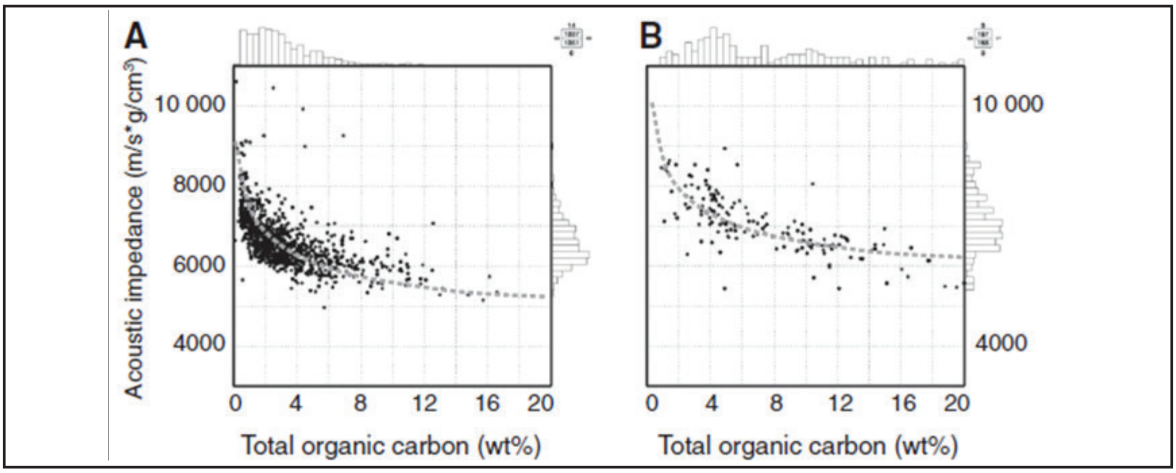

Figure 2
Relation between Total Organic Carbon (TOC) vs. AI in the well location (Loseth, 2011), that means TOC value can be estimated by using AI (Acoustic Impedance) data.

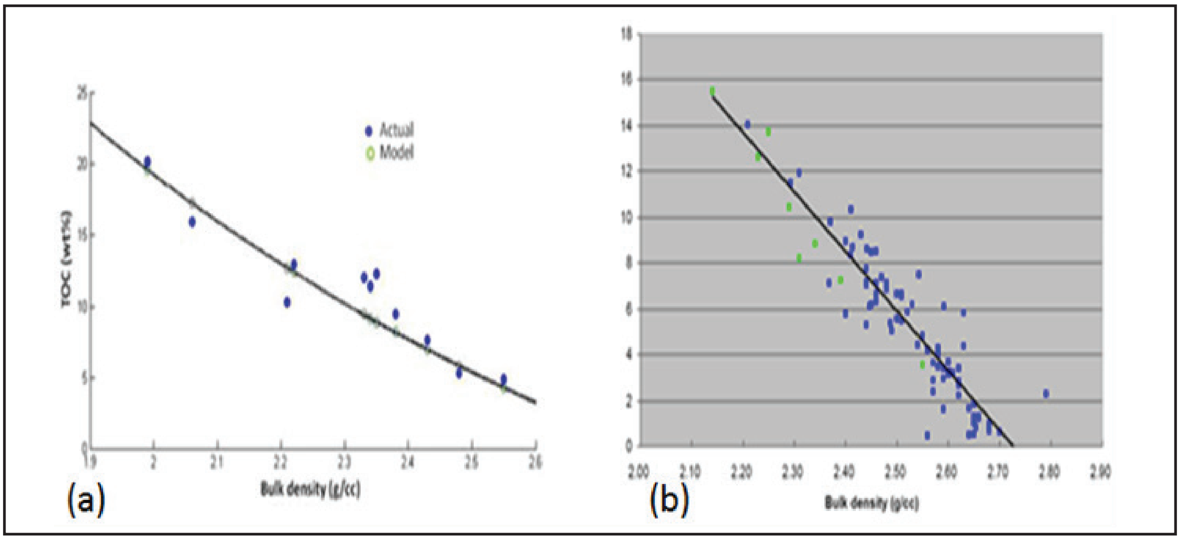

Figure 3
(a) A graph showing bulk density vs. TOC (Yunugu and Han, 2013); (b) A graph bulk density vs. TOC in Barnett shale (Crain, 2000), TOC prediction can be approached with density.

transpression folds patterns. Some structural traps of hydrocarbon in the South Sumatra Basin formed during this period. During this time, subsidence in basin area and erosion of Barisan was continued, and the materials were deposited in the west and south.

Shale Play of Talang Akar Formation

The Talang Akar Formation consists of conglomeratic sandstone, fine-coarse sandstone, siltstone, clay stone, and shale, with some coals intercalation. This unit is deposited during late period of syn-rift and early post-rift which was part of tectonic evolution of South Sumatra Basin. Lithology variations of lower part of Talang Akar Formation are associated to fluvio deltaic to shallow marine environment, for example (Figure 6), while upper Talang Akar Fm. of lower early Miocene changes to deltaic, shallow to deep marine indicating transgression event in South Sumatra Basin.

The Upper Talang Akar deposition was followed by volcanic activity, and extensive marine environment. The evidence is volcanic clastic and calcareous clastic sediments that exposed in Lahat area. Based on lithology composition, the Talang Akar Formation can be divided into two members:

Grit sand Member (GRM): consists of coarse clastic sediments as conglomeratic sandstones, quartz sandstones, and shales with coals intercalation. Sedimentary structures are bedded, cross bedded and parallel lamination.

Transitional Member (TRM): consists of fine to medium clastic sediments as interbedded sandstones, shales, and dark grey silts with intercalation of coals and bituminous clay, glauconitic minerals are abundance. It was deposited in transition to shallow marine during early Miocene.

Generally, the TAF is deposited in supralittoral to marine environments. The Talang Akar Formation is gradually overlain by reef limestone and sandy limestone of Baturaja Formation as open marine environment.

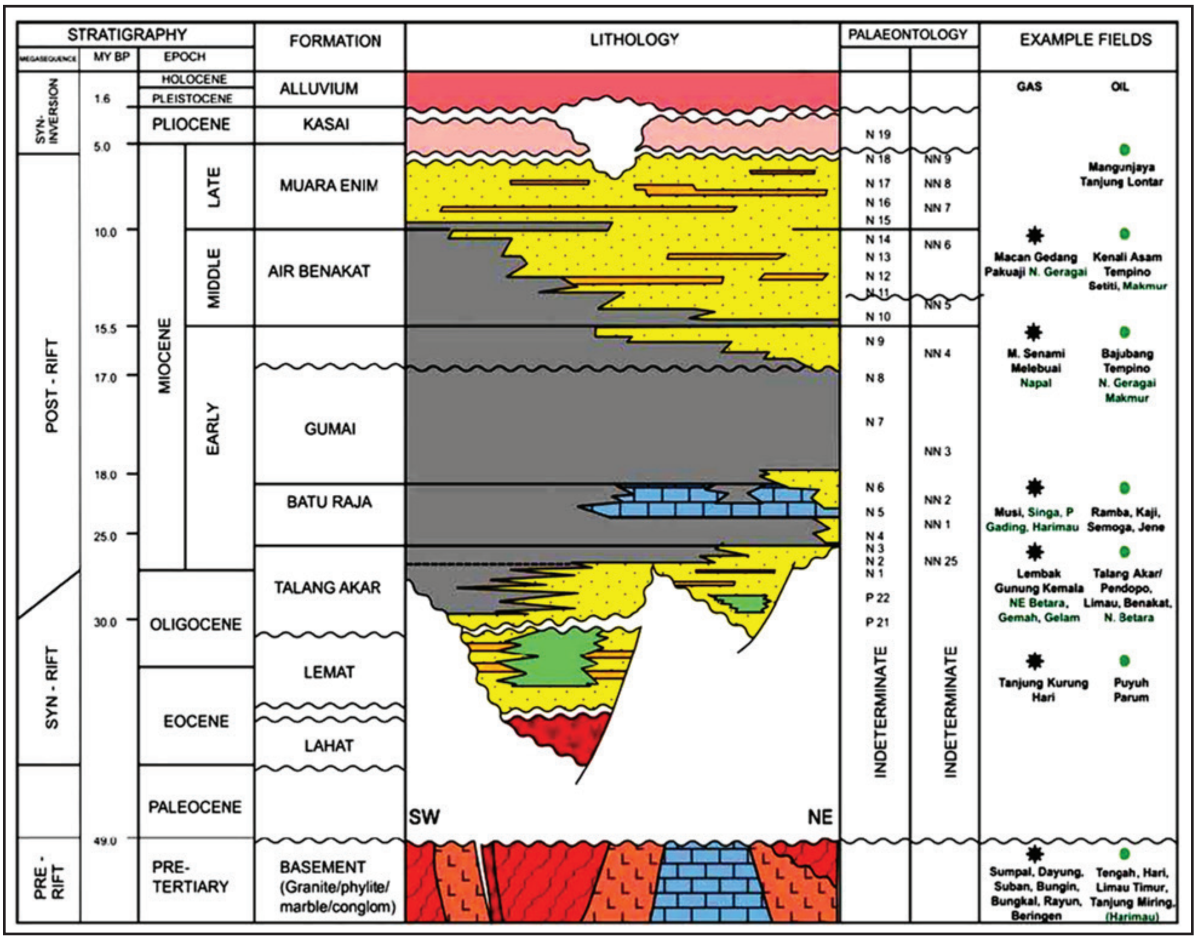

Figure 4
Chronostratigraphy of South Sumatra Basin (Ginger & Fielding, 2005).

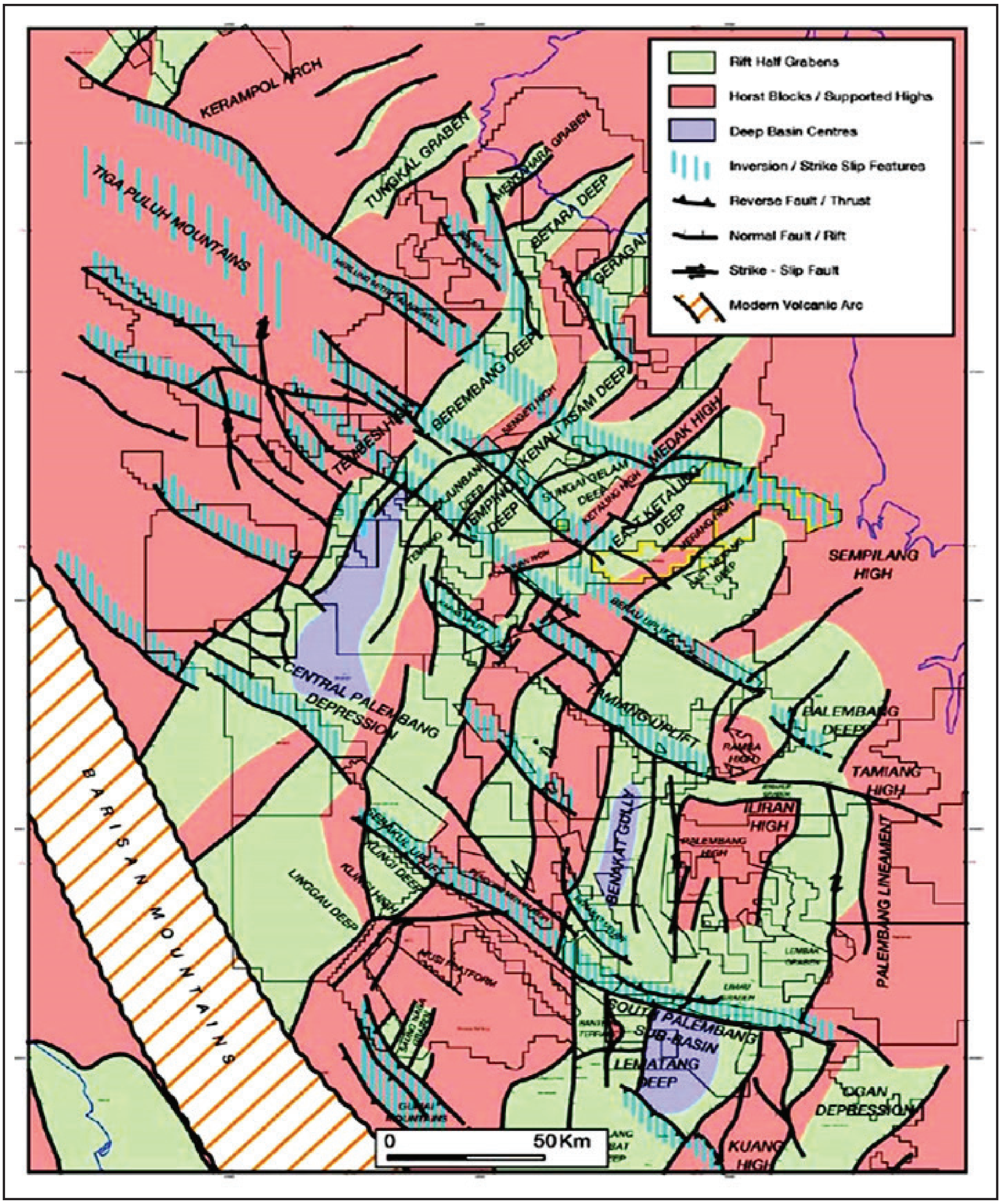

Figure 5
The structural element map of the South Sumatra Basin (Ginger & Fielding, 2005).

A shale play is a defined geographic area containing an organic-rich fine-grained sedimentary rock with the characteristics: clay to silt sized particles; high percentage of silica (and sometimes carbonates); thermally mature; hydrocarbon-filled porosity; low permeability; large areal distribution and fracture stimulation required for economic production (Caputo, 2011). In a unconventional petroleum system, beside as a source rock the shale play also act as a reservoir and as a seal (cap rock). For this reason, the shale play can also be called with term source rock-reservoir (SRR).

Based on the results of geochemical laboratory analysis of ten (10) wells, shale of the Talang Akar formation (TAF) in the Jambi Sub-Basin can act as a source rock-reservoirs with category is fair to very good. Table 1 is the geochemical data summary of the TAF shale in the Jambi Sub-Basin from about 10 wells.

C. Depth Structure of Talang Akar Formation

Fact in petroleum system, Talang Akar formation acts as a conventional reservoir as well as as a unconventional reservoir. In this paper, we emphasize at the unconventional of shale hydrocarbon. Seismic interpretation has been done, sequence boundary-1 (SB-1) is near to Top Basement, SB-2 is not always equivalent Top of Lemat Formation, SB-3 is equivalent Top Lower of TAF and SB-3.1 is near to Top TAF (Figure 7). Sequence-2 (SB-2 – SB-3) is equivalent upper TAF and sequence-3 (SB-3 – SB-3.1) is equivalent lower TAF. Generally, each well has a good thickness of shale plays (average more than 30m). Figure 8 shows depth structure maps of top basement and some maps related to the Talang Akar formation. Some of the deep structures were considered as source rock of shale hydrocarbon.

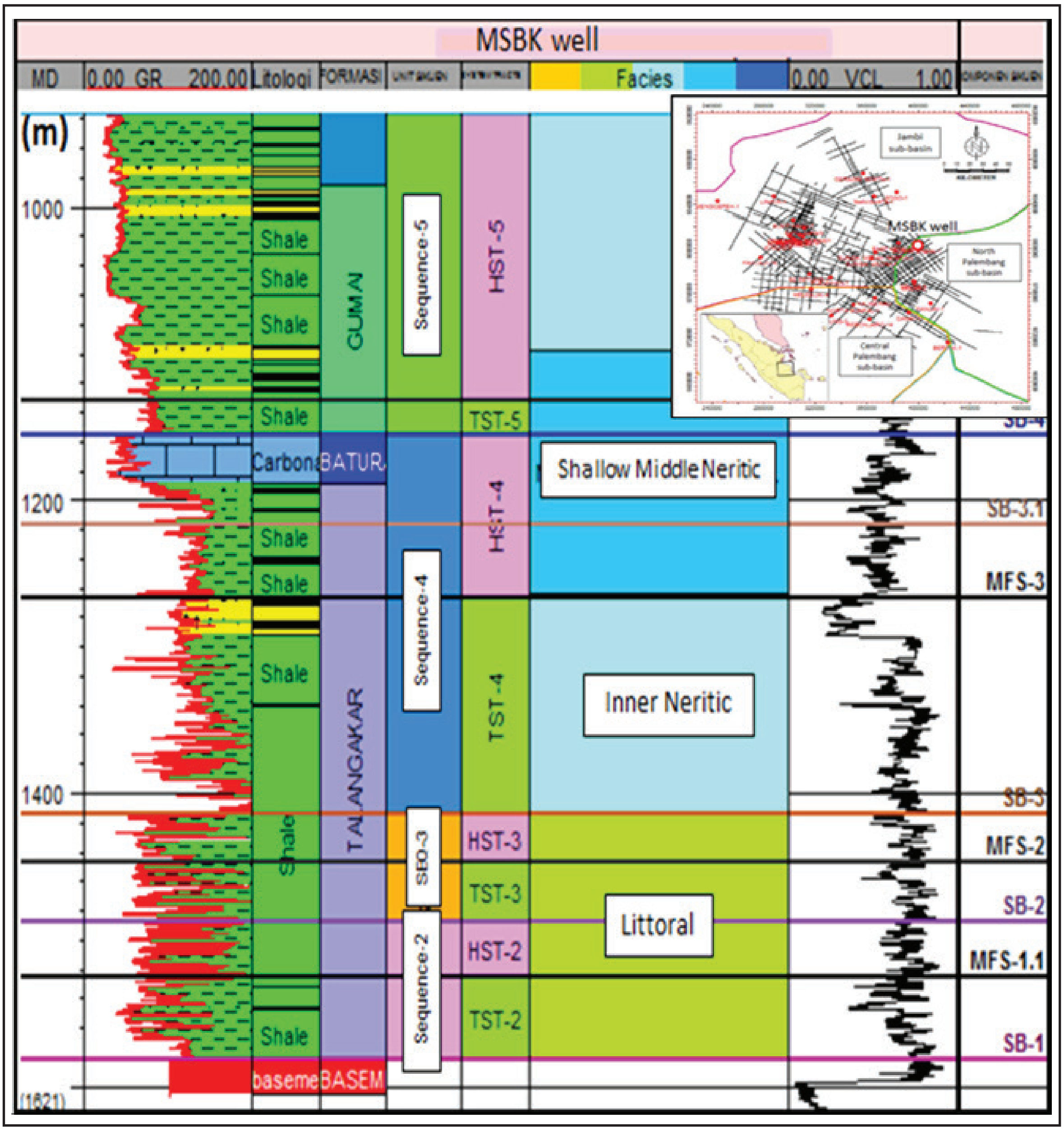

Figure 6
Analysis of MSBK well shows Lower TAF tends to littoral environment and Upper TAF change to Neritic.

Maturity, Quality and Kerogen Type

Maturity of source rock is controlled by time and temperature (Peter & Cassa, 1994). According to the maturity can be known from value of VR and Tmax. Some wells show initial of the oil generation happened at VR about 0.6-0.7 % and Tmax ≥ 435°C. From the observation of several wells shows that maturity level of source rock of TAF has already happened at depth less than 2000m (Figure 9). Figure 10 is crossplot TOC vs. S2, S2 is one of rock eval pyrolysis results. Figure 11 is kerogen type of the TAF shale play which obtained from cross-plot Tmax Vs HI for several wells.

The previous study, thermal modeling in this area had gave a yield which initial generation of the oil, wet gas and dry gas successively happened at Ro=0.6%, Ro=0.9% and Ro=1.2% (Julikah *et al.*, 2016). Based on the modeling result, shale play of TAF can generate oil or/and gas. While kerogen type tends to II, II/III and III.

Table 1
The geochemical data summary of the TAF shale in the Jambi Sub-Basin

No	Formation Name	TOC (wt%)	S2 (mg/g rock)	HI (mg/g TOC)	Tmax (°C)	Kerogen Type	Maturity (Ro %)
1	TAF	0.09-44.58 dominant (0.13-2)	0.08-27.24 dominant (0.08-2.8)	13-524 dominant (25-260)	331-482 dominant (410-480)	II,II/III and III	0.45-1.02 dominant (0.45-1)
2	Lower_TAF	0.44-8.3 dominant (0.45-6)	0.21-37.98 dominant (0.3-5)	4-330 dominant (40-300)	362-546 dominant (368-500)	II,II/III and III	0.35-1.17 dominant (0.35-1.17)

Source: from geochemical data of 10 wells, but Lower TAF information exists at 4 wells only

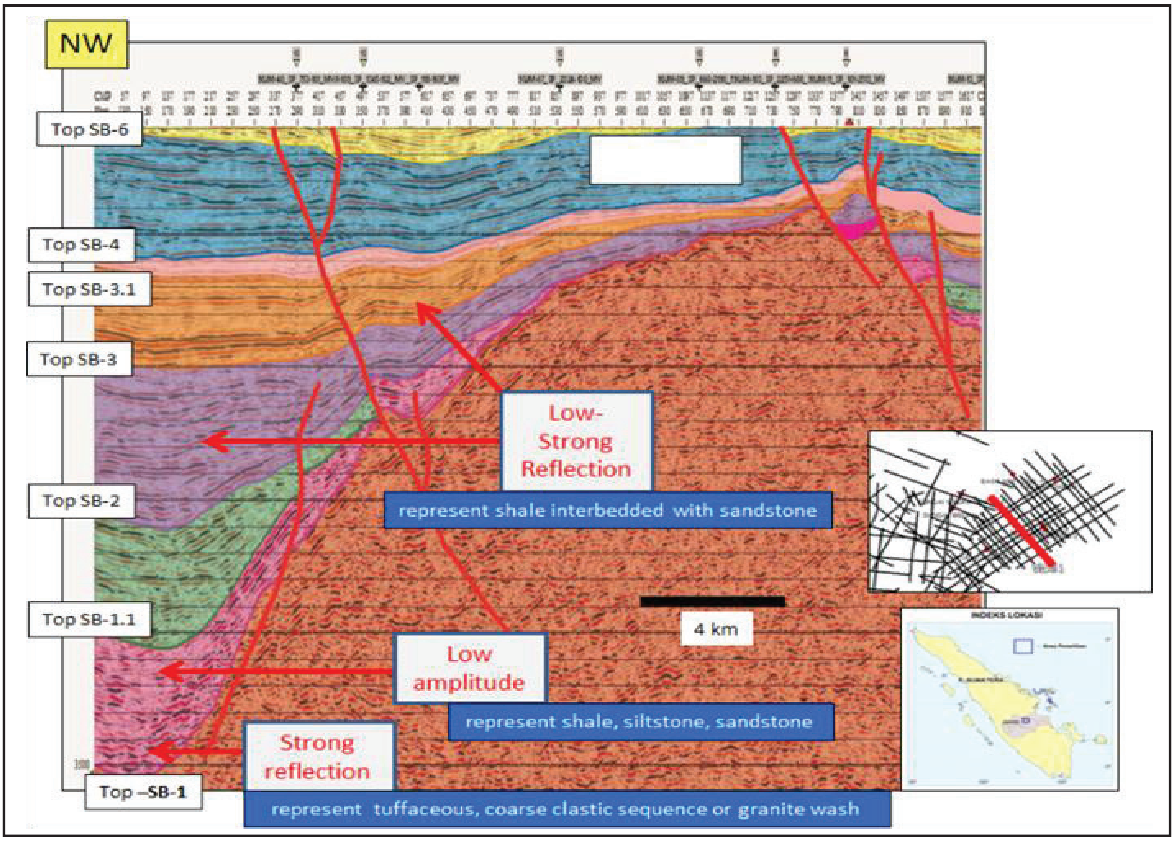

Figure 7
Seismic interpretation at edge of the basin (Julikah, *et al.*, 2016), this figure describes the seismic character and lithological interpretation of several sequences. Top SB-1 is Top Basement.

TOC (Total Organic Carbon) Prediction

Source rock quality is defined by amount of TOC and pyrolysis data. Table 2 is the potential source rock classification (Peter & Cassa, 1994) based on Total Organic Carbon (TOC) and Rock Eval pyrolysis data, such as S1 and S2. From the available geochemical data (from 10 wells), the TOC value of the TAF is very various (0.5 wt% - 20 wt%).

Beside using the geochemical data, existence of shale plays can be identified from log well data. Shale gas has a unique character. Response of shale hydrocarbon play, especially shale gas, is characterized by a high gamma ray log, a low density log, a low velocity log and a high resistivity log (Lewis, *et al.*, 2004). Generally, the log responses read in the shale play zone are proportional to the number of hydrocarbons. The existing TOC data is very limited and not continuous like log data. Several approaches have been used to predict the log TOC. Figure 12 is TOC log calculation by using the Passey, MLR and Neural Network methods.

Unfortunately, no well data which located in the basin center. Mostly of the available wells are located at the anticline structure and several wells exist in edge of the basin. Commonly in the edge of basin, source rock quality decrease due to change the depositional environment from anoxic to oxic. Characters of the shale play located in the basin center are interpreted by application of the geophysical method such as seismic inversion as well as seismic attributes.

The relationship of AI and TOC parameters in the SM-1 well shown in (Figure 13). TOC data of the

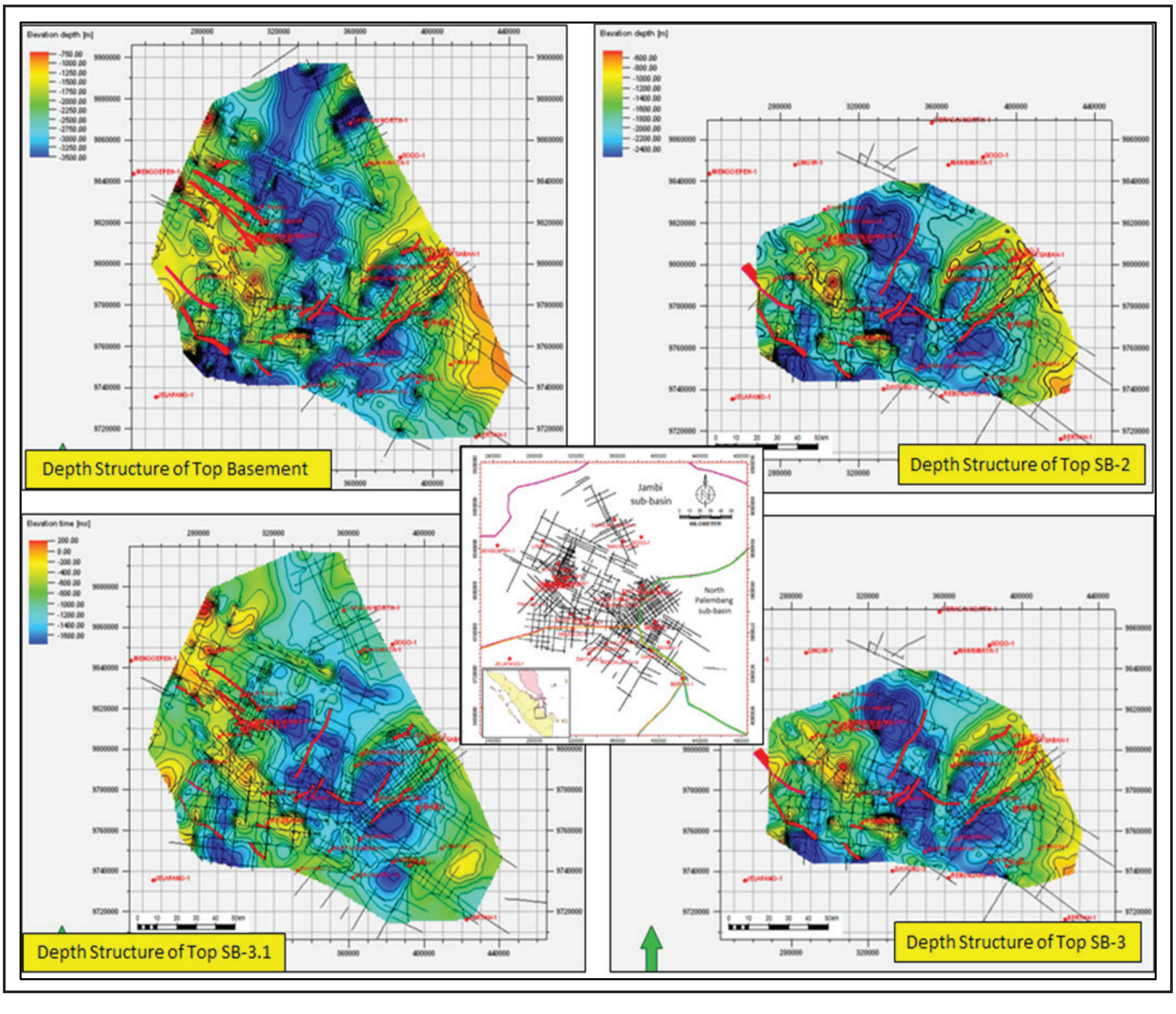

Figure 8
Depth structure maps of top: basement, SB-2, SB-3 and SB-3.1, the blue color
is the basin area and interpreted as the source rock area of the TAF (SB-2, SB-3 and SB-3.1).

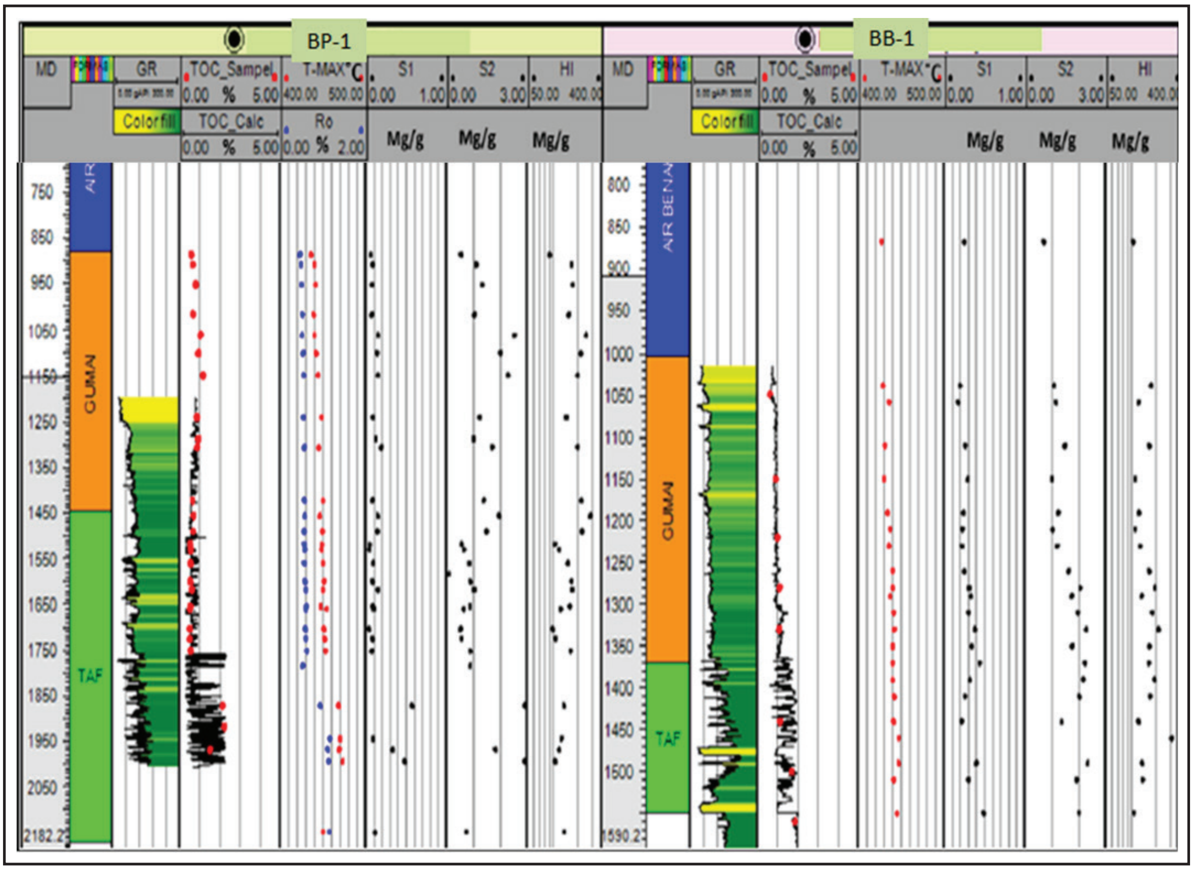

Figure 9
Maturity level of source rock of TAF was estimated happened
at depth less than 2000m (not very deep), theoretically, Ro = 0.8%
has entered the oil maturity window. In the figure, Ro = 0.8% occurs at a depth of about 1950m.

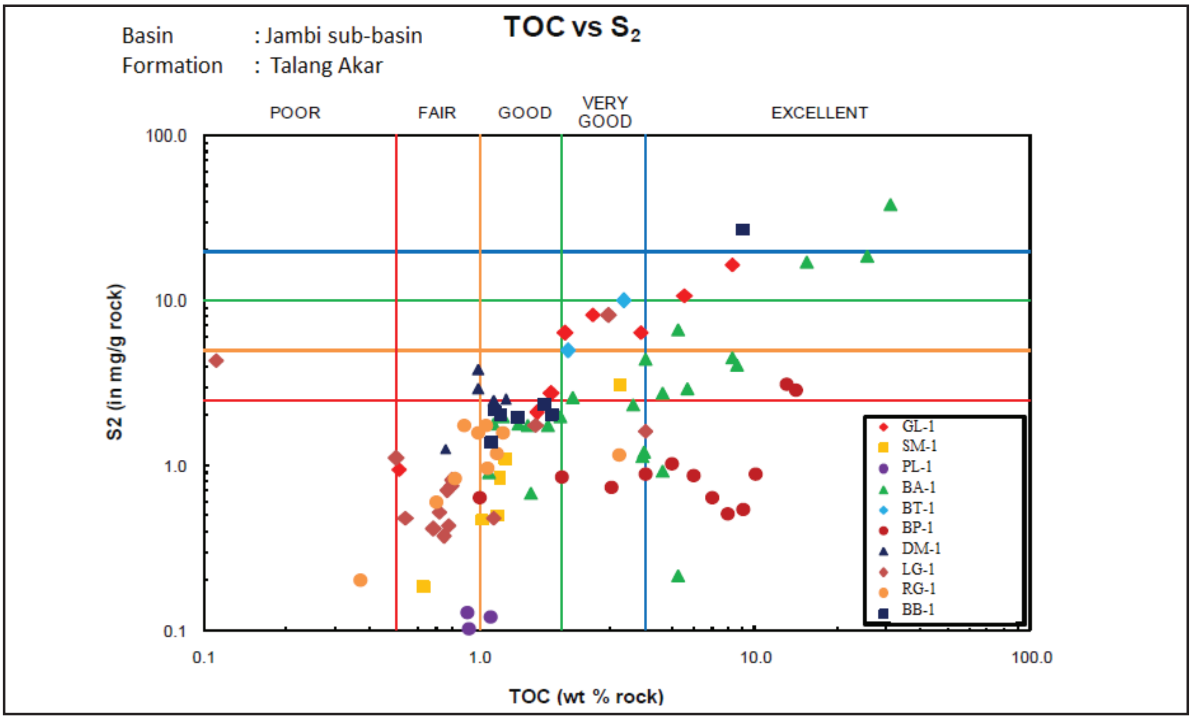

Figure 10
Crossplot TOC vs. S2 from 10 wells, shale play of TAF tends as a good quality source rock.

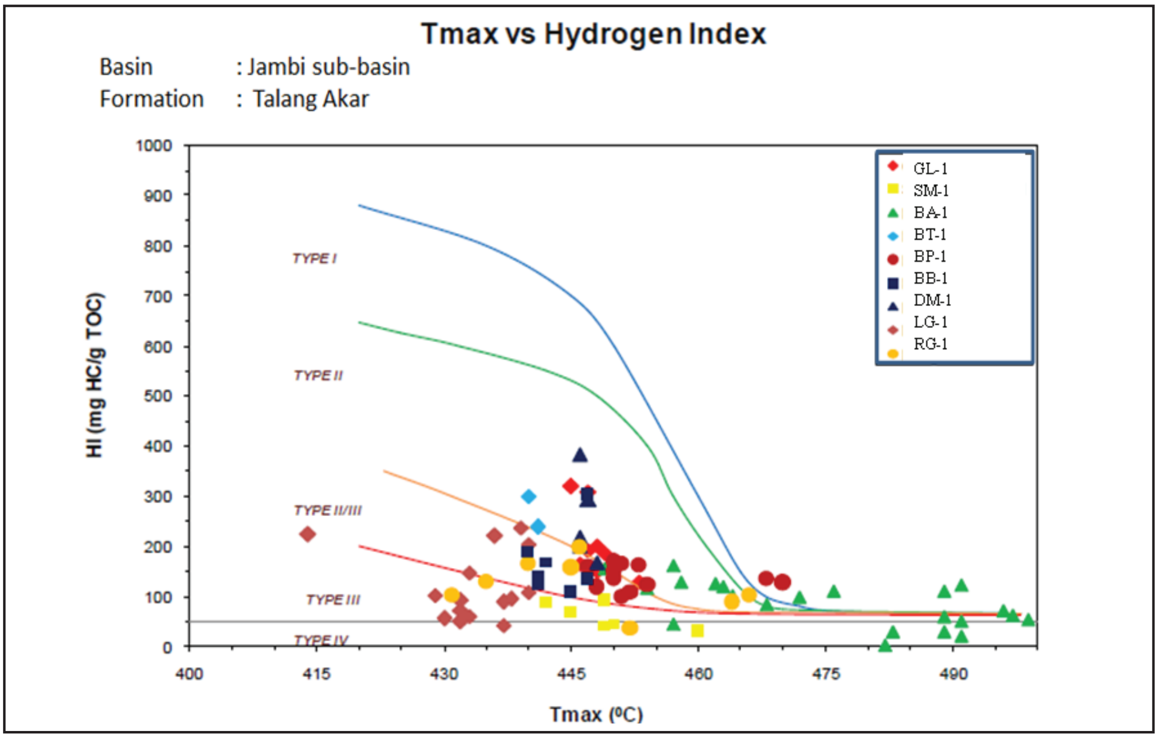

Figure 11
Kerogen type of the TAF shale play which obtained from cross-plot Tmax Vs HI
for several wells, shale plays of the formation tend to have Type II / III and III kerogen.

Table 2
Potential source rock classification based
on Total Organic Carbon (TOC) and Rock Eval pyrolysis (Peter & Cassa, 1994)

Category:	Organic Matter				Bitumen		Hydrocarbons
	Total Organic	Rock Eval Pyrolysis					
	TOC	S1	S2	PY			
	(wt%)	(mg HC/g rock)			(wt%)	ppm	ppm
Poor	0-0.5	0-0.5	0-0.25	0-0.25	0-0.5	0-500	0-300
Fair	0.5-1.0	0.5-1.0	2.5-5.0	2.5-5.0	0.05-0.10	500-1000	300-600
Good	1.0-2.0	1.0-2.0	5.0-10.0	5.0-10.0	0.10-0.20	1000-2000	600-1200
Very Good	2.0-4.0	2.0-4.0	10.0-20.0	10.0-20.0	0.20-0.40	2000-4000	1200-2400
Excellent	>4.0	>4.0	>20.0	>20.	>0.40	>4000	>2400
Stage of Thermal Maturity for Oil							
Thermal Maturity Level:	**Maturation**				**Bitumen**	**Bitumen**	**PI (Production Index)**
	VR	**Tmax**	**TAI**				
	(Ro%)	**(ºC)**	**Scale: 1-5**			**(mg/g rock)**	**=S1/(S1+S2)**
Immature	0.2-0.60	<435	1.50-2.60	1 to 2+	<0.50	<50	<0.10
Mature							
Early Mature	0.60-0.65	435-445	2.60-2.70	2+ to 2+/3-	0.50-0.10	50-100	0.10-0.15
Peak Mature	0.65-0.90	445-450	2.70-2.90	2+/3-to3-/3	0.15-0.25	150-250	0.25-0.40
Late Mature	0.90-1.35	450-470	2.90-3.30	3-/3 to 3+	-	-	>0.40
Post Mature	>1.35	>470	>3.30	>3+	-	-	-
Kerogen Type (Quality)							
Kerogen Type Classification:	**HI (Hydrogen Index)**	**S2/S3**	**Atomic H/C**		**Main Product at Peak Maturity**		
	mg HC/g TOC						
I	>600	>15	>1.5		Oil		
II	300-600	10-15	1.2-1.5		Oil		
II/III	200-300	5-10	1-1.2		Oil/Gas		
III	50-200	1-5	0.7-1.0		Gas		
IV	<50	<1	<0.7		None		

TAF recorded in SM-1 wells ranges from 1.17 to 1.50 wt % . The SM-1 well is not located in the deep structure, approximately 10 km from the basin center. Unfortunately, relationship between TOC vs. AI as well as TOC vs. density at each well is not always good. For this reason, in the study didn't use the two methods. We applied PNN (probabilistic neural network) method to generate TOC section.

The distribution of seismic and well data in the central deep area is still very limited, therefore we has not yet conducted properties mapping this study. Application of the geophysical methods aims to predict the distribution of shale play properties, especially in the center of the basin. Besides using Loseth's method, TOC distribution can also be derived by using seismic attribute method. This method is more complicated than Loseth's method. For running the method is needed the seismic (preserved seismic) and well log data, i.e. sonic and density logs. Figure 14 and 15 are the example of the seismic inversion and seismic attributes results in line seismic close to SM-1 well. The seismic attribute used in this study is Probabilistic Neural Network (PNN).

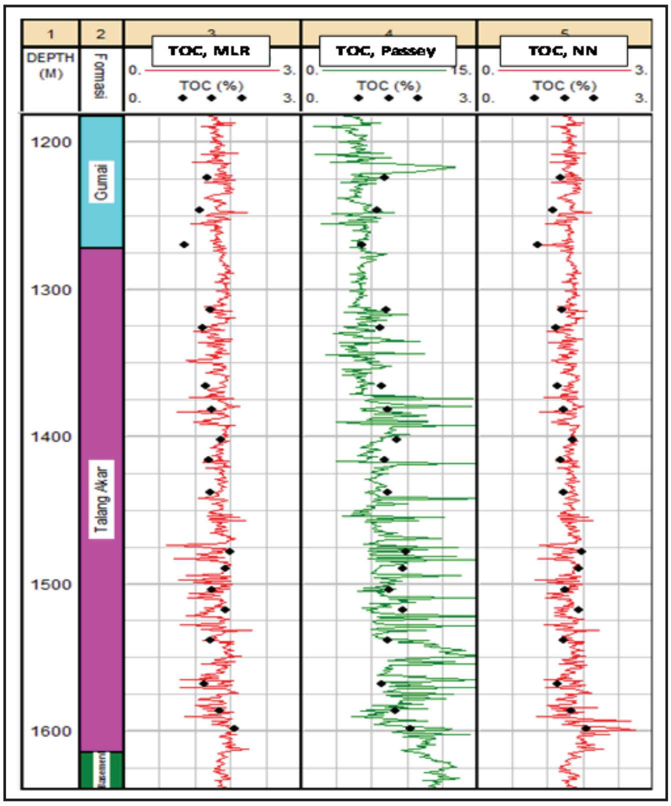

Figure 12A
TOC log calculation of RGT-1 well using: (panel 3) MLR (Multi Linear Regression) method; (panel 4) Passey's method; and (panel 5) Neural Network method, the log TOC prediction using the Neural Network method gives better results than other methods (Passey and Multi-linear regression).

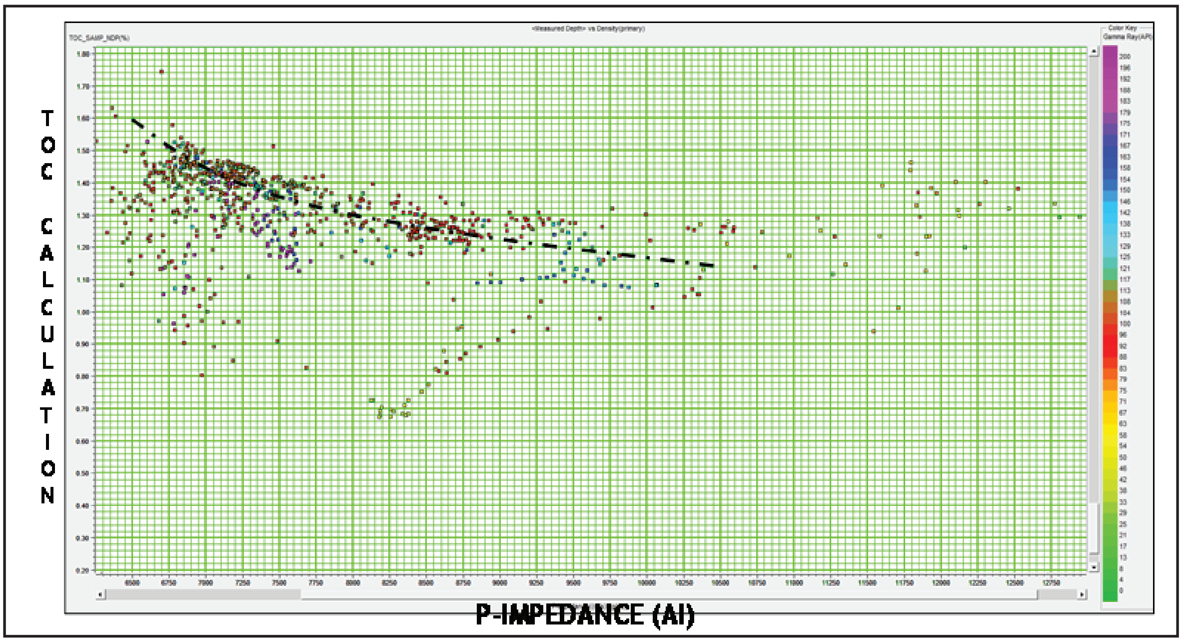

Figure 13
A graph showing relationship AI vs. TOC in the SM-1 well. In general, it can be seen that the TOC value has a fairly good negative correlation with the AI value.

Brittleness Index

In this study, availability of data such as mineral composition and s-wave velocity is very limited, so the BI value is not easy determined. Figure 16 is identification of BI value of the TAF shale play in the BP-1 well. This log is not complete, no cover all the TAF. Shale play of the TAF tends less brittle with average of BI value is less than 50%. It means that shale plays of the TAF is dominated by clay mineral composition.

While sample rock from the surface geological surveys is also observed in the laboratory sedimentology.

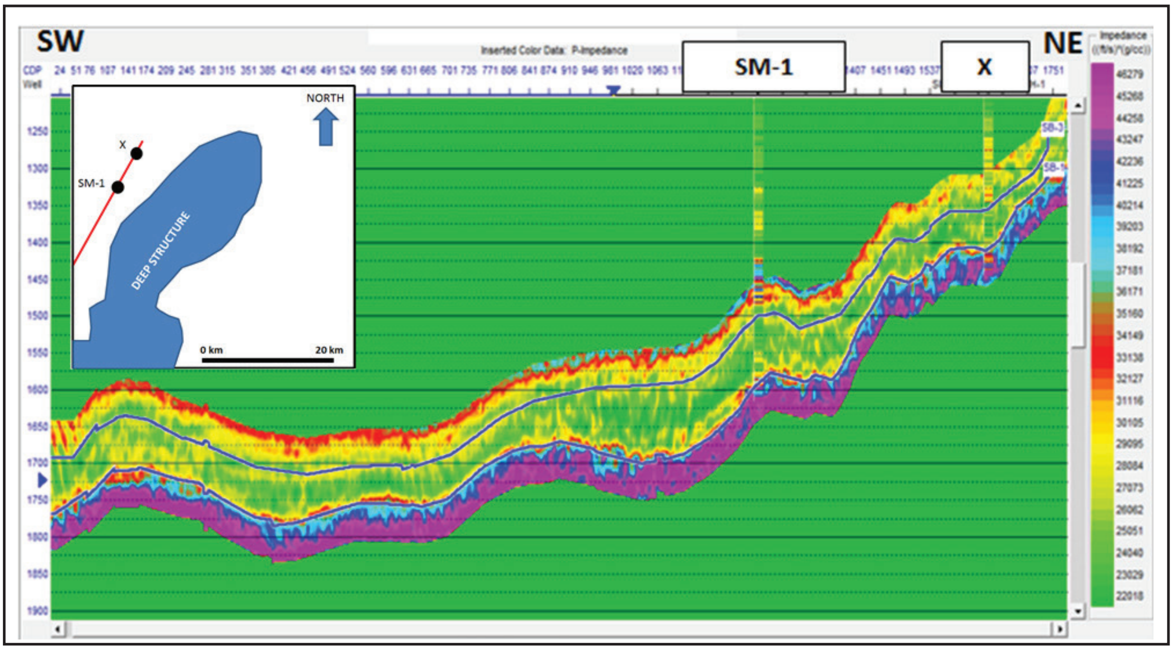

Figure 14
The AI cross-section through SM-1 well, SM-1 well is located
in the edge of basin, these results will be used as input in getting the TOC value.

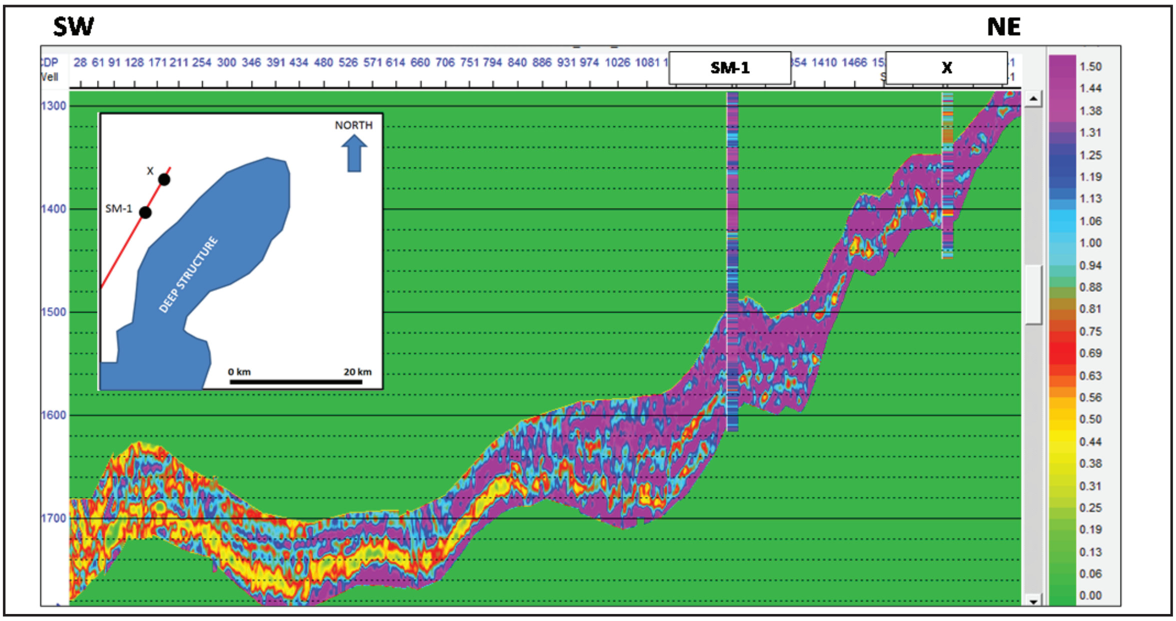

Figure 15
A TOC section of TAF derived using seismic attribute (including AI value)
with probabilistic neural network (PNN) method, the result shows that
the TOC value at the edge of the basin is still dominated by a value of around 1.3 - 1.5 %.

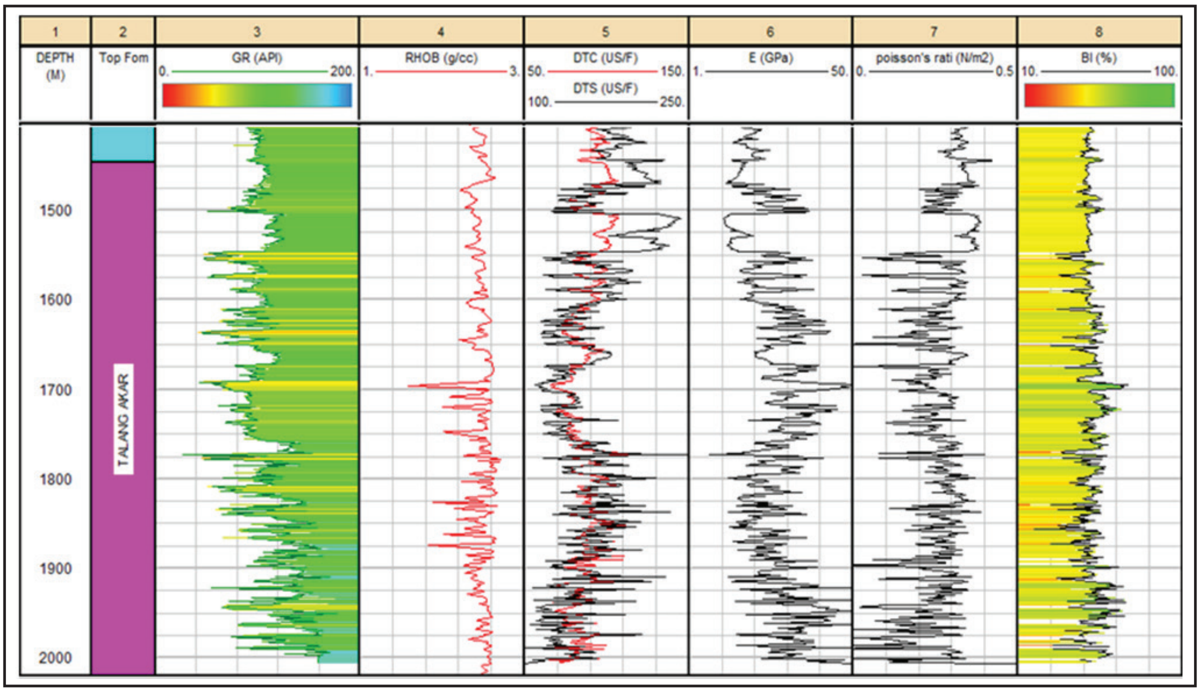

Figure 16
The brittleness index log calculation at BP-1 well.

Table 3
A brittleness index calculation of outcrop
data of the Talang Akar shale play using Wang-Gale formula (2009)

No	Sample Code	Clay Minerals (%)					Carbonate Minerals (%)			Other Minerals (%)				TOC	Britleness Index
		Smectite	Illite/Smectite	Illite	Kaolimite	Chlorite	Calcite	Dolomite	Siderite	Quartz	K-Feldsfar	Plagioclase	Pyrite		RT (Wang & Cale, 2009) = (Qz+Dol): (Qz+Dol+Cal+O+TOC)
1	14.AA05.B02	-	8	5	5	12	8	7	-	45	-	8	2	0.69	0.573
2	14.AA05.B05	-	6	7	-	16	26	2	-	30	-	10	3	0.61	0.365
3	14.AA05.B06	-	2	-	-	5	81	-	-	8	-	4	-	0.46	0.083
4	14.AA06.A13	-	10	8	-	16	14	-	-	42	-	8	2	0.87	0.462
5	14.AA06.A17	-	4	3	4	7	37	-	-	40	-	5	-	0.68	0.418
6	14.AA06.A20	-	3	5	3	5	5	-	-	54	-	24	1	0.53	0.715
7	14.AA06.A22	-	6	5	-	10	10	-	-	60	-	6	3	0.94	0.653
8	14.AA06.A24	-	8	8	5	15	8	-	-	45	-	8	3	1.06	0.5
9	14.AA06.A27	-	5	4	-	20	14	1	-	44	-	10	2	-	0.511
10	14.AA06.A29	-	-	-	-	40	3	-	-	40	-	15	2	1.18	0.475
11	S-LIM-1	-	5	-	4	10	24	-	-	50	-	7	-	0.58	0.534
12	S-LIM-4A	-	-	2	-	-	8	-	2	41	-	42	5	0.42	0.797
13	S-LIM-20	-	10	6	-	8	8	-	-	58	-	8	2	0.89	0.638
14	S-LIM-36	-	8	3	-	16	8	30	-	31	-	3	1	0.84	0.464

Mineral composition can be seen clearly by using XRD tool. Some of the Talang Akar shale play have been taken. Table 3 is a brittleness index calculation using Wang and Gale (2009) of outcrop data of the Talang Akar shale play.

CONCLUSION

Generally, the Jambi Sub-Basin has a good quality of the shale plays especially in the Talang Akar formation. This formation has proven as a mature source rock. Based on the geochemical data, most of TOC, S2 and HI values exist in the range of (1-10) wt %, (0.25-10) mg/g rock and (50-400) mg HC/ g TOC respectively. Shale plays of the Talang Akar formation tends to have Type II / III and III kerogen. All well data are located in the high structures. Geologically, quality of the shale plays in deep structures is interpreted better than the high structures. By applying the geophysical method such seismic inversion and seismic attribute, quality of the shale plays in the deep structures can be better identified.

Based on wells data analysis, the Talang Akar formation was deposited in littoral-neritic environment during Late Oligocene - Early Miocene. Age of the formation is relatively very young when compared with the formation of shale plays in North America. This fact is suspected to cause shale play in the Jambi Sub-Basin relatively less brittle. The data processing showed the brittleness index values tend to be in the range of 40% - 70%. Theoretically, shale play is considered ductile if the BI value is less than 50%.

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GLOSSARY OF TERMS

Symbol	Definition	Unit
TOC	Total Organic Carbon	wt %
BI	Brittleness Index	%
S2	One of rock eval pyrolysis results, S2 curve	mg / g (of rock)
HI	Hydrogen Index (to determine the kerogen and hydrocarbon types)	mg HC/g TOC

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