Jurnal Geologi dan Sumberdaya Mineral
Journal of Geology and Mineral Resources
Center for Geological Survey, Geological Agency, Ministry of Energy and Mineral Resources
Journal homepage: http://jgsm.geologi.esdm.go.id
ISSN 0853 - 9634, e-ISSN 2549 - 4759

Rock-Eval Pyrolysis of the Oligocene Fine-grained Sedimentary Rocks from the Pamaluan Formation, Gunung Bayan Area, West Kutai Basin, East Kalimantan : Implication for Hydrocarbon Source Rock Potential

Rock-Eval Pyrolisis pada Batuan Sedimen Berbutir Halus Berumur Oligosen dari Formasi Pamaluan, Daerah Gunung Bayan, Cekungan Kutai Barat, Kalimantan Timur : Implikasinya untuk Potensi Sebagai Batuan Induk

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Naskah diterima : 29 Februari 2018, Revisi terakhir : 12 Mei 2018, Disetujui : 12 Mei 2018, Online : 07 Juni 2018
DOI: http://dx.doi.org/10.33332/jgsm.geologi.19.2.73-82

Abstract - In this study, we perform organic geochemistry analysis for evaluating source rocks in Gunung Bayan area, West Kutai Basin. The Oligosen fine-grained sedimentary rock of Pamaluan Formation consists of shale, siltstone and claystone. The organic geochemistry data includes pyrolysis data as total organic carbon (TOC%), generating source potential (S2), production index (PI), oxygen and hydrogen indices(OI, HI) and (T_{max}). The results show that the Oligocene source rocks have poor into good quality with type III kerogen and have true capability to generate gas. The source rocks candidate is characterized by HI 5 - 115 (mg/g), TOC from 0.19 to 1.78 wt%, S1 from 0.01 to 0.09 (mg/g) and S2 from 0.05 to 1.74 (mg/g) that indicating poor to fair source rocks with type III kerogen and capable to generate gas. The maturity parameter of the fine-grained sedimentary rocks tend to indicate immature to mature stage. Overall fine-grained sedimentary rocks of the Pamaluan Formation has a capability to produce gas with poor to fair quality.

Keyword : *Oligocene, organic geochemistry, source rocks, Kutai Basin.*

Abstrak - *Dalam penelitian ini, kami melakukan analisis geokimia untuk mengevaluasi batuan induk di daerah Gunung Bayan, Cekungan Kutai Barat. Batuan sedimen berbutir halus yang berumur Oligosen yaitu Formasi Pamaluan, tersusun atas batuan serpih, lanau, dan batu lempung. Data geokimia organik yang tersedia terdiri atas total organic carbon (TOC %), potensi batuan induk (S2), indeks produksi (PI), indeks oksigen dan hidrogen (OI dan HI), dan suhu maksimum (T_{max}). Hasil dari analisis tersebut menunjukkan bahwa batuan induk berumur Oligosen mempunyai kualitas mulai dari buruk hingga baik dengan tipe kerogen III yang mengindikasikan sebagai penghasil gas. Kandidat batuan induk dicirikan dengan HI antara 5-115 (mg/g), TOC mulai dari 0.19 hingga 1.78 wt%, S1 dari 0.01 hingga 0.09 (mg/g), dan S2 mulai 0.05 hingga 1.74 (mg/g) yang mengindikasikan kualitas batuan induk buruk hingga baik dengan tipe kerogen III yang berkemampuan menghasilkan gas. Hasil dari analisis kematangan batuan induk menunjukkan tahap belum matang – matang. Secara keseluruhan, batuan berbutir halus Formasi Pamaluan mempunyai kemampuan menghasilkan gas dengan kualitas buruk – baik.*

Kata Kunci : *Oligosen, geokimia organik, batuan induk, Cekungan Kutai*

INTRODUCTION

Background

This research is located in the Gunung Bayan area, West Kutai Basin, East Kalimantan (Figure 1). This study discusses about organic geochemistry for evaluating source rocks of fine-grained sedimentary rocks. Organic geochemistry is used as fundamental approach to understand the properties of source rocks and to determine the productive and non-productive zones as well as oil migration and development of oil fields. The term source rock refers to an organic-rich fine-grained sedimentary rock which can produce hydrocarbons due to thermal maturation. Source rock is one of the main elements of a hydrocarbon system. The objective of this research is to assess hydrocarbon source potential of fine-grained sedimentary rocks of Pamaluan Formation in Gunung Bayan areas. The Pamaluan Formation has thick flakes that are suitable for shale hydrocarbon. Furthermore, the formation was deposited in Oligocene that maturity has a sufficient level of maturity.

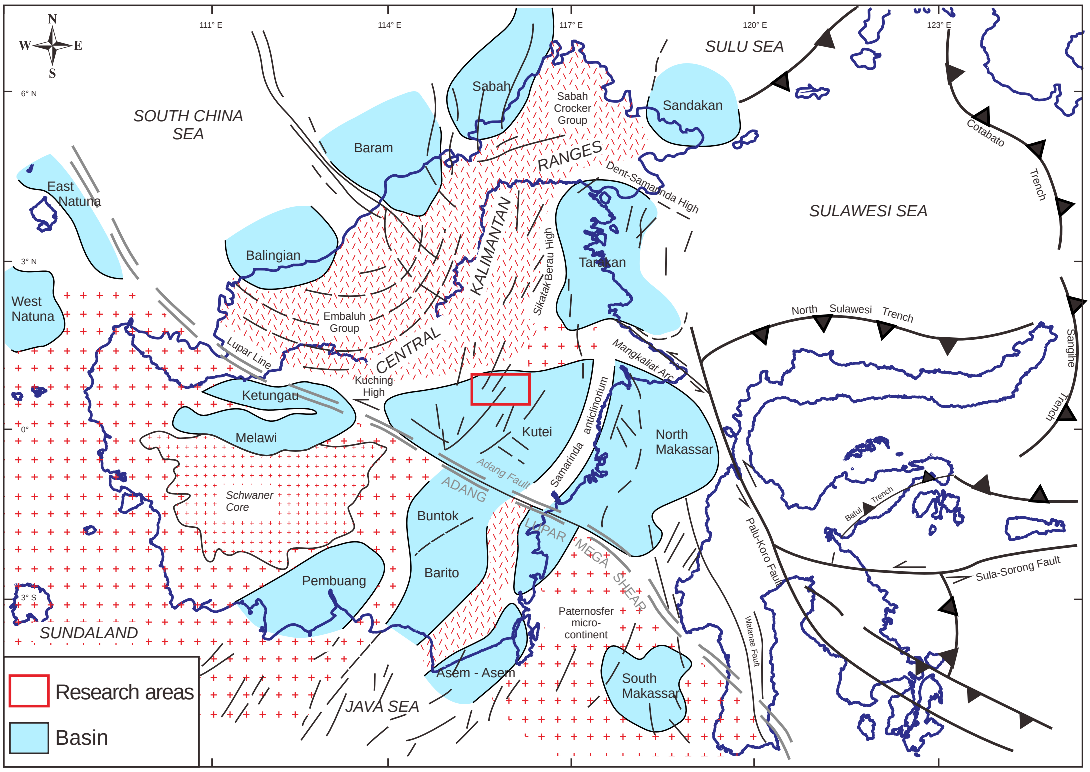
GEOLOGICAL SETTING

Kutai Basin is located at the southeast of Sundaland and influenced by three world major active tectonic plates: the Eurasian, Indo-Australian, and Pacific. This various regional tectonic activities influenced the formation of Kutai Basin.

Like most basins in western Indonesia, Kutai Basin began to emerge in Middle Eocene. According to Van der Weerd & Armin (1992), Kutai Basin formed as an extensional basin which appeared in the Middle Eocene. This is slightly different from the Bachtiar (2004) opinion which state that the Kutai Basin is an aulacogen derived from failures in the expansion phase of the continent (rifting) at Middle Eocene. Subduction accretion formation occured during Jurassic and Cretaceous. The west and northwest Borneo basement is an accretion prism containing metasediment, metavolcanic rocks, and material of magmatic and amphibole.

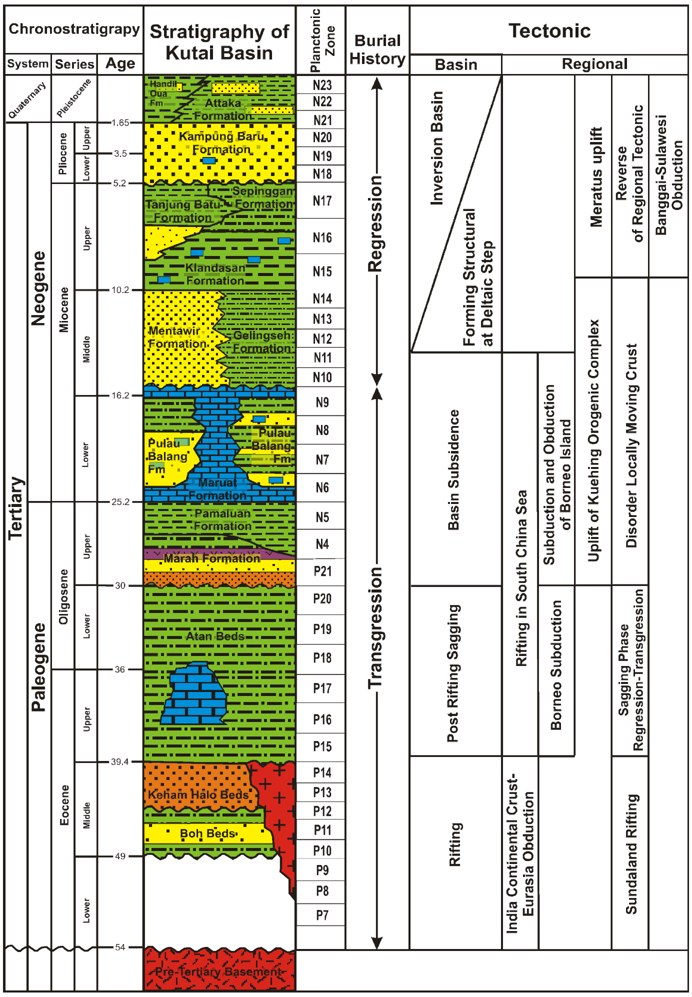
The Kutai Basin is the largest (165,000 km) and deepest (12.000 to 14.000 meters) Tertiary sedimentary basin in Indonesia. This basin is bounded by Mangkaliat High to the north, hinges of Adang-Flexure (Adang-paternoster fault) to the south, Kuching High - part of Borneo Central Range to the west, and Makassar Strait to the east (Darman and Sidi, 2000).

The Kutai Basin consists of Paleocene alluvial sediments of the Haloq Kiham Formation, close to the western boundary (Figure 2). Subsidence occurred in late Paleocene – Oligocene due to basement rifting and



Source : Modified from Pertamina BPPKA, (1999)

Figure 1. Research area on Gunung Bayan, West Kutai Basin, East Kalimantan.



Source : Satyana et al., (1999).

Figure 2. Stratigraphic coloumn of the Kutai Basin, East Kalimantan

deposition of Mangkupa Shale in the edge until open marine environment. Coarse siliciclastic sand in clay sequence indicate an interruption by lifting in this area. The basin subsidence continued by sagging phase that produced clay and carbonate deposit of Kedango Atan Formation (Satyana and Biantoro, 1995).

Tectonic uplift occurred during subsidence in Late Oligocene associated with Sembulu volcanic sediment in eastern part of the basin. The next phase inversion began with the lifting during Early Miocene. Series of alluvial deposition and a very comprehensive deltaic Pamaluan, Pulubalang, Balikpapan, and Kampung Baru Formation prograded to the east on early Miocene to Pleistocene. The deposition of the delta has continued eastwards to the Kutai Basin offshore until this day (Satyana and Biantoro, 1995).

West Kutai Sub-Basin comprised the Oligo-Miocene Purukcahu Formation which consist of claystone with thin sandstones and coal inserts intercalations. This formation is interfingering with Keramuan Formation composed by local interbedded calcareous mudstone, quartz sandstones and tuffaceous siltstone, and intercalated by fossilized limestone. In the northern part of Kutai Basin, the Wahau Formation consists of interbedded of mudstone, sandstone, and silty sandstones. The Lembak Formation comprised interbedded of marl and limestone that deposited in the eastern part of Cape Mangkaliat. The Mau Formation consists of siltstone, claystone and sandstone deposited in the southern part of Kutai Basin. In the southern bank of Kutai Basin, there was deposited of the Oligo-Miocene Pamaluan Formation which consist of sandstones with mudstone, shale, siltstone, coal and limestone. Interclast distribution of this formation is very widespread along the southern to the northern edge of Kutai Basin.

The Bebulu Formation consists of limestone reefs deposited in the Early Miocene. The Bebulu Formation interfingers with the top Pamaluan and Maau Formations. The Pulaubalang Formation was deposited with sufficient distribution area ranging from the south edge of central part of the Kutai Basin in the Middle Miocene.

The formation is composed by quartz sandstones and greywacke, claystone with interbedding of limestone, tuff, and coal. The Maluwi Formation consists of limestone, marl, and sandstone with intercalation on the bottom; claystone and sandstone, with intercalation of marl, carbonaceous shales and limestones deposited in the upper part in the north border of Tarakan Basin during Middle Miocene.

The Pulaubalang Formation is composed by interbedding of quartz sandstone, mudstone and shale, with inserts marl, limestone and coal. It was conformably deposited with the Balikpapan Formation. The Menumbar Formation consists of calcareous mudstone with limestone at the bottom and massive sandstone at the top containing glauconite and cross-bedding structure deposited in the northern part during the Late Miocene.

The volcanic activity in the Miocene resulted the Meragoh Formation volcanic rocks consisting of lava, tuff, volcanic breccia, and agglomerates where the composition is structured basalt until andesite. The volcanic rock source is estimated derived from the Meragoh Mountain and distributed on the western edge of Kutai Basin.

The Kampung Baru Formations was deposited in Pliocene, on the southern edge of Kutai Basin. The Kampung Baru Formation is non-conformably deposited above the Balikpapan Formation which consist of sandy mudstone, quartz sandstone, siltstone with intercalation of coal, marl, limestone and lignite. Interbedding of coal and lignite have a thickness of less than 3 m. At the same time in the northern edge of Kutai Basin, there was unconformable deposition of the Golok Formations above the Menumbar Formation. Furthermore, the Machete Formation consists of an insert marl clay, marly limestone, molluscs and coal material of yellowish gray to brown colour.

Deposition event in the Kutai Basin ended by the volcanic activity in Pliocene resulting in the Mentulang volcanic rock units which consist of andesite, basalt, lava, lava breccia, tuff, agglomerate, breccia lava with andesite to basalt composition.

METHODS

Specific field geological investigation and laboratory analysis were carried out to achieve the aims of the study. The study focuses on the stratigraphic analysis of the Pamaluan Formation by measuring section (MS) method using geological compass and global positioning system (GPS). Each location (Figure 3) was selected considered the most representative section, which was supported by rock samples collecting for laboratory analysis such as total organic carbon (TOC) and rock-eval pyrolysis. Rock-eval pyrolysis and total organic carbon (TOC) were performed at Lemigas Laboratories by following the standard procedures.

RESULT

Stratigraphic

The Pamaluan Formation in Gunung Bayan area is composed by sandstone, shale, claystone, coal, and siltstone (Figure 4 and 5). Sedimentary rock in the research area is interpreted as a lower part of the Pamaluan Formation.

Source Richness

The results of TOC analysis on thirty samples of fine-grained sedimentary rocks from Pemaluan Formation indicate that the shale, siltstone, and claystone have TOC range 0.38% - 1.78 %, 0.19% - 0.77%, and 0.57% - 0.82%, respectively (Table 1).

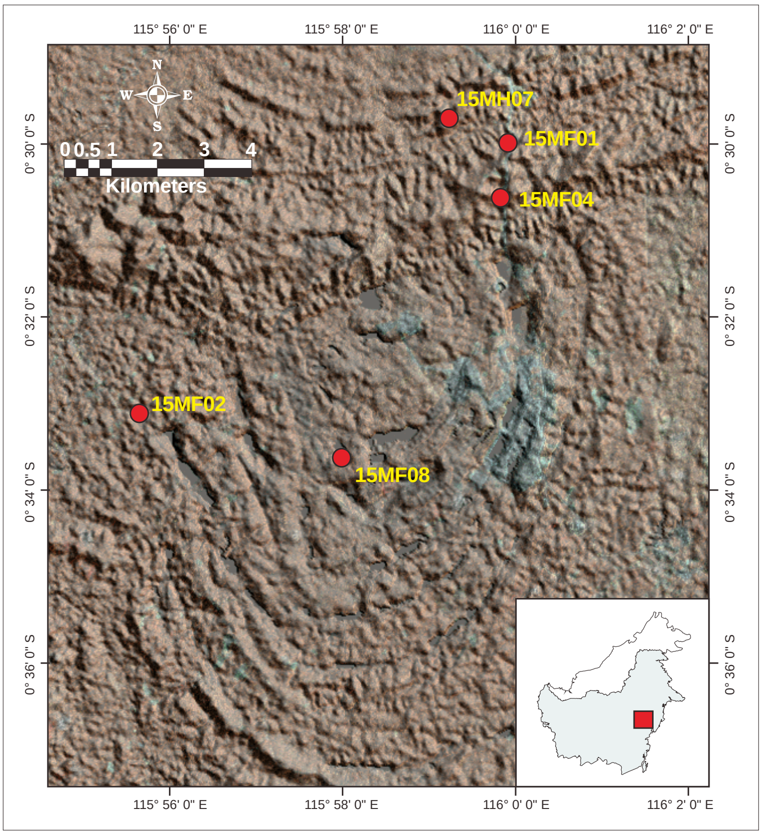


Figure 3. Locality of sampling for laboratory analysis in Gunung Bayan area.

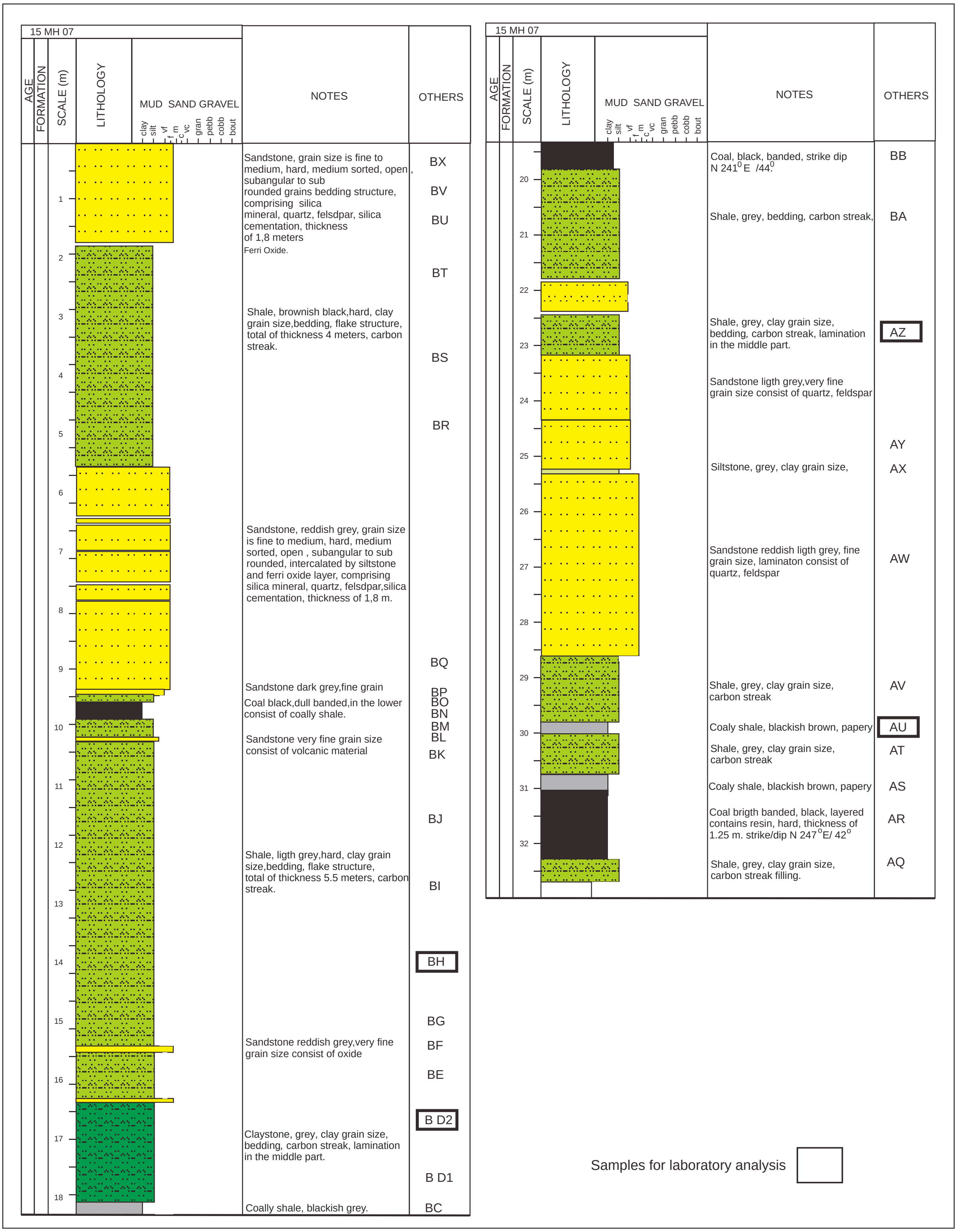


Figure 4. Stratigraphic section of the upper part Pamaluan Formation In Gunung Bayan area.

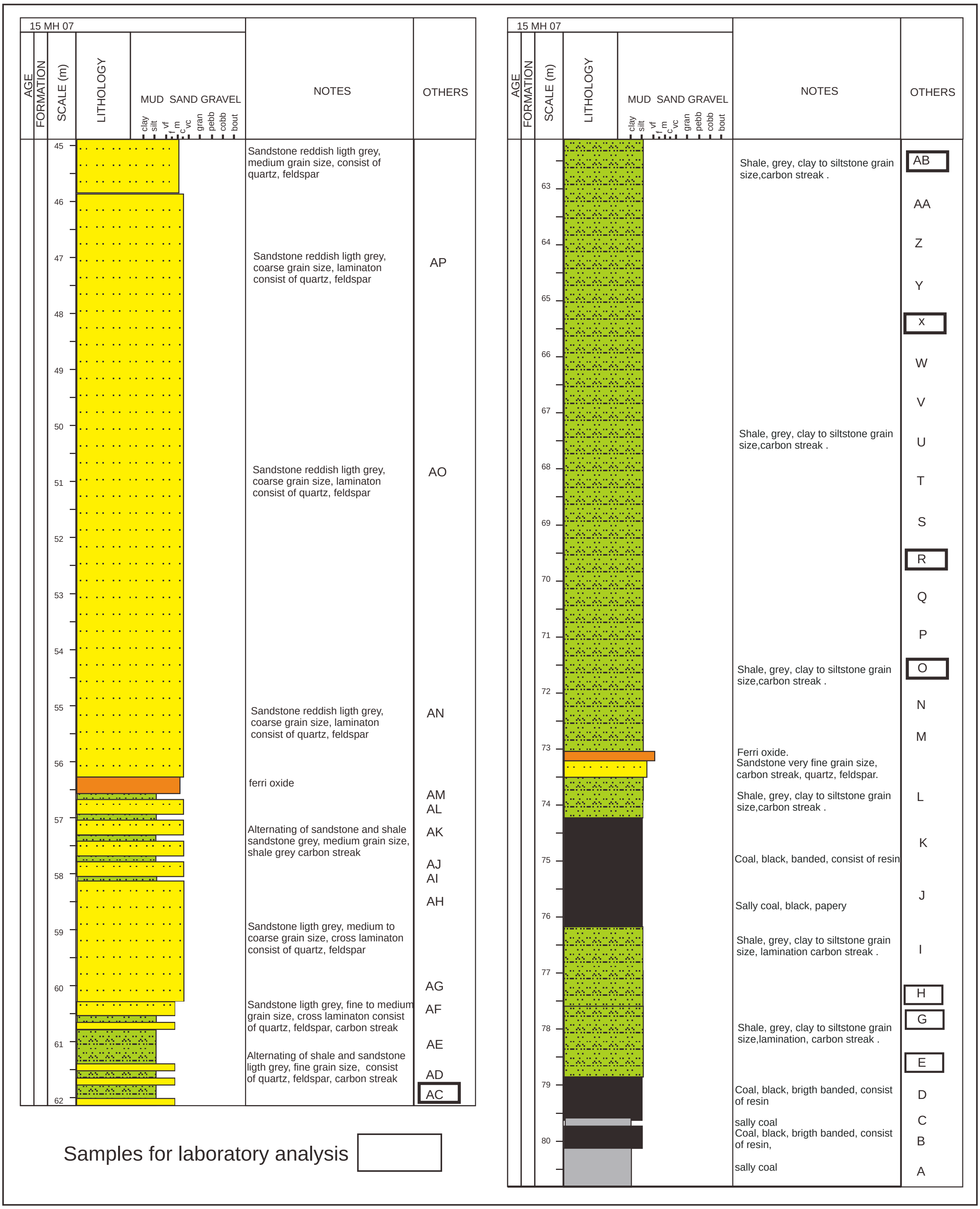


Figure 5. Stratigraphic section of the lower part of Pamaluan Formation in Gunung Bayan area

Table 1. Geochemical data the from fine-grained sedimentary rocks of Pamaluan Formation

No.	Sample ID	Sample Type	General Lithology Description	TOC	S1	S2	S3	PY	Tmax	PI	PC	HI	OI
				(%)	mg/g				(°C)				
1	15MH7E	OC	Shale, lt grey,soft, oxidated, Non Calc	0.72	0.04	0.34	0.19	0.38	436	0.11	0.03	47	26
2	15MH7G	OC	Shale, lt grey,hard, oxidated, Non Calc	0.78	0.02	0.27	0.17	0.29	434	0.07	0.02	35	22
3	15MH7H	OC	Shale, lt grey,hard, oxidated, Non Calc	1.09	0.04	0.46	3.31	0.50	439	0.08	0.04	42	303
4	15MH7O	OC	Shale, lt grey,hard, oxidated, Non Calc	0.85	0.05	0.46	1.05	0.51	440	0.10	0.04	54	124
5	15MH7R	OC	Shale, lt grey,hard, oxidated, Non Calc	0.93	0.01	0.05		0.06	542	0.17	0.00	5	
6	15MH7X	OC	Shale, lt grey, soft, oxidated, Non Calc	1.05	0.07	0.62	0.55	0.69	437	0.10	0.06	59	52
7	15MH7AB	OC	Shale, brownish grey, soft, Non Calc	0.64	0.05	0.42	1.41	0.47	435	0.11	0.04	66	220
8	15MH7AU	OC	Shale, lt grey, soft, oxidated, Non Calc	1.78	0.05	1.74	0.24	1.79	434	0.03	0.15	98	13
9	15MH7AZ	OC	Shale, lt grey, soft, oxidated, Non Calc	0.84	0.02	0.41	0.89	0.43	436	0.05	0.04	49	106
10	15MH07 AQ	OC	Shale, lt grey, soft, Non Calc	0.40	0.02	0.17	0.14	0.19	438	0.11	0.02	42	35
11	15MH7BD2	OC	Claystone, lt grey, soft, oxidated, Non Calc	0.66	0.02	0.35	0.62	0.37	438	0.05	0.03	53	94
12	15MH7BH	OC	Claystone, lt grey, soft, oxidated, Non Calc	0.57	0.03	0.28	1.85	0.31	436	0.10	0.03	49	323
13	15MH7BW	OC	Shale, lt grey, soft, oxidated, Non Calc	0.72	0.09	0.84	0.21	0.93	429	0.10	0.08	116	29
14	15MF2B	OC	Shale, dk grey, soft, oxidated, Non Calc	0.75	0.07	0.53	0.54	0.60	445	0.12	0.05	71	72
15	15MF2J	OC	Shale, dk grey, soft, oxidated, Non Calc	0.52	0.03	0.26	0.18	0.29	446	0.10	0.02	50	35
16	15MF2T	OC	Shale, lt grey, soft, oxidated, Non Calc	0.93	0.07	0.58	0.55	0.65	445	0.11	0.05	62	59
17	15MF2W	OC	Shale, lt grey, soft, oxidated, Non Calc	1.15	0.08	0.57	0.15	0.65	434	0.12	0.05	49	13
18	15MF2Y	OC	Shale, lt grey, soft, oxidated, Non Calc	1.17	0.09	0.55	0.18	0.64	436	0.14	0.05	47	15
19	15MF2AB	OC	Shale, dk grey, soft, oxidated, Non Calc	0.62	0.05	0.38	0.23	0.43	441	0.12	0.04	61	37
20	15MF2AS	OC	Siltstone, lt grey, soft, oxidated, Non Calc	0.77	0.06	0.37	0.09	0.43	441	0.14	0.04	48	12
21	15MH02	OC	Shale, lt grey, soft, oxidated, Non Calc	1.03	0.02	0.37	0.26	0.39	437	0.05	0.03	36	25
23	15MF08	OC	Shale, brownish grey, soft, oxidated, Calc	0.62	0.02	0.34	0.57	0.36	441	0.06	0.03	55	93
24	15MH06	OC	Shale, lt grey, soft, oxidated, weathered, Non Calc	1.55	0.05	0.80	0.79	0.85	424	0.06	0.07	51	51
25	15MH04	OC	Shale, lt grey, soft, oxidated, Non Calc	1.06	0.08	0.93	0.39	1.01	437	0.08	0.08	88	37
26	15MH01	OC	Shale, dk grey, soft, oxidated, Non Calc	1.25	0.02	0.63	0.26	0.65	435	0.03	0.05	50	21
27	15MF01	OC	Claystone, lt grey, soft, oxidated, Non Calc	0.82	0.07	0.41	0.13	0.48	446	0.15	0.04	50	16
28	15MF04	OC	Shale, lt grey, soft, oxidated, Non Calc	0.72	0.08	0.27	0.08	0.35	458	0.23	0.03	37	11

Remarks :

S_1 : Amount of free hydrocarbon
S_2 : Amount of Hydrocarbon released from kerogen
S_3 : Organic Carbondioxide
HI : Hydrogen Index = (S2/TOC) x 100
PY : Amount of Total Hydrocarbons = (S1 + S2)
PI : Production Index = (S1/ S1 + S2)
TOC : Total Organic Carbon
PC : Pyrolysable Carbon
OC : Outcrops
Tmax : Maximum Temperature (°C) at the top of S peak
OI : Oxygen Index = (S_3/TOC) x 100

Based on the TOC analysis result, fine-grained sedimentary rocks tend to indicate a poor to good quality source rock.

Maturity

Thermal maturity can be indicated by T_{max} from pyrolysis data. Maximum temperature (T_{max}) of the shale, siltstone, and claystone shows varying values 424 - 542C, 441C, and 436 - 446C, respectively. The shale tends to indicate as an immature until mature stage, while one sample indicates over mature (15 MH 07R). The siltstone and claystone tend to indicate early mature until mature stage.

The hydrogen index (HI) for shale, siltstone, and claystone shows result 5-115, 48, 49-53, respectively. Based on the HI / T_{max} plot (Figure 6), the maturity level suggested as immature until mature categories with minor over mature (Figure 6).

According to Figure 6, the shale, siltstone, and claystone tend to indicate gas prone source rock especially condensate to wet gas zone.

Type of Kerogen

The initial genetic type of organic matter of a particular source rock is essential for predicting oil or gas production potential. Waples (1985) used the hydrogen index values (HI) to differentiate types of organic matter. Hydrogen index value <150 mg/g indicate a potential source for generating gas (mainly Type III kerogen). Source rock with hydrogen index values between 150 and 300 mg/g defined more as a Type III kerogen (gas generation) instead the type II kerogen (oil generation). Source rock with hydrogen index value >300 mg/g contains a substantial amount of Type II organic matter and thus is considered to have a good potential for generation of oil and minor gas. Kerogen with hydrogen index value >600 mg/g usually consist Type I or Type II kerogen; it has excellent potential to generate oil.

Based on TOC versus S2 plot, kerogen in the present study is suggested as Type III (Figure 7). The diagram also reflects that all of the samples tend to indicate as a kerogen Types III. Therefore the studied fine-grained sedimentary rocks from Pamaluan Formation have the opportunity to produce gas.

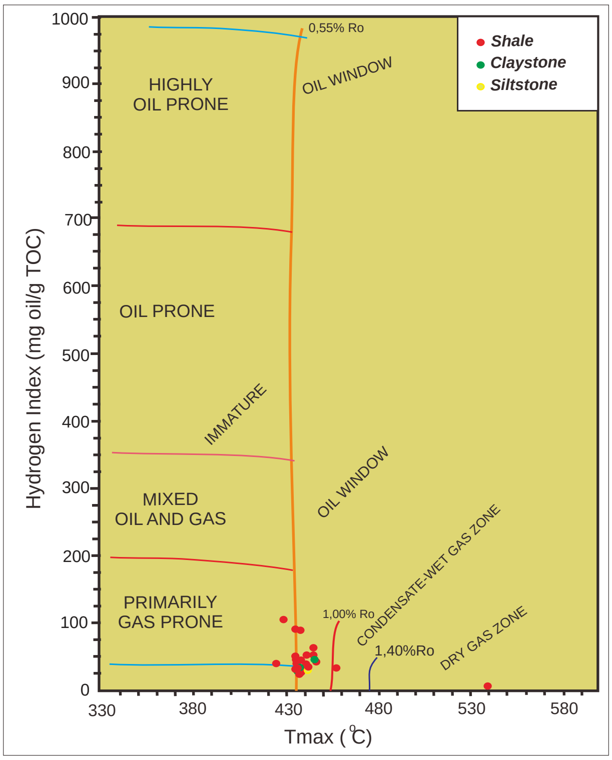


Figure 6. Hydrogen Index (HI) versus Tmax diagram shows kerogen type of sedimentary rock from the Pamaluan Formation.

also a non-marine especially the lacustrine facies which occurred more frequently (Zhang *et al.*, 2008 in Ju *et al.*, 2014).

According to Widayat (2013), the availability of carbon matter is strongly influenced by water fluctuations. Water level fluctuations can induce the water conditions become oxic, anoxic, or sub-oxic. Anoxic condition is a condition which organic materials are formed more abundant rather than the oxic condition. For example only one – third shale gas resources in North America generated from marine environment shale, while the other two-third derived from transition and terrestrial environments, including lacustrine (Zhang *et al.*, 2012). On the other hand, according to El Nady *et al*, (2015) the plot of S1 versus TOC can be used to differentiate the non indigenous (allochthonous) with indigenous hydrocarbons (autochthonous). In conclusion, the studied fine grained sedimentary rocks tend to indicate the autochthonous (indigenous hydrocarbons) (Figure 8).

Hydrocarbon Potential

The generation potential of a source rock is identified using the results of pyrolysis analysis. The generation

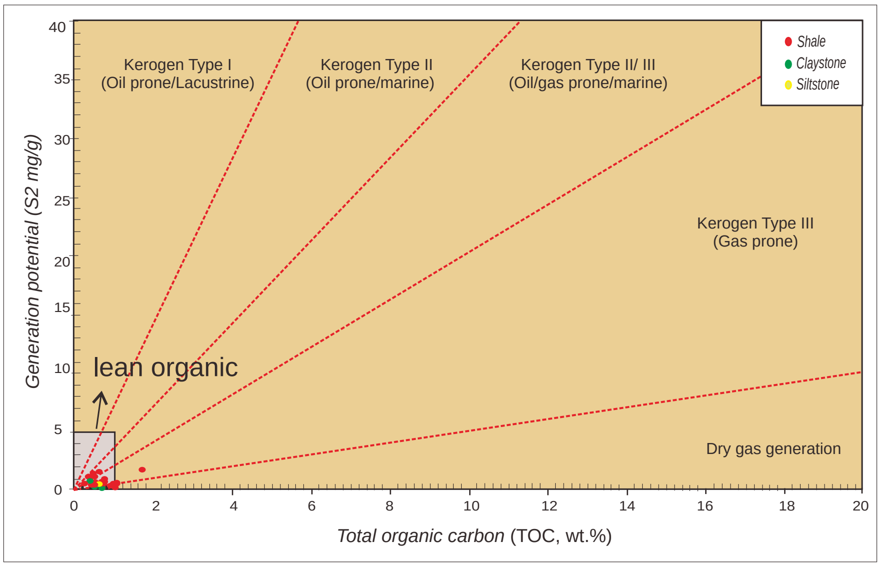


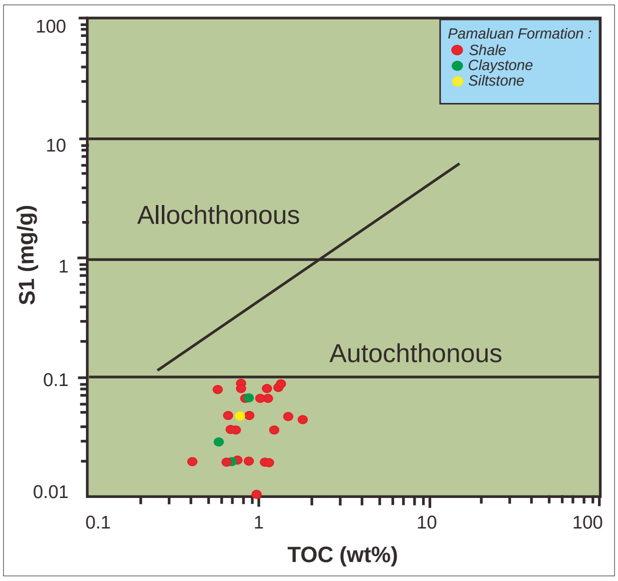
Figure 7. TOC vs S2 diagram shows the kerogen type and possibility to produce oil or gas.

Origin of Organic Matter

The kerogen type of the shale, siltstone, and claystone samples shows that the organic material is composed by a terrestrial environment that lack in fatty or waxy component (Waples, 1985). The depositional environment of Kutai Basin is generally terrestrial to transitional (deltaic). An organic matter richness on shale is not only derived from marine environment, but

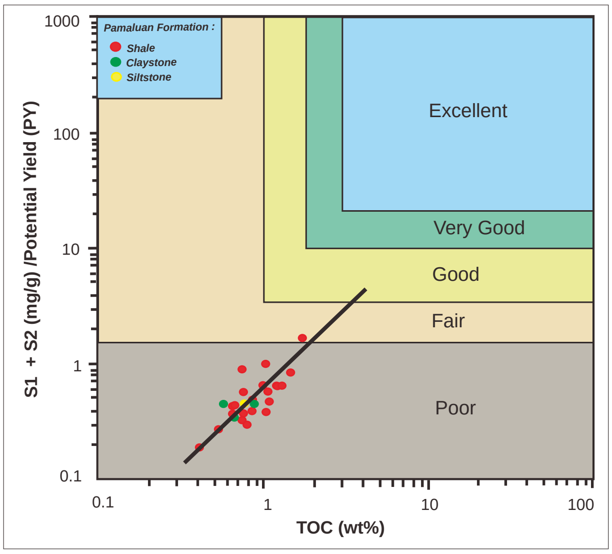
potential (GP) is the sum values of S1 and S2. According to Hunt (1996), source rocks with GP <2, 2 to 5, 5 to 10 and >10 are considered to have a poor, fair, good, and, very good generation potential, respectively. The relationship between (S1+S2) and TOC can be found in Figure 9.

As seen in Figure 10, the plot of TOC (wt%) versus HI mg/g reflects that the shale tends to be potentially as a gas producer or less oil producer.



Source : modified from El Nady.et.al., (2015).

Figure 8. Origin of organic matter in fine-grained sedimentary rocks formation.



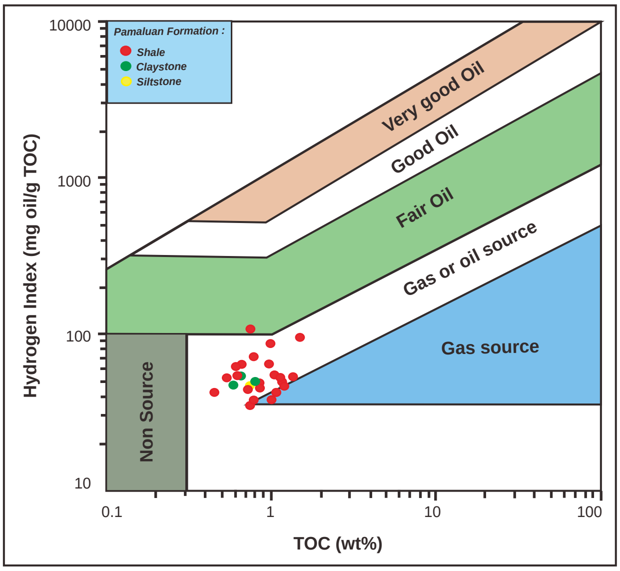
Source : modified from El Nady.et.al., (2015).

Figure 9. Plot of TOC versus PY that showing the potential of fine-grained sedimentary rocks of Pamaluan Formation.

Subsequently, the siltstone and claystone concluded as a gas producer. Therefore, the fine-grained sedimentary rocks of Pamaluan Formation tend to indicate as gas source rocks and one sample as fair oil source rocks.

DISCUSSION

The organic carbon richness of the rock samples (TOC %), is important in evaluating sediments as a source for petroleum generation. Tissot and Welte (1984), Peters and Cassa (1994), and Peters (1988) presented a scale for the assessment of source rocks potential, based on the %



Source : modified from El Nady.et.al., (2015)

Figure 10. Plot of TOC versus HI that showing the producing type of fine grained sedimentary rocks of Pamaluan Formation.

TOC and rock–eval pyrolysis data, such as S1 and S2.

Based on the organic matter richness and depositional environmental of the fine-grained sedimentary rocks of the Pamaluan Formation, there is a relationship between depositional environment with an organic matter richness in the research areas. Deltaic system of fine grained sedimentary rocks is defined as a transitional environment that correlate to the kerogen Type III in the research area.

The plot of S1 versus TOC shows that the sedimentary rocks of Pamaluan Formation can be determined as an indigenous hydrocarbons (autochthonous). Source rock potential rocks from the Pamaluan Formation have a poor to fair quality, so that the majority produced gas from Oligocene source rocks sample assumed not migrated from another source rock.

Figure 9 shows a positive correlation between Potential Yield (PY) and Total Organic Carbon (TOC). The higher TOC content results the higher value of PY (S1 + S2). Water level change during depositional event have influenced the fine grained sedimentary rocks of Pamaluan Formation quality for hydrocarbon resources in Gunung Bayan Areas.

CONCLUSIONS

Based on the maturity level, source rocks in the Pamaluan Formation have potential for generating gas with a poor to fair quality. Moreover, all samples are assumed to have potential as source rocks for hydrocarbon especially the shale. In general, the kerogen type is dominated by Type III.

The majority of rocks in the Pamaluan Formation are located at gas prone zone specifically poor to fair level.

The fine-grained sedimentary rocks of Pamaluan Formation, analyzed from the shale, siltstone, and claystone, appear to be more gas prone rather than oil prone. This condition is also presumed to indicate as a low gas potential.

ACKNOWLEDGEMENTS

The authors express their gratitude to PT Gunung Bayan who have allowed author to attain the data and stay on coal site.

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