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Geochemical Evaluation and Pore Type Characterization of Carbonaceous Rich Facies in Brown Shale Formation, Central Sumatra Basin

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Abstract - Brown Shale Formation of Pematang Group is a key source rock in the Central Sumatra Basin. The formation consists of three lithofacies: algal rich facies, mixed algal-carbonaceous facies, and carbonaceous rich facies. This paper focuses on evaluating the geochemistry and on characterizing the porosity of the carbonaceous rich facies. Geochemical evaluation of the carbonaceous source rocks was conducted using Rock-Eval pyrolysis, while mineralogy and microtextural characterization were assessed by incident light microscopy and scanning electron microscopy (SEM). The results show that the organic components of the carbonaceous source rocks are predominantly composed of vitrinite with minor inertinite and liptinite. The geochemical characteristics indicate that the carbonaceous rich facies could be ranked as a good to excellent level in terms of source rock potential with high TOC content, mainly containing kerogen type III as a gas prone potential. SEM results show that the pore types in the carbonaceous source rocks can be classified into three main types: porous floccules, organic-porosity, and intraparticle pores. Thus, the carbonaceous rich facies of the Brown Shale Formation contains gas prone source rocks with good generation potential, as well as organic rich shale unconventional reservoirs.

Keywords: organic geochemistry, pore type, Brown Shale Formation, Central Sumatra Basin, unconventional reservoirs

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Introduction

Shales are the most abundant form of sedimentary rocks on the earth. In conventional hydrocarbon exploration, shales play an important role as the source rocks for hydrocarbons migrating into more permeable reservoirs and as seals for trapping oil and gas in underlying sediments. In unconventional hydrocarbon development, organic rich shales have demonstrated potential to act not only as source rocks, but also as the reservoir from which hydrocarbons can be produced.

The Pematang Group is a well-known lacustrine source rock in western Indonesia. The formation comprises three lithofacies, those are algal, rich mixed algal-carbonaceous-, and carbonaceous rich facies (Longley *et al.,* 1990; Hwang *et al.,* 2002; Mazied *et al.,* 2008). The algal rich and mixed facies are considered to be oil prone, while the carbonaceous rich facies has previously been identified as gas prone with subordinate amount of condensate/light oil (Hwang *et al.,* 2002). An alternative explanation has been made by Robinson and Kamal (1988), where

they suggested that the oil fields in Merbau and Lirik areas could be sourced from carbonaceous and coaly zones within the Pematang Formation equivalence.

As discussed above, it is known that the type and the origin of organic matter have an important role in defining a shale gas formation. It is generally recognized that organic material rich in hydrogen content typically results in oil generation, whilst organic matter with less hydrogen may generate gas (Caineng *et al.,* 2013). Thus, investigation of the organic matter is necessary to determine the potential character of shale gas prospects.

This study investigates the Eocene to Oligocene Brown Shale Formation in the Pendalihan area, located on the northwestern margin of the Central Sumatra Basin (Figures 1a and 1b). The Brown Shale facies is characterized by highly calcareous and carbonaceous siltstones with rare thinly bedded sandstones. The siltstones are very well laminated and highly fissile containing high total organic content (TOC). This paper presents the geochemical and mineralogical characterizations of the carbonaceous source rocks of the Brown Shale Formation, in order to define a geochemical framework, to identify the type and origin of its organic matter, and to characterize the porosity of the shale gas potential in this area.

Geological Background

The Central Sumatra Basin was formed during the Early Tertiary (Eocene-Oligocene) as a series of subparallel north to northwest trending half graben structures, separated by horst blocks. These half graben structures formed early and were filled with nonmarine clastics and lacustrine sediments, known as the Pematang Group. These sediments can reach the thickness of greater than 1,800 m in some deep graben areas (Williams *et al.,* 1985). Several plate tectonic models with associated crustal rifting have been proposed to explain the origin of Palaeogene grabens in Central Sumatra and their sedimentary fill. However, the best explanation to date is perhaps the four-stage model of Williams and Eubank (1995),

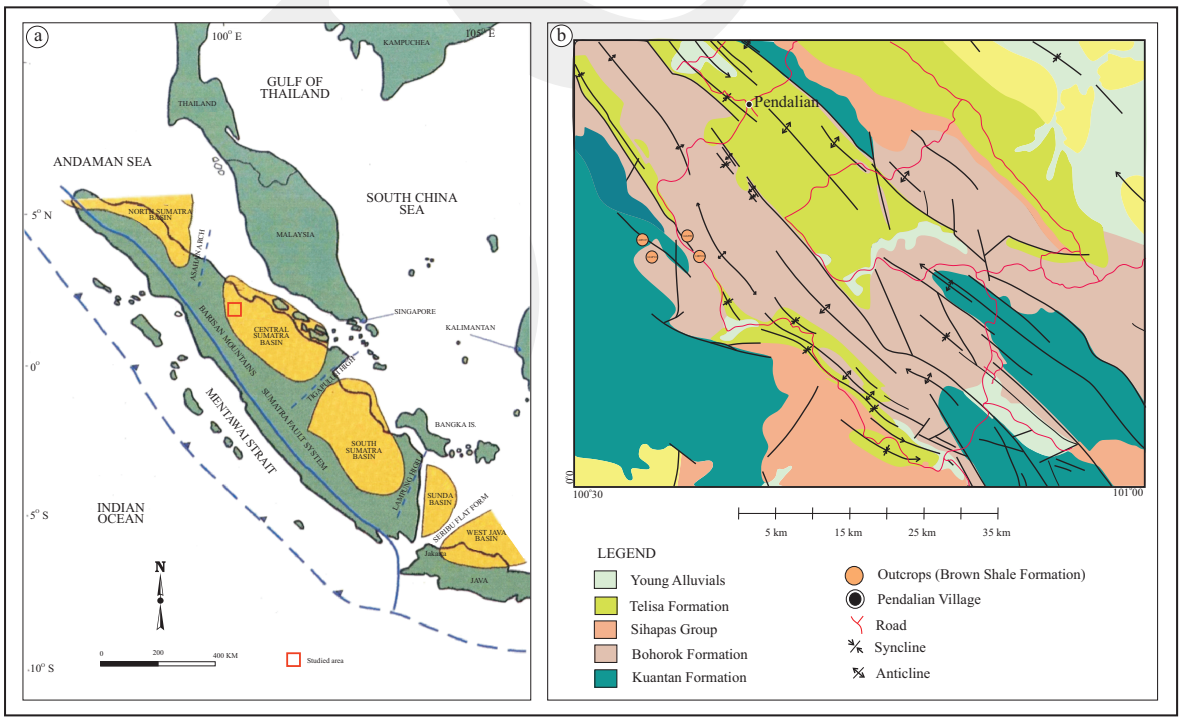

Figure 1. (a) Location map showing the studied area (Pendalihan area; hown by the red square area) in the Central Sumatra Basin, (b) Simplified geological map of the Pendalihan area (modified from Clarke *et al*., 1982 and Rock *et al*., 1983) showing the outcrop locations of the Eocene to Oligocene Brown Shale Formation.

who present a synthesis of the Pematang graben development based on plate tectonic concepts.

The stratigraphic sequence of the Central Sumatra Basin is composed of a nonmarine syn-rift sequence and a marine post-rift sequence (Katz and Dawson, 1997). The nonmarine syn-rift sequence includes the Pematang Group which has been subdivided into three formations based on associated facies; the Lower Red Bed Formation, the Brown Shale Formation, and the Upper Red Bed Formation (Figure 2).

The Brown Shale Formation consists predominantly of a mudstone facies, brown to black in colour, which is thought to have been deposited in a lacustrine environment. This formation has been recognized as a good hydrocarbon source rock in the Central Sumatra Basin. Field observations by William *et al.,* (1985) indicate a close association in lithostratigraphic features between the Lower Pematang Red Beds Formation and the organic-rich lacustrine Brown Shales, which are laterally facies equivalents.

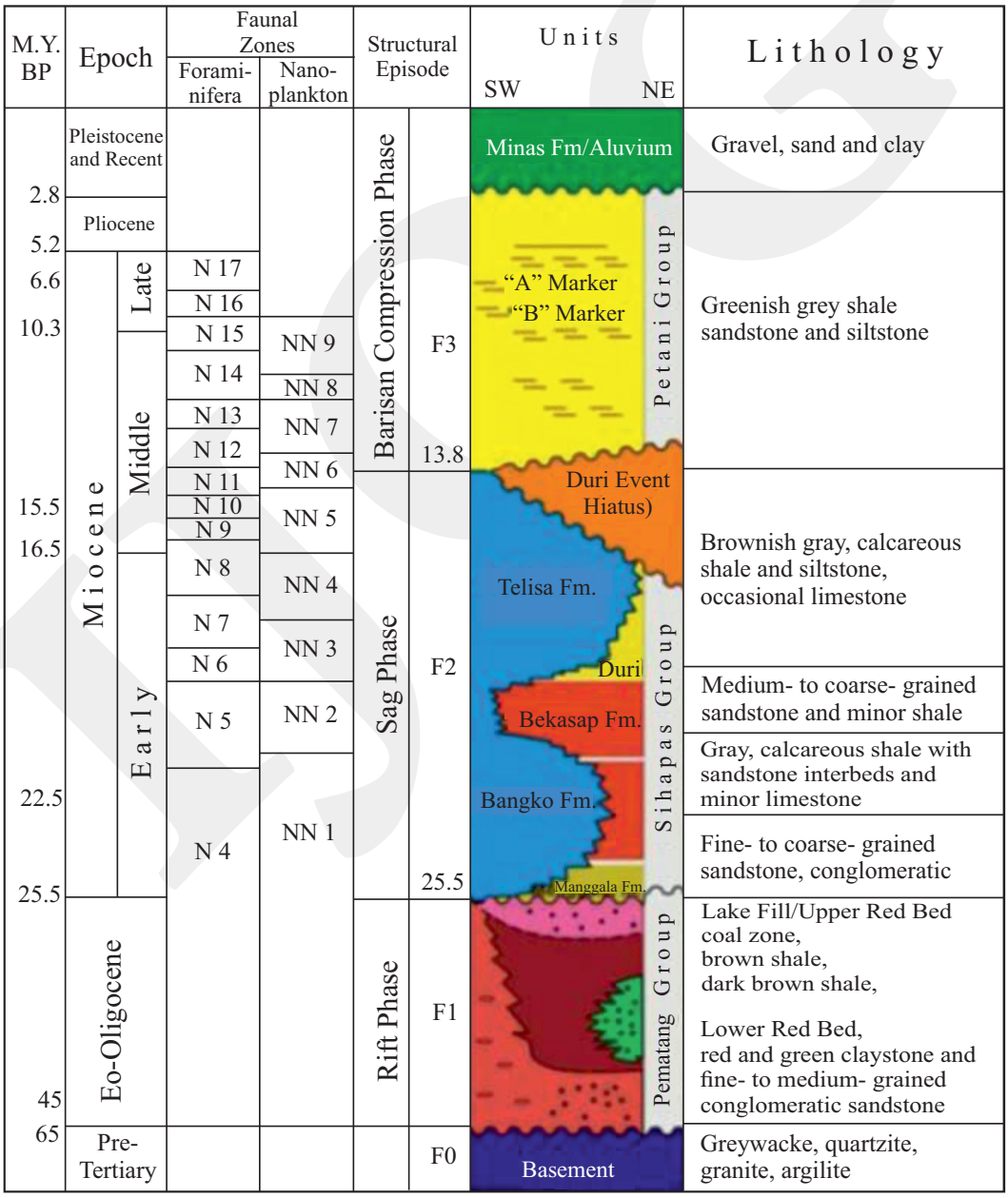

Figure 2. Generalized stratigraphy of the Central Sumatra Basin (Modified from Heidrick and Aulia, 1993).

Materials and Methods

The study was conducted on outcrop samples collected from the Brown Shale Formation. Fresh and representative samples were subjected to organic petrological and geochemical studies. Fifteen polished sections of the fine-grained clastic rock (shale) samples were examined using a Zeiss Axioplan reflected light microscope, with both white (100 W halogen) and blue violet (HBO) light sources; two oculars with magnifications of 25x and 50x were employed. Maceral description used in this study follows the Australian Standard 2856.2 (Standards Australia, 1998).

The shale samples were also examined under scanning electron microscopy (SEM) to get more detailed modes and the occurrence of maceral and mineral matter as well as to identify the pore type and microfractures within the samples. Another eleven samples were selected on the basis of lithological changes representing different part of the Brown Shale Formation such as coal or lignite. They were subjected to geochemical analysis, such as TOC and Rock-Eval pyrolysis, to define the organic matter type and origin for source rock quality of the samples (Espitalié *et al.,* 1987; Lafargue *et al.,* 1998).

Results and Discussion

Lithological Description and Interpretation

The stratigraphic unit succession of the Brown Shale Formation is well exposed along the road of the Pendalihan Village. A detailed stratigraphic section (Figure 3) can be subdivided into three different units as folows.

The lower unit (Location 14 RY 007) is 5 m thick, consisting of thinly bedded, laminated, dark grey shales, interbedded with few coal or lignite beds (net of thickness around 60 cm) and thinly bedded fine-grained sandstone (Figures 4a and 4b).

The next stratigraphically higher section was examined at Location 14 AP 009. This location is composed of thinly bedded and laminated, dark grey to black shales (Figures 4c and 4e) containing lacustrine fish fossils; interbedded with dull to bright coal, and thinly bedded fine-grained sandstones in the middle of the section. The coal beds decrease in thickness upwards in the section with a coal bed of 1.5 m in the thickness at the bottom to a coal bed of 0.3 m at the top (Figure 4d).

The upper part of section at Location 14 AP 010 and 14 RY 010 comprises a 'sandstone facies' which actually interbedded with thin claystone and siltstones. Sandstone beds are tabular in nature, commonly laminated, fine- to medium-grained, with cross lamination and current ripple structures (Figure 4f).

Overall, the combined sections of the Brown Shale Formation at the Pendalihan area define a coarsening-upwards succession. This section changes from a lower energy regime at the bottom, mainly consisting of carbonaceous shales and coal or lignite beds, to a higher energy regime of the upper part of the section containing fine- to medium-grained sandstones with cross laminations and ripples. This suggests the section may be a tidally dominated estuary with tidal mud flats sand bars. Intertidal-flat deposits are generally topped by saltmarsh deposits, and underlain by different subtidal successions, like thick subtidal channel-fills, sand-bar complexes (if occurring in sheltered coastal settings) with coarsening upward successions of subtidal mudflats or thick subtidal sand ridge/bar complexes (Daidu *et al.,* 2013).

Organic Petrology

Petrographic analysis of the organic material found in the carbonaceous rich facies of the Brown Shale Formation is predominantly composed of vitrinite (the average= 16%) with minor inertinite (the average <1%) and liptinite macerals (the average= 1%). The fabric of the shale contains mineral such as clay, pyrite, and oxide minerals accounting for 82% of the total rock volume (as shown in Table 1).

Macerals of vitrinite group are mainly telocollinite and densinite with minor desmocollinite and sparse atrinite. They are intimately bound together with clay minerals as the groundmass, and in some cases cutinite and pyrite (Figures 5a, 5b, and 5d) can also be found. The telocollinite has

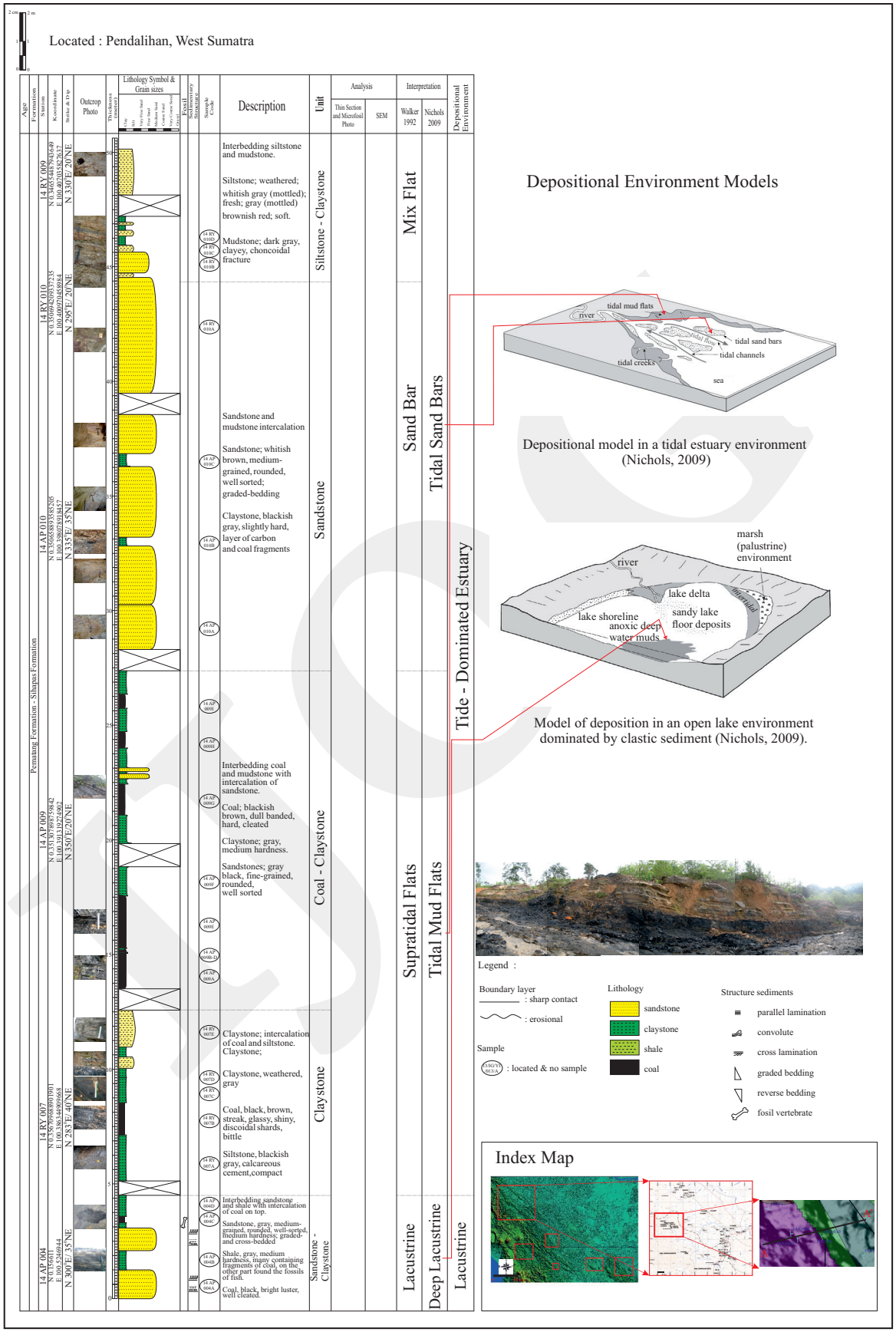

Figure 3. Detailed stratigraphic section of the Pendalihan area.

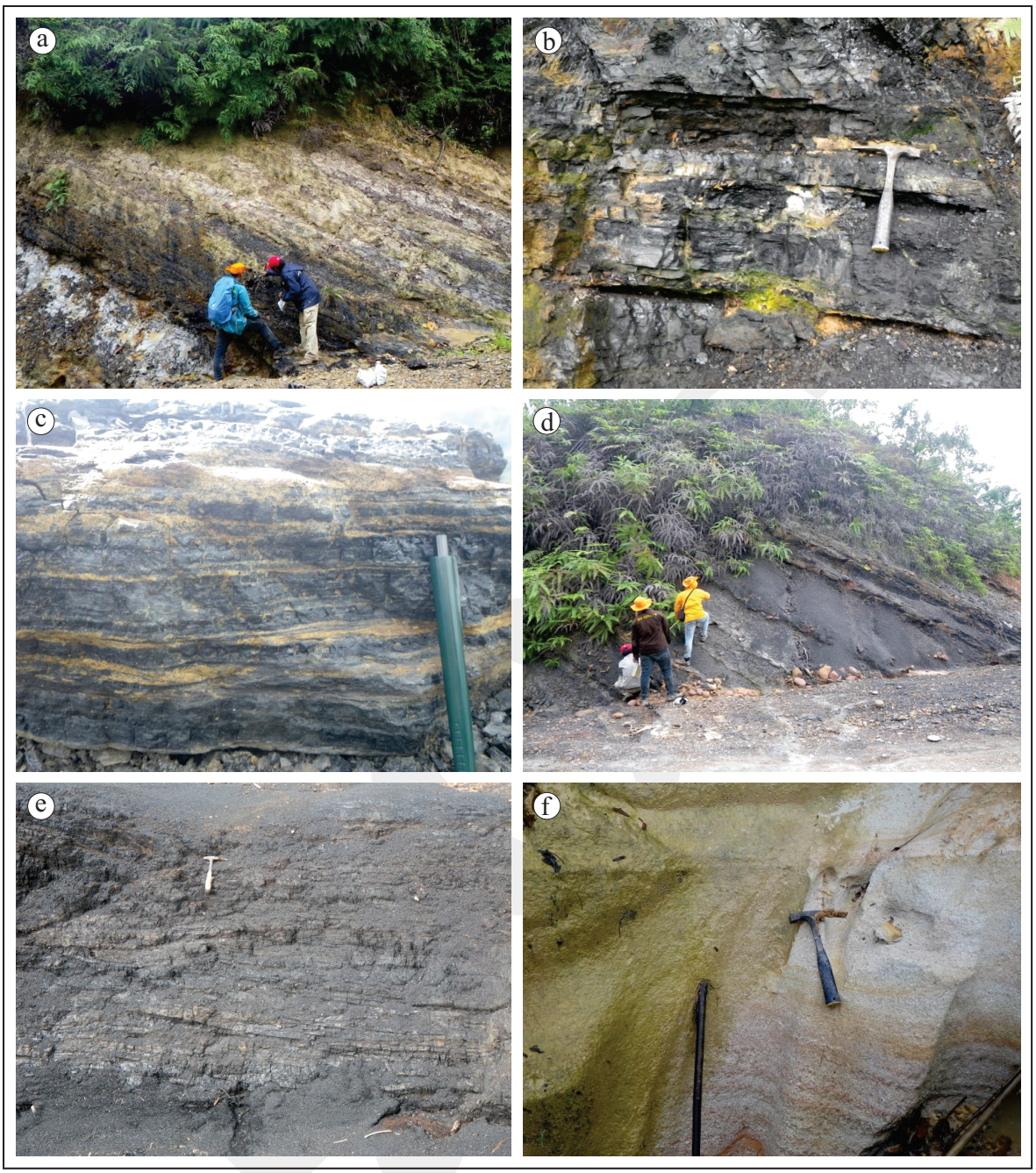

Figure 4. Typical lithologies of the Brown Shale Formation in the Pendalihan Section: a) Thinly bedded, laminated dark grey shale interbedded with coal and sandstone; b) Dull coal, black, < 1 m thick; c) Black shale with flaser-bedding structures; d) Coal beds on the upper part section; e) Dark grey shale; f) Fine- to medium-grained sandstones, and cross laminated to current rippled sedimentary structures.

a massive texture with fairly uniform structures, while corpocollinite is usually present as discrete particles with various shapes, usually subrounded to rounded (Figure 5c). Densinite mainly occurs in shales with various shapes of fine huminitic particles and dark grey in colour (Figures 4a and 4e). While desmocollinite is mainly found in a light grey finely layered morphology, and occurs as coaly shale, lignite, and dull or bright coal (Figures 4a, 4b, and 4c). The inertinite macerals mainly consist of fusinite, semifusinite, and funginite. Semifusinite occurs as large lenses or thin bands (Figure 5e), while funginite is found as rounded, isolated particles (Figure 5a). Liptinite

Table 1 Petrographic Composition of Carbonaceous Shales of the Brown Shale Formation

No.	Sample No.	Lithology	Vitrinite (%)					Liptinite (%)				Inertinite (%)					Mineral Matter (%)			
			Tl	Atr	Dns	Dsc	V	Sp	Ct	Lpt	L	F	Smf	Fg	Int	I	Ox	Cy	Py	MM
1	14 AP 009A	Shale	2.4	-	10.2		12.6	0.3	3.2	0.6	4.1	1.8	2.2		0.3	4.3	0.4	76	2.6	79
2	14 AP 009F	Carbonaceous Shale	-	-	7		7	0.1	1.2	0.7	2	0.2	0.4		0.2	0.8	0.2	86	4	90.2
3	14 AP 009G	Coaly Shale	24.5	-		12.5	37	0.4	1.3	0.4	2.1		0.2	0.2		0.4	0.3	60	0.2	60.5
4	14 AP 009H	Carbonaceous Shale	1.5	-	5.5		7	0.2	1.2	0.4	1.8	0.3		0.1		0.4	0.5	90	0.3	90.8
5	14 AP 009I	Coaly Shale	25.2	-		12	37.2	0.2	0.8	0.3	1.3	0.5		0.2		0.7	0.2	60	0.6	60.8
6	14 RY 007C	Carbonaceous Shale		1.2	6.4		7.6	0.6	2.6	1.4	4.3					0	1.1	84	3	88.1
7	14 RY 007 D	Shale	1.6				1.6				0					0	2.8	94	1.6	98.4
8	14 AP 010C	Carbonaceous Shale			4.6		4.6				0					0			95.4	95.4
9	14 AP 010D	Shale			1.6		1.6				0					0			99	99
10	14 AP 010E	Carbonaceous Shale			5.0		5				0					0		1.4	93.6	95
11	14 AP 010F	Carbonaceous Shale			20.8		20.8				0					0		39.6	39.6	79.2
12	14 AP 010G	Coaly Shale	1.4			39.0	40.4				0					0		7	52.6	59.6
13	14 AP 010J	Carbonaceous Shale	4		31.6		35.6				0					0		49	15.4	64.4
14	14 AP 010L	Carbonaceous Shale	18.6		4.6		23.2				0					0	0.6	75.2	1	76.8
15	14 AP 010M	Carbonaceous Shale			5.5		5.5		0.9		0.9					0	0.3	92	1.3	93.6
	AVG		9.9	1.2	9.5	8.5	16.4	0.3	1.6	0.6	1.1	0.7	0.9	0.2	0.3	0.4	0.7	62.6	27.3	82.1
	Min		1.4		1.6	0.4	1.6	0.1	0.8	0.3	0.9	0.2	0.2	0.1	0.2	0.7	0.2	1.4	0.2	59.6
	Max		25.2		21.4	17.6	40.4	0.6	3.2	1.4	4.3	1.8	2.2	0.2	0.3	4.3	2.8	94	95.4	99

Notes:

Tl	: telocollinite	V	: vitrinite	L	: liptinite	Int	: inertodetrinite	Py	: pyrite	
Atr	: attrinite	Sp	: sporinite	F	: fusinite	I	: inertinite	MM	: mineral matter	
Dns	: densinite	Ct	: cutinite	Smf	: semifusinite	Ox	: oxides			
Dsc	: desmocollinite	Lpt	: liptodetrinite	Fg	: funginite	Cy	: clay			

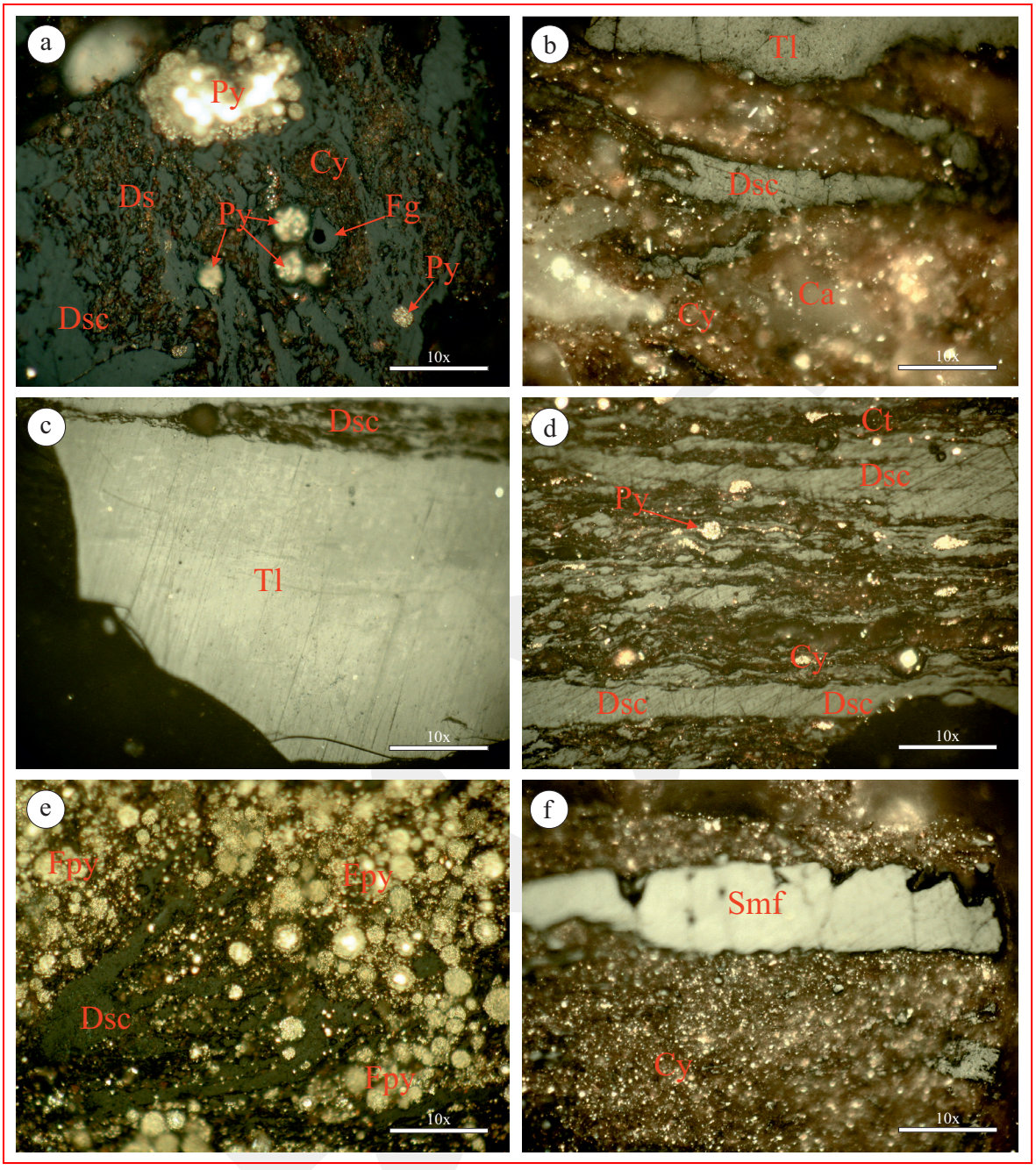

Figure 5. Photomicrographs taken under reflected white-light. a). Densinite (Ds) associated with framboidal pyrite (Py) and rounded shape funginite (Fg) with clay minerals (Cy) as a groundmass; b). Telocollinite (Tl) and desmocollinite (Dsc) with clay (Cy) and carbonate (Ca) minerals; c). Telocollinite (Tl) and desmocollinite (Dsc); d). Desmocollinite (Dsc) with embedded pyrite (Py) associated with cutinite (Ct) and clay minerals (Cy); e). Framboidal pyrite (Fpy) and desmocollinite (Dsc); f). Semifusinite (Smf) and clay minerals (Cy).

macerals comprise sporinite and cutinite in association with desmocollinite (Figure 5d).

Clay minerals were identified commonly as a groundmass in small to large lenses, and as cell lumen infillings in association with desmocollinite (Figures 5a, 5b, 5d, and 5f). Pyrite generally has a rounded morphology and is almost always associated with desmocollinite (Figures 5a and 5e). Pyrite occurs in both framboidal (Figure 5e) and nonframboidal morphologies. Carbonates occur either as lenses or infilling in fractures (Figure 5b).

The mode and association of maceral and mineral matter occurrences are also identified by the SEM. Macerals identified are mainly composed of telocollinite, desmocollinite, and funginite (Figure 6). The rounded isolated funginite is an effective organic-porosity in this carbonaceous shale. The presence of organic porosity as nanopores network was also found in the Longmaxi shale specimen formed during the thermal cracking of hydrocarbon generation of organic matter (Guo *et al.* 2014). Loucks *et al.* (2010) have imaged organic nanoporosity in the Barnet Shales by using SEM, and it has become the standard industry practice for identification of pore systems and mudstone reservoir characterization.

Pore Type Characterization

SEM investigation was performed for visualizing the distributions and associations of macerals, minerals, pores, and microfractures within the carbonaceous rich zones of the Brown Shale Formation.

The SEM results show that the pore types in the carbonaceous source rocks can be classified into three types, *i.e.* porous floccules, organic-porosity, and intraparticle pores (Figures 6b, 6c, and 6d, respectively). Loucks *et al.* (2010) demonstrated that the interparticle- and organo-pore-dominated pore networks had the better potential for connectivity, resulting in a higher permeability than an intraparticle-pore-dominated network. The variety of nanopores and micropores in mudrock systems is broad. Different combinations of these pore types produce pore networks that have various permeability characteristics to free-gas flow. The classification of matrix pore types in mudrock systems presented in this study can be used in contrasting and comparing pore

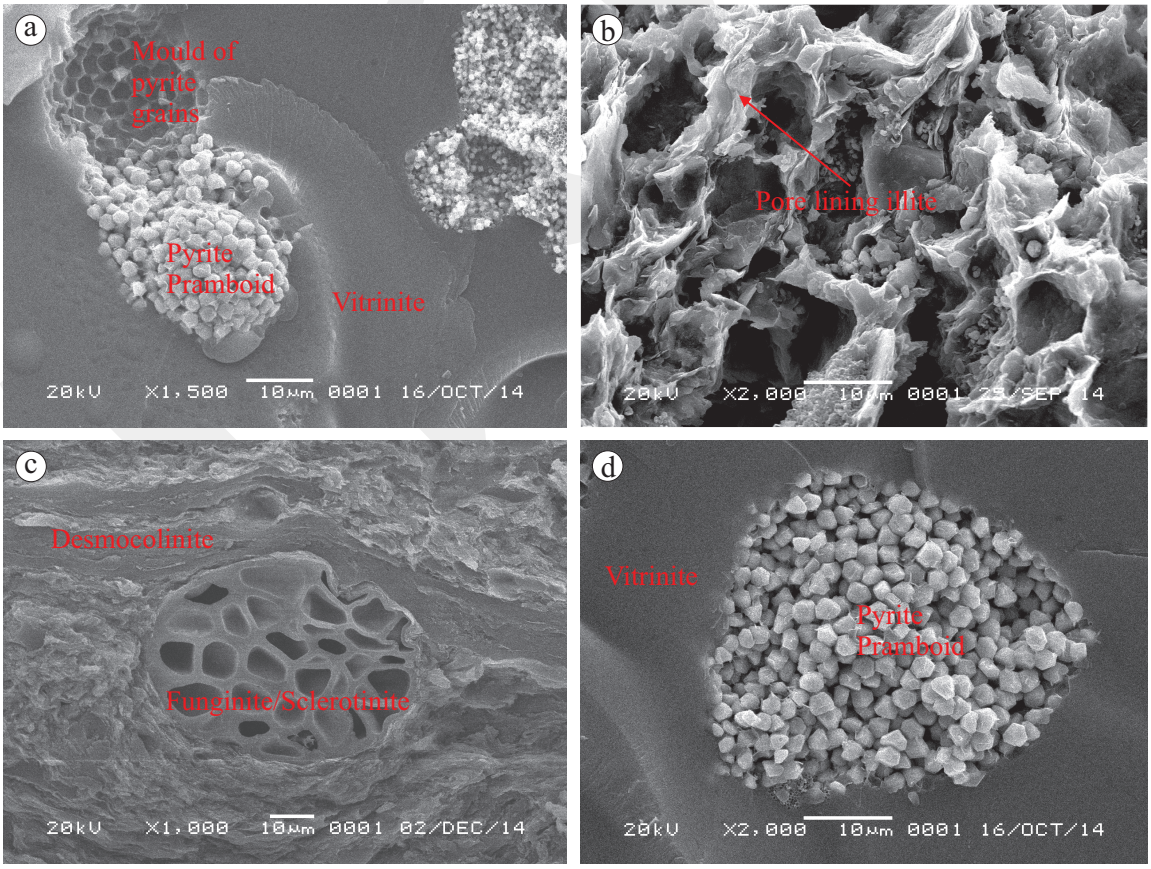

Figure 6. Scanning Electron Microscope images that show the pore type characterization of carbonaceous rich shales. a) Mould of crystals, pyrite grains within the telocollinite and desmocollinite macerals; b) Porous floccules with pore lining illite minerals; c) Organic-porosity as pore space within a funginite maceral; d) Intraparticle pores within an assemblage of framboidal pyrites.

types and relative abundances of pore types in different shale-gas systems.

The organic-porosity of the carbonaceous rich facies of the Brown Shale Formation contributes to the total porosity and hence hydrocarbon storage. This relationship, noted by Löhr *et al.* (2015), shows that organic matter (OM)-hosted pores, rather than mineral-hosted pores, are considered to be the dominant contributors to the total porosity and hydrocarbon storage in many organic-rich unconventional reservoirs. OM-hosted pores are thought to develop during thermal maturation as generated hydrocarbons expelled from the kerogen, leaving behind pores. However, the carbonaceous rich facies rank of the Brown Shale Formation is not high enough to generate hydrocarbon.

Microfractures

Natural microfractures are important in shale gas reservoirs, because they can be proposed as a secondary porosity and permeability network in the hydrocarbon produced from shale gas. However, it is difficult to define the natural microfractures from surface samples (outcrops). As mentioned above, some samples were examined under the SEM for microfracture characterization. Microfractures are found within the carbonaceous rich samples from the studied area, but they are assumed to be artifact microfractures related to sampling, desiccation, stress release, or dehydration of surface samples. These microfractures are mostly parallel or perpendicular to the bedding, as open curved cracks, associated with clay minerals or pyrites (Figures 7a and 7b).

Organic Geochemistry

TOC and Rock-Eval pyrolysis results show that the source rocks have TOC of 5.02 - 32.26% with potential yields of 3.86 - 18.31 mgHC/g rock for shales, and 37.71 - 57.22% with potential yields of 4.68 - 98.86 mgHC/g rock for coals (Table 2). The HI values of shales and coals ranging from 39 to 203 mgHC/TOC indicate the assemblage type III kerogen. This shows that the carbonaceous rocks and coals or lignites from the Brown Shale Formation have a high organic matter content and potential for gas generation (Figures 8a and 8b). However, Rodrigues and Philp (2015) revealed that the oil samples were generated from the Eocene-Oligocene lacustrine Brown Shale Formation, with various source rock facies environments, primarily under oxic or suboxic depositional conditions. Coal-derived oils and oils with a mixed shale and coal-derived facies seem to be restricted to the northern part of the Central Sumatra Basin. This condition indicates that oxidizing conditions and increased contribu-

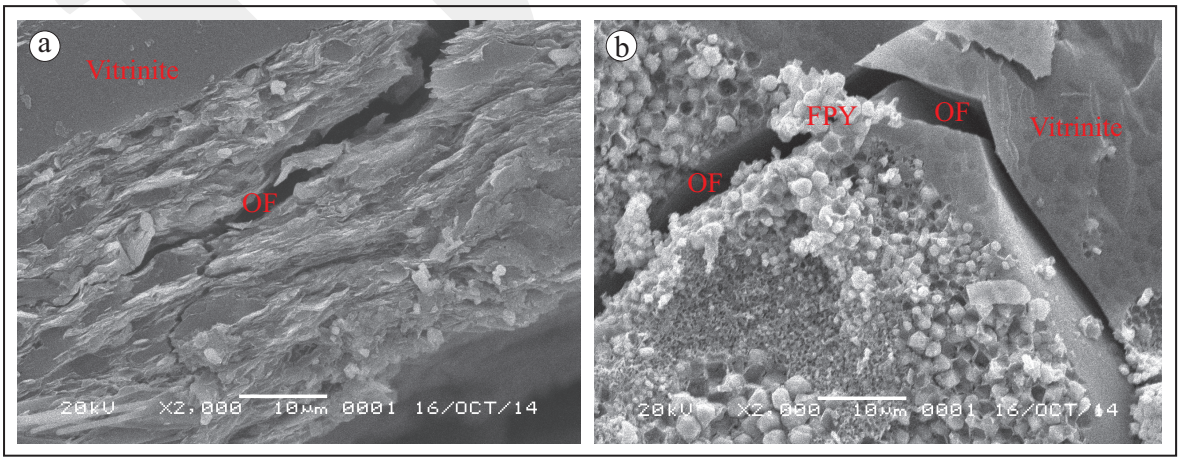

Figure 7. SEM images showing the artifact microfracture characteristics within the carbonaceous rich shale. a) Curved microfractures showing an open aperture (OF) within the vitrinite associated with clay minerals, parallel to bedding plane; b) Microfractures showing an open aperture (OF) perpendicularly crossing bedding plane, with some pyrite mineral infillings (FPY) in the centre of fracture spaces.

Table 2. Total Organic Carbon (TOC) and Rock-Eval Pyrolysis Data of Coals and Carbonaceous Shales of the Brown Shale Formation

No.	Sample No.	Lithology	TOC (wt.%)	mg/g rock			Tmax (°C)	Potential Yield (S1+S2)	Hydrogen Index	Oxygen Index
				S1	S2	S3				
1	14 AP 009B	Lignite	37.71	6.6	38.1	8	459	44.68	101	21
2	14 AP 009D	Lignite	40.87	3.48	45.4	4.91	460	48.83	111	12
3	14 AP 009F	Carbonaceous Shale	6.37	1.64	10.3	1.94	447	11.9	161	30
4	14 AP 009H	Carbonaceous Shale	6.03	0.14	3.72	4.03	449	3.86	62	67
5	14 AP 010F	Carbonaceous Shale	5.02	0.78	10.2	0.38	440	10.98	203	8
6	14 AP 010G	Coal, Dull	52.82	1.58	78.3	3.57	443	79.91	148	7
7	14 AP 010H	Coal, BB	57.22	0.95	97.9	11.7	443	98.86	171	20
8	14 AP 010J	Carbonaceous Shale	20.52	0.03	8.04	12.9	450	8.07	39	63
9	14 AP 010K	Carbonaceous Shale	8.01	0.73	9.15	1.15	442	9.88	114	14
10	14 AP 010L	Carbonaceous Shale	32.26	0.22	18.1	5.03	447	18.31	56	16
11	14 AP 010M	Carbonaceous Shale	6.37	0.98	8.69	0.73	435	9.67	136	11

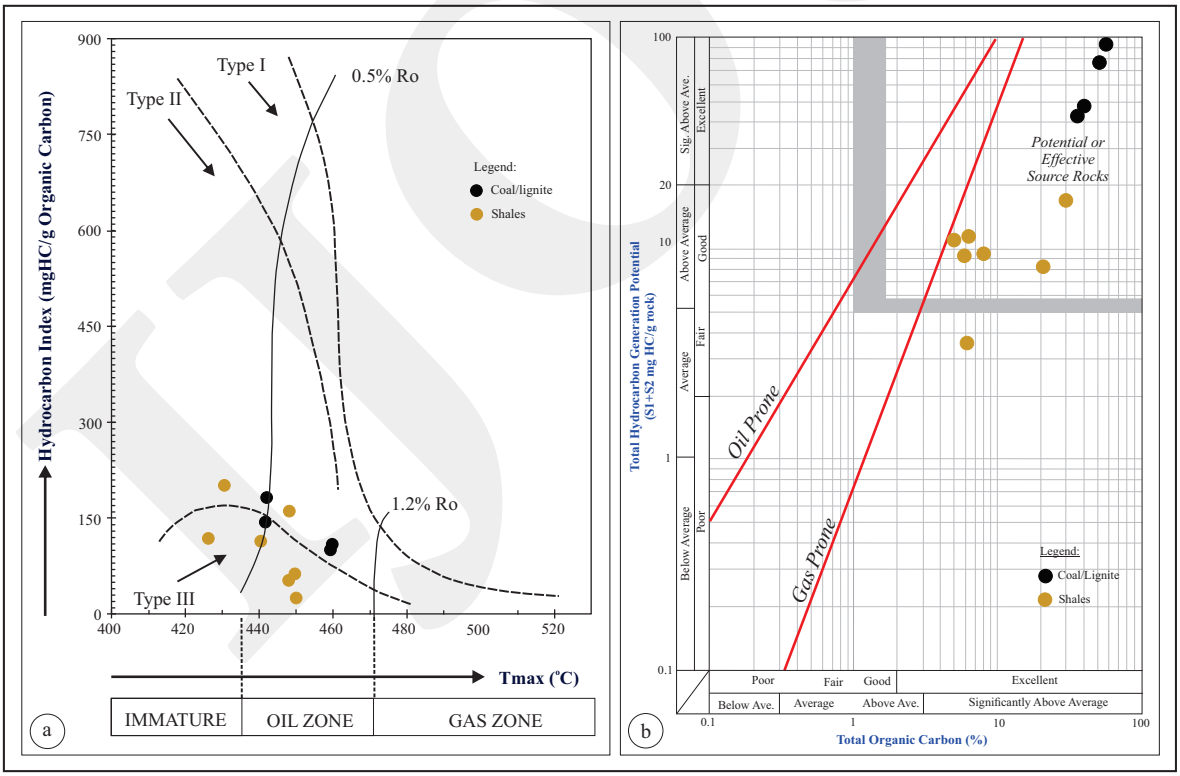

Figure 8. Geochemical characteristics of Brown Shale Formation. a). Hydrogen Index (HI) *vs*. T*max* diagram (modified van Krevelen diagram) showing kerogen type and thermal maturity of carbonaceous source rocks of the Brown Shale Formation; b). Total Hydrocarbon Generation Potential (S_1+S_2) *vs*. Total Organic Carbon (TOC) showing the hydrocarbon prone potential of the carbonaceous shales.

tions from terrigenous organic matter prevailed in the northern part of the basin. Thus, it is likely that the carbonaceous shales unit from Pendalihan were deposited in a more oxic environment.

A diagram of Hydrogen Index *vs*. T*max* (Figure 8a) shows that the kerogen types of the carbonaceous rocks and coal consist predominantly of type III gas prone kerogen. Considering the petrology, the kerogen result was likely derived from terrestrial plants (dominated by vitrininite/huminite with lesser inertinite). T*max* values range from 435^{o} - 460°C that indicate the maturity of the organic matter, rated in an immature form of the outcrops and might be more mature elsewhere in the basin.

The crossplot of the total hydrocarbon generation potential *vs*. total organic carbon (Figure 8b) shows the majority of the samples, both shale and coal source rocks, which are good to excellent for gas generation. Thus, the geochemical characteristics of the sampled carbonaceous rocks indicate that they have gas generation potential, similar to the Tertiary lacustrine shales in the northern Central Sumatra which has been studied by Hwang *et al.* (2002).

Caineng *et al.* (2013) found a positive correlation between the amount of adsorbed gas and TOC in shale formations with higher organic carbon contents, which usually have relatively high gas storage properties of gas potential. The prospective shale gas reservoirs should have organic richness greater than 2% TOC, thermally mature category, and have a brittle mineral content of over 40%. For a commercial development, the thickness of the producing interval minimum needs to be of 30 - 50 m. If the shale gas reservoir is continuous, then the producing interval can be as thin as 30 m. However, 50 m thick is thought to be needed for a commercial development, if the reservoir is discontinuous and/or the TOC content is less than 2%. However, there are exceptions to this, such as the Fayetteville deposit in North America where a minimum thickness of 6 m is sufficient for commercial development. As discussed above, although the Brown Shale Formation is rich in organic matter content, it is not mature enough and too thin as indicated from the outcrop. Additional subsurface (borehole and seismic) delineation is needed for the formation.

Conclusions

Petrological and geochemical evaluations, as well as SEM analysis of the carbonaceous rocks of the Brown Shale Formation in the Central Sumatra Basin indicate that this organic rich facies could be a good potential mature gas prone source rock. The samples have relatively high TOC, consisting predominantly of type III kerogen with a large proportion of vitrinite/huminite macerals. It is considered to be immature, tending to be categorized under oil zone with a good to excellent potential for gas generation. Mineralogical and pore type analyses of the carbonaceous source rocks suggest the presence of a good porosity which is required to develop the unit as an organic rich shale reservoir.

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