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SHALE HYDROCARBON POTENTIAL IN BROWN SHALE OF PEMATANG FORMATION BASED ON TOTAL ORGANIC CARBON CONTENT AND GEOMECHANIC APPROACH

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ABSTRACT: *The shale hydrocarbon potential can be defined by analyzing the geochemical and geomechanical characteristics. This research discusses how to examine the shale hydrocarbon potential in Brown Shale of Pematang Formation, Central Sumatra basin, Bengkalis trough. The analysis is done by considering the total organic carbon content and geomechanical approach based on the brittleness index and fracability index. TOC is predicted using Passey (2010) method, brittleness index is predicted using Grieser and Bray (2007) method, and fracability index is predicted using Jin et al. (2014) method. Analysis results show that the Brown Shale exists at 7867–8851 ft (interval of 984 ft) and it contains average TOC of 2.17 wt% (0.71–8.02 wt%), indicated as a very good category. From the geomechanics approach, average BI of 0.68 (0.42–0.88) indicated as brittle rocks and average FI of 0.76 (0.57–0.86) indicated as frackable zone. Those parameters were selected using modified cut-off from McKeon's (2013) and Bai (2016), it means the shale hydrocarbon of Brown Shale is prospect to be developed.*

KEYWORDS: shale hydrocarbon; brown shale; total organic carbon; geomechanic; brittleness index; fracability index

INTRODUCTION

The Central Sumatra basin contains approximately 50% of Indonesia's known recoverable reserves and over 90% of these known 10+ billion barrels of petroleum are present in fields containing at least 100 million barrels (Root et al., 1987). Four possible source rocks have been suggested for the central Sumatran reserves, these include the shales of the Petani, Telisa, Pematang Formations and the coals of the Sihapas Group, however, that only the Brown Shale of the Pematang Formation actually represents a viable petroleum source (Katz, 1995). The Pematang Formation is known only in the subsurface, where it may obtain thickness in excess of 1,800 meters (Williams et al., 1985), the oil-prone Brown Shale Member may reach thicknesses in excess of 580 meters (Katz, 1995).

Stratigraphically equivalent lacustrine rocks, which also display oil source rock characteristics, are present in the Ombilin basin to the southwest of the study area (Koning & Aulia, 1984). The Pematang Formation and its stratigraphic equivalents are the oil sources of Central Sumatra. Of all the potential source rock candidates it is the only unit that contains sufficient quantities of the appropriate type of organic matter at the appropriate level of thermal maturity to explain the quantities of liquid hydrocarbons available (Katz, 1995).

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The objective of this paper is to examine the shale hydrocarbon potential in Brown Shale Member of Pematang Formation, through the process of comparing the prediction results of several parameters with the cut-off from several papers. These parameters are total organic carbon content from well log (resistivity and porosity log) and geomechanic approaches, such as brittleness index and fracability index from rock mechanical properties (Young's modulus and Poisson's ratio). The analysis is done after validating those parameters with the results of laboratory analysis.

GEOLOGICAL OVERVIEW

Regional Structural Geology

Brown Shale of Pematang group formation is one of the formations in Central Sumatra Basin. The Central Sumatra Basin is bound to the southwest by the Barisan Mountains geanticlinal uplift and volcanic arc, to the north by the Asahan arch, to the southeast by the Tigapuluh high, and to the east by the Sunda craton (Heidrick & Aulia, 1993), as shown in Figure 1. The NW structural and topographic grain is largely a late Cenozoic phenomenon that is superimposed upon the NNE-trending Asahan arch and Lampung High and ENE-trending Tigapuluh arch (Mertosono & Nayoan, 1974). These arches and high combine to effectively subdivide the Sumatran foreland into north, central, and south basins.

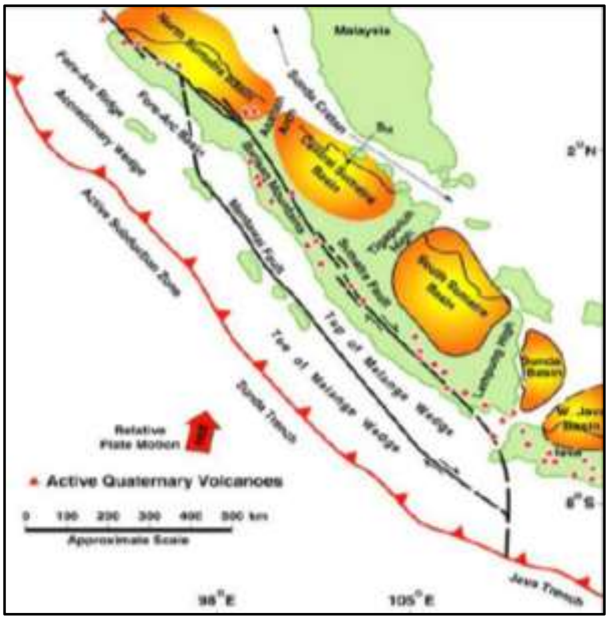

Figure 1. Map of Central Sumatra Basin (Heidrick & Aulia, 1993).

Convergent tectonics between Indian Ocean Plate and Asian Continent Plate control the formation and development of the Central Sumatra Basin. A type of structure common to the Central Sumatra Basin is named the Sunda Fold, generated in a specific depositional and tectonic setting. This type changes from anticlinal at the crest to synclinal or half graben at depth. They are the product of a tensional regime, with a thick sedimentary fill of the grabens and half grabens, and a wrench component creating an anticlinal fold above the graben (Eubank & Makki, 1981).

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Stratigraphy

Mertosono and Nayoan (1974) proposed a five-fold subdivision for the Cenozoic rock-stratigraphic units in the Central Sumatra Basin where the five units include (oldest to youngest), the Pematang formation, Sihapas group, and Telisa, Petani, and Minas formations (Heidrick & Aulia, 1993). Eubank and Makki (1981) proposed a time-rock stratigraphy and indicates the temporal limits of the three major episodes of structural development and modified by Heidrick and Aulia (1993), shown Figure 2.

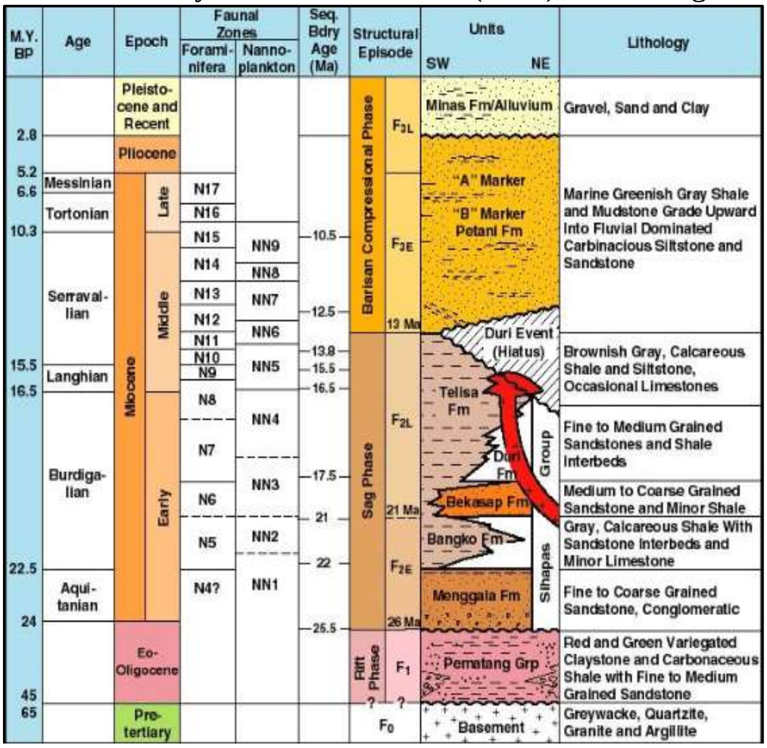

Figure 2: Stratigraphy of Central Sumatra Basin (Eubank & Makki, 1981 in Heidrick & Aulia, 1993).

The Pematang formation directly overlies basement in the Central Sumatra Basin and consists of two continental-dominated facies: 1) varicolored mottled claystone and fine grained sandstone that are locally interbedded with organic-rich lacustrine shale, and 2) a sequence of conglomerate, coarse grained sandstone, and variegated claystone (Heidrick & Aulia, 1993). The Neogene transgressive phase is represented by Sihapas group, an upward fining conglomeratic, coarse to fine grained sandstone succession (Menggala formation) that is capped by calcareous shale of Bangko formation. While the Upper Sihapas records a continuation of the early Miocene transgression with medium to coarse grained micaceous sandstone of Bekasap representing marginal facies of Telisa formation (more basinal shales) (Lee, 1982).

The lower to middle Miocene Telisa formation consists of a shale-dominated succession with interbeds of limestone and fine grained glauconitic sandstone. The overlying sediments of Petani formation constitute a monotonous sequence of shale-mudstone containing minor sandstone and siltstone intercalations. Top Neogene is characterized by a pronounced erosional unconformity overlain by a thin veneer of Holocene Minas alluvial sandstone and gravel. The regional of the unconformity and marked increase in sediment coarseness suggest that considerable uplift of the basin margins occurred at the end of Pliocene time (Heidrick & Aulia, 1993).

TOTAL ORGANIC CARBON CONTENT

As it is well known that generally organic-rich mudstones have generated much of the oil and gas that resides in conventional reservoirs around the world. This type of rock is known as "source rocks". The critical parameters related to whether or not a given rock will be a good source rock is the organic richness (generally recorded as wt% Total Organic Carbon), the current and past maturity level of the formation (generally referenced as Vitrinite Reflectance, Ro), and the organic matter type (whether the primary thermogenic product will be oil, gas, or a mixture) (Passey et al., 2010).
Passey et al. (2010) established a relationship between vitrinite reflectance (Ro) and level of organic maturity (LOM), as shown in Figure 3, both parameters further will be used to predict TOC. The principal generation windows for oil-prone kerogen (Type I and Type II) ranges from Ro=0.5 (for early generation) through peak generation Ro=0.8, to overmature Ro>1.1 (Passey et al., 2010).

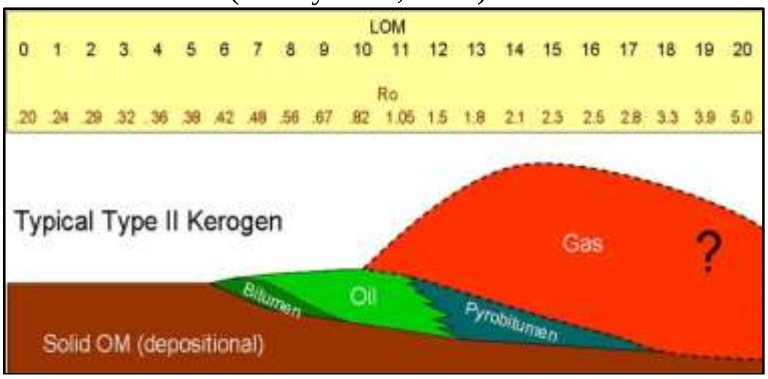

Figure 3: Schematic of maturation of Type II (Oil-Prone Kerogen) and respective Level of Organic Maturity corresponding to Vitrinite Reflectance (Passey et al., 2010).

Based on the relationship between Ro and LOM, we can generate an approach to defining LOM from Ro with a certain value, as shown in Figure 4. It is limited with Ro of 0.2–5 and divided into two equations. The first equation for Ro of 0.2–1.1 is (R2=0.994):

$$LOM = 16.066\ Ro3 - 48.897\ Ro2 + 52.7\ Ro - 9.0712 \quad (1)$$

while the second equation for Ro of 1.1 – 5 is (R2=0.9979):

$$LOM = 0.2276\ Ro4 - 2.8826\ Ro3 + 12.295\ Ro2 - 17.765\ Ro + 19.539 \quad (2)$$

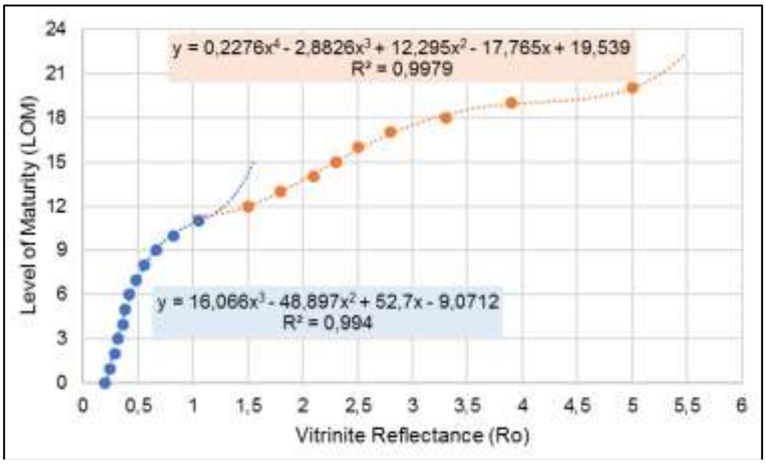

Figure 4: An empirical relationship between Vitrinite Reflectance and Level of Organic Maturity.

Passey's Method

Passey et al. (1990) established a methodology to predict total organic carbon (TOC) content in source rock based on ΔlogR separation, designed from the separation of transit-time curve and resistivity curve. In application, the transit-time curve and resistivity curve are scaled such that their relative scaling is –100 µs/ft (–328 µs/m) per two logarithmic resistivity cycles (i.e., a ratio of –50 µs/ft or –164 µs/m to one resistivity cycle) (Passey et al., 1990). Figure 5 shows the overlay of resistivity and sonic log to obtain a baseline condition, a condition where the transit-time curve and resisitivity curve directly overlie each other and it presents as the non-source rock.

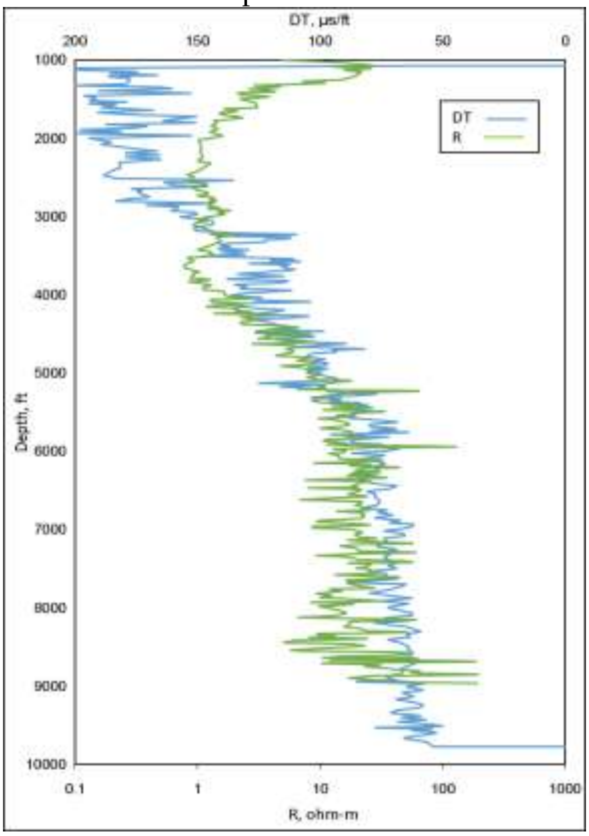

Figure 5: An overlay of resistivity and sonic log.

As the baseline established, approximately at depth of 4000–5500 ft, organic-rich intervals can be recognized. The ΔlogR separation can be calculated from baseline condition and organic-rich intervals with the equation below:

$$\Delta logR = Log10\ R/Rbaseline + 0.02 \times (\Delta t - \Delta tbaseline) \quad (3)$$

where ΔlogR is the curve separation measured in logarithmic resistivity cycles where exists at depth of 6000 ft and deeper, R is the resistivity measured in ohm.m, Δt is the sonic measured in μs/ft, Rbaseline and Δtbaseline are the resistivity and sonic baselined. TOC can be predicted using ΔlogR and LOM data, as they explained before. The empirical equation for calculating TOC in clay-rich rocks is:

$$TOC = \Delta logR \times 10(2.297-0.1688 \times LOM) \quad (4)$$

where TOC is the total organic carbon content measured in wt%, ΔlogR is the curve separation measured in logarithmic resistivity cycles, and LOM is the level of organic maturity.

GEOMECHANIC APPROACH

Compressional-Wave and Shear-Wave Velocities

Castagna et al. (1985) established the general ratio of compressional to shear wave velocity (Vp/Vs). The Vp/Vs relationship famous established for mudrock line, water-saturated siliciclastic rocks composed primarily of quartz and clay minerals (Castagna et al., 1985). As it gives:

$$Vs = 0.862\ Vp - 1.172 \quad (5)$$

where the compressional and shear wave velocities are in km/s.

Rock Mechanic

It is necessary to know the value of Young's modulus and Poisson's ratio in order to determine the hydraulic fracturing program. These parameters can be defined from well logs as dynamic parameters. Fjær et al. (2008) established an empirical equation of Young's modulus from sonic and density log, as shown below:

$$E = \rho \times Vs^2 \frac{(3V_p{}^2 - 4V_s{}^2)}{(V_p{}^2 - V_s{}^2)} \quad (6)$$

While Zoback (2007) established an empirical equation of Poisson's ratio from sonic log, as shown below:

$$\upsilon = \frac{V_p{}^2 - 2V_s{}^2}{2(V_p{}^2 - V_s{}^2)} \quad (7)$$

where the compressional and shear wave velocities are in km/s, Young's modulus is in Gpa, and Poisson's ratio in fraction.

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Brittleness Index

Mineral composition and the presence of organic matter can not only affect the pore distribution and fluid saturation, but also the stimulation effectiveness of hydraulic fracturing (Buntoro et al., 2018). Brittleness is one of few parameters to understand the effectiveness of hydraulic fracturing. Grieser and Bray (2007) established a relationship between Young's modulus and Poisson's ratio to predict the brittleness average. This relationship based on normalization of Young's modulus and Poisson's ratio in their ranges of minimum and maximum. Normalize Young's modulus:

$$E_{brittleness} = \frac{E - E_{min}}{E_{max} - E_{min}} \tag{8}$$

where E_{min} and E_{max} are minimum and maximum Young's modulus measured in the logged formation, and normalize Poisson's ratio:

$$v_{brittleness} = \frac{v - v_{max}}{v_{min} - v_{max}} \tag{9}$$

where v_{min} and v_{max} are minimum and maximum Poisson's ratio measured in the logged. Then they define brittleness average as the brittleness index:

$$BI = \frac{E_{brittleness} + v_{brittleness}}{2} \tag{10}$$

Fracability Index

Fracability is a value to understand the behavior of complex fracture networks and stimulated reservoir volume as they show higher brittleness and lower critical strain energy release (Jin et al., 2014). Jin et al. (2014) established an empirical relationship between brittleness and strain energy release in order to know the fracability index. They saw the same trend between strain energy release and Young's modulus. Therefore, the strain energy release can be substituted with Young's modulus:

$$FI = \frac{B_n + E_n}{2} \tag{11}$$

where B_n and E_n are normalized brittleness and Young's modulus value in their ranges of minimum and maximum. Normalize brittleness:

$$B_n = \frac{B - B_{min}}{B_{max} - B_{min}} \tag{12}$$

where B_{min} and B_{max} are minimum and maximum brittleness measured in the logged formation, and normalize Young's modulus:

$$E_n = \frac{E_{max} - E}{E_{max} - E_{min}} \tag{13}$$

where E_{min} and E_{max} are minimum and maximum Young's modulus measured in the logged formation.

METHODOLOGY

The methodological approach adopted is to make predictions of total organic carbon and geomechanics to analyze the potential of shale hydrocarbon. Total organic carbon is predicted using Passey's method based on resistivity and porosity log, then validate

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it with total organic carbon estimated from core data. While the geomechanic aspects, brittleness index, and fracability index, are estimated using Grieser & Bray's method and Jin's method from Poisson's ratio and Young's modulus, then validate it with brittleness index from core data. There is no validation data for fracability index. Those three parameters are analyzed to determine the interval of sweet spot zone based on cut-off from Peter and Cassa (1994), Altamar and Marfurt (2014), Jin et al. (2014), and McKeon (2013).

RESULT AND DISCUSSION

Based on the results, TOC calculated using Passey's method and BI calculated using Grieser and Bray's method are validated with TOC and BI obtained from laboratory analysis of the same well. High local organic carbon is a critical factor to assess when evaluating potential shale-gas reservoirs. To make it easier in order to classify source rock based on organic carbon content, Peter and Cassa (1994) proposed a source rock classification based on TOC content as shown in Table 1.

Table 1: Classification of source rock based on TOC content (Peters & Cassa, 1994).

Source Rock	TOC (wt%)
Poor	0 – 0.5
Fair	0.5 – 1
Good	1 – 2
Very Good	2 – 4
Excellent	> 4

A potential source rock can be defined as it contains TOC more than 1 wt% or at least as a good source rock. Sukhyar and Fakhruddin (2013) said, the potential shale gas is commonly presented by TOC more than 2 wt%, while from Jarvie (2012) the shale oil is indicated by TOC more than 1 wt%. So TOC more than 1 wt% indicate a potential shale hydrocarbon to be produce economically.

Grieser and Bray (2007) proposed that the brittle rocks exhibit a moderate to high Young's modulus and low Poisson's ratio, while the ductile rocks exhibit a low Young's modulus and high Poisson's ratio. Altamar and Marfurt (2014) then proposed a concept to classify rock characteristics based on its brittleness index. Brittleness value of >0.48 indicates as a brittle rock, the value of 0.48–0.32 indicates as a less brittle rock, value of 0.32–0.16 indicate as a less ductile rock, and value of <0.16 indicate as a ductile rock (Altamar & Marfurt, 2014).

An ideal hydraulic fracturing candidate is of relatively higher brittleness and Young's modulus. But brittleness close to 1 might not be good for fracturing, because it's Young's modulus which might lead to lower fracability index (Jin et al., 2014). There is a relationship between brittleness and Young's modulus on fracability index trend, the higher they get, the higher fracability index.

Potential shale hydrocarbon can be produced economically when it has: interval depth of >100 ft (McKeon, 2013); TOC >1 wt% or at least as a good source rock (Peter & Cassa, 1994); BI >0.48 indicate as a brittle rock (Altamar & Marfurt, 2014) or a moderate to high Young's modulus and low Poisson's ratio (Grieser & Bray, 2007); and high fracability index from high brittleness and Young's modulus (Jin et al., 2014). Grieser and Bray (2007) established a relationship between Young's modulus and Poisson's ratio to determine the rock brittleness. Figure 6 shows a data plot from the result of Young's modulus and Poisson's ratio calculation using Fjær et al. (2008) and Zoback (2007) method. Only data in interval of Brown Shale unit are displayed in the cross plot. The majority data show trends in less brittle to brittle region as it means Brown Shale unit is the prospect to apply hydraulic fracturing.

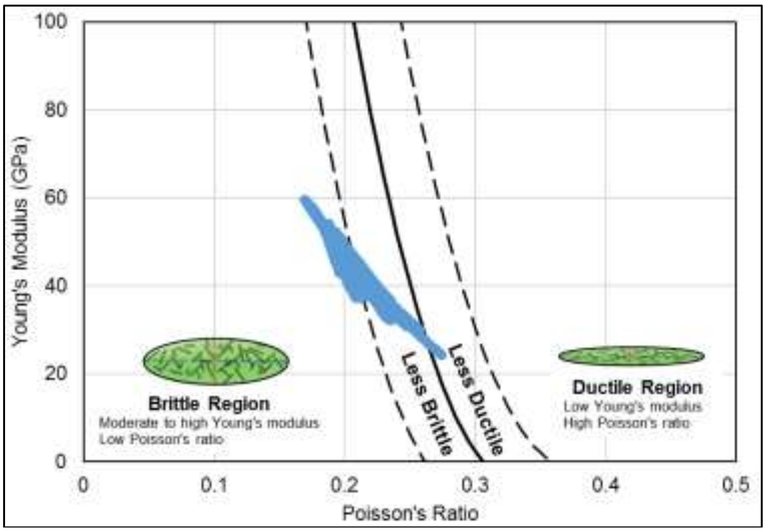

Figure 6: A Cross Plot of Young's Modulus vs Poisson's Ratio Shows Brittle and Ductile Region (Modified from Grieser & Bray, 2007 and Altamar & Marfurt, 2014).

Figure 7 shows the prediction results of total organic carbon, brittleness index, and fracability index correlated with gamma ray log where TOC and BI have validated with data from laboratory analysis. Brown Shale unit exists at 7867–8851 ft depth or interval depth of 984 ft. Brown Shale unit contains (Table 2): TOC average of 2.17 wt% (range of 0.71–8.02 wt%), BI average of 0.68 (range of 0.42–0.88), and FI average of 0.76 (range of 0.57–0.86).

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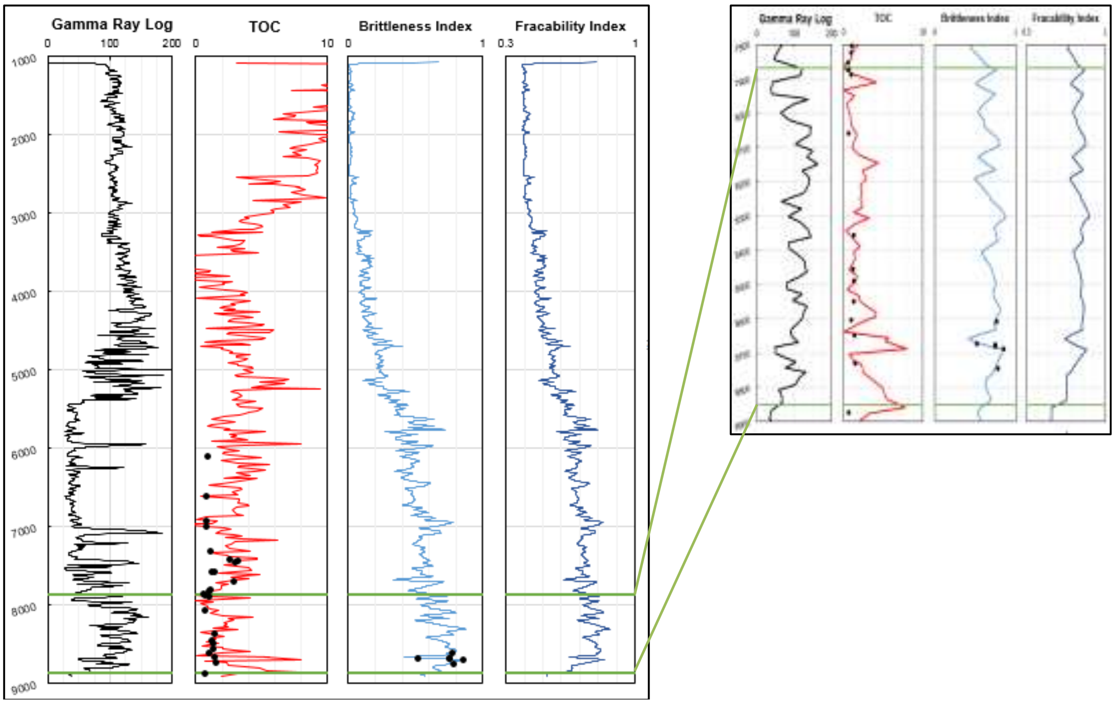

Figure 7: Correlation of gamma ray log, Total Organic Carbon, Brittleness Index, and Fracability Index

Table 2: Summary of the results of Total Organic Carbon, Brittleness Index, and Fracability Index in unit Brown Shale.

Brown Shale: 7867–8851 ft (interval depth of 984 ft)				
	Average	**Range**	**Cut-off**	**Reference**
TOC	2.17 wt.%	0.71–8.02 wt.%	>1 wt.%	(Peter & Cassa, 1994)
BI	0.68	0.42–0.88	>0.48	(Altamar & Marfurt, 2014)
FI	0.76	0.57–0.86	High	(Jin et al., 2014)

CONCLUSION

1. Brown Shale unit exists at 7867–8851 ft depth or interval depth of 984 ft with a cut-off of interval depth >100 ft (McKeon, 2013).
2. TOC average of 2.17 wt%, a range of 0.71–8.02 wt%, with cut-off of TOC >1 wt% or at least as a good source rock (Peters & Cassa, 1994).
3. BI average of 0.68, a range of 0.42–0.88, with cut-off of BI >0.48 indicates as a brittle rock (Altamar & Marfurt, 2014).
4. FI average of 0.76, a range of 0.57–0.86, with cut-off of high fracability index from high brittleness and Young's modulus (Jin et al., 2014).
5. Data on Young's modulus and Poisson's ratio in the interval of Brown Shale unit show trends in less brittle to brittle region.

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