

CHARACTERIZATION OF TOTAL AND EFFECTIVE POROSITY IN EARLY MIOCENE POST-RIFT SANDSTONE RESERVOIRS OF THE “NOIR” FIELD, CENTRAL SUMATRA BASIN

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ABSTRACT

The Early Miocene post-rift sandstone reservoir of the Sihapas Group represents a key hydrocarbon-producing layer in the Central Sumatra Basin. Reservoir quality within these sandstones is controlled by pore characteristics, mainly total porosity (PHIT) and effective porosity (PHIE), which determine the storage capacity to store fluids and connectivity of pore spaces. This study aims to characterize the allocation of total and effective porosity within the “Noir” field employing well-log analysis supported by conventional core and sidewall core data. The volume of shale (VSH) was determined from the gamma-ray logs utilizing the linear gamma-ray approach. Conversely, the total porosity was assessed from the density logs, while the effective porosity was derived by removing the volume of clay-bound water from the total porosity. The computed porosity values were investigated to assess the reservoir quality of the tested periods. Total porosity (PHIT) is always greater than the effective porosity (PHIE) at all intervals. This is due to the fact that PHIT accounts for the pore spaces filled with clay bound water and shale, while PHIE only takes into account the interconnected pore spaces that are essential for hydrocarbon storage and fluid movement. The maximum mean total porosity is 19.6% and the highest effective porosity of 16.5% are seen in the Top B of Noir-1, indicating that it has the most favorable reservoir characteristics among the tested periods. During this period, Top C of Noir-2 exhibits a dramatic decline in PHIT (16.7%) to PHIE (7.0%), showing that the increased shale content has caused a drop in pore connectivity. Overall, the results indicate that the quality of the reservoir is predominantly controlled by the distribution of shale. In general, cleaner sandstone intervals are characterized by increased effective porosity and improved storage capacity. The findings of this research provide a solid foundation for assessing reservoir quality and contribute to the future exploration and development of hydrocarbons in the Central Sumatra Basin.

Keywords: clay-bound water, density porosity, formation evaluation, pore connectivity, shale volume

INTRODUCTION

Central Sumatra is one of Indonesia's most prolific hydrocarbon basins. One of the main hydrocarbon reserves in the basin is considered to be the Early Miocene post-rift sandstones of Sihapas Group (Heidrick and Aulia, 1993; Fardiansyah et al., 2017). Ellis and Singer (2007), Worden et al., (2018), and Tiab and Donaldson (2015) observed that the features of pores in these sandstones significantly influence the performance of the reservoirs such as hydrocarbon storage capacity and flow of fluids. Well logs from wireline devices are useful for lithological interpretation and quantitative petrophysical evaluation since they give continuous data from the subsurface (Rider and Kennedy,

2011; Kennedy, 2015; Cannon, 2015). Two petrophysical variables that may be estimated from well logs and are key factors in the determination of reservoir quality are Total Porosity (PHIT) and Effective Porosity (PHIE). Effective porosity (PHIE) is the connected pore network that stores hydrocarbons and allows fluid flow, while total porosity (PHIT) is the total pore spaces in the rock, irrespective of whether they contribute to fluid movement or not. Thus, effective porosity is usually regarded as a better proxy for reservoir quality and production (Ellis and Singer, 2007; Worden et al., 2018). The effective porosity is less than the effective porosity. Here's why. Therefore, proper estimation of these porosity parameters is very important for reservoir

characterization and hydrocarbon field development.

While petrophysical analysis has been extensively utilized in hydrocarbon exploration in the Central Sumatra Basin, many prior studies have concentrated on overall reservoir assessment. Comprehensive characterization of overall and effective porosity in the early Miocene post-rift sandstone reservoirs, especially at the field scale, is still scarce. The absence of comprehensive porosity data heightens the uncertainty in assessing reservoir heterogeneity and pinpointing sections with advantageous reservoir quality (Lai et al., 2018; Zhang et al., 2024). This study investigates the distribution of total porosity (PHIT) and the “Noir” Field situated in the Central Sumatra Basin through wireline well-log analysis. The outcomes are anticipated to enhance the evaluation of reservoir quality and offer valuable insight for upcoming hydrocarbon exploration and field development.

REGIONAL GEOLOGY

The “Noir” Field is situated in the Central Sumatra Basin, specifically within the Aman Graben, which is one of the primary structural depressions in the basin. The graben formed during the Eocene-Oligocene extensional tectonics phase and has significantly influenced the geological development of the basin, especially in managing sediment distribution and deposition (Heidrick and Aulia, 1993). It is made up of two north-south-oriented section linked by a northwest-south-east-oriented accommodation zone and its southern section shifts direction to a northwest-southeast trend via another accommodation zone (William and Eubank, 1995). The tectonic evolution of Central Sumatra Basin is illustrated in Figure 1.

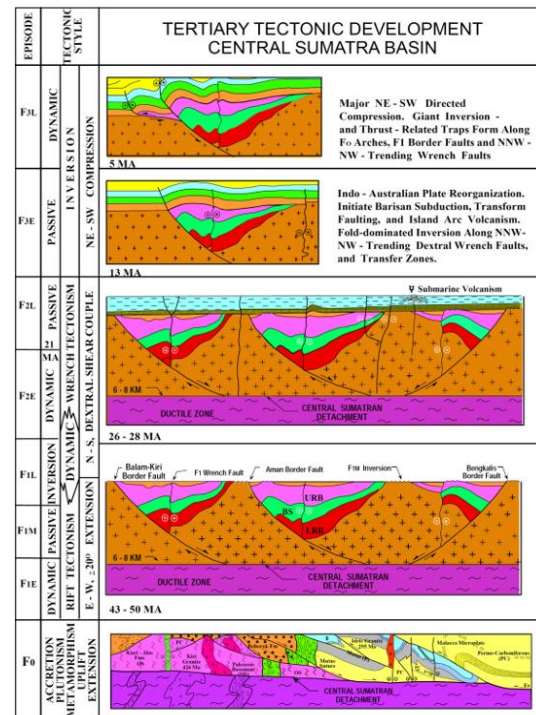


Figure 1. The tectonics evolution of the Central Sumatra Basin (Heidrick and Aulia, 1993)

Stratigraphically, the Central Sumatra Basin comprises the basement complex, the Pematang Group, the Sihapas Group, the Petani Formation, and the Minas Formation, organized from the oldest to the youngest (Heidrick and Aulia, 1993). The Pematang Group was formed in lacustrine to fluvial setting during the Eocene-Oligocene and acts as the primary hydrocarbon source rock. It is overlain unconformably by the Early-Middle Miocene Sihapas Group, which serve as the main hydrocarbon reservoir layer in the basin (Heidrick and Aulia, 1993; Haris et al., 2018; Andriyani et al., 2023). The regional stratigraphic framework of the Central Sumatra Basin is presented in Figure 2.

M.Y. BP	Epoch	Faunal Zones		Structural Episode	Units		Lithology
		Forami- nifera	Nano- plankton		SW	NE	
2.8	Pleistocene and Recent			Barisan Compression Phase	Minas Fm/Aluvium		Gravel, sand and clay
5.2	Pliocene				"A" Marker "B" Marker		Greenish grey shale sandstone and siltstone
6.6	Late	N 17					
10.3		N 16	NN 9				
		N 15	NN 8				
		N 14	NN 7				
	Middle	N 13	NN 6	Sag Phase			
15.5		N 12	NN 5				
16.5		N 11	NN 4				
		N 10	NN 3				
		N 9	NN 2				
	Early	N 8	NN 1	Rift Phase			
		N 7					
		N 6					
		N 5					
		N 4					
22.5	Eo-Oligocene			F0			
25.5							
45	Pre-Tertiary			F1			
65							

Figure 2. The stratigraphic column of the Central Sumatra Basin (Heidrick and Aulia, 1993)

The Early Miocene sandstone reservoirs investigated in this study from part of the Sihapas Group and are composed of interbedded sandstone, shale and siltstone (Heidrick and Aulia, 1993; Herdiansyah et al., 2023). These sediments were deposited in deltaic to shallow-marine settings influenced by tidal processes during the Early-Middle Miocene (Fardiansyah et al., 2017; Herdiansyah et al., 2023). Within the petroleum system of the Central Sumatra Basin, these sandstones constitute the principal hydrocarbon reservoir, whereas the associated shale interval act as an effective regional seal (Heidrick and Aulia, 1993; Herdiansyah et al., 2023).

PETROPHYSICAL PARAMETERS

Shale Volume

Shale Volume (SH) indicates the proportion of shale contained within a reservoir rock and is commonly used to evaluate reservoir quality. Because shale minerals generally contain higher concentration of naturally occurring radioactive elements than clean sandstone, gamma ray logs provide an effective means of distinguishing shale-rich intervals from cleaner reservoir zones (Rider and Kennedy, 2011; Kennedy, 2015). An increase in shale content reduces the volume of interconnected pore space, which in turn lowers effective porosity and restricts fluid flow (Ellis and Singer, 2007; Tiab and Donaldson, 2015). In

this research, shale volume was calculated from gamma-ray log through the linear gamma-ray technique (Ellis and Singer, 2007; Firmansyah et al., 2023).

$$V_{sh} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

where GR_{log} represents the recorded gamma-ray log value, GR_{min} denotes the gamma-ray value of clean sandstone, and GR_{max} indicates the gamma-value of shale.

Porosity

Porosity indicates the volume of pore space found in a rock and is a key factor in assessing reservoir quality as it influences the reservoir's ability to hold fluids. Two porosity types are commonly considered in petrophysical analysis: total porosity (PHIT) and effective porosity (PHIE). Total porosity includes all pore spaces within the rock, whereas effective porosity represents only the interconnected pores that can store and transmit fluid (Ellis and Singer, 2007; Tiab and Donaldson, 2015).

Density and neutron logs are widely applied in porosity evaluation because they provide continuous measurement of formation properties and allow porosity to be estimated throughout the reservoir interval (Rider and Kennedy, 2011; Kennedy, 2015). In this study, total porosity (PHIT) was derived from density log information through the density porosity formula:

$$PHIT (\Phi_D) = \frac{\rho_{ma} - \rho_{log}}{\rho_{ma} - \rho_{fl}} \quad (2)$$

where ρ_{ma} denotes the matrix density, ρ_{log} represents the bulk density obtained from the density log, and ρ_{fl} indicates the fluid density.

Effective porosity was then derived by accounting for the effect of shale. Although shale contributes to total pore volume, some of its porosity is taken up by clay-bound water, which does not contribute to hydrocarbon storage or fluid movement. To achieve a more accurate assessment of reservoir pore space, the total porosity was adjusted by removing the shale-related porosity using this equation:

$$PHIE = PHIT - (V_{SH} \times \Phi_{WSH}) \quad (3)$$

where V_{SH} represent shale volume and Φ_{WSH} denotes wet shale porosity. The resulting PHIE represents the interconnected pore volume that is available for the hydrocarbon storage

and fluid movement (Tiab and Donaldson, 2015; Kennedy, 2015; Worden et al., 2018).

RESEARCH METHOD

This study was carried out in the “Noir” Field located in the Aman Graben, Central Sumatra Basin, Indonesia. The studied reservoir belongs to the Early Miocene post-rift sandstone sequence of the Sihapas Group, which is one of the primary hydrocarbon-producing layers in the basin (Heidrick and Aulia, 1993; William and Eubank, 1995; Fardiansyah et al., 2017). The data included gamma-ray (GR) and bulk density (RHOB) logs from a pair of wells, together with conventional core, side-wall core (SWC), and formation marker data used for reservoir correlation and validation of the petrophysical interpretation, following an integrated workflow commonly applied in reservoir characterization studies (Kamila et al., 2023). Wireline logs provide continuous subsurface measurement and are widely applied for lithological interpretation and quantitative reservoir evaluation (Rider and Kennedy, 2011; Kennedy, 2015). The location of the study area is presented in Figure 3.

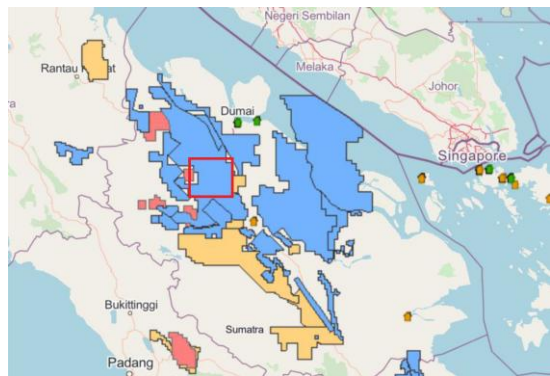


Figure 3. The study area of the “Noir” field

Shale volume (VSH) was calculated from gamma-ray logs reading utilizing the linear gamma-ray method, a commonly recognized technique for determining shale content in siliciclastic reservoirs (Ellis and Singer, 2007; Tiab and Donaldson, 2015).

Total porosity (PHIT) was calculated from the density log by applying the density porosity formula. Effective porosity was subsequently calculated by implementing a shale adjustment to PHIT, enabling more precise representation of the porosity linked to interconnected pore space (Kennedy, 2015; Tiab and Donaldson, 2015). The determined porosity values were then examined to assess their vertical distribution within each well and to evaluate lateral differences among wells by employing standard petrophysical evaluation

techniques (Cannon, 2015; Worden et al., 2018)

The petrophysical findings were confirmed by contrasting porosity values derived from well logs with existing conventional core and side wall core data. Given that core data offer direct insights into reservoir characteristics, they served as a benchmark to assess the accuracy of well-log interpretation (Ellis and Singer, 2007; Tiab and Donaldson, 2015). The resulting distributions of total and effective porosity was subsequently utilized to evaluate reservoir quality within the Early Miocene post-rift sandstone section of the “Noir” Field (Worden et al., 2018; Zhang et al., 2024).

RESULT AND DISCUSSION

Shale Volume

The shale volume (VSH) was derived from the well-log data varies between 15% and 100% throughout the study region. Differences in VSH are noted across the reservoir intervals, indicating variation in shale composition within the sandstone. Table 1 shows the average VSH value for every reservoir interval.

Table 1. Result of Volume Shale Calculation

Well Name	Top Marker	Average of VSH (%)
Noir-1	Top A	73
	Top B	52
	Top C	57
	Top D	66
	Top E	67
Noir-2	Top A	54
	Top B	62
	Top C	56
	Top D	46
	Top E	44

Porosity

Total Porosity (PHIT) observed in the examined well varies from 0 to 38.2% with mean values differing accord the reservoir intervals identified by the top marker. The noted differences in PHIT indicate that the sandstone reservoirs contain varying total pore space, possibly linked to variation in depositional environment and diagenetic

actions. Table 2 displays the average PHIT values for every reservoir interval.

Table 2. Result of Total Porosity Calculation

Well Name	Top Marker	Average of PHIT(%)
Noir-1	Top A	12.3
	Top B	19.6
	Top C	18.5
	Top D	14.5
	Top E	14.2
Noir-2	Top A	16
	Top B	16.1
	Top C	16.7
	Top D	13.5
	Top E	17.7

Effective porosity (PHIE) varies between 0 and 30.1%, with average values varying across the reservoir intervals. Compared with PHIT, PHIE values are generally lower because the calculation excludes pore spaces associated with shale. This reduction reflects the influence of the shale content on the interconnected pore system and provides a

more representative estimate of the pore volume available for fluid storage and flow. Table 3 summarizes the effective porosity (PHIE) values calculated for each reservoir intervals.

Table 3. Result of Effective Porosity Calculation

Well Name	Top Marker	Average of PHIT(%)
Noir-1	Top A	6
	Top B	16.5
	Top C	14.2
	Top D	9
	Top E	8.9
Noir-2	Top A	11.6
	Top B	11
	Top C	7
	Top D	6
	Top E	13.9

The result of petrophysical calculations for each well is presented in Figure 4 and Figure 5.

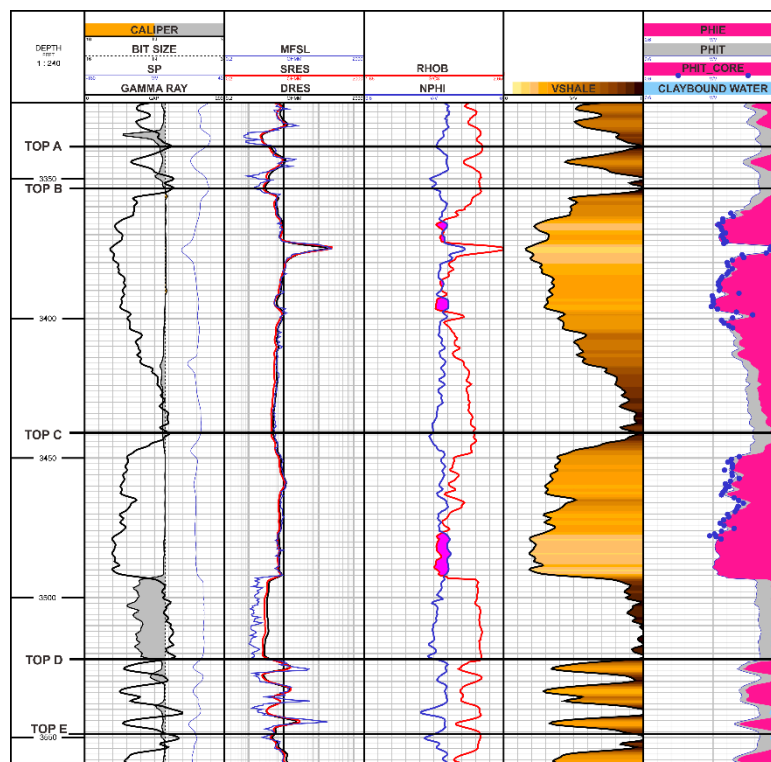


Figure. 4 Well "Noir-1" Petrophysical Calculation Result

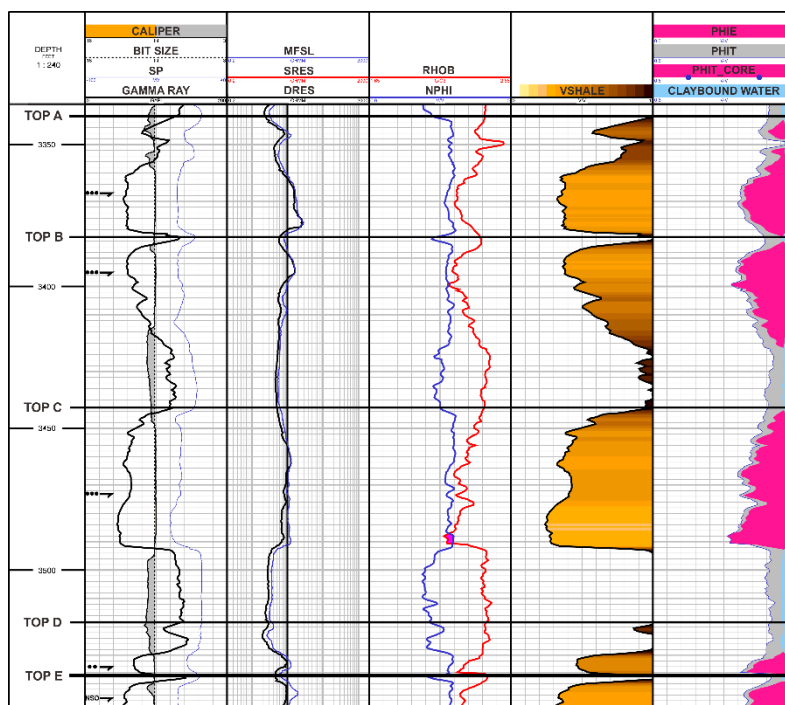


Figure. 5 Well "Noir-2" Petrophysical Calculation Result

Comparison between PHIT and PHIE

Figure 6. illustrates a robust positive relationship between total porosity (PHIT) and effective porosity (PHIE), indicating that intervals with higher total porosity generally also exhibit higher effective porosity. However, PHIT values are consistently higher than PHIE throughout the reservoir intervals because PHIT includes the total pore volume, including pores associated with clay minerals that contain clay-bound water. Due to its immobility, clay-bound water does not aid in the interconnected pore system that facilitates hydrocarbon storage and fluid movement (Ellis and Singer, 2007; Tiab & Donaldson, 2015).

The difference between PHIT and PHIE is controlled by the shale content represented by the calculated shale volume (VSH). Reservoir intervals with relatively high VSH show a greater reduction from PHIT to PHIE because large of proportion of the pore space is associated with shale. Conversely, cleaner sandstone intervals with lower VSH display only a small difference between PHIT and PHIE, indicating better pore connectivity and higher effective storage capacity (Worden et al., 2018). A comparable trend is noted in the cross plot shown in Figure 6, where the majority of data points are grouped near the regression line. This trend indicates that the amount of shale present has a restricted influence on porosity in the majority of the examined reservoir intervals.

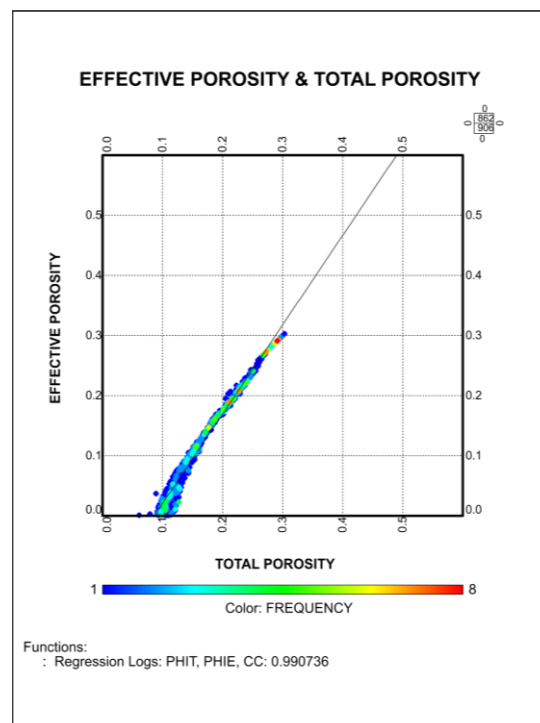


Figure 6. Cross plot between PHIT and PHIE

Reservoir Quality

The determined PHIT and PHIE values indicate variation in reservoir quality across the assessed interval. Reservoir intervals exhibiting greater PHIT and PHIE typically have increased pore space and improved pore connectivity, creating more advantageous conditions for hydrocarbon storage and fluid

flow (Ellis and Singer, 2007; Tiab and Donaldson, 2015). In contrast, intervals with lower PHIE are commonly associated with higher shale content, as indicated by the calculated shale volume (VSH). The presence of shale introduces clay-bound water and poorly connected pore spaces, reducing the effective pore volume available for moveable fluids (Worden et al., 2018).

Among the other examined intervals, the Top B of Noir-1 has the highest average total porosity and effective porosity with values of 19.6% and 16.5%, respectively. In other words, this interval is the one with the best reservoir quality in the studied geographical area. The top C of Noir-2 shows a considerable drop in PHIE (7.0%) compared to PHIT (16.7%). This indicates that a large portion of the total pore space is probably related to shale. This observation is consistent with the findings of the study as the study of shale volume concluded that the intervals with high VSH values are more vulnerable to effective porosity reduction thus less effective hydrocarbon storage and fluid movement (Tiab and Donaldson, 2015; Lai et al., 2018).

The shale content of the post-rift sandstone formed in Early Miocene is an important factor in the quality definition of the reservoir according to the porosity patterns. In general, intervals with cleaner sandstone and lower VSH have higher effective porosity and better pore connectivity. Shale intervals have poorer reservoir quality than other types of intervals (Worden et al., 2018). This is due to the action of clay minerals on the pore structure and reduction of the number of connected pore spaces.

CONCLUSION

This research has concentrated on evaluating the overall porosity (PHIT) and effective porosity (PHIE) of the Early Miocene post-rift sandstone reservoirs in the "Noir" Field, Central Sumatra Basin utilizing well-log information enhanced by core and side-wall core data. Results show that PHIT values are consistently greater than those of PHIE. This is owing to the fact that total porosity included pore space related to shale and clay-bound water (CBW), while effective porosity is linked pore volume available for hydrocarbon storage and fluid transport.

Among the evaluated intervals, Top B of Noir-1 exhibits the highest average PHIT (19.6%) and PHIE (16.5%), indicating the most favorable reservoir interval with better pore connectivity and storage capacity. In contrast, Top C of Noir-2 shows a significant reduction

from PHIT (16.7%) to PHIE (7.0%), reflecting the influence of higher shale content and clay-bound water that reduces effective pore space.

The quality of reservoir of the Early Miocene post-rift sandstone reservoir is mostly determined by the distribution of shale. Shale distribution has an impact on the retention of higher effective porosity and better reservoir characteristics in the cleaner parts of the reservoir with lower VSH. The integration of porosity and shale volume study is very useful to better understand the reservoir quality for the hydrocarbon assessment in the Central Sumatra Basin.

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