

# POROSITY CUT-OFF VALUES EVALUATED BY CLASSIFYING RESERVOIR ROCK TYPES FROM CORES DATA. A CASE STUDY FOR TRIASSIC RESERVOIR T1, BLOCKS 433A&416B, ALGERIA

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## Summary

This paper introduces the method to determine the porosity cut-off values by classifying rock types from cores data based on permeability cut-off value by 1 mD (for sandstone reservoir with oil). The purpose of this method is to calculate net pay reservoir more precisely for estimating hydrocarbons initially in place and building static models. Normally, the cut-off values of porosity are defined on a cross-plot of porosity versus permeability obtained from core data. However, the results of petrophysical analysis are not consistent with DST results. There are some wells with reservoir net pay of several meters, but the DST does not deliver flows. The application of a new method determining the porosity cut-off values on T1 reservoir shows the reservoir net pay is consistent with actual data of the field.

**Key words:** Porosity, permeability, cut-off, rock type, net pay.

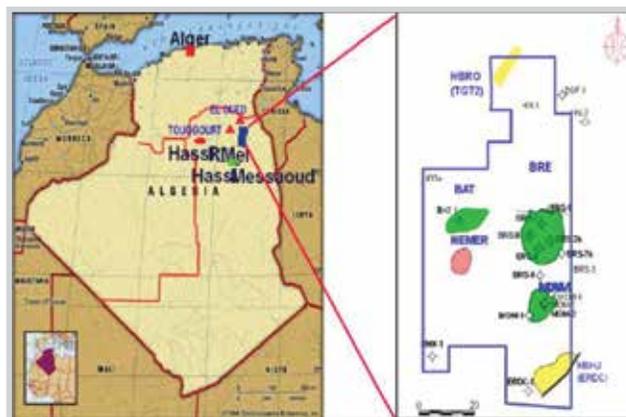
## 1. Introduction

The Blocks 433a&416b locates in the northern part of the Hassi Messaoud uplift in the Sahara basin. To the east of the uplift is the Berkin trough and to the west is the Oued Mya trough, approximately 550 km southeast of the Algiers capital and about 130 km northeast of the Hassi Messaoud oil field (Figure 1).

In 1996, Mobil Oil Company drilled the MAM-1 exploration well and discovered hydrocarbons in the sandstone reservoirs of the Ouargla and Triassic S1 formations. Five wells were drilled to explore the Triassic-T1 reservoir. Two wells, MAM-3 and MAM-4, were conducted core sampling, while three wells (MAM-3, MAM-4 and MAM-5) got the DSTs conducted to evaluate the reservoir performance capacity. The DST showed the MAM-4 was dry well; MAM-3 and MAM-5 had good oil production rate with main flow rate of 1,300 barrels per day and 850 barrels per day, respectively.

The analysis of core samples from the drilling wells indicates significant variations in the porosity

- permeability relationship within a wide range. This demonstrates changes in sedimentary characteristics and depositional environments, leading to changes in reservoir properties. Considering these distinct characteristics, the conventional approach applied in previous studies, using a porosity - permeability correlation coefficient of  $r^2 = 0.73$  (Figure 19), does not accurately reflect the effective thickness of the reservoir. Therefore, a new approach is implemented, dividing the core sample data into relative rock types (RRTs). Each RRT exhibits similar flow unit characteristics which enables the determination of



**Figure 1.** Location of Blocks 433a&416b.



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separately critical values for each RRT, resulting in higher correlation coefficients  $r^2$  ranging from 0.83 - 0.9. Based on the predicted RRT results and the application of cut-off values for each RRT, the net pay thickness of commercial value can be accurately determined. Additionally, this approach facilitates the construction of a detailed reservoir property simulation model.

## 2. Reservoir characterization of Triassic-T1 formation, Blocks 433a&416b, Algeria

The field is located on the Amguid Messaoud uplift, between the Oued Mya trough and the Berkine basin. The reservoir consists of Triassic-aged sandstone formations, with proven hydrocarbon systems. The source rock is Silurian-aged shale; seal rocks are shale and thick salt formations; reservoir rocks are TA and T1B sandstones belonging to the Triassic-T1 formation. The sedimentary rocks consist of interbedded sandstones, siltstones, and shales, with occasional dolomite layers. They were deposited in a fluvial to deltaic environment (Figure 2), fining upward as indicated on log data, sand body thicknesses ranging from 15 m to 20 m (Figure 3) [1]

In terms of petrography: the analysis of petrographic components in samples taken at depths of 3,692.3 mMD and 3,712.2 mMD from the well MAM-4 reveals that the rock is predominantly composed of quartz, accounting for approximately 75 - 77% of the composition. The main clay minerals present are chlorite and illite, constituting around 12% of the composition. Minor minerals include anhydrite, comprising 1 - 2% of the composition. The fine-grained sandstone is characterized by a grayish blue/dark gray color, medium grain size, good sorting, and subangular to rounded grains. The siltstones are green or light green, with medium hardness and fine grain size, while the shales are brown or reddish brown, with medium hardness and subangular grains (Figures 4 - 7) [2].

Rock properties: according to the results by applying the cut-off value to the porosity of 8% of reservoir T1A, the average net pay thickness is 4.3 m, the average porosity is 10%, and the average water saturation is 25%. Reservoir T1B has an average net pay thickness of about 5.3 m, average porosity is 12%, and average water saturation is 24%.

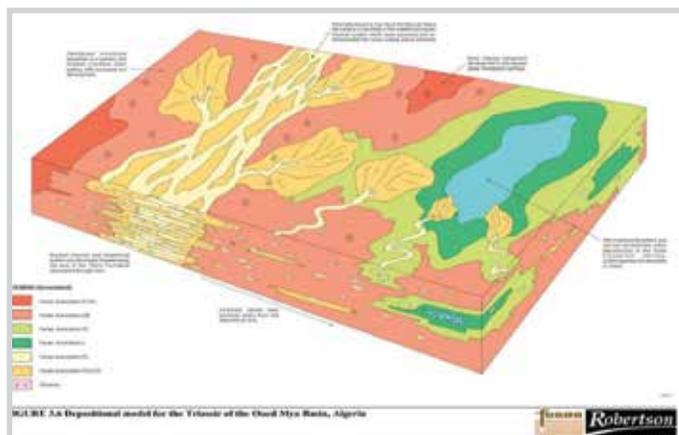


Figure 2. Triassic sedimentary model.

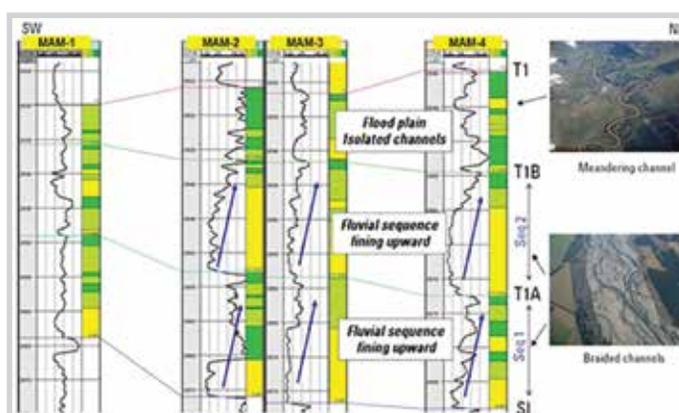


Figure 3. Characteristics of well log.

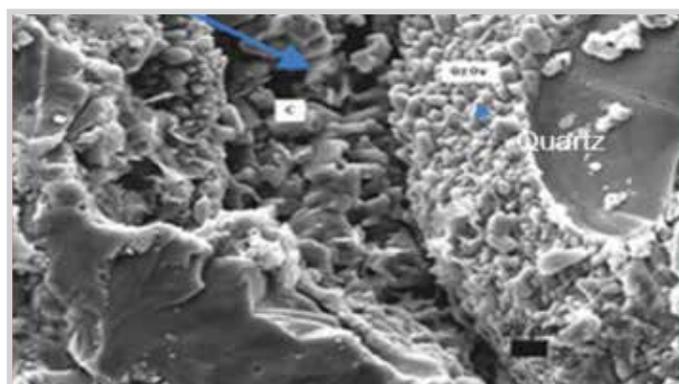


Figure 4. SEM sample at depth 3692.3 mMD MAM-4.

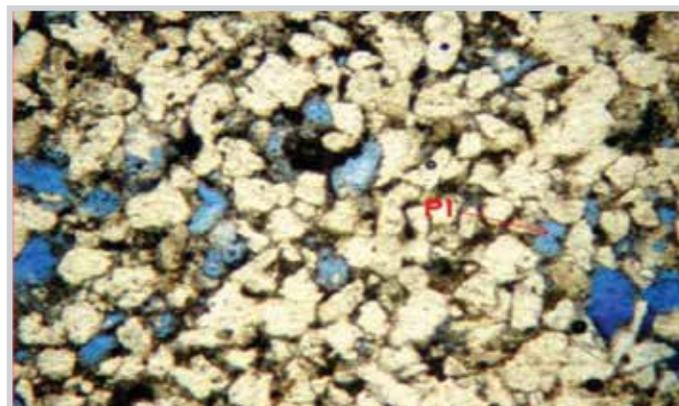


Figure 5. Thin section sample at depth 3692.3 mMD, MAM-4.



Figure 6. Thin section sample at depth 3712.2 mMD, MAM-4.

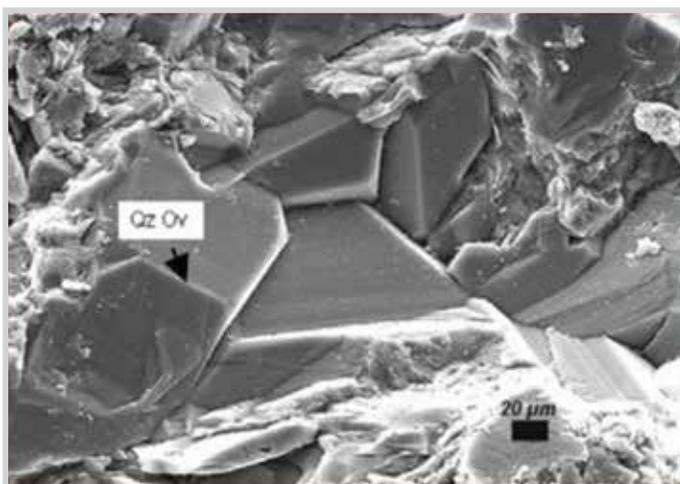


Figure 7. SEM sample at depth 3712.2 mMD, MAM-4.

Table 1. Summary of core data for MAM and nearby field wells.

Name of wells	sample	Sampling interval (mMD)	Formation	Length (m)	Recovery (%)
MAM-3	1	3,665 - 3,702	Triassic-T1	37	100
MAM-4	1	3,690 - 3,720.7	Triassic-T1	30.65	100
BRE-1	2	3,598.5 - 3,625	Triassic-T1	26.5	100
BRE-202	1	3,631 - 3,649	Triassic-T1	18	100

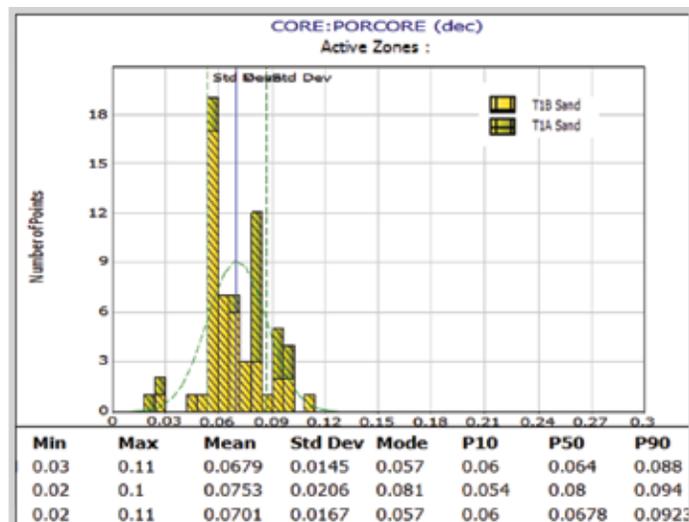


Figure 8. Porosity distribution chart of well MAM-3.

### 3. Core data analysis result and rock typing classification (RRT) to determine the cut-off value of porosity

In the field area, core samples were taken from T1 formation at the wells MAM-3 and MAM-4. These core data were used for classifying RRT. In addition, core sample documents from the wells BRE-1 and BRE-202 in the nearby field BRE were also used (due to the same sedimentary formation and characteristics). The total length of the core samples is 112.15 m with a successful recovery rate of 100% (Table 1) [3].

All core data are used not only for petrophysical evaluation and interpretation but also for other studies, including identifying RRT to determine the cut-off value of porosity.

Detailed results of MAM wells core analysis are below:

- The porosity at the well MAM-3 is from 2.3% to 15.4% with an average of 9.7%; the permeability is from 0.02 mD to 19.6 mD with an average of 1.2 mD. The T1A sand reservoir has better porosity and permeability than the T1B sand reservoir, as shown in Figures 8 and 12.

- The porosity of well MAM-4 is from 2% to 11% with an average of 7%; the permeability is from 0.01 mD to 72 mD with an average of 9.9 mD. The T1A sand reservoir has lower porosity and permeability than the T1B sand reservoir, as shown in Figures 9 and 13.

- The porosity of well BRE-1 is from 1.7% to 14% with an average of 7.3%; the permeability varies from 0.1 mD to 78 mD with an average of 15 mD. There is no T1B sand reservoir in the BRE mining area, Figure 10 and Figure 14.

- The porosity of BRE-202 is from 2.9% to 13% with an average of 7.9%; the permeability is from 0.02 mD to 36.9 mD with an average of 5.3 mD. Like the well BRE-1, there is no T1B sand body in the BRE-202 drilling area, Figures 11 and 15.

The results of core data analysis from the wells show a large variation in porosity and permeability. This indicates variations in sediment characteristics and depositional environments due to changes in reservoir properties. The evaluation of the gamma ray curve characteristics (Figure 3) shows that sedimentary rocks formed in levee or floodplain

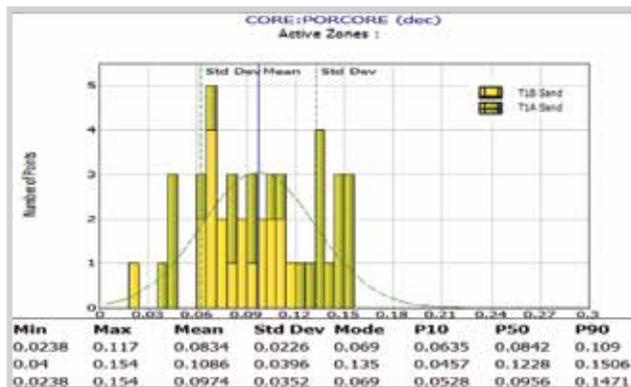


Figure 9. Porosity distribution chart of well MAM-4.

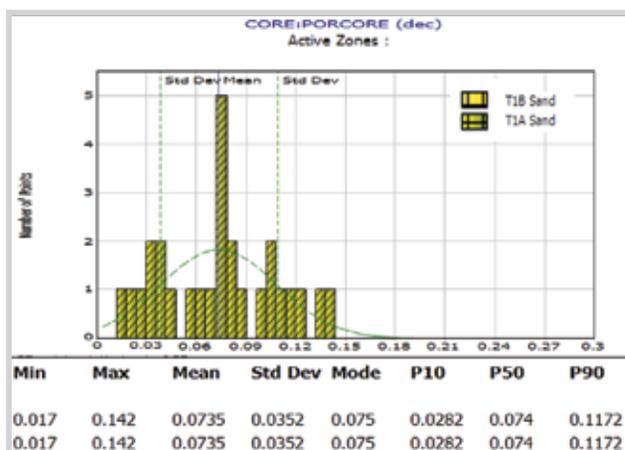


Figure 10. Porosity distribution chart of BRE-1 well.

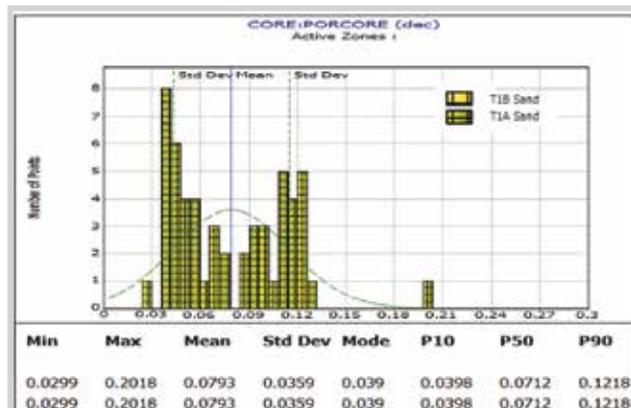


Figure 11. Porosity distribution chart of well BRE-202.

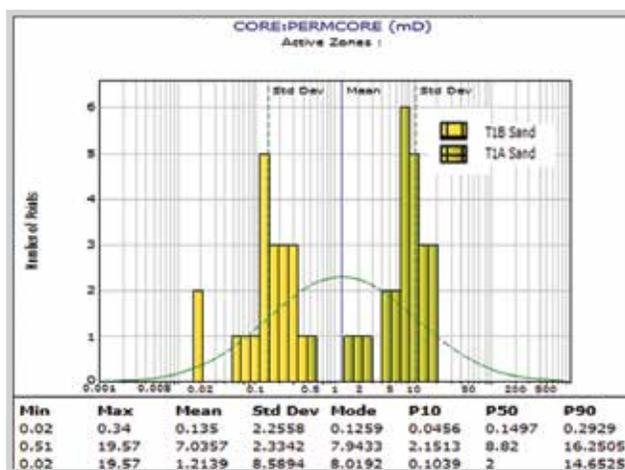


Figure 12. Permeability distribution chart MAM-3.

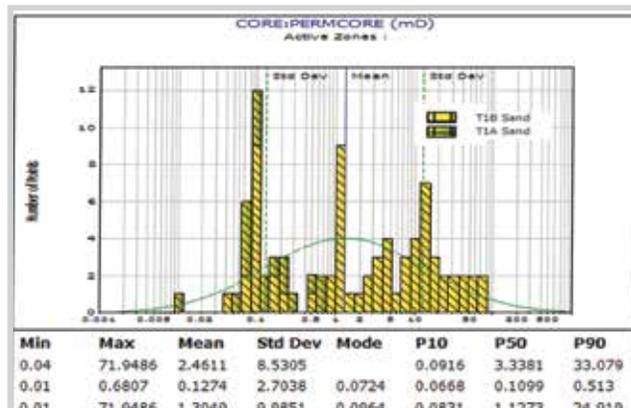


Figure 13. Permeability distribution chart of MAM-4.

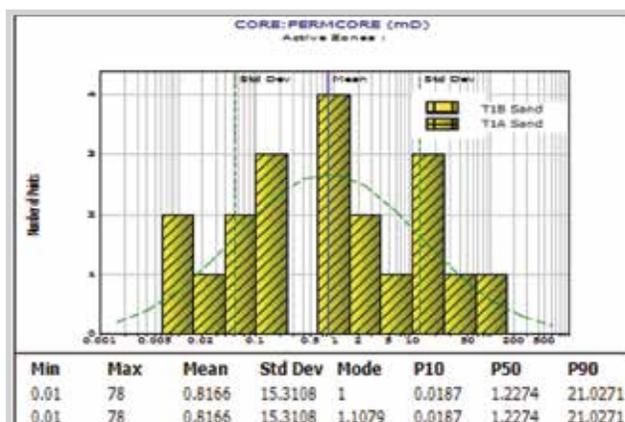


Figure 14. Permeability distribution chart of BRE-1.

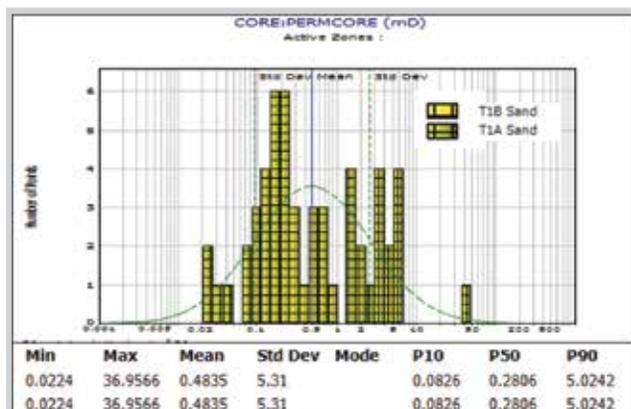


Figure 15. Permeability distribution chart of BRE-202.

environments correspond to lower porosity and permeability, while rocks formed in channel environments correspond to higher porosity and permeability. Based on these results, the core samples are divided into rock reservoir types (RRTs), each with similar characteristics to a specific flow unit, in order to determine individual cut-off values for each rock type. Applying these cut -

off values accurately determines the reservoir net pay thickness. This approach also builds a detailed simulation model.

Each type of rock is characterized by specific geological permeability and properties, which are represented by a flow unit. There are various methods to determine the flow unit from porosity and permeability data, such as constructing a cross-plot graph between rock quality index (RQI) and porosity index (PhiZ) or using statistical analysis with the Ward algorithm. In this paper, the flow zone indicator (FZI) distribution chart method is used to determine and classify RRT [4].

FZI distribution chart method: reservoir quality indicators (RQI), flow zone indicator (FZI), permeability of rock, and porosity index (PhiZ) are determined from core data.

In which:

$$RQI = 0.0314 \times \text{Sqrt}(K/\Phi)$$

$$\Phi Z = \Phi / (1 - \Phi)$$

$$FZI = RQI / \Phi Z$$

To build an FZI distribution chart on a logarithmic scale, depending on the sample data set, there will be different distributions. When the sample groups are clearly separated, the number of RRT and the average FZI value for each RRT type can be determined.

Based on the core sample of the field and core samples from neighboring wells, the FZI distribution chart method has identified 3 main types of RRT (Figure 17) as follows:

- RRT-1: a non-productive background type with poor reservoir characteristics, varying porosity from 5.1% to 12.7%, permeability from 0.01 - 0.43 mD, with an average of 0.1 mD, and FZI ranging from 0.046 to 0.65, with an average of 0.37.
- RRT-2: is a type of RRT with average reservoir properties, porosity varies from 2.3% - 13.6%, permeability varies from 0.019 - 15 mD, average 0.96 mD, FZI changed from 0.64 to 2.19 with an average of 1.29.
- RRT-3: is a type of RRT with good reservoir properties, porosity varies from 3 - 14.2%, permeability varies from 0.17 - 78 mD, average 4.96 mD, FZI changed from 2.19 - 4.78 with an average of 3.

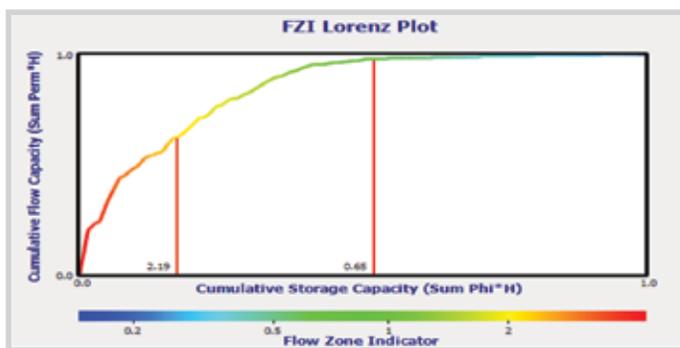


Figure 16. Cumulative FZI distribution chart.

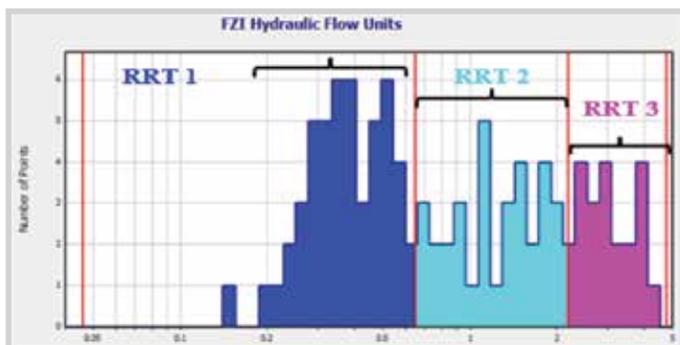


Figure 17. FZI distribution chart.

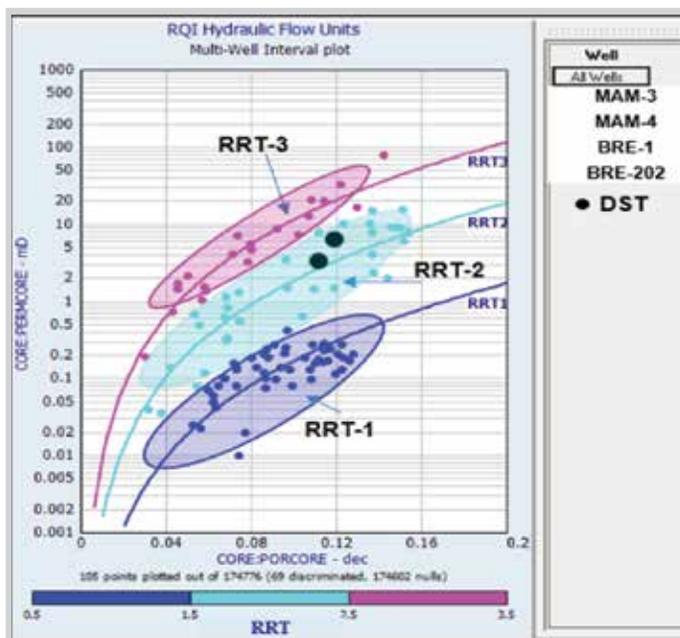


Figure 18. Porosity/permeability cross plot.

Determining the cut-off value of porosity:

Based on the porosity and permeability data from core samples of wells in the Blocks 433a&416b and nearby field, the relationship between porosity and permeability shows a large variation in permeability at the same porosity value. The conventional method of establishing the empirical relationship between porosity and permeability has a correlation coefficient  $r^2 = 0.73$  (Figure 19). If a permeability cut-off value

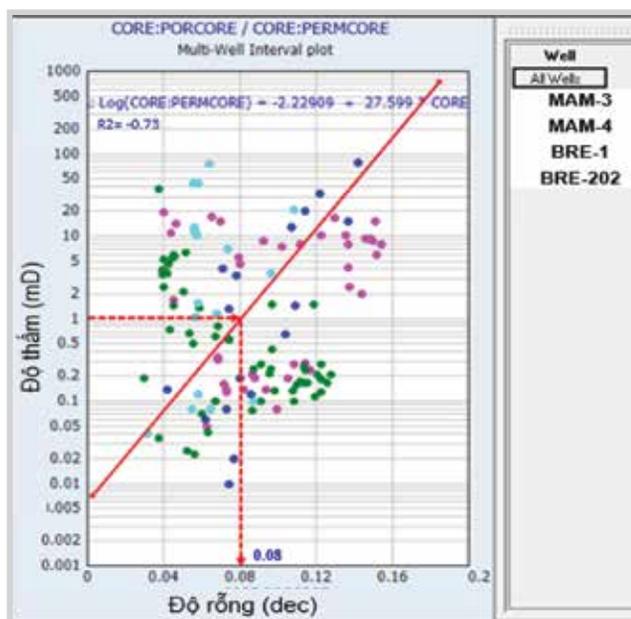


Figure 19. Determining the porosity cut-off value by conventional method.

of 1 mD is applied to determine the porosity cut-off value, it is 0.08 (Figure 19). Meanwhile, using the RRT division results from core sample documents and applying a 1 mD cut-off value for each RRT through the equation  $Perm = Phi^3 * (FZI / (0.0314 * (1 - phi)))^2$  (Kozeny Carman empirical equation), the cut-off values are determined for each RRT type (Figure 20) as follows:

- RRT-1 porosity cut-off value is 17%,  $r^2 = 0.29$
- RRT-2 porosity cut-off value is 8.2%,  $r^2 = 0.83$
- RRT-3 porosity cut-off value is 4.5%,  $r^2 = 0.91$

where r is the correlation coefficient.

#### 4. The cut-off values after applying the RRT method.

Applying the permeability cut-off 1 mD for each type of RRT, where the cut-off value of porosity for RRT-1 is 17%, for RRT-2 is 8.2%, and for RRT-3 is 4.5%. The results show a significant decrease in the net pay of the T1B sand reservoir in most of the wells. In well MAM-4, if the cut-off value of porosity is applied using the conventional method ( $Phi \geq 8\%$ ), the net pay thickness is 4.11 m, while the actual test results for this well show no flow. When the cut-off value of porosity is applied according to RRT, the net pay thickness is 0.76 m, which is more consistent with the actual data of the field (Figure 21).

For the T1A sand reservoir, if the porosity cut-off is applied according to RRT, the results show an increase in the net pay thickness at well MAM-3 by 0.44 m and a decrease in the net pay thickness at well MAM-5 by 0.45 m (Figure 22).

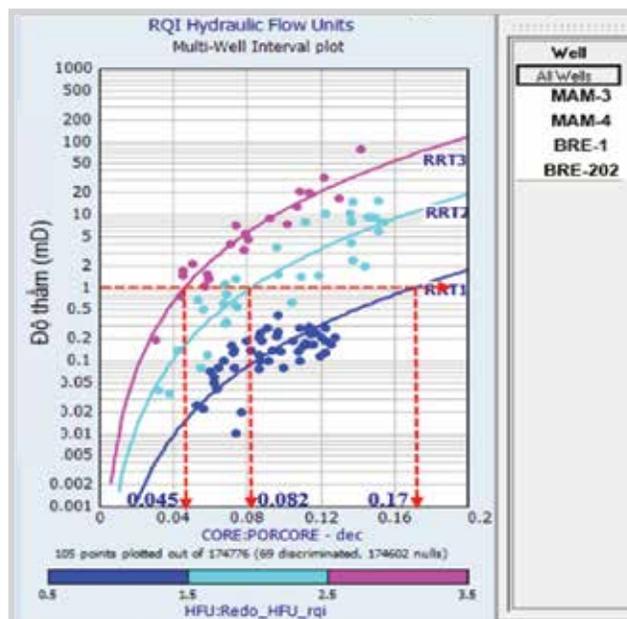


Figure 20. Determining the cut-off value for each RRT type.

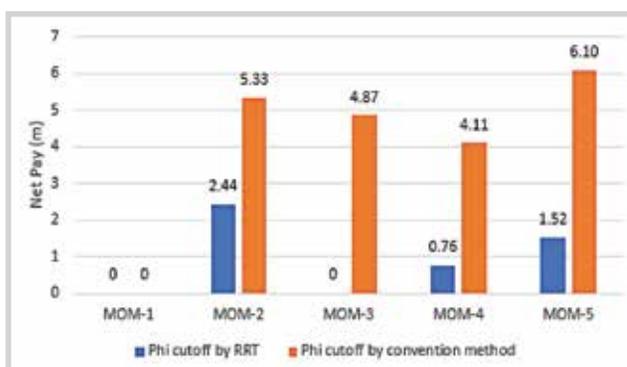


Figure 21. Distribution chart of the net pay thickness of the T1B reservoir.

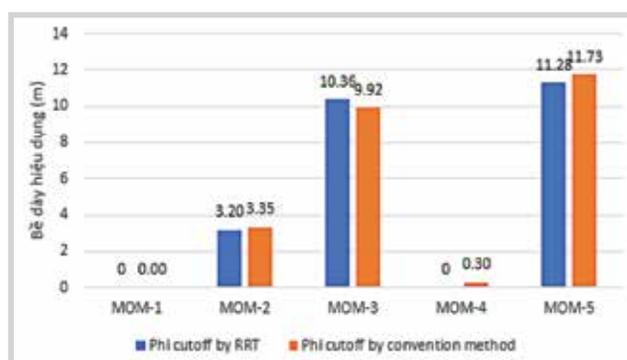


Figure 22. Distribution chart of the net pay thickness of the T1A reservoir.

Table 2. Summary of the effective thickness parameters applying the porosity threshold according to RRT

Reservoir Name	Net pay (m)	Different results
T1B	0.94	No flow in DST at MAM-4, tight RRT at MAM-5
T1A	4.97	Good flow in DST at MAM-3 and MAM-5

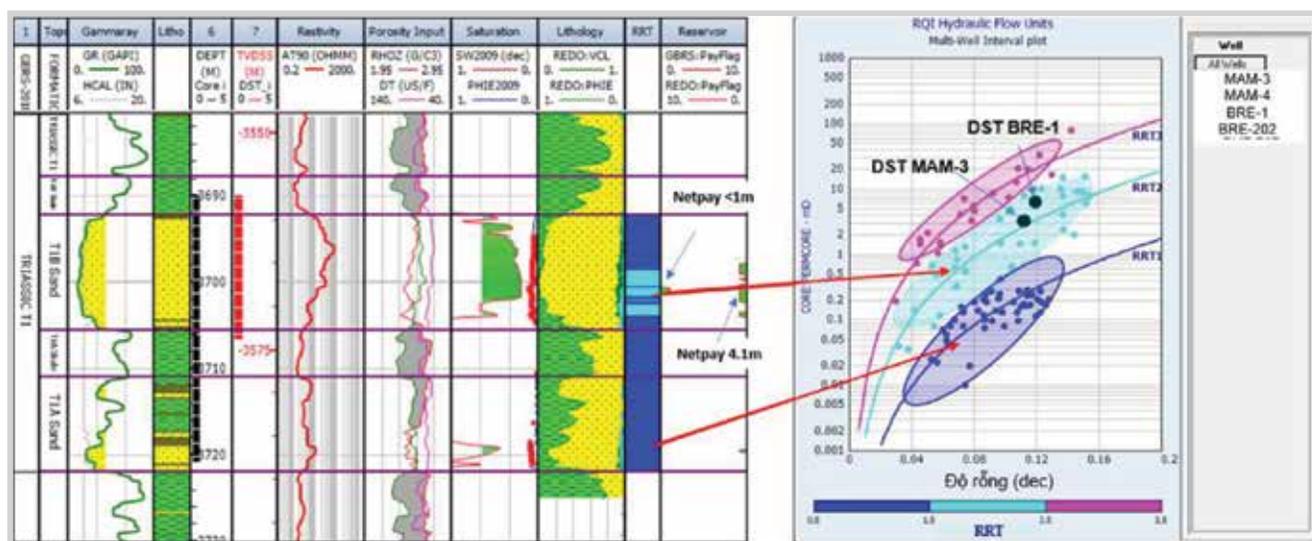


Figure 23. Composite logs derived from the porosity cut-off by RRT and the conventional method.

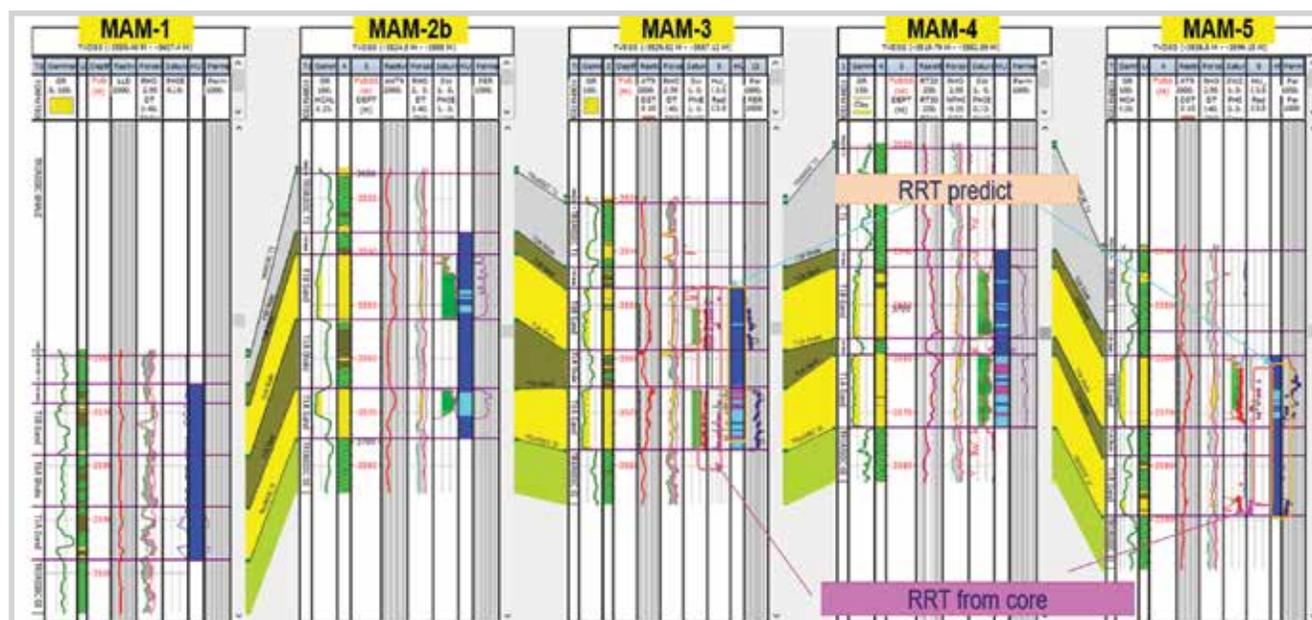


Figure 24. Well correlation in Blocs 433a&416b area.

Table 3. Summary of the petrophysical parameters result by using the porosity cut-off by RRT and conventional method.

Formation top			Petrophysical parameters using porosity cut-off by RRT method							Petrophysical parameters porosity cut-off by conventional method				
Reservoir/ well name	Top	Bottom	Thickness m	Net pay m	N/G	Av Phi dec	Av Sw dec	Vcl dec	Net pay m	N/G	Av Phi dec	Av Sw dec	Vcl dec	
	TVDSS	TVDSS												
T1B	MAM-1	3,565	3,578	13.36	0	---	---	---	0	---	---	---	---	
	MAM-2	3,537	3,553	15.82	2.44	0.15	0.09	0.18	5.33	0.34	0.09	0.23	0.15	
	MAM-3	3,542	3,558	16.55	0	---	---	---	4.87	0.29	0.10	0.30	0.14	
	MAM-4	3,555	3,573	18.15	0.76	0.04	0.09	0.26	4.11	0.23	0.10	0.29	0.04	
	MAM-5	3,535	3,556	20.19	1.52	0.08	0.10	0.20	6.10	0.30	0.10	0.20	0.21	
T1A	MAM-1	3,578	3,593	14.82	0	---	---	---	---	---	---	---	---	
	MAM-2	3,553	3,571	18.5	3.20	0.17	0.11	0.31	3.35	0.18	0.11	0.32	0.07	
	MAM-3	3,558	3,577	18.49	10.36	0.56	0.12	0.26	9.92	0.54	0.12	0.26	0.09	
	MAM-4	3,573	3,589	16.32	0	---	---	---	0.30	0.02	0.08	0.51	0.11	
	MAM-5	3,556	3,573	16.96	11.28	0.67	0.12	0.20	11.73	0.69	0.12	0.20	0.13	

## 5. Conclusions

The Triassic-T1 sedimentary rocks deposited in a fluvial and deltaic environment, lithologically characterized by quartz and clay minerals such as chlorite and illite. In addition, there are accessory minerals such as anhydrite and calcite in a small quantity (up to 1 - 2%). The presence of clay minerals and accessory minerals is the main factor affecting the reservoir properties. Therefore, the cut-off value for porosity obtained by conventional methods and then the derived net pay thickness do not accurately reflect the effective thickness of the reservoir which can actually deliver flow.

A new approach for estimation of the cut-off value is introduced using the data from core analysis. Based on the lithological properties, the reservoir will be classified into reservoir rock types (RRT). Each RRT has certain lithological and physical characteristics and is represented by a "flow unit" and then the cut-off values will be defined. By using the newly derived cut-off value for each RRT type, net pay thickness is accurately determined for each reservoir

of the wells. Based on this approach, the estimated net pay thickness at well MAM-3 and MAM-5 are 10.36 m and 11.28 m respectively, that conforms with the DST test results with a flow rate of 850 - 1,300 barrels per day. This new approach also serves to build a detailed simulation model.

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