

# The use of cross-plots in lithology delineation and petrophysical evaluation of some wells in the western Coastal Swamp, Niger Delta

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**Abstract** The inaccurate delineation of the sand intervals in well logs can significantly affect the porosity, permeability, pore-size geometry and net-to-gross ratio of the reservoir units. This study utilized well log cross-plots to accurately delineate the lithologic units and also used petrophysical evaluation methods to determine the reservoir properties of the sandstone intervals in three wells (L, M, N wells) of the Daura field, Niger Delta. The cross-plots of the gamma ray with density, gamma ray with sonic and gamma ray with depth were generated using the Hampson Russel software. The result of the cross-plot clusters shows two major lithologies of sandstone and shale with occasional intercalation of sand and shale units. Fluid detection analysis shows that reservoirs L3 (well L), M4–M5 (well M), and N2–N3 (well N) were found to contain oil, while reservoir M2 (well M) contains gas. The rest of the reservoir intervals in the three wells contain water, and the average porosity ranges from 14.23 to 28.01%. This study has shown that the cross-plots approach can be used to accurately delineate reservoirs for further formation evaluation. It therefore means that an outright estimation of petrophysical properties on wrongly delineated reservoirs can significantly affect the porosity, permeability, pore-size geometry and net-to-gross ratio of the reservoir units.

**Keywords** Log cross-plot · Lithologic discrimination · Reservoir quality

## Introduction

Exploration for new reserves and recovery from existing accumulations have become increasingly challenging due to inadequate description and delineation of reservoir architecture using well logs, seismic and geological information (Ekine and Ibe 2013; Adewoye et al. 2015). The knowledge of reservoir dimensions such as thickness and areal extent is an important factor in quantifying producible hydrocarbon reservoir (Schlumberger 1989). These parameters are important because they serve as veritable inputs for reservoir volumetric analysis (Edward et al. 1988; Ekine and Ibe 2013). The challenges in reserve estimation and developments are sometimes attributed to clay volume effects on the reservoirs (Asquith 2004). Additionally, there are issues relating to poor prediction of reservoir properties and lithofacies from core analysis due to poor core sample quality and preservation techniques. Such core information is also usually wrongly correlated with seismic or well log data. As a result of these, detailed petrophysical evaluation is usually required for optimized development and production, especially in the highly heterogeneous environments like the paralic successions of the Agbada Formation of the Niger Delta.

In order to resolve this challenge, the use of well log cross-plots and petrophysical studies to predict the reservoir properties and lithofacies were employed in this study. Cross-plotting or statistical techniques enable evaluation of lithology and pore fluid variations on both regional and detailed reservoir scales (Hunze and Wonik 2007; Lamont et al. 2008). Gray and Andersen (2000) as well as Anderson and Gray (2001) had demonstrated that many different lithologies like coal, shale, sandstone, gas saturated sands and carbonates can be identified by cross-plots of well logs (e.g. resistivity vs gamma ray, density versus gamma ray).

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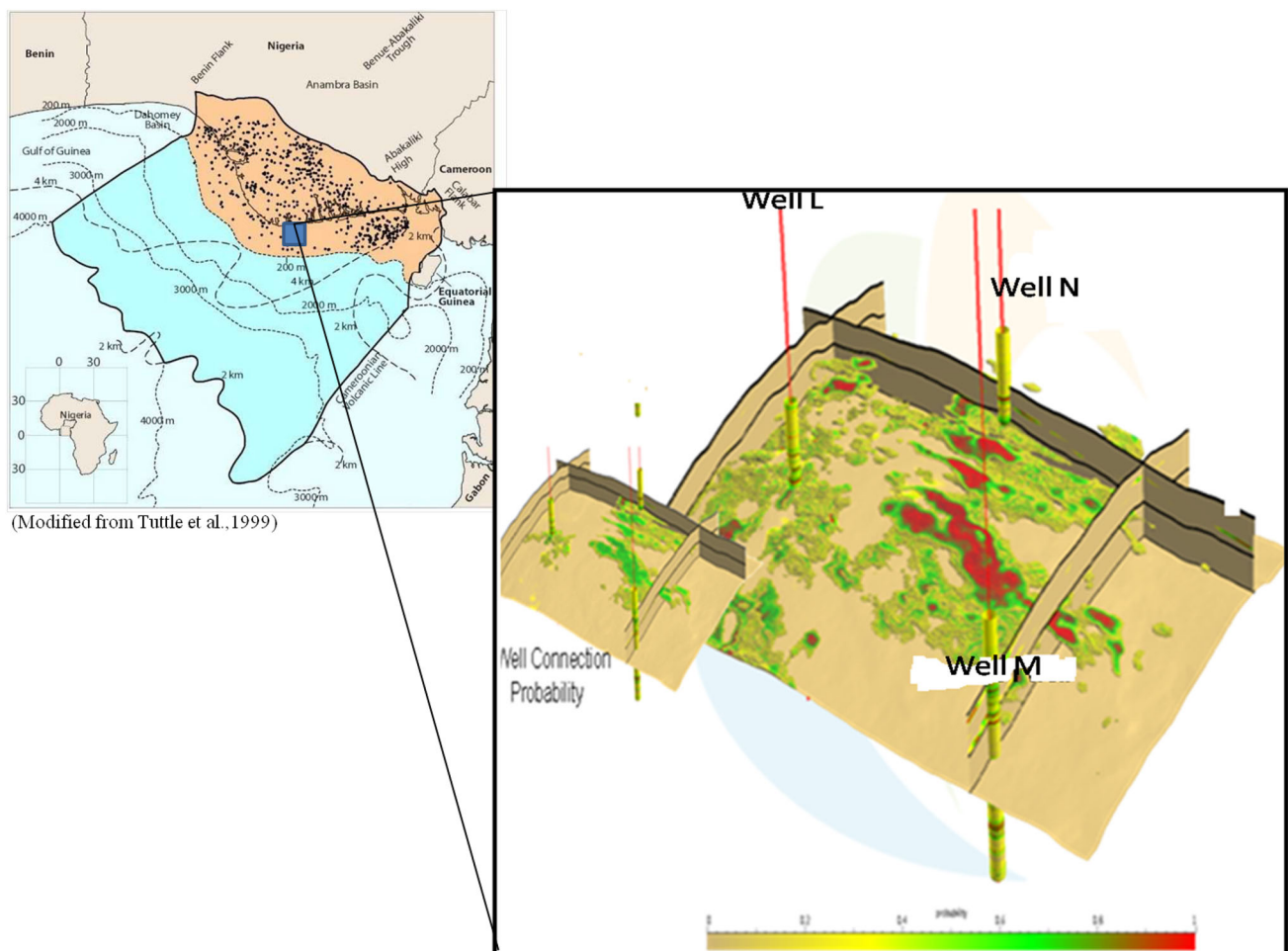
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The objective of this study is to analyse well logs in order to delineate the lithofacies and predict the reservoir qualities of the sand units using the clusters of log cross-plots (Chatterjee and Paul 2012) and petrophysical evaluations.

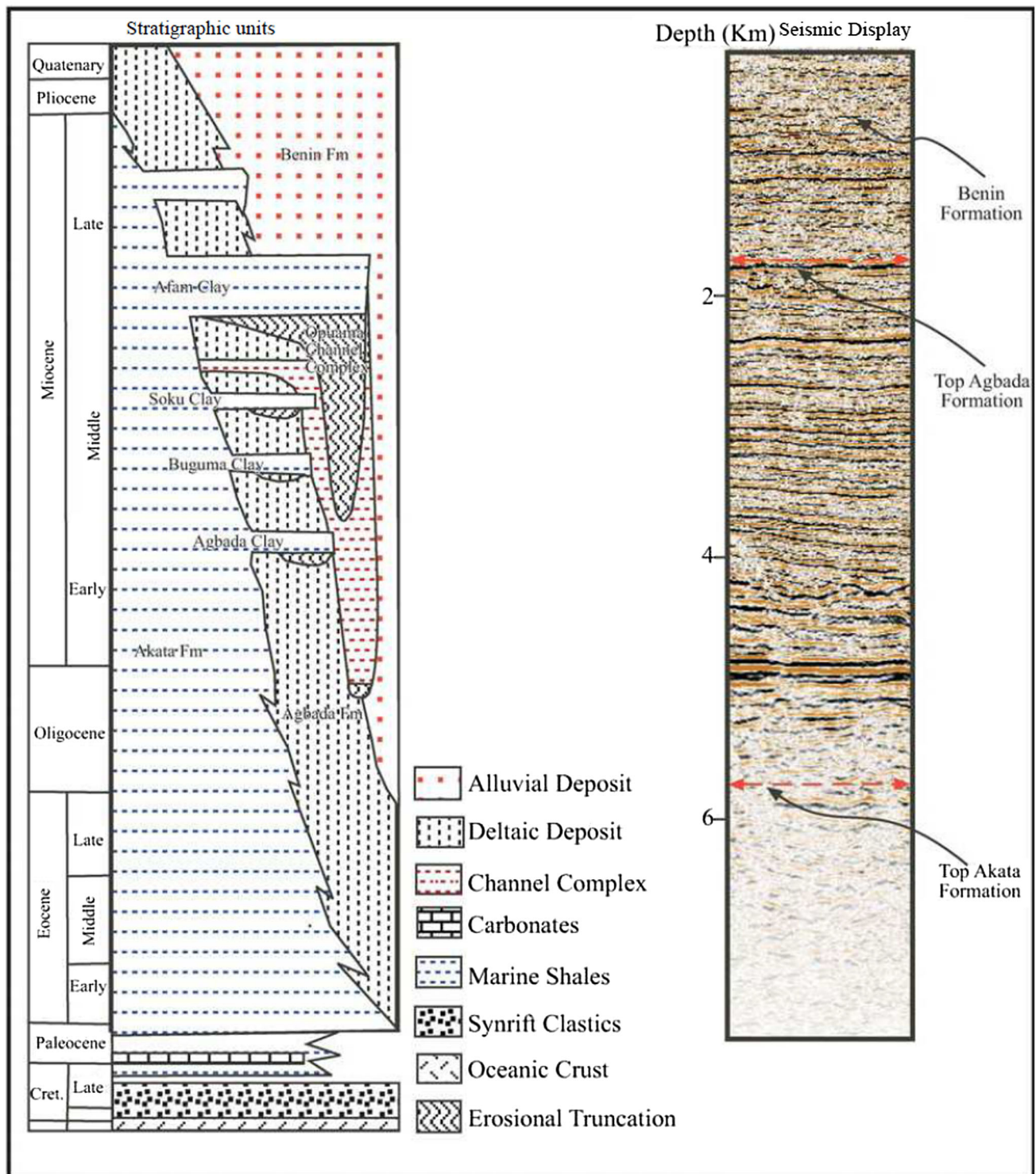
## Geologic Setting and Stratigraphy of the Niger Delta

The study area (Fig. 1) is located within the transition between the Coastal Swamp II and the western Offshore Niger Delta. The Tertiary Niger Delta covers an area of about 75,000 km<sup>2</sup> and is composed of an overall regressive clastic sequence which reaches a maximum thickness of 9000–12,000 m (Evamy et al. 1978). The stratigraphy of the Niger Delta consists of three diachronous lithostratigraphic units that form a major regressive cycle from Eocene to Recent in age (Fig. 2). These are the continental top facies (Benin Formation), the paralic delta front facies (Agbada Formation) and the Akata Formation which form the pro-delta facies. This pro-delta facies is represented by the

prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios which apparently decrease in age, basinward (Short and Stauble 1967). The Benin Formation is the shallowest unit of the Niger Delta clastic wedge and occurs throughout the entire onshore and part of the offshore Niger Delta. The overall thickness of the formation varies from 1000 ft in the offshore to 10,000 ft, onshore. Various structural units are identifiable within the formation, and they include point bars, channel fills and natural levees. The oldest known age of the Benin Formation at the surface is Miocene, while the subsurface is Oligocene. The Agbada Formation underlies the Benin Formation and occurs throughout Niger Delta clastic wedge with thicknesses ranging from 3000 to 4500 m, where it outcrops around Ogwashi and Asaba, southern Nigeria (Doust and Omatsola 1989). The lithologies consist of alternating sands, silts and shales, arranged within ten- to hundred-feet successions, and defined by progressive upward changes in grain size and bed thickness. The strata are generally interpreted to have been formed in fluvial-deltaic environment. The formation ranges in age from Eocene to Pleistocene. Most structural traps



**Fig. 1** Province geologic outline map of the Niger Delta (*inset*) showing sand connectivity analysis of the three wells



**Fig. 2** Stratigraphy of the Niger Delta and variable density seismic display of the main stratigraphic units in the outer and thrust belt and the main reflectors (Lawrence et al. 2002)

observed in the Niger delta developed during syn-sedimentary deformation of the Agbada paralic sequence (Evamy et al. 1978). The interbedded shales within the formation form the primary seal.

The Akata Formation is the basal sedimentary unit 73 estimated to be 21,000 ft thick in the central part of the clastic wedge (Doust and Omatsola 1989). It is characterized by dark grey shales and silts, with rare streaks of sand



of probable turbidite flow origin (Doust and Omatsola 1989). The Akata shales are typically under-compacted and over-pressured. The shales also form diapiric structures including shale swells and ridges which often intrude into overlying Agbada Formation. These shale structures form a variety of structural traps for the hydrocarbons in the overlying sand-shale succession of Agbada Formation.

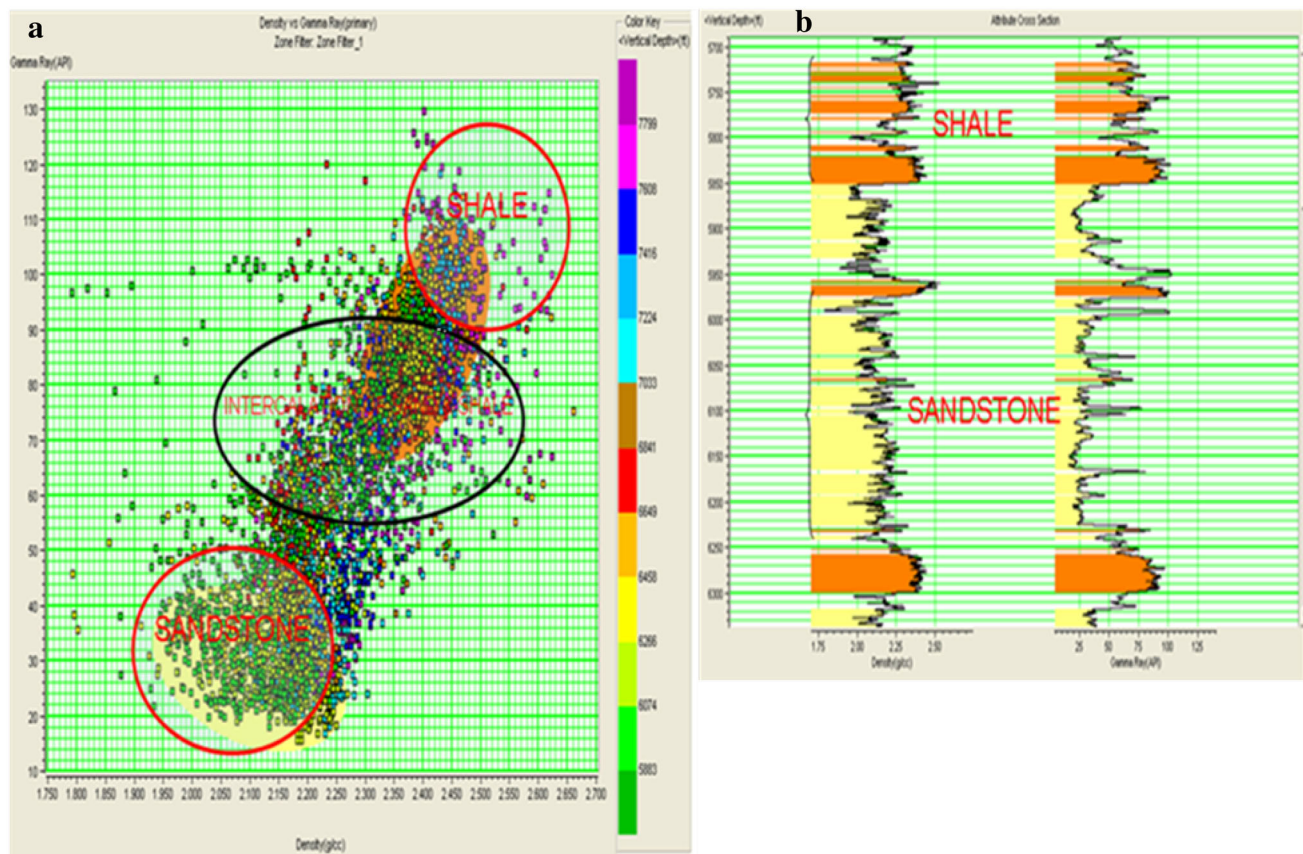
## Materials and methods

In this study, a suite of well logs from wells L, M and N (Fig. 3), obtained from the ‘Daura Field’ of the Niger Delta, was analysed using the Hampson Russell software to generate log cross-plots that were interpreted. The cross-plots of the gamma ray with density (GR-RHOB), gamma ray with sonic (GR-DT) and gamma ray with depth (GR-Depth) were generated using this software. These cross-plot clusters were used to accurately delineate the different lithofacies and mark out the reservoir units for further petrophysical evaluation. The well logs used for this analysis comprise gamma ray (GR), deep laterolog (LLD), shallow laterolog (LLS), density log (RHOB) and transit time log (DT). Then, the clay volume ( $V_{\text{clay}}$ ) was estimated using the Larionov (1969) equation for

Tertiary rocks;  $V_{\text{clay}} = 0.083(2(3.7 \times x) - 1)$ , where  $x$  is the gamma ray index. The interval of evaluation is 0.5 ft. Assessment of reservoir porosity was done using the density log (RHOB), which is given as  $\Phi_D = \rho_{\text{ma}} - \rho_b / \rho_{\text{ma}} - \rho_{\text{fl}}$ , where  $\Phi_D$  = density porosity,  $\rho_{\text{ma}}$  = matrix density (sandstone = 2.65 g/cc),  $\rho_b$  = density log reading,  $\rho_{\text{fl}}$  = fluid density (fresh water = 1.0 g/cc). The calculated total porosity values were corrected for clay effect using standard equation for correcting total porosity for clay to obtain the effective porosity for the reservoirs. The standard equation is stated thus:  $\Phi_E = \Phi_T - V_{\text{clay}} \times \Phi_{\text{clay}}$ , where  $\Phi_E$  = clay corrected effective porosity,  $\Phi_T$  = total formation porosity,  $V_{\text{clay}}$  = clay volume and  $\Phi_{\text{clay}}$  = total porosity 96 in clay. These effective porosity values were then adopted for the water saturation evaluation using the following formula:  $S_w = (1/\Phi) \times (\sqrt{R_w/R_t})$ , where  $S_w$  = water saturation,  $\Phi$  = porosity,  $R_w$  = water resistivity,  $R_t$  = true formation resistivity.

## Results and discussion

The result of the GR-RHOB cross-plot in well L shows three clusters (Fig. 3a). The lowest cluster between 5883 and 6458 ft indicates the existence of sandstone with a



**Fig. 3** **a** Lithological identification cross-plot of GR-DT. **b** Attribute cross section of GR-DT cross-plot for well L

**Table 1** Summary of petrophysical results for well L

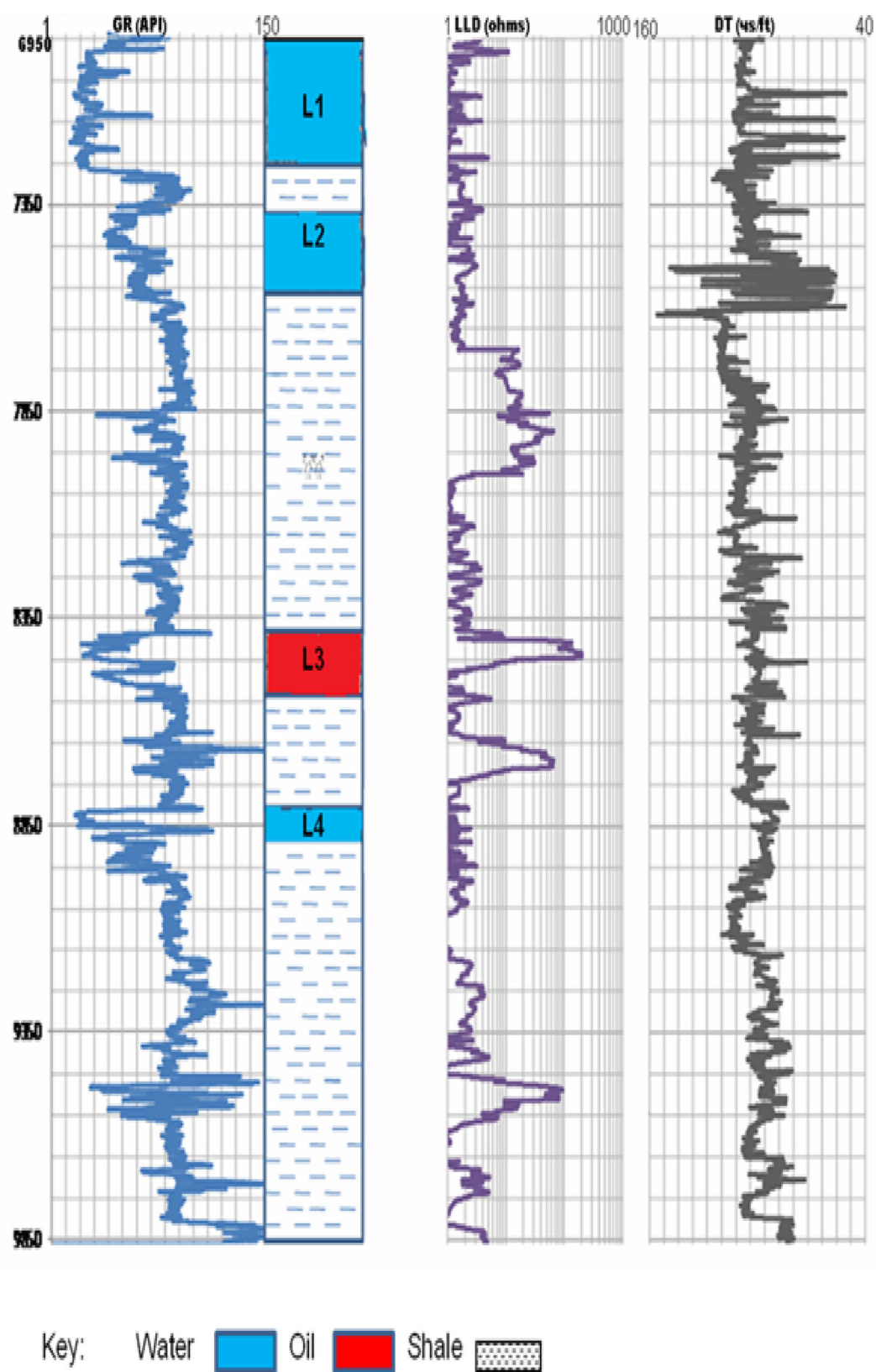
Reservoir units	Interval (ft)	Net sand (ft)	Average porosity (%)	Average permeability (md)	Average MHI	Average water saturation (%)	Average Vshale (%)	Average resistivity ( $\Omega$ m)	Fluid type
L1	6989–7240	252	20	–	0.31	82.01	6.53	3.44	Water
L2	7382–7570	187	19	–	0.24	78.43	5.69	4.41	Water
L3	8390–8499	110	21	79.79	0.16	26.68	7.13	43.07	Oil
L4	8750–8830	21	16	–	0.36	64.60	9.21	1.04	Water

gamma ray range of 15–45 API and density range of 1.90–2.25 g/cc values. The middle cluster is a unit consisting of the intercalation of sand and shale. The gamma ray and density readings range from 55 to 90 API and 2.15–2.55 g/cc, respectively. The third cluster occurs within GR value of 92–122 API and density value of 2.40–2.80 g/cc, and represents the more shaley interval of the well. The cross-plot of Depth-DT for well L also shows a similar result as that of GR–DT plot. The vertical attribute (cross section) of the generated cross-plot shows a clear distinction between sand and shale units with the associated heterolithic interval (Fig. 3b); four reservoir units (L1–L4) were delineated. Estimated clay volumes for the reservoirs range between 5.69 and 9.21% (Table 1). The low values of the volume of shale are indications that the reservoir sands are perhaps very clean and are far below the standard limit of 10–15%, which is known to have effect on the water saturation (Hilchie 1978). The effective porosity values obtained for the reservoirs range from 16 to 20%, which suggest moderate to good porosity. The average core porosity for well L (16.8–19.5%) is in the same range with the calculated porosity (Table 1). Virtually all reservoirs in well L are saturated with water ( $S_w = 64.60$ – $82.01\%$ ), except for reservoir L3 that contains oil (Fig. 4). The evaluated hydrocarbon saturation for reservoir L3 is 73.32% with a total resistivity value of 43.07  $\Omega$ m. Also, the moveable hydrocarbon index (MHI) values in the range of 0.16 and 0.36 are far below the conventional standard threshold of 0.7, which is an indication of good fluid flow.

In well M, the GR–RHOB and GR–Depth cross-plots were used for the analysis (Fig. 5a). The results show that the shale cluster is plotted on the upper right part of the plot. The sandstone points are found at the lower portion of the plot with the gamma ray value in the range of 16–56 API and density value in the range of 1.95–2.25 g/cc. Additionally, the vertical attribute profile of the cross-plot shows distinct sand and shale intervals (Fig. 5b). The thicknesses of the seven delineated reservoir units (M1–M7) range between 25 and 64 ft. The average porosity values for these reservoirs range from 14.23 to 26.06% (core porosity 15.65–24.0), which

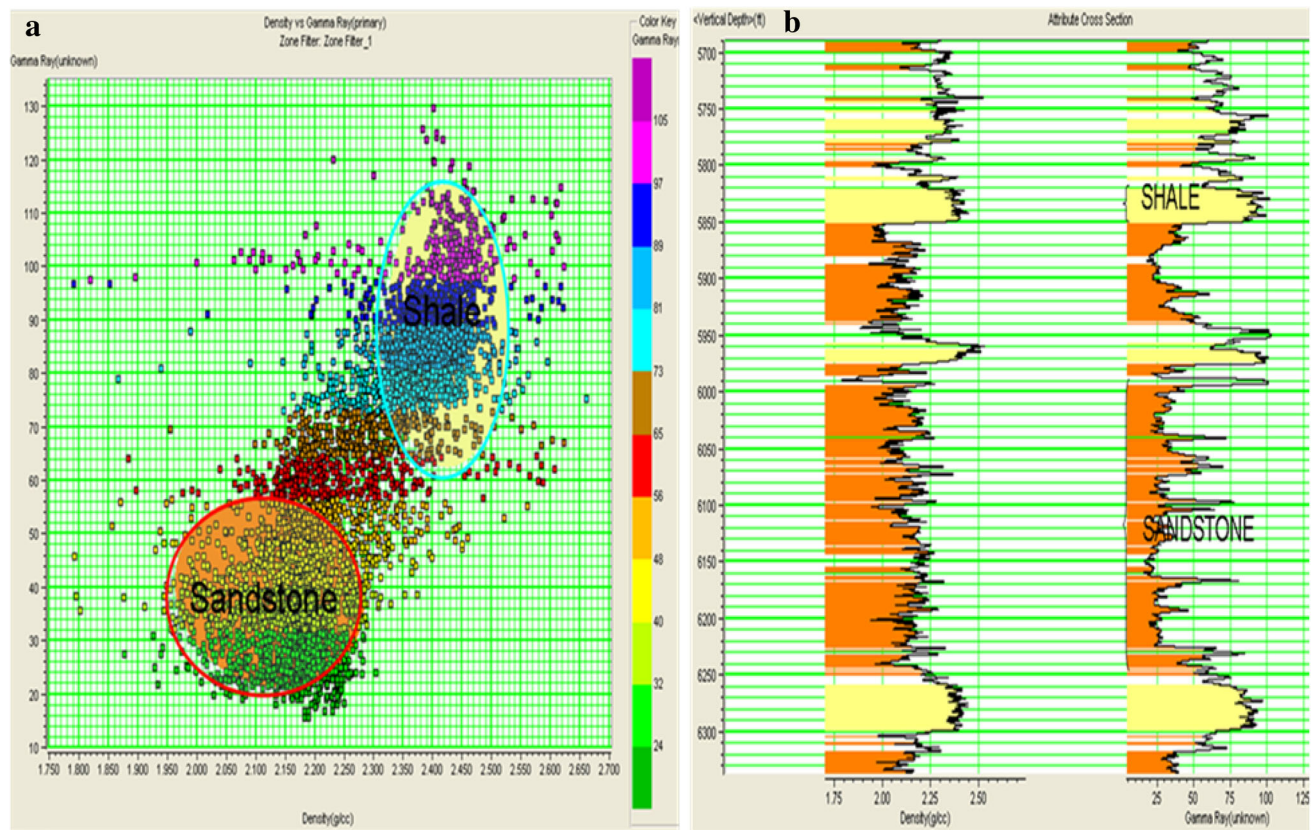
are moderate to good porosity values for both gas and oil flows (Table 2). The moderate to clean nature of the reservoirs is shown by their low volume of shale values (2.2–9.4%). Reservoirs M5 and M6 are oil bearing with high total resistivity values of 43.19 and 36.33  $\Omega$ m, respectively. The M2 reservoir is also evaluated to be gas bearing with relatively high total resistivity of 25.8  $\Omega$ m. This is further confirmed by the low water saturation values of the two reservoirs (Table 2, Fig. 6). The high water saturation values of reservoirs M1, M3, M4 and M7 with their associated low average resistivity (Table 2) are a clear indication of the presence of water in those reservoirs. The average permeability values for the reservoirs range from 1145 to 2316 md (Table 2). These high permeability values of the hydrocarbon-bearing reservoir units suggest possible good fluid mobility.

Similarly, the GR–RHOB and GR–Depth cross-plot results for well N show two unique clusters. The cluster at the lower part of the plot indicates the presence of sandstone with low GR (20–56 API) and RHOB (1.97–2.31 g/cc) values (Fig. 7a). The low density reading recorded in this cluster is evident that the density of the materials increases with depth. The second cluster that is shown at the upper right of the plot with high GR (67–97 API) and RHOB (2.25–2.60 g/cc) values indicates shale lithology, which is in agreement with the works of Adewoye et al. (2015). The vertical attribute profile of the cross-plot shows distinct sand and shale intervals with the associated heterolithic interval at the top (Fig. 7b). A total of five reservoir intervals were delineated (N1–N5), and their thicknesses range from 61 to 209 ft (Table 3). The average porosity values evaluated for these reservoirs range from 16.67 to 27.06%, which suggest good porosity values for oil and excellent for gas reservoirs. Average volume of shale (Vsh) in these reservoirs ranges from 4.9 to 10.5%. It is an indication of relatively clean sands with variable dirty intervals within the well. Similarly, the value of the total resistivity in reservoirs N2 and N3 is higher than that of N1, N4 and N5 (Table 3). These high resistivity values (62.83  $\Omega$ m for N2 and 48.87  $\Omega$ m for N3) relative to others suggest that the reservoirs are hydrocarbon



**Fig. 4** Log suite, lithology and fluid interpretation of well L





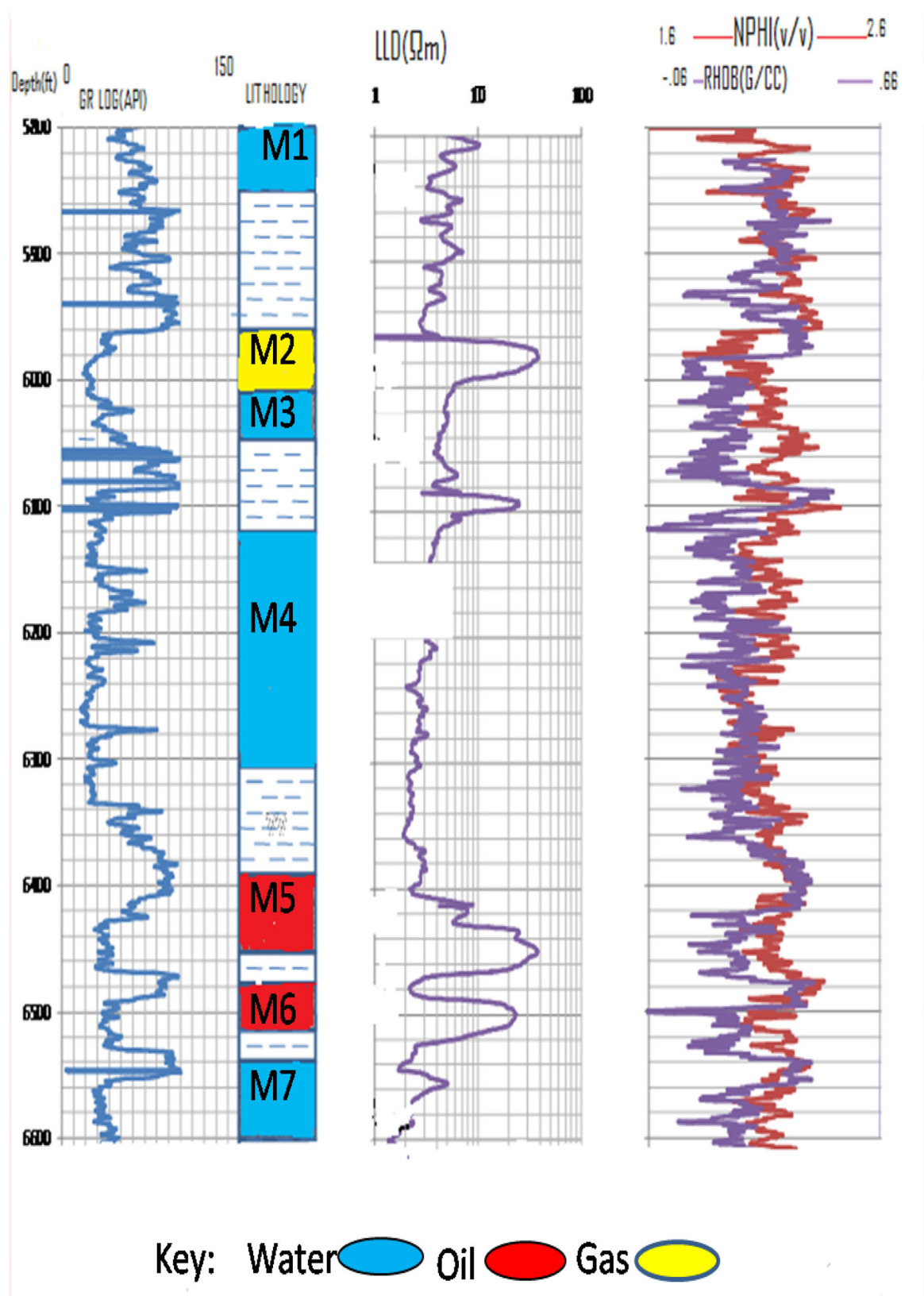
**Fig. 5** **a** Lithologic cross-plot of GR-RHOB. **b** Attribute cross section of GR-RHOB cross-plot for well M

**Table 2** Summary of petrophysical results for well M

Reservoir units	Interval (ft)	Net sand (ft)	Average $\Phi$ (%)	Average K (md)	Average MHI	Ave. water saturation (%)	Average Vshale (%)	Average resistivity ( $\Omega$ m)	Fluid type
M1	5800–5850	48	19.11	–	0.36	68	4.6	4.12	Water
M2	5961–5985	25	26.06	1772	0.57	26	3.3	25.8	Gas
M3	6010–6044	35	14.41	–	0.46	72	9.4	4.78	Water
M4	6425–6469	42	18.17	–	0.21	33	6.1	3.48	Water
M5	6490–6531	46	21.22	1209	0.27	29	5.2	43.19	Oil
M6	6552–6624	64	16.01	2316	0.48	81	2.2	36.33	Oil
M7	6740–6800	58	14.23	–	0.55	78	2.8	6.23	Water

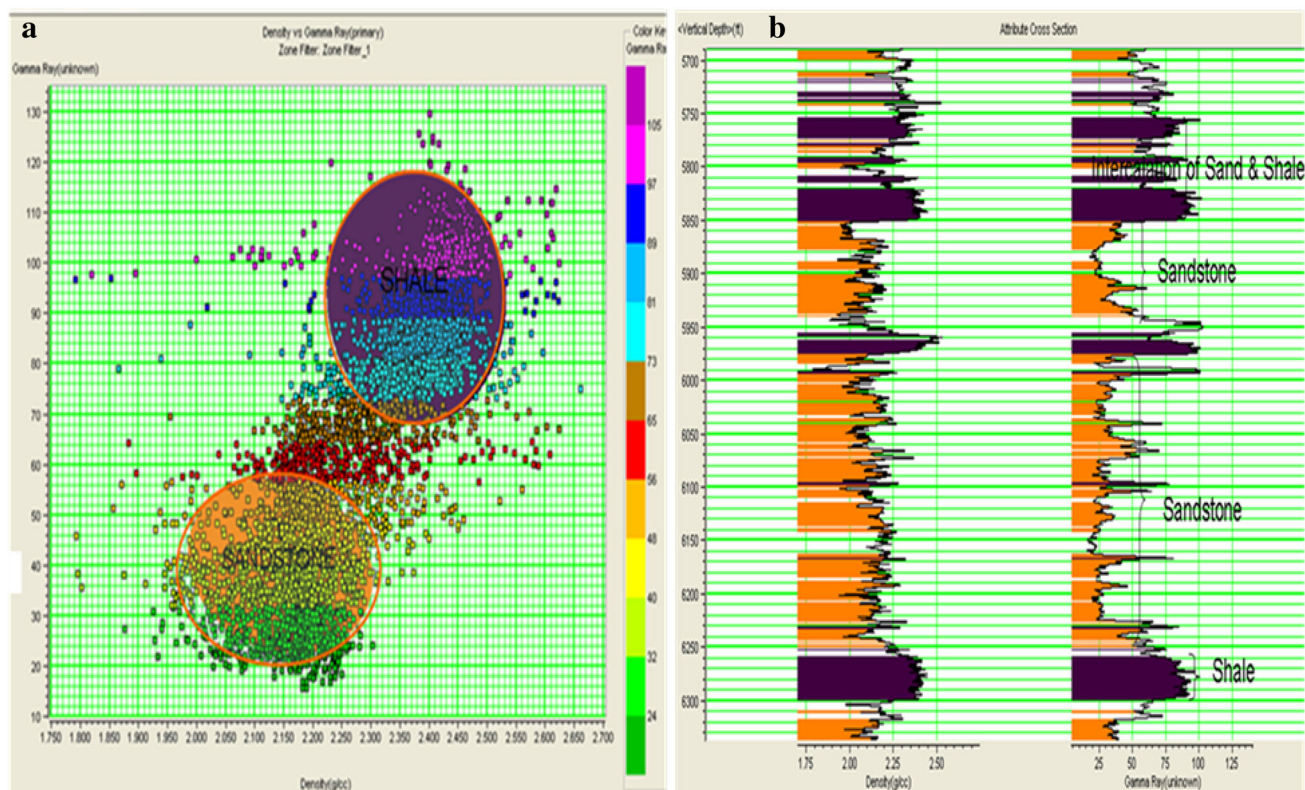
bearing (Fig. 8). The low water saturation within these two reservoirs (23.23 and 28.01%) also suggests the hydrocarbon saturation of 76.77 and 71.99%, respectively. Reservoirs N1, N4 and N5 are water bearing with little or no hydrocarbons due to their high water saturation values (Table 3). The average moveable hydrocarbon index (MHI) values range from 0.01 to 0.09 indicating good fluid mobility. This is also evident by the high permeability values of 1384.14 md for reservoir N2 and 2255.2 md for reservoir N3 (Table 3, Fig. 8).

The reservoir delineation results using well log cross-plots in the wells show distinct lithologies of sand, shale and intercalations of sand and shale, which agrees with the results of Chatterjee and Paul (2012) in their application of well log cross-plots in distinguishing coal and non-coal litho-units in Jharia Coal Field, India. Sand connectivity analysis of the three wells shows good communication between wells M and N, with partial connectivity with well L. (Figure 1; Inset). The petrophysical results also indicate good to excellent reservoir quality for the reservoirs



**Fig. 6** Log suite, lithology and fluid interpretation of well M





**Fig. 7** **a** Lithologic cross-plot of GR-RHOB. **b** Attribute cross section of GR-RHOB cross-plot for well N

**Table 3** Summary of petrophysical results for well N

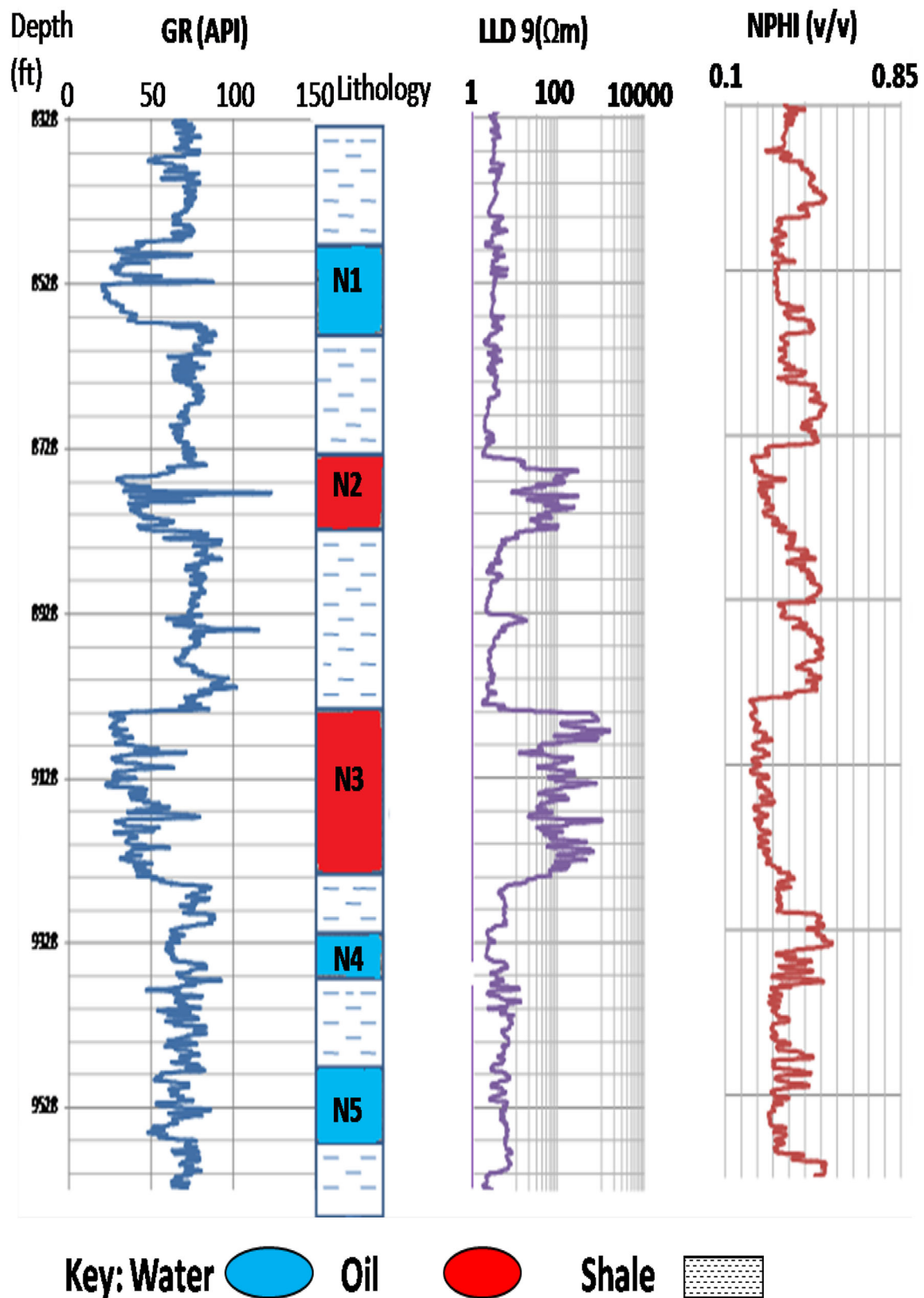
Reservoir units	Interval (ft)	Net Sand (ft)	Average $\Phi$ (%)	Average K (md)	Average MHI	Average water saturation (%)	Average Vshale (%)	Average resistivity ( $\Omega$ m)	Fluid type
N1	8474–8576	98	27.06	—	0.08	72.31	8.7	3.14	Water
N2	8750–8834	84	19.23	1384.14	0.02	23.23	7.6	62.83	Oil
N3	9045–9256	209	21.45	2555.25	0.01	28.01	6.4	48.87	Oil
N4	9308–9371	61	19.11	—	0.06	86.07	10.5	2.63	Water
N5	9485–9598	110	16.67	—	0.09	66.56	9.8	3.92	Water

encountered in the wells (Tables 1, 2, 3). Most importantly, the moveable hydrocarbon index (MHI) values that are far below the conventional standard threshold of 0.7 are indications of good fluid flow and confirmation of the relative good connectivity of the discovered sands, especially in wells M and N.

## Conclusions

This study has shown that cross-plots of GR-RHOB and Depth-RHOB can be used as an additional tool to delineate lithologies in well logs prior to petrophysical evaluation of the reservoir units. It has also confirmed that the conventional use of the Archie (1942) equation for

estimating fluid's saturation in shaly sands over estimates the parameter. The cross-plots identified mainly sandstone, shale and in some cases intercalations of sand and shale in all the wells. The results also confirmed that the reservoirs are moderate to clean, containing clay volumes ( $<0.10$  v/v) that are below the threshold that can greatly affect the porosity values. Similarly, the effective porosities of all the reservoirs are moderate to good and will allow greater flow of both oil and gas. In the three wells, reservoirs L3, M5, M6, N2, and N3 were found to contain oil; M2 contains gas, while the rest are water-filled. The study also shows a remarkable increase in reservoir thickness from well M through wells N and L, giving rise to good sand development towards well L. As a result of this, the sandstone reservoirs for the discovered



**Fig. 8** Log suite, lithology and fluid interpretation of well N

hydrocarbons (Fig. 1) are relatively connected between wells M and N, though showing partial connectivity with well L. This allows for a better flow efficiency between the two connected wells.

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