PRINT ISSN 1119-8362
Electronic ISSN 2659-1499

Full-text Available Online at
https://www.ajol.info/index.php/jasem
https://www.bioline.org.br/ja

J. Appl. Sci. Environ. Manage.
Vol. 28 (4) 1061-1068 April 2024

# Assessment of Sealing Potential of Fault-Bounded Hydrocarbon Prospect in Gabo Field, Niger Delta, Nigeria

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**ABSTRACT:** Sealing potentials of faults are an important exploration risk to consider in the assessment of fault-bounded hydrocarbon prospects. This technique has been used for predicting potential hydrocarbon columns for mitigating risk in exploration and appraisals. Hence, the objective of the paper is to assess the sealing potential of the fault-bounded hydrocarbon prospects of the Gabo Field in the Niger Delta basin using seismic, well-log, and X-ray diffraction data. Three faults were interpreted as normal and syn-depositional faults. The well-log correlation showed that the shale sequence was inter-bedded with sands and showed a good spread with a relative thickness ranging between 12-105m from shallow to intermediate depth intervals. Results of the rock property analysis showed that the volume of shale ranged from 18 – 73.72% with an average of 63.59%. The total porosity ranged from 15.9 – 31.7 (good to excellent) with an average of 16.7 (good) in the shales and 27.2 (very good) in the sand. The effective porosity of the field ranged from 3.58 – 22.71 with an average of 6.028 in the shales and 20.13 in the sand. The estimated pore pressure ranged from 42.13 – 47.62psi with an average of 47.0psi in the shales and 42.8psi in the sand. The results of the X-ray diffraction analysis showed that the predominant minerals were kaolinite, rutile, gypsum, albite, microcline and quartz, which constitute the caprock sequence and the faulted rocks. Results of the sealing potential showed poor sealing in the shale sequence while the fault analysis showed good sealing along the fault planes. These results deduced the sealing uncertainty of the field and may be applied to similar siliciclastic trap configurations in deltaic environments.

**DOI: https://dx.doi.org/10.4314/jasem.v28i4.7**



**Cite this Article as**: IHEATURU, TC; ABRAKASA, S; JONES, AE; NJOKU, IO; IDEOZU, RU; UGWUEZE, CU (2024). Assessment of Sealing Potential of Fault-Bounded Hydrocarbon Prospect in Gabo Field, Niger Delta, Nigeria. *J. Appl. Sci. Environ. Manage.* 28 (4) 1061-1068

**Dates:** Received: 22 January 2024; Revised: 29 February 2024; Accepted: 23 March 2024 Published: 19 April 2024

**Keywords:** Shale, Caprock, Seal, Trap, Niger Delta Basin

The driving mechanisms that create basins around the World are of three types and they are; divergent or extensional plate movements, the convergent and the shear plate movements. The primary objective of a reservoir geologist is to recognize occurrences of low-risk but volumetrically significant traps in terms of size and sealing potential. This is important because local and regional tectonics have an impact on trap size and integrity. The Niger Delta environments fulfil these conditions and are comprised of a wide variety of hydrocarbon traps and sealing rocks. When rocks are deposited, they undergo single to multi-phases of

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distortion as well as diagenetic alterations from their original state. Their deformational patterns have unique characteristics from proximal to distal settings based on the Niger Delta physiography and knowledge of regional and local tectonostratigraphic history is used to characterize associated risks and uncertainties (Obi, 2023). A trap may be described as any rock configuration that can keep hydrocarbon in-place for an appreciable period. While a seal is a rock unit or some physical barrier such as pressure, rock facies change or any combination of these, that can impede or contain the continuous migration of hydrocarbon. Traps are formed when rocks deform or when their quality becomes altered in such a manner that creates a configuration suitable for keeping hydrocarbon in-place (Obi, 2023). According to Nooraiepour (2018), caprock sequences seal at the reservoir-caprock interface by capillary forces which counteracts the buoyancy forces of a hydrocarbon column. If the hydrocarbon buoyancy is greater than the displacement pressure, the caprock or seal will leak. The primary role of the caprock is that of containment of in-place hydrocarbon or carbon IV oxide ($CO_2$) as in the case of carbon capture and storage. An important factor in hydrocarbon containment is the role of fine-grained argillaceous shale which acts as caprock in most siliciclastic reservoirs. Other subsurface factors are the rock deformational history, timing of deformation, thickness and spread of the argillaceous shale or caprock sequence. Fine-grained argillaceous shales may act as source rock, caprock or unconventional hydrocarbon reservoirs. Some of the properties of shales that make them unique as caprocks are their very fine grain sizes, their high capillary entry pressures into their pore spaces and their low matrix permeability. These qualities make them unique flow barriers in conventional and unconventional petroleum systems. Shales are described as mudrocks characterized by lamination and fissility, which is a strong tendency to break in a particular direction, parallel to its bedding. The fissility arises from the preferential alignment of the phyllosilicates contained in the mudstones (Nooraiepour, 2018). Both the fissile shales and ductile mudstones act as planes of weaknesses along which rocks may deform. These planes of weakness may result in leakages ranging from capillary leaks, hydrodynamic leaks, fault or fracture leakages, and caprock erosion (Nooraiepour, 2018). Therefore, the identification of these conditions and their sealing potentials helps the reservoir geologist ensure a closed or semi-closed system. Previous studies in the Gabo Field include those of Iheaturu *et al.*, (2022); Iheaturu *et al.*, (2022); Gbenga *et al.*, (2022) Agbasi *et al.*, (2021); Nduaguibe and Ideozu (2019); Didei and Akana (2016) and Etimita (2015). These studies did not address the sealing potential of the field and this allowed us to evaluate this property by matching empirical results to sealing scenarios. Hence, the study set out to assess the sealing potential of the fault-bounded hydrocarbon prospects of the Gabo Field by matching empirical results to the sealing scenarios.

## MATERIALS AND METHOD

*Geologic Setting of the Niger Delta:* The Niger Delta is situated in the Gulf of Guinea at the site of the rift triple junction related to the opening of the southern Atlantic Ocean. This represents a passive extensional environment. And structures predominant in this kind of setting are faults, syn-depositional and post-depositional structures. The Niger Delta is described as an arcuate-shaped wave, tide and fluvial-dominated prograding deltaic system. The northern boundary of the delta is recognized along the Benin flank, the Cretaceous outcrops of the Abakaliki high and further southeast by the Calabar hinge line (Michele *et al.*, 1999). It is bound by the Dahomey basin in the West. The age of the Niger Delta ranges from Eocene to Recent. Short and Stauble, (1967) recognized the stratigraphy of the Tertiary Niger Delta and grouped them into three main units or formations. These formations are the Benin Formation, the Agbada Formation and the pro-delta marine Akata Formation. In the Niger Delta, hydrocarbons are predominantly found within the Agbada Formation. According to Jev *et al.* (1993), the Agbada Formation is characterized by extensive syn-depositional normal faults. The hydrocarbon accumulations are trapped in a series of configurations, either in simple unfaulted dip closures or in a combination of fault-dependent traps. The Gabo Field is located in the central swamp depo-belt of the Niger Delta (Figure 1). The field covers an aerial extent of about 12,513m along the X-axis and 6,246.55m along the Y-axis. This represents an area between $4^o$ and $7^o$N latitude and $3^o$ – $9^o$ E longitude (Agbasi *et al.*, 2021).

*Materials:* Data used for this research was acquired from one of the multinational oil companies operating in Nigeria through the permission of the Nigeria Upstream Petroleum Regulatory Commission (Formerly, the Department of Petroleum Resources - DPR). The data provided include; 3D seismic volume in Seg-Y, ditch cutting samples and wells data.

*Method of Research:* The seismic volume enabled the picking, labelling and building of the fault models. The faults were interpreted in two-way-time, posted on a time slice as well as converted to depth for spatial correlation and analysis. Horizons were also mapped on the seismic by picking continuous lateral reflections and integrating them into the fault model to show the horizontal continuity and vertical variations in lithofacies. The seismic volume was interpreted, bearing in mind the gross tectonic setting of the Niger Delta from proximal to distal setting. The Petrel application software allowed the manipulation of the reservoirs, fault blocks and reconstruction of the pre-faulted as well as the deformational history while observing gaps in the resultant structure. Recall that, a fault that may initially look simple may be complicated, depending on the historical cycles of distortion. For instance, Obi, (2023) enumerated the different stages of multi-phase deformation in rocks and they are:

*1.* *Extension stage* – this is a period when the trap configuration or fault structure is formed.


**Fig 1:** Location of the Gabo Field, Western Niger Delta

*2.* Shortening stage – this is a time when the rocks begin to buckle due to space constraints. At this stage, the formed trap could be preserved or leaked.

*3.* Inversion stage – this is a period when the trap configuration changes due to an increase in overburden stress and subsurface re-adjustments. At this stage, the trap configuration may be altered.

*4.* Stress release – at this stage the trap takes a more stable configuration after accumulated stress is released. The trap may be either preserved or leaked.

This guided the timing and classification of the trap configuration and is key to providing risk assurance. The well correlation was carried out using the gamma-ray logs. The shales were recognized from the ditch cuttings and shale cut-off from the gamma-ray logs. Six shale samples from 4 different wells were subjected to x–ray diffraction analysis. The results gave an idea of the average spacings (d-spacings) between layers of atoms for the unknown lithologies. This became necessary to address the sealing assumptions along the caprock sequence and fault planes (Yielding, *et. al.*, 1997; Obi, 2023). Rock property evaluation was carried out to determine the quality of the sand and shale intervals. The rock characteristics estimated are the volume of shale and the total and effective porosities. Porosity is a static property and was measured using neutron logs. Comparison was made between porosity in the shales and porosity in the sand. According to Cannon (2018), facies changes and boundaries may act as barriers to flow if porosity and permeability contrasts are significant. Furthermore, the formation pore pressures were estimated from well logs using Eaton's method (Eaton, 1975). The Biot effective stress coefficient was assumed to be 1. The result of the hydrostatic pore pressure estimated by Agbasi *et al.*, (2021) for the Gabo Field was used for comparison. The result gave an idea of the post-depositional conditions of the sand and shales. For sealing to be effective, pore pressure contrasts need to be significant in other to create some form of physical barrier against the continuous migration of hydrocarbon. To address the sealing potential of the field, certain considerations and assumptions were made, they are (Obi, 2023):

1. *Scenario A:* For a non-sealing fault plane and caprock sequence with poor sealing tendency. The assumption was that there would not be containment for any early or late migration of hydrocarbon into the trap configuration. Similarly, the fault will not seal and the shale caprock will also not seal. Therefore, the prospects of hydrocarbon containment on adjacent sides of the fault block will have no success.
2. *Scenario B:* For a non-sealing fault plane and caprock sequence with very good sealing potential. The assumption was that the shale caprock would seal while the faults would not seal for any early or late migration of hydrocarbon into the trap configuration. Therefore, the shale caprock will seal and the hydrocarbon column height will depend on the leak point elevation along the fault structure. This scenario provides a semi-closed system for hydrocarbon habitation.
3. *Scenario C:* For a sealing fault plane and non-sealing caprock sequence with very poor sealing potential. The assumption was that the shale caprock would leak due to the buoyancy pressures from any early or late migration of hydrocarbon into the trap configuration. While the fault will seal effectively.
4. *Scenario D:* For sealing fault plane and caprock sequence with good sealing potential. The assumption was that there would be sealing for early and late migration of hydrocarbon into the trap configuration and there would be a high possibility of finding oil and gas on both sides of the fault blocks. This scenario provides a closed system for hydrocarbon habitation.

The shale gouge ratio (SGR) algorithm was applied to estimate the mixing of rocks along the fault plane (Iheaturu *et al.*, 2023). The shale gouge ratio (SGR) algorithm estimated the percentage of shale volume from the host strata that may have been sandwiched between the fault planes. The result of Iheaturu *et al.*, (2022) on fault plane analysis was adopted.

## RESULTS AND DISCUSSION

Three faults were identified and labelled F1, F2 and F3 (Figure 2). Faults F1 and F2 were recognized as closely spaced normal faults while F3 was interpreted as a syn-depositional fault. The tectonostratigraphic structure of the field is situated at a relative depth of 2,252m - 2,700m MD and equivalent to 7,386ft - 8,856ft MD respectively from the surface (Figure 3).

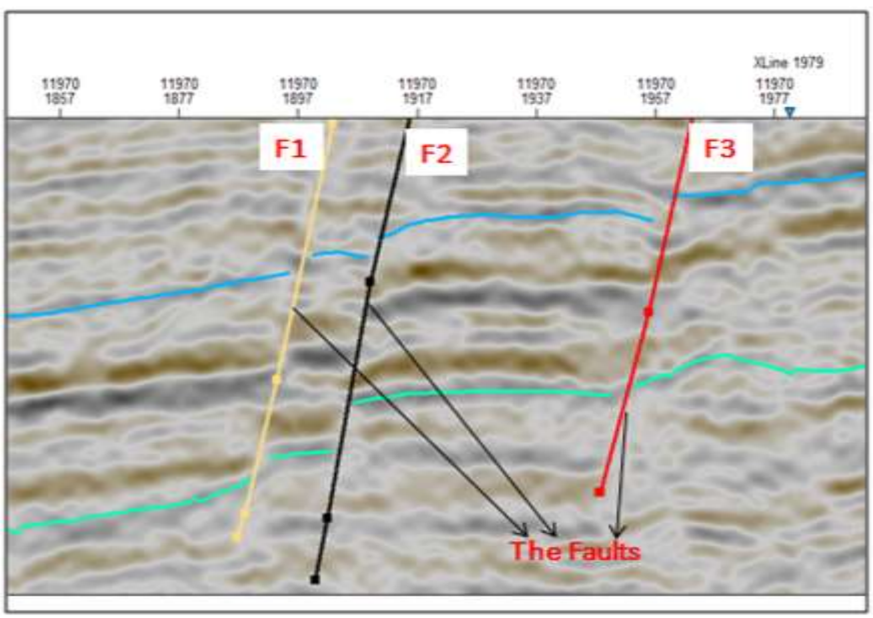


**Fig 2:** Seismic Section Showing the Fault Relationships

The result represents an extract of the deformational history of the field as well as the depositional and post-depositional framework. The field is characterized by multiple stages of deformation and the timing of deformation shows the buckling stage. It also gave an idea of the relative time the fault healed. This is evident in the substantial lateral variation in the stratigraphic thickness of accumulated sediments and below this interval is arguably the expected target of exploration. Adjacent sides of faults F1 and F2 showed the juxtapositions and possible compartments without any significant thickening or thinning of the sediments on adjacent sides.

The well correlation showed the cyclic succession of sand and interbedded shales typical of the Niger Delta sequence. The result showed that the interbedded shales have a minimum and maximum thickness of 12 and 105m respectively (Table 1).

The sand tops lie within the relative depths of 2100 - 2700m MD and are interbedded with shales of varying mineralogical composition, volume, thickness and spread. The interbedded shales were interpreted as floodplain or placid swamp deposits. These quiet sedimentary environments encourage the formation of fine-grained sealing rocks, they require sufficient time to expel water and compact as sediments are continually deposited. They are largely affected by diagenesis and are expected to create some form of physical barrier at the sand-shale interface.

According to Konrad, (1967), the intrinsic properties of clays are basically derived from their fine grain sizes. They occur as a mixture of two or more clay minerals and their properties may be largely influenced to an extent by minor constituents of others.

Hence, the spread and uniformity of these intrinsic properties of argillaceous shales at well and field scale influence the sealing potential of the field. The volume of shale ranged from 18 – 73.72% with an average of 63.59% (Table 2). A plot of the $V_{sh}$ distribution against depth showed that the bulk density increased with depth while the strata thickness decreased with depth (Figure 5). These shale intervals also showed a good spread but may not be very well compacted (Figure 4).

The results also showed that the average total porosity of the shales ranged from 18.5 (good) in the shallow intervals to 13.6 (poor) in the deeper intervals.

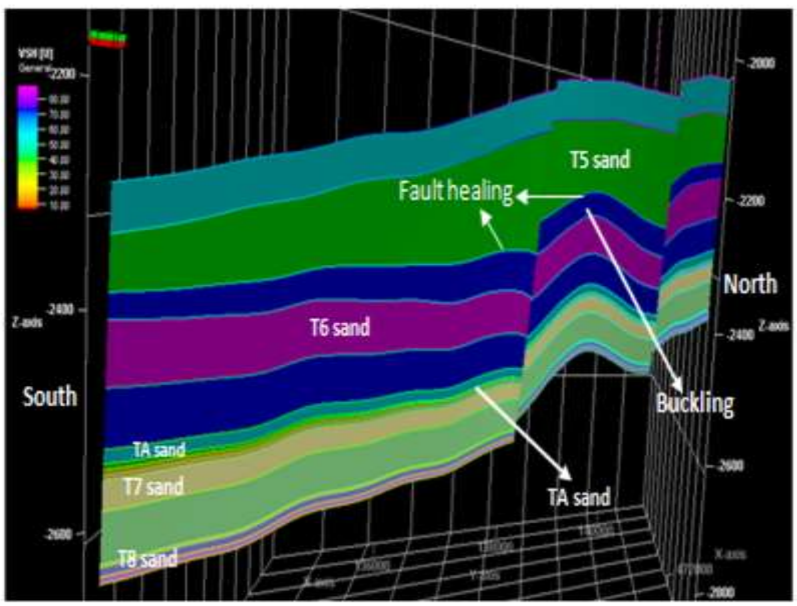


**Fig 3:** This Shows the Shortening or Buckling Stage

**Table 1:** Shale Mineralogical Evaluation. NA- Not available

| Measured Depth interval (m) | Thickness (m) | Lithology | Litho facies description | Bulk mineralogy |
|---|---|---|---|---|
| 2175 – 2208 | 33 | Shale | Shale | NA |
| 2239 – 2251 | 12 | Shale | Shale | NA |
| 2286 – 2383 | 97 | Shale | Shale, dark brown | Quartz, Kaolinite |
| 2426 – 2499 | 73 | Shale | Shale, dark brown | Quartz, Kaolinite |
| 2426 – 2499 | 73 | Shale | Shale, dark brown | Quartz, Rutile |
| 2526 – 2570 | 44 | Shale | Shale | NA |
| 2591 – 2650 | 59 | Shale | Shale | NA |
| 2676 – 2715 | 39 | Shale | Shale | NA |
| 2727 – 2755 | 28 | Shale | Shale, dark brown | Quartz, gypsum and kaolinite |

| | | | | |
|---|---|---|---|---|
| 2771 – 2962 | 105 | Shale | Shale, dark brown, very very fine | Quartz, Kaolinite and Albite |

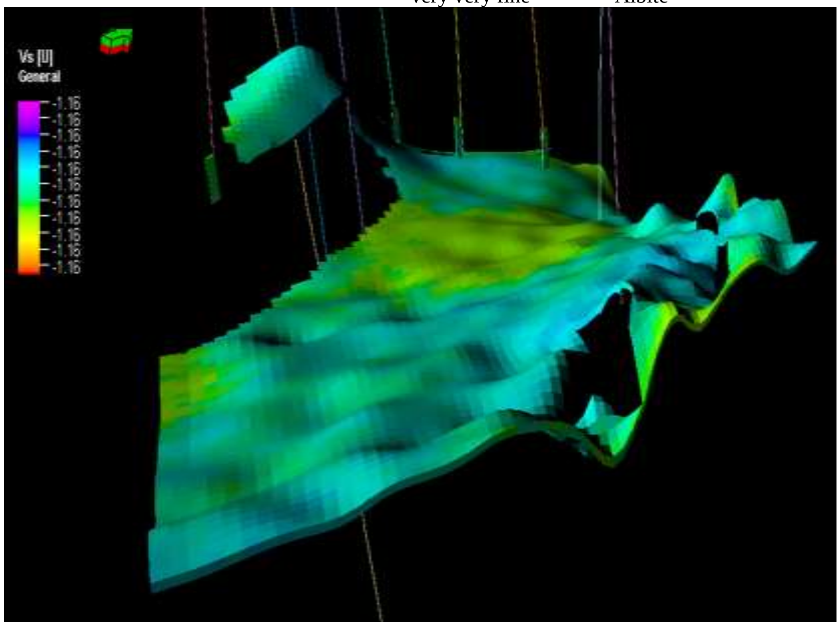


**Fig 4:** Volume of Shale across the Field

**Table 2:** Sand and Shale Quality

| Measured Depth interval (m) | Lithology | Average vol. of shale (Vsh) | Average porosity (Av. PHIT) | Average Effective porosity (Av. PHIE) |
|---|---|---|---|---|
| 2175 - 2208 | Shale | 57.76 | 18.5 | 7.54 |
| 2209-2238 | T4 Sand | 22.25 | 28.6 | 22.27 |
| 2239 - 2251 | Shale | 60.04 | 19.0 | 7.39 |
| 2252 -2285 | T5 Sand | 18 | 27.2 | 22.4 |
| 2286 - 2383 | Shale | 56.1 | 14.6 | 6.44 |
| 2384 - 2425 | T6 Sand | 22.93 | 26.0 | 20.53 |
| 2426 - 2499 | Shale | 61.7 | 15.9 | 6.04 |
| 2426 - 2499 | Shale | 61.7 | 15.9 | 6.04 |
| 2500 - 2525 | TA Sand | 25.34 | 29.2 | 21.98 |
| 2526 - 2570 | Shale | 60.03 | 17.3 | 6.97 |
| 2571 - 2590 | TC Sand | 32.89 | 25.8 | 17.23 |
| 2591 - 2650 | Shale | 66.01 | 13.4 | 4.16 |
| 2651-2675 | T7 Sand | 22.67 | 20.8 | 16.26 |
| 2676 - 2715 | Shale | 67.13 | 23.2 | 7.65 |
| 2716 - 2726 | T8 Sand | 28.99 | 31.7 | 22.71 |
| 2727 - 2755 | Shale | 71.72 | 15.5 | 4.47 |
| 2756-2770 | T9 Sand | 37.3 | 28.3 | 17.66 |
| 2771 - 2962 | Shale | 73.72 | 13.6 | 3.58 |
| Range | | 18 – 73.72 | 15.9-31.7 | 3.58-22.71 |
| Average in shale | | 63.59 | 16.7 | 6.028 |
| Average in sand | | 26.3 | 27.2 | 20.13 |

Evaluation of the sealing potential of the shale intervals showed that there is a likelihood of poor sealing or leakage due to buoyance pressures from hydrocarbon columns. This is inferred from the fact that the total and effective porosities are good (16.7 and 6.028 respectively) and may exhibit low capillary entry pressures. According to Cannon (2018), rock fluid interaction is a function of volume, connectivity of pore geometry and mineralogy affecting wettability and capillary pressures. According to studies by Akaha-Tse *et al.,* (2020) on the fracturing potentials of organic-rich shales of the Anambra basin, they highlighted that, as a result of the near absence of permeability in shales, the fluid content of a shale sequence can only be released under certain conditions. These conditions include those of Zhang *et al.,* (2018) which highlight that the permeability of the shales should be at least greater than 100mD while porosity should be greater than 2%. Comparing the results of this research to Zhang *et al.,* (2018) criteria, it could be seen that the shale sequence may have not created enough conditions in terms of quality to contain any early emplacement of hydrocarbon.

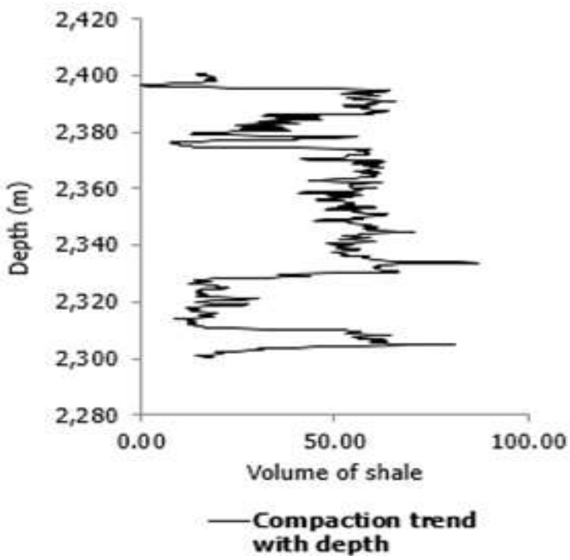


**Fig 5:** Plot of Volume of Shale Versus Depth, Gabo 14

**Table 3:** Pore Pressure Evaluation

| Depth interval (m) | Lithology | Pore pressure |
|---|---|---|
| 2175 - 2208 | Shale | 46.18 |
| 2209-2238 | T4 Sand | 42.89 |
| 2239 - 2251 | Shale | 46.43 |
| 2252 -2285 | T5 Sand | 43.04 |
| 2286 - 2383 | Shale | 47.62 |
| 2384 - 2425 | T6 Sand | 43.44 |
| 2426 - 2499 | Shale | 46.96 |
| 2500 - 2525 | TA Sand | 43.26 |
| 2526 - 2570 | Shale | 47.08 |
| 2571 - 2590 | TC Sand | 42.41 |
| 2591 - 2650 | Shale | 47.1 |
| 2651-2675 | T7 Sand | 42.51 |
| 2676 - 2715 | Shale | 47.19 |
| 2716 - 2726 | T8 Sand | 42.99 |
| 2727 - 2755 | Shale | 47.33 |
| 2756-2770 | T9 Sand | 42.13 |
| 2771 - 2962 | Shale | 47.41 |
| Range | 42.13 – 47.62 | |
| Average shale | 47.0 | |
| Average sand | 42.8 | |

In addition, results of the X-ray diffraction (XRD) analysis showed that the bulk mineralogical composition of the shales comprised quartz, rutile, gypsum, clay minerals and feldspar minerals while the estimated pore pressures ranged from 42.13 – 47.62psi and the average in shale was 47psi (Table 3). This implied that the shale units were only mildly over-pressured while the sand units remained hydrostatic or normally pressured. These mild overpressures may also not be sufficient to prevent hydrocarbon capillary leakage. Shales are known to be the causes of overpressures in the Niger Delta but, for it to effectively create a pressure-enhanced sealing system, the pore pressure differential between the sand and shale intervals need to be significant among other relevant factors such as the grain sizes, stratigraphic spread, capillary entry pressures and matrix permeability (Konrad, 1967; Cerveny *et al.*, 2004; Nooraiepour, 2018).

Lastly, studies by Iheaturu *et al.*, (2022) demonstrated that the faults in the Gabo Field seal by capillary forces at the fault rock interface, with a shale gouge ratio between 0.2 – 0.7. The result reflects the spatial distribution of the estimated shale gouge around the fault planes ranging from low permeability seals to clay-matrix gouges and the fault planes are expected to support hydrocarbon sealing.

*Conclusions:* The Gabo Field subsurface structures are similar to those identifiable in the Niger Delta petroleum system. The total and effective porosity of the shales was good and exhibited low capillary entry pressures. Similarly, the mild overpressures in the shale intervals may not be strong enough to hold back the buoyancy pressures from the hydrocarbon-bearing sands and may leak under high pressure. Caprock and fault plane compositions may act as easily compressible grains, ductile grains, cement or matrix materials along the shale sequence and fault planes. Therefore, the trap and sealing configuration is comparable to a sealing fault plane and non-sealing caprock sequence with poor sealing potential assuring a semi-closed system.

*Acknowledgements:* This article is an extract of Mr Iheaturu's PhD thesis and the authors express their immense gratitude to the Nigeria Upstream Petroleum Regulatory Commission (Formerly, the Department of Petroleum Resources – DPR) for granting permission to access and use data. Our gratitude goes to the Petroleum Technology Development Fund (PTDF) for funding this study. Similarly, our appreciation goes to the Total Energies, Nigeria for providing the data for this study. In addition, it is worth noting that, inferences made from this study are solely that of the authors and do not represent that of any organization.

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