SSRG International Journal of Geo-informatics and Geological Science
ISSN: 2393–9206 / https://doi.org/10.14445/23939206/IJGGS-V12I1P104

Volume 12 Issue 1, 38-44, Jan-Apr 2025

Original Article

Correlations for Permeability-Porosity Derived from Log and Core Data for an Onshore Niger Delta Field Using Cross Plotting

ADIZUA Okechukwu Frank[1], ODU Victor Chukwuma[2]

[1,2]*Geophysics Research Group – GRG, Department of Physics, Faculty of Science, University of Port Harcourt, Port Harcourt, Rivers State, Nigeria.*

[1] *Corresponding Author : okechukwu.adizua@uniport.edu.ng*

Received: 18 February 2025 Revised: 25 March 2025 Accepted: 11 April 2025 Published: 28 April 2025

Abstract *- A previous study from the "NEMA" field by Adizua and Uzu (2024) evaluated petrophysical properties such as porosity, permeability, net to gross (NTG), and water and hydrocarbon saturation from five wells in the field. In this complementary study, we seek to establish the degree of correlations between permeability-porosity derived from both log and core results in Well 09, where both data are available. The study aims to establish that if a high correlation exists between log and core-derived porosities and permeabilities, we can validate log-derived petrophysical parameters in other well locations (Wells 01, 04, 07 and 12) where core data are unavailable. Petrel routines were used to generate the cross plots. The results showed a correlation coefficient (R) of 0.732845 for the core permeability versus core porosity cross plot. A correlation coefficient (R) of 0.79945 for core porosity versus log porosity cross plot and a correlation coefficient (R) of 0.833588 for core permeability versus log permeability cross plot. The plots revealed that core-derived permeabilities correlated very well with log-derived permeability for NEMA 09. Therefore, we can conclude from our findings that in wells where core data were not available, log-derived permeabilities and porosities were true approximations of the actual subsurface petrophysical parameters in those wells. This would ultimately guide in field development planning and exploitation objectives in the field.*

Keywords *- Log Derived Parameters, Core Derived Parameters, Cross Plotting, Cross Plot Analysis, Correlation of Parameters, Informed Field Development Planning.*

1. Introduction

Reliable rock property estimation is essential, and effective reservoir characterization is needed. It is challenging to create forecasts when there are insufficient permeability measurements. Even now, estimating permeability from wireline logs has proven difficult; employing additional techniques, such as coring, formation testing, etc., is frequently even more expensive (Ubanatu, 2023). Determining reservoir petrophysical properties is based on direct laboratory measurements of porosity and permeability using core analysis or indirect measures using well-logging techniques. Implementing direct measuring techniques can be costly, time-consuming, and frequently plagued with several setbacks. For example, the nature of the explosives employed in the recovery process may cause significant damage to the reservoir samples, which are typically too small and fragile to be handled properly. However, there are improvements in acquiring trustworthy petrophysical parameters generated from the core (Ubani et al., 2012; Douglas et al., 2013; Gamal et al., 2015; and Jagadisan et al., 2022). However, this is not the primary focus of this study. Correlations studies for log and core-derived petrophysical properties have not been sufficiently carried out within the Niger Delta sedimentary Basin in Nigeria. This study, therefore, seeks to champion such data integration for a more meaningful formation evaluation that would be most realistic and achieve its intended objectives. Suffice to say, however, that similar works have been performed by Rafdal (1996), Yan (2002) in the North Sea and most recently by Ardo (2016) in the Stezyca oil and gas field in Poland but not exactly in the dimensions or scope of the present study.

An essential component of evaluating a formation is coring and core analysis, which offer crucial information not possible from productivity testing or log measures. Core information includes the reservoir rock's multiphase fluid flow properties, including directional flow properties, capillary pressure data that define fluid distribution in the reservoir rock system, detailed lithology, and microscopic and macroscopic definitions of the reservoir rock's heterogeneity (Ubani et al., 2012). Additionally, certain core data, such as neutron or acoustic logs, which can be used to measure porosity, could

calibrate log responses. Consequently, core data continues to be a vital tool for gathering fundamental reservoir data aimed at the final assessment of the reservoir's recoverable hydrocarbons (oil and gas). In Well 09 of the NEMA field, where both log and core results are available, the goal of this study, which is a follow-up to Adizua and Uzu (2024), is to determine the extent of correlation between permeability and porosity. The goal and novelty of the study were to demonstrate that log-derived petrophysical parameters can be validated at other well locations where core data is unavailable if there is a high degree of correlation between log and core-derived porosities and permeabilities. Therefore, this study's main takeaway is this validation goal for log-derived petrophysical parameters in cases where core findings are unavailable based on the correlation patterns we aim to establish.

2. Outline of the Geologic Settings of the Study Area

According to Klett et al. (1997), the Niger Delta is located in the Gulf of Guinea and encompasses the whole Niger Delta province. Depobelts, the most active delta areas at each stage of its evolution, have been formed by the delta's southwestward prograde from the Eocene to the present (Doust and Omatsola, 1990). With an extent of about 300,000 km^2 (Kulke, 1995), a sediment volume of 500,000 km^3 (Hospers, 1965), and a sediment thickness of more than 10 km at the basin's depocenter (Kaplan et al., 1994), these depobelts make up one of the largest regressive deltas in the world. There is just one recognized petroleum system in the province of the Niger Delta (Kulke, 1995; Ekweozor and Daukoru, 1994). The Tertiary Niger Delta (Akata-Agbada) petroleum system is the name given to this system. The geology of southern Nigeria and southwestern Cameroon defines the onshore area of the Niger Delta province, which is where the field is located. Three formations, which exhibit prograding depositional facies and are differentiated mainly by sand-shale ratios, make up the Tertiary portion of the Niger Delta basin. According to Avbobvo (1978), Doust and Omatsola (1990), and Kulke (1995), the geology of these formations is described in detail in their published works.

The thick shale sequences (possible source rocks), turbidite sands (possible reservoirs in deep waters), and trace amounts of clay and silt make up the marine-origin Akata formation at the Delta's base. The Akata formation was created during low stands, which occurred from the Paleocene to the Recent when clays and terrestrial organic materials were carried to deep-water regions with low energy and oxygen shortage. Only a structural map of the top of the formation is available because not much of it has been drilled. The structure is thought to be as thick as 7 km (Doust and Omatsola, 1990). Usually, under excessive pressure, the formation forms the base of the whole Delta. During the Delta's formation, turbidity currents most likely deposited deep sea fan sands in the upper Akata formation (Burke, 1972). Beginning in the Eocene and continuing into the Recent, the primary petroleum-bearing unit, the Agbada formation, was deposited on top of it (Figure 1). The formation is the actual deltaic part of the sequence and comprises paralic siliciclastics that are more than 3.7 km thick. In fluvio-deltaic, delta-front, and delta-topset settings, the clastics collected. Although sandstone and shale beds were equally distributed in the lower Agbada formation, the top part is primarily sand with only a few shale interbeds. The Benin Formation, a continental latest Eocene to Recent deposit of alluvial and coastal plain sands up to 2km thick, sits on top of the Agbada Formation (Avbovbo, 1978).

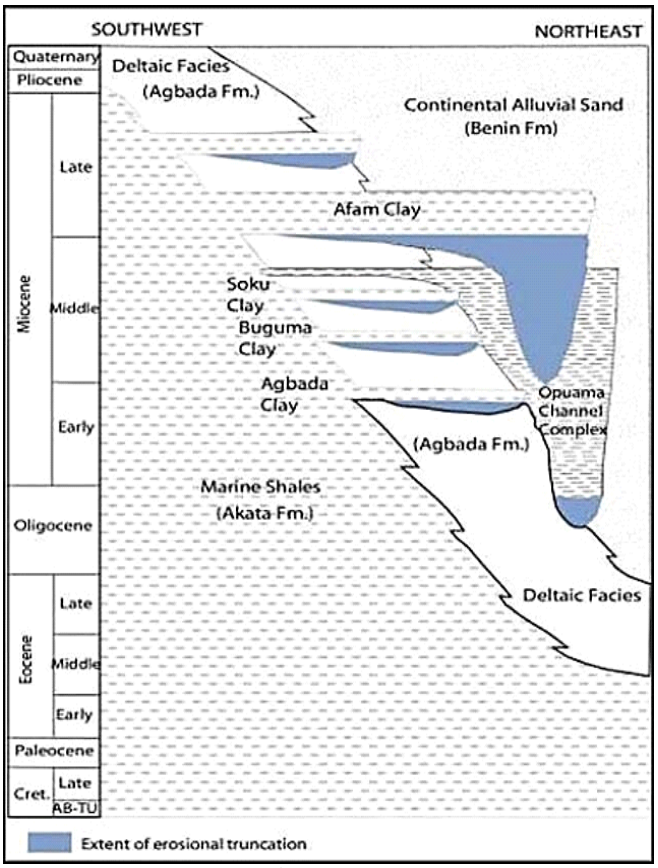

Fig. 1 Stratigraphic column of the Niger Delta Basin showing the three major formations (Modified after Doust and Omatsola, 1990)

3. Some Theoretical Backgrounds

A cursory consideration of the terms porosity and permeability will be highlighted here, as well as some models for permeability estimation from porosity and core data.

3.1. Porosity

The voids in a rock not occupied by its solid framework or structure are measured by its porosity. It is, therefore, a measurement of the fluid a formation can hold or store. Whether or not all of the pores are connected, total or absolute porosity is the volume of the pore space—the space not

occupied by mineral matter—expressed as a fraction or percentage of the rock's bulk or total volume. Effective porosity is defined as the ratio of interconnected pore space volume to the rock's total bulk volume. Using the well-known and generally recognized laws of Wyllie et al. (1958), porosity can be quantitatively calculated from bulk density log data as shown in the relation below;

$$\emptyset_{Density} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (1)$$

Where ρ_{ma} is the matrix density, ρ_f is the fluid density while ρ_b is the bulk density as measured by the bulk density logging tool.

The storing capacity of a rock substance is represented by its porosity. Core and well-log analysis can both be used to calculate porosity values. Naturally, core and log measurements only show localized porosity values; cores are tiny with the reservoir, and logging instruments can only detect porosity at a small distance from the well bore. A new set of concerns about reservoir characterization arises because of the nature of log and core analysis, which requires scaling up measurements to try and reflect true reservoir properties.

3.2. Permeability

The ease of fluid transmission across a porous media is measured by its permeability. Grain size, sorting, clay inclusions, and post-deposition operations affect it. The Darcy (D) is the unit of permeability.

The permeability known as 1 Darcy (1D) permits a viscosity of 1 centipoise (1 cp) to pass through a cross-sectional area of 1 atmosphere per centimetre (1 atm/cm). Since the Darcy is a relatively big unit, the milidarcy (mD) is commonly employed in practice due to the flow limitation of how the sand grains are laid down in a typical reservoir. Permeability is a crucial reservoir characteristic commonly referred to as the K-value. It may be quantitatively assessed using Darcy's law, which states that

$$q = -\frac{K}{\mu}\frac{dP}{dx} * A \quad (2)$$

Where
q = the rate of flow,
K = permeability,
dP = the change in pressure drop across the sample,
dx = the change in length of the sample,
μ = viscosity of the flow and
A = cross-sectional area of the sample.

Three types of permeability have been identified: absolute, effective, and relative (Schlumberger, 1987). Absolute permeability is the measure of how easily a fluid flows through a reservoir rock and is a property of the rock independent of the type of fluid (oil, gas, or water) occupied in the pore spaces of the reservoir rock. Effective permeability is the ability of the rock to transmit a fluid in the presence of another fluid when the two fluids are immiscible when two fluids are present. Relative permeability is a dimensionless quantity representing the ratio of effective permeability to absolute permeability and is a fraction that varies between 0 and 1.

$$K_{relative} = \frac{K_{effective}}{K_{absolute}} \quad (3)$$

As established by the pioneering works of Beard and Weyl (1973), permeability is strongly influenced by grain size (texture), grain shape, grain orientation/sorting, and the degree of cementation. Because it regulates the directional movement and flow rate of the reservoir fluids in the formation, the permeability of reservoir rock, K, is a crucial rock attribute.

For hydrocarbons to flow into a well, they must be able to exit the pores in the rock. Permeability is determined by the size, shape, and connectivity of the pore throats in the rock, which are the microscopic openings that connect one pore to neighbouring pores.

3.4. Permeability Estimation from Porosity and Core Data

Most of the time, there is some correlation between porosity and permeability; however, these correlations are typically derived for specific formations under specific conditions and do not show general applicability or validity.

The models for estimating permeability from porosity and core data that follow are based on the pioneering experiments of Wyllie and Rose, Tixier, Timur, Coates-Dumanoir – Dumanoir and Coates. Note that these model relationships are based on intergranular porosity data; therefore, their application is usually restricted to sandstone reservoirs (Niwaz, 2012). These models therefore are adaptable and suitable to our typical Niger Delta Basin reservoir settings, which are typically sandstone reservoirs.

4. Methodology

A suite of good logs comprising gamma ray, density, neutron porosity, calliper, sonic and resistivity logs were analyzed with core data from NEMA 09 within the prospect. The workflow (Figure 2) highlights the schematic well-log data analysis schemes deployed during the study.

Adizua and Uzu (2024) deployed the same workflow but stopped at the presentation of an evaluated petrophysical parameter. This concluding part of the comprehensive study is now targeted at performing correlations for well-derived and log-derived petrophysical properties to arrive at a formal position to support meaningful reservoir quantitative interpretation - RQI.

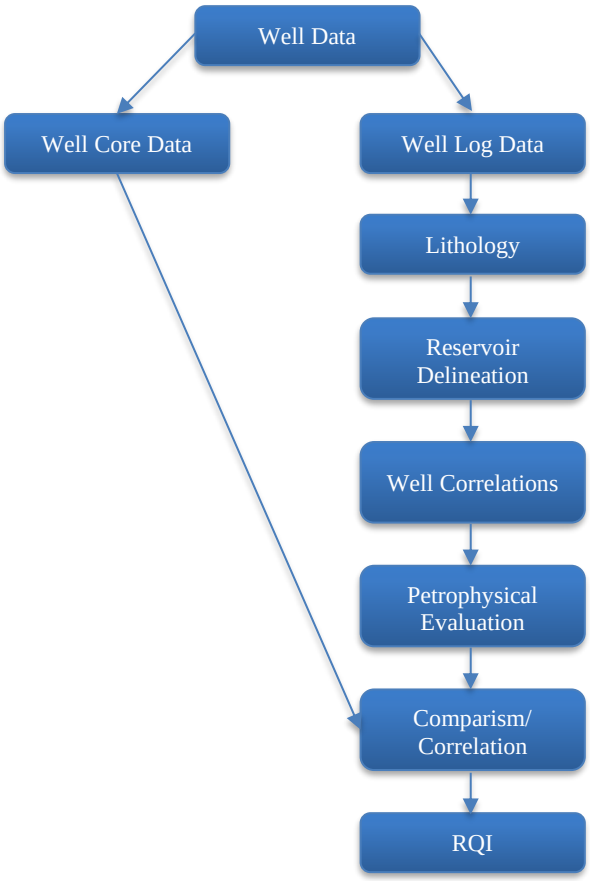

Fig. 2 Comprehensive workflow of well log data and core data analysis adopted for the study. The emphasis of this study was on correlations of log and core-derived properties leading to RQI

The analysis of well logs, which was aimed at a qualitative and quantitative determination of the petrophysical properties of delineated reservoirs, has been adequately discussed in Adizua and Uzu (2024), with the average petrophysical properties already provided. In order to achieve the aim of this complementary work, we leveraged *Schlumberger Petrel*^{TM} tools to perform cross plotting of well log data and core data derived petrophysical properties using appropriate processing and analysis flow commands. The results obtained are presented and discussed in the next section.

5. Presentation of Results and Discussion

Results obtained from the cross plotting using the interactive *Petrel*^{TM} are hereby presented in sub-sections.

5.1. Cross Plotting of Core Permeability versus Core Porosity

There was a relatively high degree of correlation between core permeability and core porosity. In reservoir intervals with low porosities, there was also a corresponding decrease in measured core permeabilities, as inferred from Figure 3. Therefore, we assert a high correlation between core-derived permeability and core-derived porosity, which is also evidenced by the correlation coefficient (R = 0.732845) obtained from the functionalized cross-plot in Figure 4.

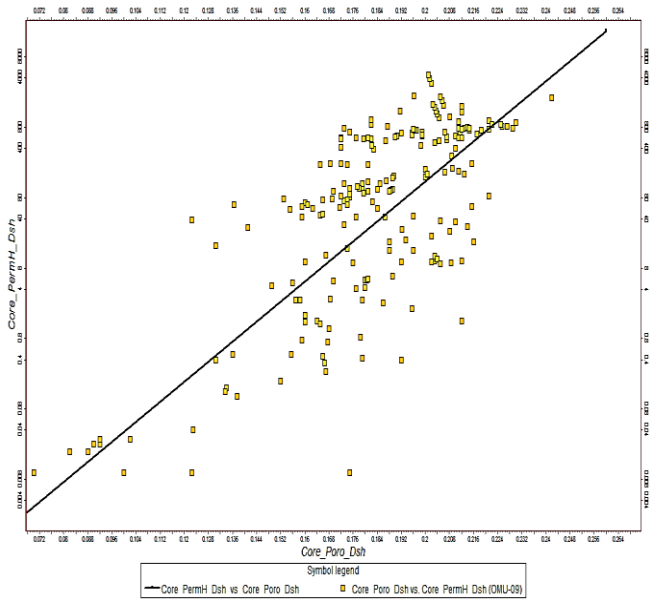

Fig. 3 The cross plotting of core permeability versus core porosity

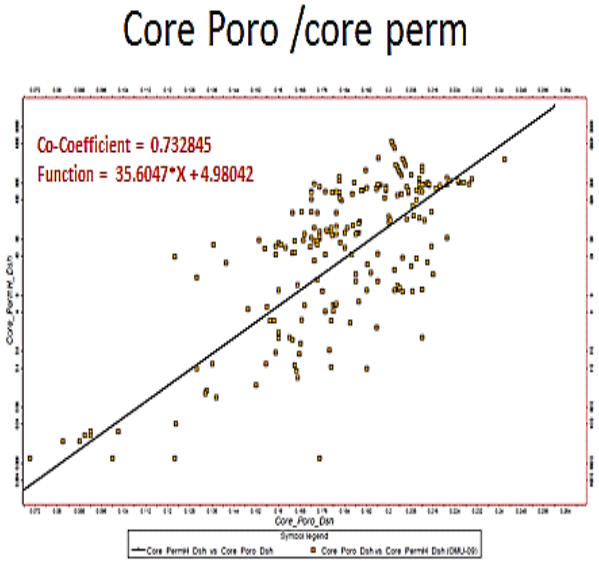

Fig. 4 The cross plotting of core permeability versus core porosity with a fitted function and correlation coefficient R = 0.732845

5.2. Cross Plotting of Core Porosity versus Log Porosity

There was a remarkable correlation between core porosity when cross-plotted against log-derived porosity. The implication is that as porosities along reservoir intervals increase, as inferred from core data, there was also a corresponding increment in log-derived porosity along the same reservoir intervals. The same trend was noticed in instances of porosity decrement along intervals of low

porosities by both core and well log data. This trend is described by the cross plot in Figure 5, which shows a correlation (R = 0.79945) between the fitted functionalized cross plot.

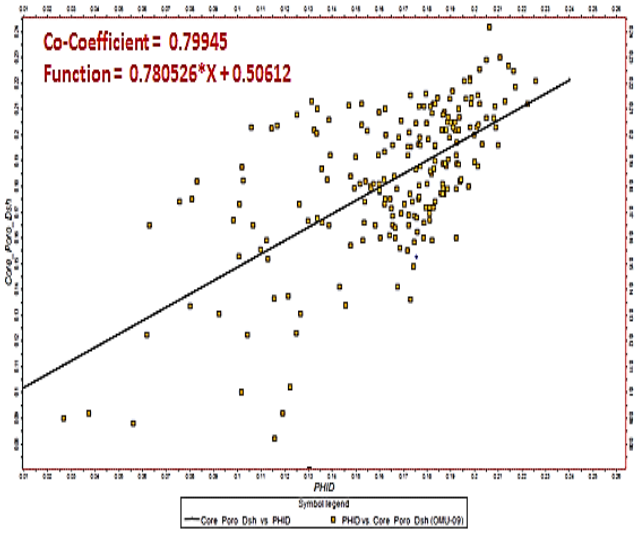

Fig. 5 The cross plotting of core porosity versus log porosity with a fitted function and correlation coefficient R = 0.79945

5.3. Cross Plotting of Core Permeability versus Log Permeability

The highest correlation was observed when core permeabilities were cross-plotted with log-derived permeability. The cross-plot clusters accumulated at the top right end of the fitted function, and this shows that log-derived permeabilities could be easily approximated as core permeabilities for regions of the field where no cores were obtained. This strong correlation pattern is shown in Figure 6 with a correlation coefficient (R = 0.833588).

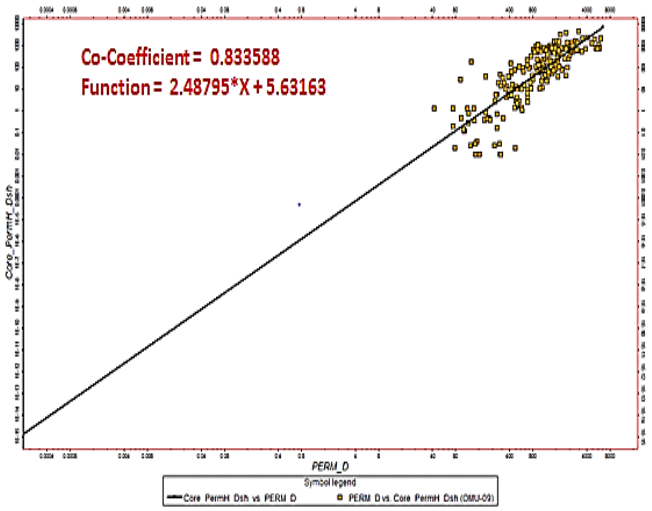

Fig. 6 The cross plotting of core permeability versus log permeability with a fitted function and correlation coefficient R = 0.833588

5.4. Cross Plotting of Core Water Saturation versus Log Water Saturation

Finally, core-derived water saturation versus log-derived water saturation was also cross plotted in Figure 7, with a direct proportionality trend observed all through the reservoir intervals where both log and core data were available. The correlation coefficient was observed to be the highest here, with R = 0.9

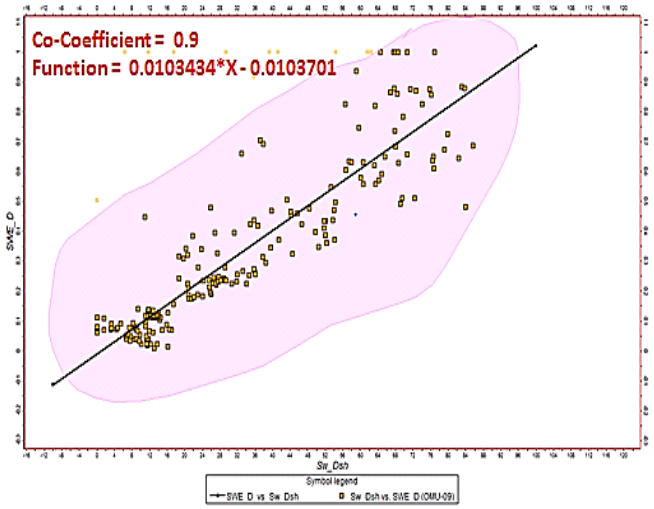

Fig. 7 The cross plotting of core water saturation versus log water saturation with a fitted function and correlation coefficient R = 0.9

Correlation of core and well log-derived petrophysical data is crucial if one seeks to optimize data, reduce uncertainties, and ultimately gain a better understanding of what to anticipate within formations during the implementation of drilling programs during exploration and exploitation of hydrocarbon resources.

In summary, we can posit that in the NEMA field, onshore Niger Delta Basin, for the wells 01, 04, 07 and 12, where no core data were obtained due to the expensive cost implications of their data acquisition, we can propose that log derived petrophysical properties as obtained in the previous study by Adizua and Uzu (2024) are true approximations of the actual petrophysical properties in those wells in real reservoir scenario and settings. Hence, derived petrophysical properties correctly approximate core-derived petrophysical properties and can indicate actual petrophysical properties in wells not cored for the onshore NEMA field. This vital correlation trend that has been established by this study for the NEMA field will be an invaluable resource for the asset management teams of NEMA as it would guide them in their reservoir quantitative interpretation (RQI) programs.

6. Conclusion

This study, a sequel and concluding part to Adizua and Uzu (2024), has successfully cross plotted log-derived petrophysical properties with core-derived petrophysical properties for Well 09 in the NEMA field where both log and

core data were acquired. The cross plots showed a very high degree of correlations for log porosity versus core porosity, core permeability versus core porosity, core permeability versus core porosity, core permeability versus log permeability and core water saturation versus log water saturation. The implication of these results for the reservoir quantitative interpretation – RQI of the NEMA field is that log-derived petrophysical properties are actually good approximations of core-derived petrophysical properties and, as such, could be relied upon as true and near-accurate petrophysical properties of the reservoirs of NEMA field in wells that were not cored.

This could solve some problems associated with the inexactness of log-derived petrophysical properties since they correlated well with their more reliable core-derived petrophysical properties. The outcome of this study will, therefore, be an invaluable tool for asset managers of the NEMA field and will guide them in performing precise reservoir quantitative interpretations, fostering the overall reservoir characterization goal of the field.

Acknowledgements

The authors thank **Nigeria Agip Oil Company (NAOC)** and the **Department of Petroleum Resources (DPR)** for providing the academic research dataset; we had fruitful discussions with Mr Chijioke Zion Okabie, who was affiliated with the ***Laser Petroleum Geoscience Center*** in Port Harcourt at the time of this study but is currently with ***Pioneer-Alfa Petroleum Services***; we are grateful to the University of Port Harcourt, Nigeria, for providing the research and teaching platforms; and we are deeply grateful to ***Seventh Sense Research Group – SSRG***, India, the publishers of the ***International Journal of Geoinformatics and Geological Science – IJGGS*** for kindly approving and waiving the full publication fee for this research paper thereby promoting our modest research.

References

[1] B.U. Ardo, "Correlating Core Analysis and Well Logging: The Stezyca Oil and Gas Field," *Oil Gas Research*, vol. 2, pp. 1-11, 2016. [Google Scholar] [Publisher Link]

[2] Akpoyovbike Abogo Avbovbo, "Tertiary Lithostratigraphy of Niger Delta" *American Association of Petroleum Geologists–Bulletin*, vol. 62, no. 2, pp. 295-300, 1978. [CrossRef] [Google Scholar] [Publisher Link]

[3] D.C. Beard, and P.K. Weyl, "Influence of Texture on Porosity and Permeability of Unconsolidated Sand," *AAPG Bulletin*, vol. 57, no. 2, pp. 349-369, 1973. [CrossRef] [Google Scholar] [Publisher Link]

[4] K.C. Burke, T.F.J. Dessauvagie, and A.J. Whiteman., "Geological History of the Benue Valley and Adjacent Areas," *African Geology*, vol. 1, no. 8, 1972. [Google Scholar]

[5] Douglas Ruth, Craig Lindsay, and Mark Allen, "Combining Electrical Measurements and Mercury Porosimetry to Predict Permeability," *Petrophysics*, vol. 54, no. 6, pp. 531-537, 2013. [Google Scholar] [Publisher Link]

[6] John D. Edwards, and Patricia Ann Santogrossi, *Divergent/Passive Margin Basins*, American Association of Petroleum Geologists, pp. 239-248, 1990. [Google Scholar] [Publisher Link]

[7] C.M. Ekweozor, and E.M. Daukoru, "Northern Delta Depobelt Portion of the Akata-Agbada Petroleum System, Niger Delta, Nigeria," *The Petroleum System – From Source to Trap, American Association of Petroleum Geologists*, Tulsa, pp. 599-614, 1994. [CrossRef] [Google Scholar] [Publisher Link]

[8] Gamal R. Gaafar, Raj Deo Tewari, and Zahidah Md. Zain, "Overview of Advancement in Core Analysis and Its Importance in Reservoir Characterization for Maximising Recovery," *SPE Asia Pacific Enhanced Oil Recovery Conference*, pp. 1-17, 2015. [CrossRef] [Google Scholar] [Publisher Link]

[9] J. Hosper, "Gravity Field and Structure of the Niger Delta Nigeria, West Africa," *Geological Society American Bulletin*, vol. 76, no. 4, pp. 407-422, 1965. [CrossRef] [Google Scholar] [Publisher Link]

[10] Archana Jagadisan, Jin-Hong Chen, and Stacey M. Althaus, "Improved Methods for Determination of Petrophysical Properties of Unconventional Tight Rocks Using Particulate Samples," *ACS Omega*, vol. 7, no. 11, pp. 9636-9641, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[11] R.W. Wiener et al., *Tectonic Map of the World*, AAPG Foundation, 1985. [Publisher Link]

[12] T.R. Klett et al., "*Ranking of the World's Oil and Gas Provinces by Known Petroleum Volumes*," United States Geological Survey Open File Report, 1997. [CrossRef] [Google Scholar] [Publisher Link]

[13] Holger Kulke, *Regional Petroleum Geology of the World: Africa, America, Australia, and Antarctica*, G. Borntraeger, pp. 1-729, 1995. [Google Scholar] [Publisher Link]

[14] Ahmad Niwaz, "*Permeability Modeling of Lavrans Field*," Master's Theses, Universitetet i Stavanger, pp. 1-50, 2012. [Google Scholar] [Publisher Link]

[15] Jan Rafdal, *Coring Analysis to Calibrate Well Log Interpretation*, Gordan and Breach Science Publication, pp. 35-51, 1996. [Publisher Link]

[16] Schlumberger, "Log Interpretation Principles and Application," *Schlumberger Wireline and Testing*, Houston, Texas, pp. 21-89, 1989. [Google Scholar]

[17] Ubanatu Samuel, and Igwilo Kevin, "A Permeability-Porosity-Saturation Correlation for Niger Delta," *Asia Pacific Journal of Multidisciplinary Research*, vol. 2, no. 2, pp. 20-23, 2023. [Google Scholar] [Publisher Link]

[18] C.E. Ubani, Y.B. Adeboye, and A.B. Oriji, "Advances in Coring and Core Analysis for Reservoir Formation Evaluation," *Petroleum and Coal*, vol. 54, no. 1, pp. 42-51, 2012. [Google Scholar] [Publisher Link]

[19] M.R.J. Wyllie, A.R. Gregory, and L.W. Gardner, "An Experimental Investigation of Factors Affecting Elastic Wave Velocities in Porous Media," *Geophysics*, vol. 23, no. 3, pp. 459-493, 1958. [CrossRef] [Google Scholar] [Publisher Link]

[20] Jun Yan, "Reservoir Parameters Estimation from Well Log and Core Data: A Case Study from the North Sea," *Petroleum Geoscience*, vol. 8, no. 1, pp. 63-69, 2002. [CrossRef] [Google Scholar] [Publisher Link]