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NEW SIMPLIFIED APPROACH FOR THE EVALUATION OF HYDROCARBON POTENTIALS IN SANDSTONE RESERVOIRS

(Case Studies: Ritchie's Oil Block & Osland Oil and Gas Field, Niger Delta, Nigeria)

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Supervisor: Prof. Dr. Fabio Taioli

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ABSTRACT

RICHARDSON M A-A. **New Simplified Approach for the Evaluation of Hydrocarbon Potentials in Sandstone Reservoirs.** 2018. 54p. Thesis [PhD in Energy, Option in Exploration Geophysics with the Bias for Petrophysics and Seismic Methods] Postgraduate Program in Energy, Institute of Energy and Environment of the University of São Paulo, São Paulo, 2018.

The aim of this research is to evaluate the hydrocarbon potential using a simplified approach in the sandstone reservoirs of the fields within the two case studies. It includes the modification of some traditional equations for the relevant parameters to help provide alternative expressions to aid the prediction of the reservoirs' flow (hydraulic) units, transmissibility and primary recovery in Ritchie's Oil Block and Osland Oil and Gas Field. It also involves the estimation of the recoverable volumes of hydrocarbons with the associated water cuts (C_w), and the use of correct time/depth correlations and enhanced velocity analysis for petrophysics and seismic interpretations involving the recommendation of the points for siting developmental wells in Osland Oil and Gas Field. Overall, four traditional equations of permeability (Tixier's, Timur's, Coates' and Coates and Denoo's) were modified for the comparative analysis and prediction of the selected reservoirs transmissibility and primary hydrocarbon recovery. Similarly, the Schlumberger's equation for the free fluid index (FFI), the Tiab, and Donaldson's equations for Flow zone indicator (FZI) and reservoir quality index (RQI) were redefined and engaged to aid the flow unit's evaluations. In addition, the Schlumberger's equations for fluids relative permeability were also modified and engaged for the prediction of the associated C_w. The results indicate reservoirs with good flow units and rates of recoveries. The volumes of C_w in the evaluated reservoirs are within the acceptable rates and other probable depths and drainage areas were recommended. Well to seismic tie (W-S_T) aided to reduce the doubt regarding pay thickness (P_t) and drainages' area (A_d). Models, in form of equations and handy charts, were suggested for the evaluation of reservoirs within sandstone units. The drudgery in the use of tradition equations was bypassed. The computational errors that may come with the calculation of a range of equations before flow units are evaluated were avoided. The methods adopted herein are believed to have minimised risk and uncertainty that comes with the flow unit evaluations and volumes estimations. It is supported herein that a geologist upskilled in geophysics or a geophysicist unskilled in geology should always be engaged in seismic and petrophysical interpretations. This will also contribute to risk and uncertainty reduction.

Keywords: Flow Units, Transmissibility, Primary Recovery, Water Cut Estimation
Well To Seismic Tie, Well Points Recommendation, Risk/Uncertainty Reduction

RESUMO

RICHARDSON M A-A. **Nova abordagem simplificada para a avaliação da potencialidade de ocorrência de hidrocarbonetos em reservatórios de arenito**. 2018. 54f. Tese [Doutor em Energia, Opção em Geofísica de Exploração com o Viés de Métodos Petrofísicos e Sísmicos] Programa de Pós-Graduação em Energia, Instituto de Energia e Meio Ambiente da Universidade de São Paulo, São Paulo, 2018.

O objetivo desta pesquisa é avaliar o potencial de ocorrência de hidrocarbonetos utilizando uma abordagem simplificada para reservatórios de arenito com dados de dois campos petrolíferos. Inclui a modificação de equações tradicionais para os parâmetros relevantes objetivando ajudar a fornecer expressões alternativas para auxiliar na previsão das unidades de fluxo (hidráulicas) dos reservatórios, transmissibilidade e recuperação primária no Bloco de Petróleo de Ritchie e no Campo de Petróleo e Gás de Osland, ambos situados no Delta do Niger, Nigéria. Também envolve a estimativa dos volumes recuperáveis de hidrocarbonetos com os cortes d´água (Water cut - C_w), o uso de correlações de tempo/profundidade corretas, análise de velocidade aprimorada para petrofísica e interpretações sísmicas envolvendo a recomendação dos pontos para localização de poços de desenvolvimento no Campo de Petróleo e Gás Osland. No geral, quatro equações tradicionais de permeabilidade (Tixier, Timur, Coates e Coates e Danio's) foram modificadas para a análise comparativa e previsão da transmissibilidade dos reservatórios selecionados para a recuperação primária de hidrocarbonetos. Da mesma forma, a equação da Schlumberger para as equações de cálculo do índice de fluido livre (Free Fluid Index - FFI), Tiab e Donaldson para o indicador de zona de fluxo (Flow Zone Indicator - FZI) e índice de qualidade do reservatório (Reservoir Quality Index - RQI) foram redefinidas e incorporadas para auxiliar nas avaliações da unidade de fluxo. Além disso, as equações da Schlumberger para a permeabilidade relativa de fluidos também foram modificadas e utilizadas para a predição da C_w associada. Os resultados indicam reservatórios com boas unidades de vazão e taxas de recuperação. Os volumes de Cw nos reservatórios avaliados estão dentro das taxas aceitáveis e permitiram, também, a identificação de outras profundidades prováveis e a recomendação de áreas de drenagem. A utlização de dados de perfilagem de poços em conjunto com os dados sísmicos (Well to Seismic tie - W-S_T) ajudou a reduzir a dúvida sobre a espessora econômica (Pay Thickness - P_t) e a área de drenagem (Drainage Area - A_d). Modelos, em forma de simples equações e gráficos, foram sugeridos para a avaliação de reservatórios dentro de unidades de arenito. Com isso, o trabalho penoso no uso de equações tradicionais foi contornado. Desta forma, os erros computacionais que se somam quando se utliza uma série de equações antes das unidades de fluxo serem

avaliadas foram evitados. Portanto, acredita-se que os métodos aqui adotados tenham minimizado o risco e a incerteza que acompanham as avaliações da unidade de fluxo, assim como as estimativas de volumes. Recomenda-se que um geólogo com experiência em geofísica ou mesmo um geofísico deve estar sempre envolvido em interpretações sísmicas e petrofísicas. Isso também contribuirá para a redução de riscos e incertezas.

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LIST OF ABREVIATIONS AND SYMBOLS

RQI_{aa}	Alternative expression **a** for RQI
RQI_{ab}	Alternative expression **b** for RQI
RQI_{ac}	Alternative expression **c** for RQI
FZI_{aa}	Alternative expression **a** for FFI
FZI_{ab}	Alternative expression **b** for FFI
FZI_{ac}	Alternative expression **c** for FFI
$RQI_{average}$	Average of the values of RQI_{aa}, RQI_{ab} and RQI_{ac}
$FZI_{average}$	Average of the values of FZI_{aa}, FZI_{ab} and FZI_{ac}
bbl	Billion barrels
ρ_b	Bulk density of formation
ρ_{sh}	Bulk density of adjacent shale
Cc	Conversion constant
Cu.ft.	Cubic feet
LLD	Deep Laterolog
ROHB	Density Log
Φ_D	Density derived porosity corrected for shalez
a	Factor of tortuosity
m	Factor of cementation
FZI	Flow Zone Indicator
F	Formation factor
ρ_f	Fluid density of formation (1.0gm/cc)
FFI	Free Fluid Index
GR	Gamma-ray Log
GOC	Gas-Oil-Contact
GUT	Gas-Up-To
GOR	Gas-to-Oil Ratio
GIP	Gas-In-Place
h_i	Hydrocarbon indication
S_h	Hydrocarbon saturation
HUT	Hydrocarbon-Up-To
ρ_{ma}	Matrix density of formation (2.65gcc for sandstone)
MF/F	Major Fault

mf/f	Minor Fault
mD	Millidarcy
μm	Micrometre
NPHI	Neutron Porosity Log
OIP	Oil-In-Place
K_{or}	Oil relative permeability
μ_o	Oil viscosity
OUT	Oil-Up-To
OWC	Oil-Water-Contact
PT/Pt	Pay Thickness
K	Permeability
K_{mc}	Permeability modified from Coates' expression
K_{mtm}	Permeability modified from Timur's expression
K_{mtx}	Permeability modified from Tixier's expression
Φ	Porosity
Φ_r	Porosity ratio
RF	Recovery factor
V_{Rg}	Recoverable volume of gas
V_{Ro}	Recoverable volume of oil
R-A_h	Reservoir A-horizon
R-B_h	Reservoir B-horizon
RB/ RS-B	Reservoir Base/ Reservoir Sand Base
P_{f_2}	Reservoir pressure
RQI	Reservoir Quality Index
RS-T	Reservoir Sand Top
RT	Reservoir Thickness
LLS	Shallow Laterolog
P_{f_1}	Surface pressure (15atm)
V_{sh}	Volume of shale
C_w	Water Cut
Kwr	Water relative permeability
S_W	Water Saturation
μ_W	Water viscosity
W-S_T	Well to Seismic Tie

TABLE OF CONTENT

1. INTRODUCTION

Hydrocarbon exploration and production are high-risk ventures. This research hopes to use new simplified approach to evaluate the hydrocarbon potential of the selected reservoirs in Ritchie Oil Block and Osland Oil and Gas Field within the Niger Delta, Nigeria. Exploration and production start with data acquisition, either on the onshore or offshore. In any case, risk and uncertainty management habits are advisable to be inculcated in the whole process, from the planning of the survey to the preparation of equipment and human labour (skilled and unskilled), through to the field processes and data processing and interpretation. Every instrument in use (equipment, technical expertise, and proper planning) contributes to the quality of the data acquired. Most times, data are analysed by scholars and experts who are never there during the time of acquisition. Therefore, during interpretation, the interpreter is left alone with no other option than to carefully deal with the data and then interprets and presents the result to the best ability. Without ignoring the fact that there are other means of errors, this work tends to redefine some equations for the evaluation of the selected reservoirs. Well logs and 3-D seismic data were engaged in this study. Core samples are not available; therefore, it is important to use alternative methods to upgrade the integrity of the results. As such, the drudgery and possible computational errors that come with the use of the traditional equations are bypassed. In this way, risk and uncertainty will be minimised.

The prediction of hydrocarbon transmissibility within the selected reservoirs and the recoverability of hydrocarbons were carried out, by predicting the flow units via the estimation of some relevant parameters. The equations for the free fluid index (FFI), permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) were modified to allow the direct relationship of porosity with these parameters. This assisted to avoid the approximation of the tortuosity factor (a), porosity exponent (m), formation factor (F), irreducible water saturation (S_{wirr}) and porosity (Φ) over a range of equations. The normal trend of involving the calculation of the first equation before the second and so on is avoided. This approach was used to evaluate the flow units for the prediction of transmissibility and primary recoveries of the selected reservoirs in Ritchie Oil Block and Osland Oil and Gas Field. In the same vein, the equations for water relative permeability (K_{wr}) and oil relative permeability (K_{or}) were modified and used to predict the anticipated volumes of water cut (C_w), which will be produced with the hydrocarbon in some other reservoirs. Well to seismic tie (W-S_T) was carried out and aided the correct time/depth correlations and enhanced velocity analysis for petrophysics and seismic

interpretations. Consequently, pay thicknesses (P_t) and drainage areas (A_d) were evaluated. Points were also recommended for siting developmental wells.

Porosity is an influential parameter in the petrophysical and volumetric evaluation and the majority of the reservoirs physical characteristics are not completely expressed without the use of porosity. The relationship between porosity and flow units is very effective for explaining reservoirs' geological attributes such as grain sizes and sorting, shale content, cementation, consolidation of rocks, pore sizes and interconnectivity among others [Schlumbeger 1989; Asquith and Krygowski. 2004; Tiab and Donaldson 2012]. The predictability of the occurrence of hydrocarbon in the reservoirs and the recoverability of hydrocarbon from the reservoirs are dependent on these attributes. Porosity plays a major role in formation evaluation and when it is well calculated and harnessed, it could boost the confidence on the results of the interpretations. This study suggests ways of using porosity as the only variable in the selected equations (FFI, K, RQI, and FZI) for the evaluation of the reservoir herein. The relevance of porosity for formation evaluation cannot be overemphasised. In volume estimations, for instance, if all other parameters are taken to be fine, an increase or decrease of 0.05 to 0.1 (5 to 10%) in porosity value could result in a notable increase or decrease in the computed volumes of hydrocarbons in place. Similarly, in qualitative evaluations the expression for FZI is dependent upon RQI, which is dependent upon K. In the same vein, K is dependent upon S_{wirr} and/or FFI, both S_{wirr} and FFI are dependent upon formation factor (F) while F is dependent upon Φ. If one must follow the computation in steps from the determination of F, Φ will be approximated over a range of equations and these equations never give their results in whole figures. Errors due to estimation are always undesirable, especially when it comes to volumetric analysis and other decision dependent calculations, where overestimation or underestimation error as low as ±0.05 can result in a notable difference. This can increase the risk and uncertainty

In the end, it anticipated that this work presents the evaluation of the hydrocarbon potential of the selected reservoirs and suggests ways to reduce the associated risks and uncertainties through four highlighted objectives that are publishable in relevant scientific journals. It looks at the modification of traditional equations for the relevant parameters to help provide alternative expressions in the sandstone reservoir. It involves the evaluation of the reservoirs' flow (hydraulic) units to aid in the prediction of transmissibility and primary recovery. Furthermore, the estimation of the recoverable volumes of hydrocarbons with the associated water-cuts production will be carried out. Finally, well to seismic tie (W-S_T) will be

done painstakingly, to aid correct time/depth correlations and enhanced velocity analysis for petrophysics and seismic interpretations involving; pay thickness (P_t) determination, drainage area (A_d) delineation and the recommendation of the points for siting developmental wells.

1.1 Objectives

The aim of this work is to evaluate the hydrocarbon potentials of the selected hydrocarbon wells with a view to minimising risk and reducing uncertainty through the modification of some relevant equations and methods for qualitative and quantitative evaluation. It is based on four objectives:

- Modification of some traditional equations for the desired parameters to help provide alternative expressions in sandstone units in Ritchie's Oil Block;
- Prediction of the reservoirs' flow (hydraulic) units, transmissibility and primary recovery in the reservoirs in Osland Oil and Gas Field;
- Estimation of the recoverable volumes of hydrocarbons with the associated water-cuts production and
- Use of well to seismic tie (W-S_T) to aid correct time/depth correlations and enhanced velocity analysis for petrophysics and seismic interpretations involving the recommendation of the points for siting developmental wells (Osland Oil and Gas Field)

1.1.1 Hypotheses

Most geologists do not believe in the use of well logs alone for the evaluation of flow units. Therefore, one of the concepts this study tries to address is based on how to improve on the integrity of the results of well log analysis in the absence of core data for comparative studies. Therefore, equations for the desired parameters were modified and engaged to study the hydrocarbon potentials of the selected sandstone hydrocarbon reservoirs. The modified expressions depend on each other. Normally, one is calculated and then used as input for the calculation of the next. Apart from simplifying the methods of predicting the flow units in sandstone reservoirs, this study could also provide alternative expressions and quick-look models for the prediction of the selected parameters. These redefined expressions are expected to have the porosity as the only variable input for the evaluation of flow units. Volumes estimation was also addressed, partly with a similar approach and with correct time/depth correlations. Therefore, the hypotheses are:

- The evaluation could suggest a simplified approach to the prediction of flow units in sandstone reservoirs, hence, assist to avoid underestimation and/or overestimation of the desired parameters;
- The prediction of the reservoirs' flow (hydraulic) units, transmissibility and primary recovery in sandstone hydrocarbon reservoirs will be made easy;
- The redefined expressions for fluids relative permeability could enhance the estimation of the volumes or percentages of the water cut (C_w) in the reservoirs and
- Correct time/depth correlation using well to seismic tie (W-S_T), when carried out painstakingly, can help to reduce doubts regarding pay thickness (Pt), drainage area (Ad) and points for sitting developmental wells.

1.1.2 Expected Outcome

The results of this research are expected to influence the decision on whether or not to go ahead with production activities in the evaluated Oil and Gas Fields. This research is also expected to produce articles in reputed journals and presentations in relevant conferences based on the stated hypotheses and objectives. The highlights of the published/Submitted articles (Table 1) and extended abstracts in conferences (Table 2) include:

- Modified (alternative) expressions for the evaluation of free fluid index (FFI), permeability (K), reservoir quality index (RQI), flow zone indicator (FZI), water relative permeability (K_{wr}) and oil relative permeability (K_{or}), mainly in sandstone units;
- A combined (quick-look) model for the prediction of RQI and FZI;
- Predicted transmissibility and recoverability of the reservoirs fluids across Wells R-D_a, R-D_b and R-D_c;
- Estimated volumes or percentages of the water cut (C_w) in the reservoirs across wells D_1 and D_2;
- Correct time/depth correlations and enhanced velocity analysis;
- Recommended points for sitting developmental wells and
- Risks and uncertainties reduction.

Table 1: The corresponding publications based on objectives and hypotheses

Objectives	**Publication**
Modification of traditional equations for the relevant parameters to help provide alternative expressions in sandstone units	***(2017) Maximising porosity for flow units evaluation in sandstone hydrocarbon reservoirs, a Case Study of Ritchie's Block, Offshore Niger Delta***. IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG). 3:2, pp 06-16. (See appendix A)
Estimation of the recoverable volumes of hydrocarbons with the associated water-cuts production	***(2018) Redefining fluids relative permeability for reservoir sands. (Osland oil and gas field, Offshore Niger Delta, Nigeria),*** Journal of African Earth Sciences (JAES) in **Elsevier**. 10: 024 pp 1-8. (See appendix B)
Prediction of the reservoirs' flow (hydraulic) units, transmissibility and primary recovery in the reservoirs in	***(2018) Hydrocarbon Viability Prediction of Some Selected Reservoirs in Osland Oil and Gas Field, Offshore Niger Delta, Nigeria.*** Journal of Marine and Petroleum Geology (JMPG) in Elsevier. Vol. 100. 195-203 (See appendix C)
The use of well to seismic tie ($W\text{-}S_T$) to aid correct time/depth correlations and enhanced velocity and the recommendation of the points for siting developmental wells	***(2018) Asserting the Pertinence of the Interdependent Use of Seismic Images and Wireline Logs in the Evaluation of Some Selected Reservoirs in the south Atlantic Passive Margin. (Osland oil and gas field, Offshore Niger Delta, Nigeria),*** **[**Under review by the paired reviewers in Brazilian Journal of Geology**]**. (See appendix D)

Table 2: The corresponding presentation in conferences based on objectives and hypotheses

Extended Abstract in Conferences
A simplified approach to hydraulic units' evaluations using wire-line logs. Oral presentation at "**3rd International Convention on Geosciences and Remote Sensing**", October 19-20, 2018, Ottawa, Canada. (See appendix F)
The relevance of porosity in the evaluation of hydrocarbon reservoirs. Oral Presentation 44027, 9th Congress of the Balkan Geophysical Society 5-9 November 2017, Antalya, Turkey. (See appendix E)

2. LITERATURE REVIEW

2.1 GEOLOGY AND PETROLEUM OCCURRENCE.

The emergence of the Niger Delta basin is consequent upon series of events. According to Burke (1972), the prevailing Southwestern wind and the regular pattern of longshore currents resulted in the geomorphology of the Niger Delta. Some of the river deposits are picked up by longshore currents in the coastal plain, while the rest is deposited in the coast. Consequently, a larger percentage of the sand accretes along the front of barrier bars, but a minor portion moves down the slope along submarine channels (Burke 1972).

2.1.1 Eocene to Recent Delta

The proliferous Niger Delta is believed to have been built over an older transgressive Palaeocene pro-delta. It underlies an estimated area of about 256,000 km^2, and was initially. The development extended from Eocene-Mid-Miocene sub-deltas to the growth of post-Mid-Miocene Delta. From the Eocene to the Mid-Miocene, the Niger Delta complex progressed along three main sedimentary axes; the Anambra and it is subsidiary basin which was fed by the Niger and Benue River and the Afikpo syncline fed by the Cross River, which also deposited some materials along the Ikang trough from Eocene to Late Oligocene. After the Mid-Miocene, the Niger-Benue and Cross River Delta systems merged and the influence of upper Cretaceous tectonic elements was no longer pronounced. Hence, from the Mid-Miocene onwards the rate of Delta advances was determined by the rate of erosion of newly uplifted blocks in the hinterland, particularly of newly emergent Cameroon Mountain (Short and Stauble, 1967).

Niger Delta (Fig. 1) consist of the Northern Depobelt, Greater Ughelli Depobelt, Central Samp Depobelt and the Coastal Swamp Depobelt. The region is believed to have emerged from a failed rift junction because of the separation of the South American and African plates in the late Jurassic to mid-Cretaceous. These depositional and tectonic events have brought about ranges of evolutional trends that have been in use for explaining the general and petroleum geology of the area. The structural and stratigraphic styles (hydrocarbon traps) that are in use for predicting the availability of hydrocarbons in-place in this region are directly related to these events. The Niger Delta consists of the regressive wedge of clastic sediments of maximum thickness of about 12km (Doust and Omatsola, 1990).

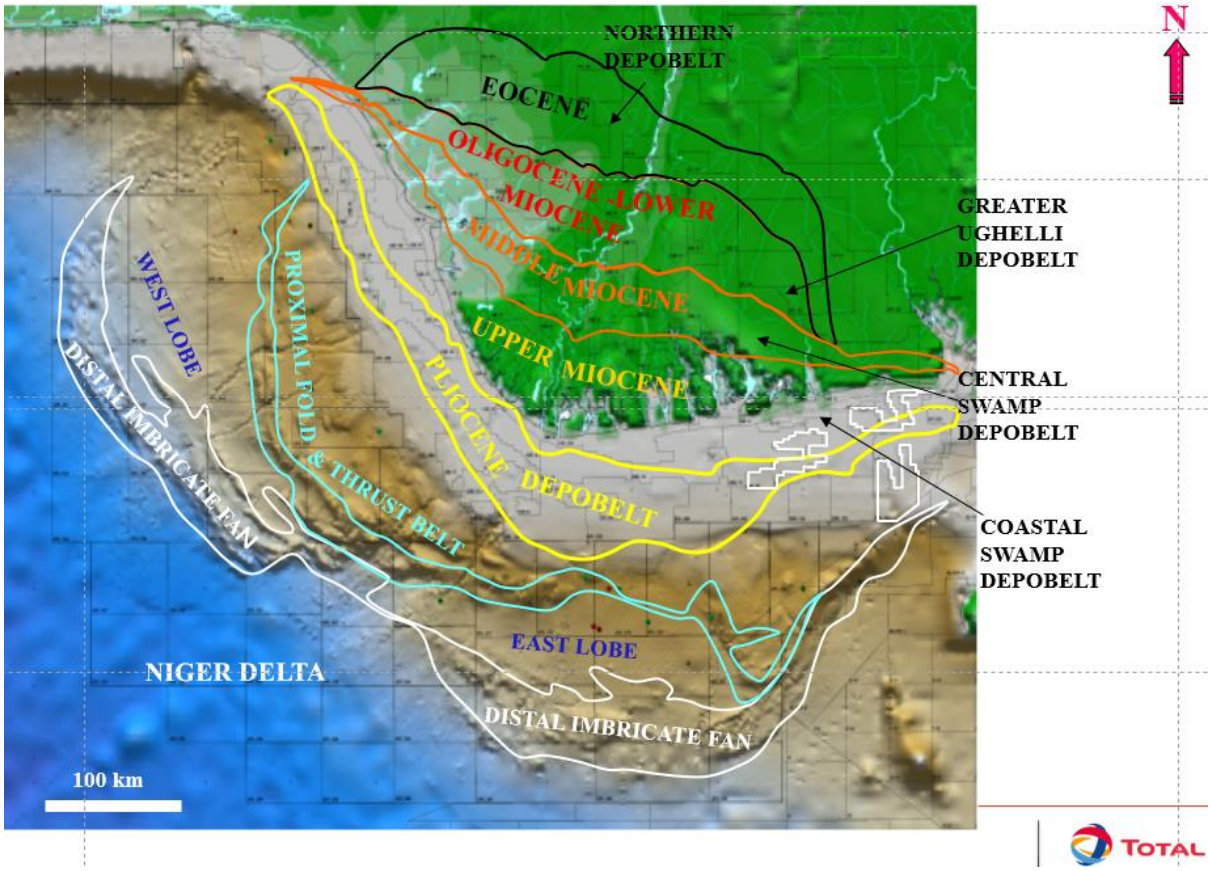


Figure 1: Niger Delta Geological Framework [Courtesy; Total Nigeria Limited]

2.1.2 Stratigraphy

There are three lithostratigraphic units (Fig. 2) in the region; Benin, Agbada and Akata Formations (Doust and Omatsola, 1990: Reijers et al., 1997). Niger Delta reservoir development was associated with the sandy regressive off lap sequence of the Agbada Formation (Haack et al., 2000). Some of the reservoirs in the Niger Delta are juxtaposed against faults within this formation (Freddy et al., 2005). This accounts for the structural traps that permitted the accumulation of hydrocarbons. The maturity of the associated hydrocarbons and reservoir quality are directly linked with depth and overpressure (Weber and Daukoru, 1975; Evamy et al., 1978). The rapid loading of the compacted shale of the Akata Formation by the sandy Agbada and Benin Formations (Reijers et al., 1997) resulted in the overpressures in the Niger Delta. Hence, fluids expelled from the over-pressured Akata shale could inflate the pressures in the adjacent sands. Compaction creates upward and downwards fluid potential gradients from the more compactable units to the more permeable units. Fluids may be expelled upwards and downwards into the adjacent reservoir rocks. The downward potential gradient

makes the shale a perfect barrier and seals to upward migrating fluids (Weber and Daukoru, 1975; Reijers, 1995).

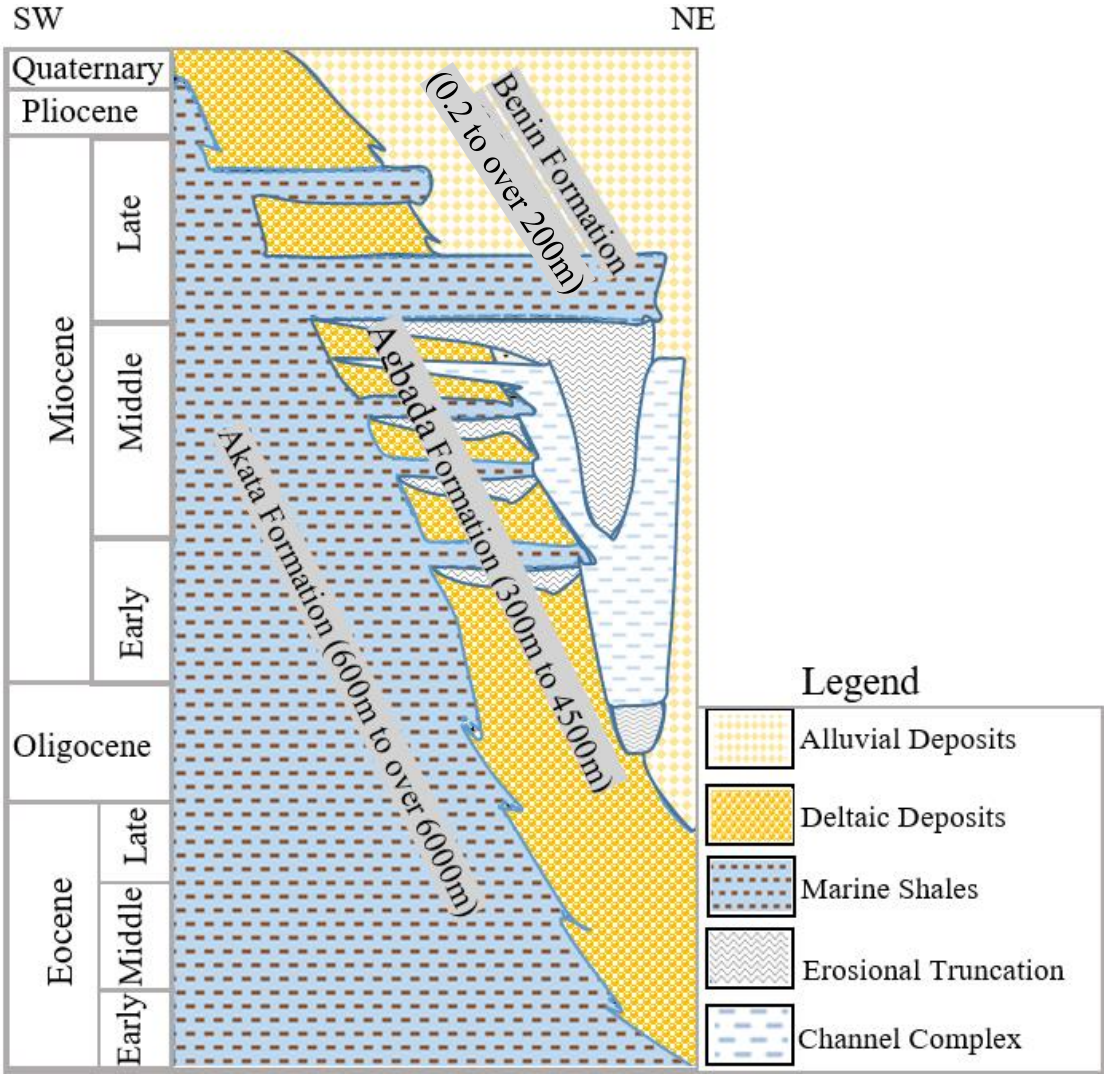


Figure 2. Niger Delta Lithostratigraphic Succession

[Modified from Shannon and Naylor, 1989 and Doust and Omatsola, 1990]

2.1.3 The Benin Formation

The uppermost layer of the Niger Delta is the Benin Formation. It extends from the West across the whole Niger Delta and has been described as coastal plain sands which outcrop in Benin, Onitsha and Owerri provinces. Very little hydrocarbon accumulation has been associated with this highly porous and generally freshwater bearing formation (Short and Stauble, 1967). The Benin Formation consists of massive continental sands and gravels with the thickness ranging from 0.2- to over 200 metres. The sand and sandstone are coarse to fine and commonly granular in texture.

2.1.4 The Agbada Formation

The Agbada Formation is rich in hydrocarbon in its own capacity in terms of accumulation and production. It is thick at the center of the delta (up to 457.2m). The upper part is predominantly sandy unit with minor shale intercalation and a lower shaly unit which is thicker than the upper sandy unit. The Agbada Formation is a paralic sequence of sandstone and shale underlying the Benin Formation. It consists of the sandy parts, which serve as the main hydrocarbon reservoir of the delta and shale as the cap rock. This sequence is associated with synsedimentary growth faulting. The depositional environment is therefore defined as "transitional" between the upper continental Benin formation and the Marine underlying Akata formation which is also associated with sources rocks and associated hydrocarbon production.

2.1.5 Akata Formation

The Akata Formation consists of the hydrocarbon source rocks in the Niger Delta. It has deeper marine shale and the deepest stratigraphic unit. It is principally characterised by plastic, low density, under-compacted and high-pressure shallow marine to deep water-shale; with only local interbedding of sands and/or siltstones. It is deposited as the high-energy delta advanced into deep water.

The shale in the Akata Formation is believed to be overpressured and this provides the mobile base for subsequent growth faulting associated with the deposition of the overlaying Paralic sequence. The rapid loading of the under-compacted shale of the Akata formation by the sandy Agbada and Benin formation brought about the encountered overpressures in the Tertiary Niger Delta. Agbada paralic sediments strongly overpressure the Akata shale across faults. Hence, fluids expelled from the overpressured Akata shale could inflate the pressures in the adjacent sands. Within a given fault block, overpressures are usually stratigraphically controlled. The expected rates of overpressures over a large part of the Delta are relatively notable.

2.1.6 Hydrocarbon Distribution

Hydrocarbon occurs throughout the Agbada Formation of the Niger Delta. However, several directional trends form an "oil-rich belt" having the largest field and lowest gas: oil ratio (Ejedawe, 1981, Evamy *et al*. 1978, Doust and Omatsola, 1990). The belt extends from the northwest offshore area to the southeast offshore and along a number of north-south trends in the area of Port Harcourt. It roughly corresponds to the transition between continental and oceanic crust and is within the axis of maximum sedimentary thickness. This hydrocarbon

distribution was originally attributed to the belief that earlier landward structures are able to trap the earlier migrating oil. This can be referred to as the timing of trap formation relative to petroleum migration.

The complex geologic structures associated with the rifting (tectonic events) in the Delta has a significant influence on the petroleum distribution. Many rollovers, movement on the structure-building fault and resulting growth continued and was relayed progressively southward into the younger part of the section by successive crestal faults, hence, there was no relation between growth along a fault and distribution of petroleum (Evamy *et al*. 1978). The position of the oil-rich areas within the belt is related to five Delta lobes fed by four different rivers and the two controlling factors are an increase in geothermal gradient relative to the minimum gradient in the delta center, and the generally greater age of sediments within the belt relative to those further seaward (Ejedawe, 1981). Collectively, these factors gave the sediments within the belt the highest "maturity per unit depth". Weber, (1971) indicates that the oil-rich belt ("golden lane") coincides with a concentration of rollover structures across depobelts having short southern flanks and little paralic sequence to the south.

The position of the oil-rich belt to oil-prone marine source rocks deposited adjacent is related to the Delta lobe, and the accumulation of these source rocks was controlled by pre-Tertiary structural sub-basins related to basement structures (Haack *et al*. 2000). The distribution of petroleum is likely related to heterogeneity of source rock type (greater contribution from paralic sequences in the west) and/or segregation due to remigration (Doust and Omatsola, 1990).

2.1.7 Source Rocks and Seals

A rock (usually sedimentary) that is generating hydrocarbon or that is capable of doing so, is referred to as a source rock. Seals, on the other hand, are relatively impermeable rock (usually, shale in the Niger Delta) that prevents the fluids to move above and around the reservoir rocks. Apparently, these seals form the top of the identified oil kitchens (Fig. 3) in the region. Both the source rocks and seals are very fundamental to the occurrence, migration and accumulation of hydrocarbons in the reservoirs in the Niger Delta.

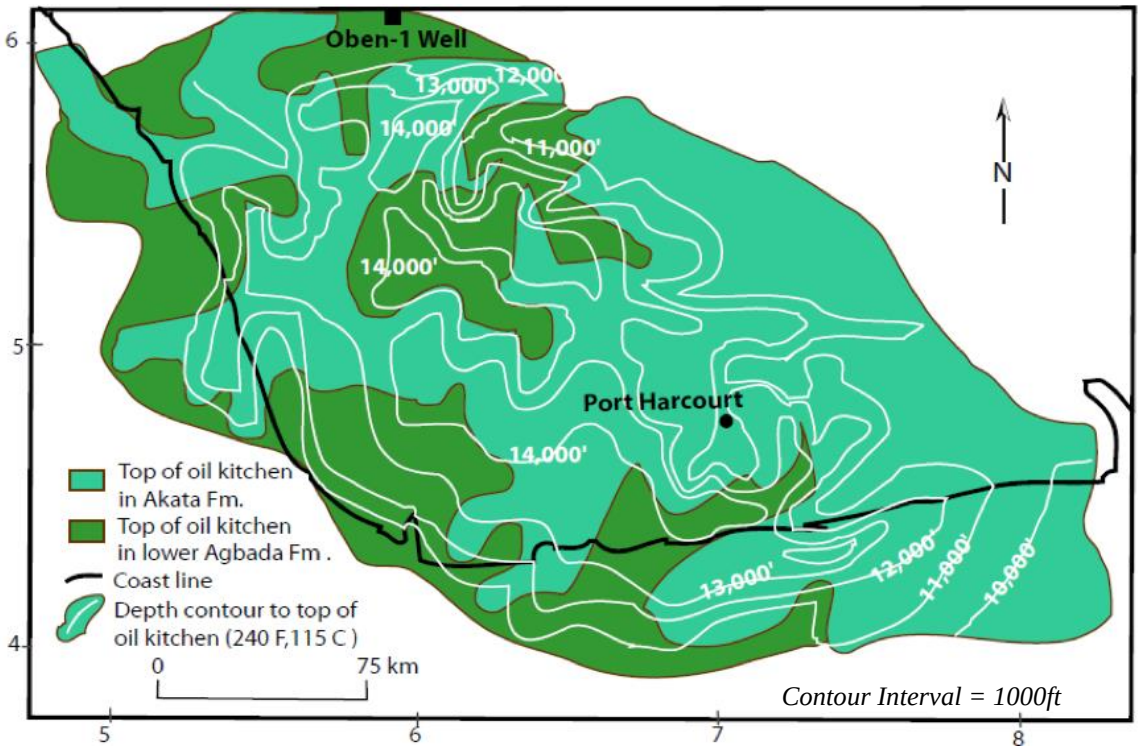


Figure 3: Depth to the seal of the oil kitchen of both Agbada and Akata Formations [Evamy et al., 1978: Tuttle et al., 1999]

There are few debates on the location of the source rocks for the large volume of oil trapped in the Niger Delta (Ekweozor and Daukoru 1994). There are three schools of thought: The Agbada source, supported by Short and Stauble (1967). Frankly and Cordery (1967); Lambert- Aikhionbare et al. (1984). The Akata source supported by Weber (1971); Weber and Daukuru (1975). The joint Akata and Agada source supported by Evamy et al. (1978); Ekweozor and Okoye (1980); Nwachukwu and Chuckwurah (1986). The cause of disagreement has been the mechanisms by which the oil migrates from the source rock into the reservoir rocks. In terms of organic matter content, the shale of both the paralic and open marine sequences (Agbada and Akata Formations) are likely to contain widely disseminated source rock levels, although the bulk is likely to occur in the paralic section (Doust and Omatsola, 1990). There are notably two types of seals in the Niger Delta; the regional shale markers and the fault seals. The regional markers have formed the basis of most hydrocarbon seal predications because of the unique biostratigraphic constituents. The fault seals consist mainly of faults that display growth faults. However, seals are bound if there is sufficient clay smear or if reservoirs are juxtaposed against shale.

2.1.8 Migration and Accumulation

The movement of hydrocarbon along porous and permeability paths, normally from the source rocks to the reservoirs or seeps is called migration. Accumulation occurs when a quantity of hydrocarbon is gradually gathered and trapped in geologic structures over time. Migrations and accumulation are collectively dependent upon the presence of the hydrocarbon within the source rocks, the reservoirs geometry, flow units and interconnectivity, structural and stratigraphic controls. When lithology alternates, like clays alternating with porous and permeable sand beds, compaction creates upward and downwards fluid potential gradients from the more compactable units to the more permeable units. Consequently, the fluids are expelled (upwards and downwards). However, the downward potential gradient makes the clay a perfect barrier and seal to any upward migrating fluids. Thus, secondary migration can only take place laterally within the permeable beds. Three types of migration are recognized; primary, secondary and tertiary migrations. Primary migration is that from source rock to reservoir rock while secondary migration is that which takes place within the reservoir rocks and it continues over long distances until it is trapped and accumulated. Tertiary migration, which is man-induced, is the movement or flow of petroleum from the reservoir rocks into a wellbore when the formation is drilled (Hunt, 1990).

The primary migration mechanism remains an enigma; secondary migration particularly upward migration (Fig. 4) in the Delta has been described as being possible where the sands are juxtaposed across faults. It is been argued that shale smearing may obstruct this movement, but Weber (1971) maintained that microfracture within the shale allows migration to take place. The occurrences of oil and gas in the Niger Delta are connected in sandstone reservoirs at various levels of the Agbada Formation. Throughout the Cenozoic history of the Niger Delta, it has been a consistent and rich system. Reservoir development is typically restricted to the sandy regressive off-lap sequences of the paralic section, where reservoir are favourably juxtaposed with intraformational seals (Beka and Otis, 1995). Reservoirs can be made up of sands, sandstone, and siltstone. Sands of barrier-bar origin are cleaner, coarser and laterally continuous than those of other depositional origins. They can be traced along the strike in a field over a distance of 10 km, but a distance of 21km parallel to the growth fault is not impossible (Weber, 1971).

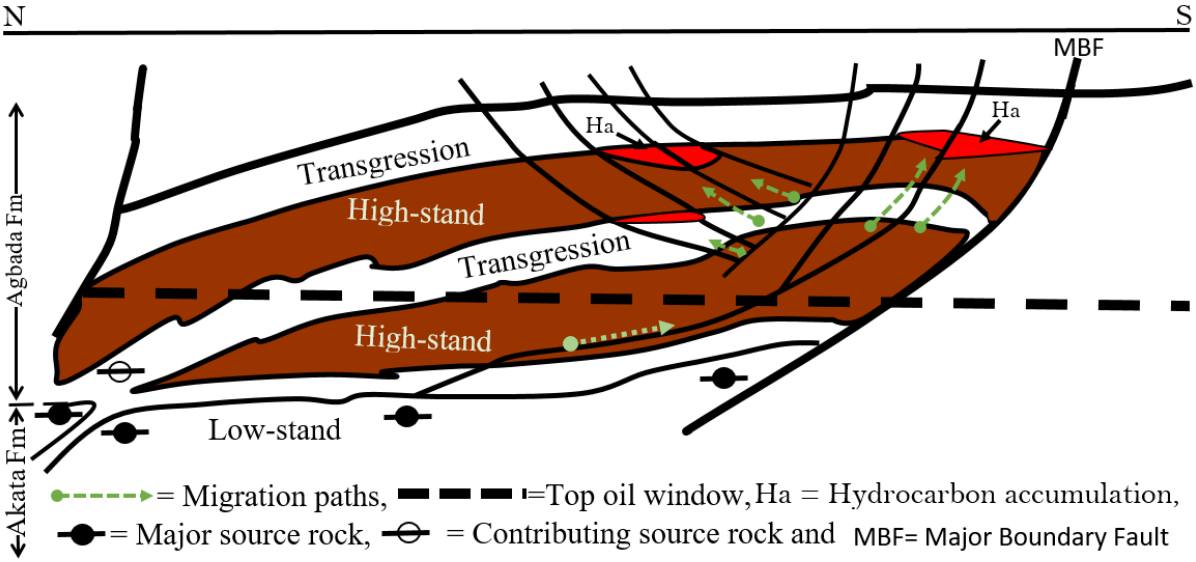


Figure 4: Conceived idea on hydrocarbon migration in the Niger Delta [Modified from Starcher, 1995]

2.2 BASIC PETROPHYSICS/WELL LOGGING

The petrophysical log interpretation is one of the most useful and important tools available to a petroleum geologist. A "log" is a continuous recording of a physical property of rock with depth and it is presented either on a continuous strip of paper (analogue) or in a digital format. Besides their traditional use in exploration to correlate, logs help to define physical rock characteristics such as lithology, porosity, pore geometry, and permeability. Logging data is used to identify productive zones, to determine depth and thickness of zones, to distinguish between oil, gas, or water in a reservoir, and to estimate hydrocarbon reserves. Open hole logs (logs that are recorded in the uncased portion of the wellbore) are most frequently used in hydrocarbon exploration. Fundamentally, porosity and the fraction of pore spaces filled with hydrocarbons are the parameters measured with well logs. logs are run by taking measurement in-place at the subsurface with the aid of a tool at the logging cable end (Lines and Newrick 2004).

2.2.1 Gamma Ray Log (GR)

GR measures the natural radioactivity of the formation, which concentrates in clay and shale. It reflects the shale content of the sedimentary formation. Normally, formations with little or no clay/shale content show a low level of radioactivity. These radioactive materials could include Uranium, Thorium, and Potassium. The GR detector records the natural gamma rays against depth in API units, on a scale of 0 to 150 API. An example is the Hostile

Environment Natural Gamma Ray Sonde (HNGS). It uses two bismuth-germanate (BGO) scintillation detectors to measure the natural gamma ray radiation of the formation (Fig. 5)

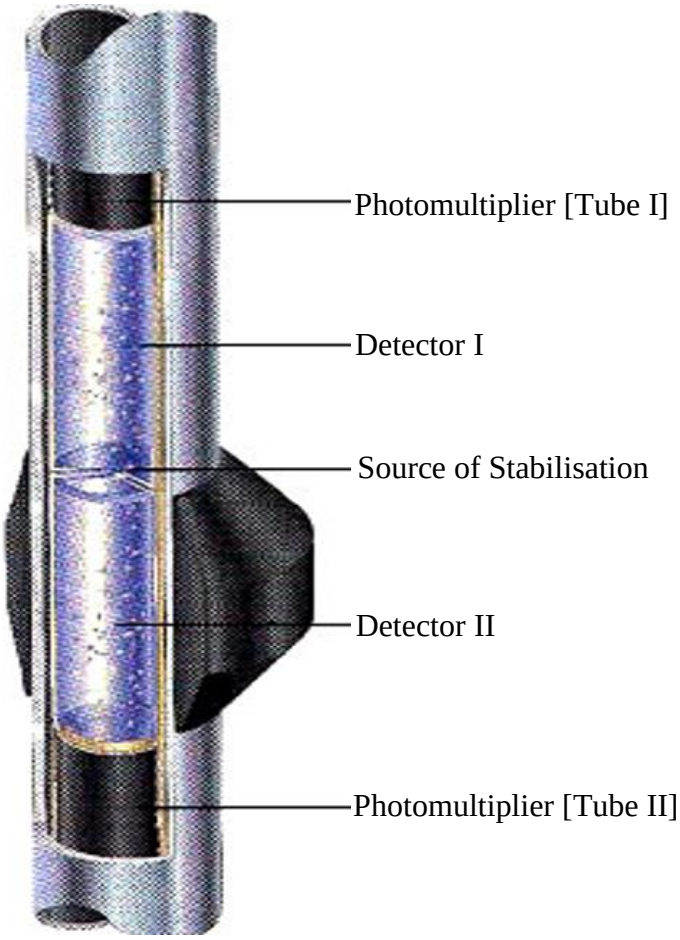


Figure 5: Hostile Environment Natural Gamma Ray Sonde (HNG)
[Schlumberger Wireline Tools, 2016]

GR is used for the identification of lithology and correlation between wells, quantitative estimation of the percentage of shale in the reservoir rock, delineation of depositional environments and identification of radioactive deposits. Gamma-ray emission is not constant (Statistical fluctuations) and as such, filtering the emission in modern digital systems is required. Borehole effect because of the hole diameter, mud weight, tool size, and position are also not uncommon, but appropriate charts are used to effect these corrections

2.2.2 Neutron Log

This porosity log measures the hydrogen ion concentration in a formation. In a shale free environment (clean formation), it measures liquid filled porosity (i.e. when pore spaces are filled with oil or water). Neutrons, electrically natural particles have a mass almost identical to the mass of a hydrogen atom. They are sourced from a chemical in the neutron–logging tool

(Fig. 6); such chemical could include a mixture of Americium and beryllium (AmBe) that will continuously emit neutrons.

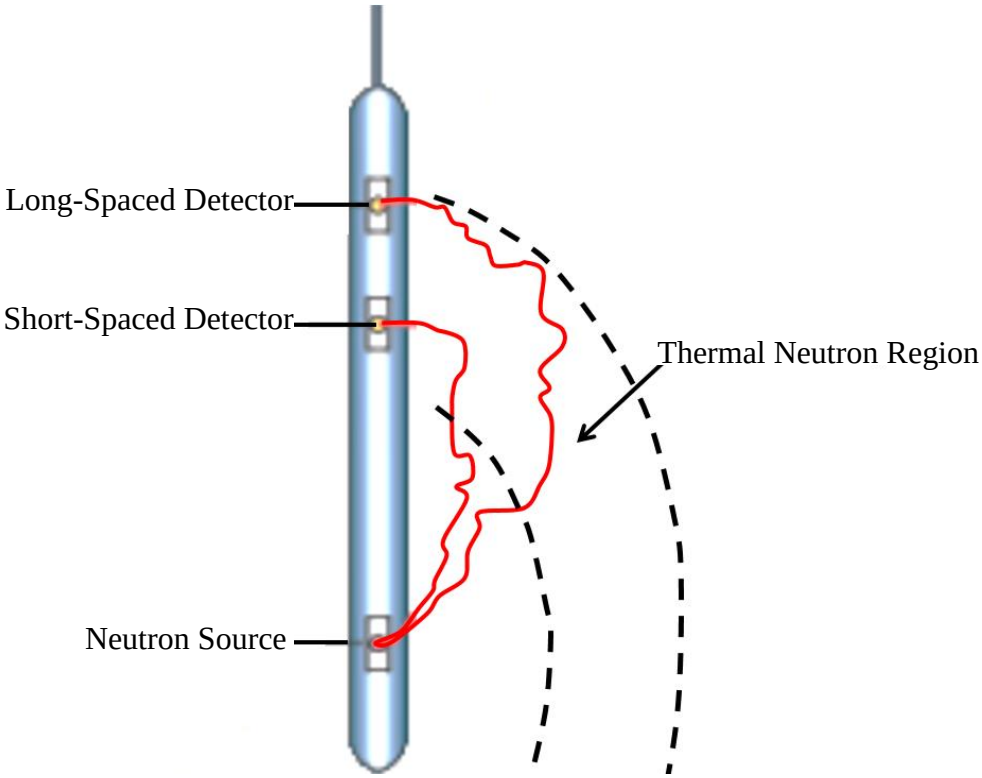


Figure 6: Neutron porosity tool

[Modified from Schlumberger Oilfield Review, 2012]

The emitted neutrons collide with the nuclei of the formation materials and result in a neutron losing some of its energies. As a result of the closeness in the mass of neutron and hydrogen, there is always maximum energy loss when they collide. The collision effects are referred to as a billiard-ball effect. The maximum amount of energy loss is a function of the formation's hydrogen concentration. When the hydrogen concentration of the material surrounding the neutron source is larger most of the neutron is lowered and captured within a short distance from the source. On the other hand, when the hydrogen concentration is small, the neutrons travel further from the source before being captured. Consequently, the counting rate at the detector increases for decreased hydrogen concentration as vice versa. Neutron Logs are used for: porosity determination, fluids differentiation (oil, gas and water), lithology and shally-sand interpretation and gas-bearing zones determination when used in combination with density log. Compensated neutron tool (CNL) is designed to reduce most environmental effects and Neutron logs can be run in cased hole. Nonetheless, the tool measurements are affected by borehole size, salinity, and mud-weight and mud cake thickness. Other include temperature

and pressure, lithology and shale effects and casing and/or cement with excavation effect. These effects can be corrected.

2.2.3 Density Log

The formation density log (Fig. 7) is a porosity log that measures electron density of a formation. A density logging device is a contact tool, which consists of a medium-energy gamma-ray source that emits gamma rays into a formation. The gamma-ray source is either Cobalt-60 or Cesium-137. Density logging is responsible for photoelectric absorption effect, Compton scattering effect and pair production.

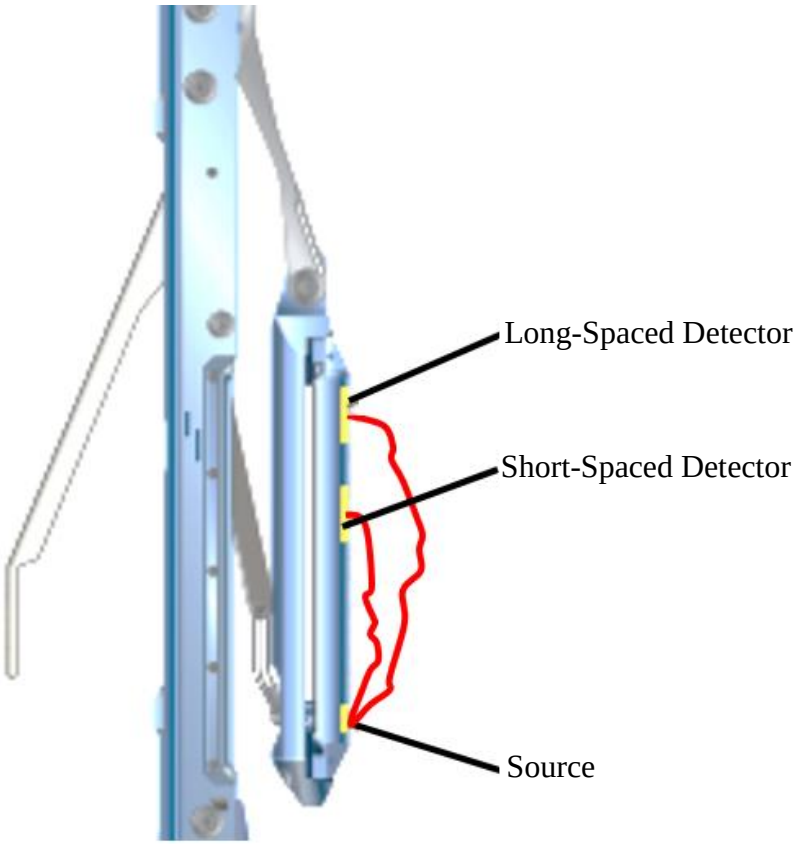


Figure 7: Density porosity tool

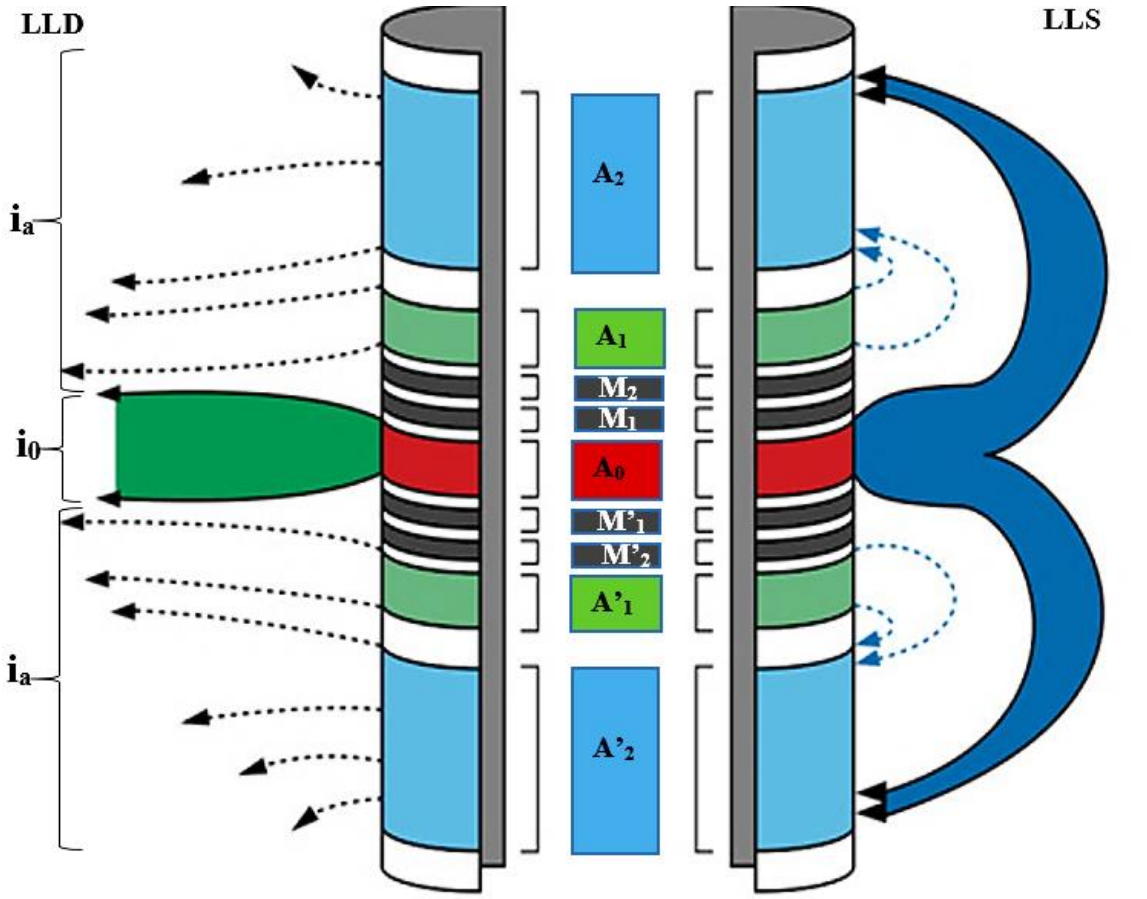
[Modified from Schlumberger Oilfield Review, 2012]

The density tool has a two gamma-ray detector (short-spaced detector and long-spaced detector). When the emitted rays collide with electrons in the formation, the collisions result in a loss of energy from the gamma ray particle. The scattered gamma rays that return to the detector in the tool are measured in two energy ranges. The number of returning gamma rays in the higher energy range, affected by compton scattering, is proportional to the electron density of the formation. Formation bulk density (ρb) is a function of matrix density, porosity, and density of the fluid in the pores (salt, mud, fresh mud, or hydrocarbons). Density log is

used for the determination of formation porosity, identification of minerals in evaporite deposits, gas zone detection when used in combination with Neutron log, determination of hydrocarbon density, evaluation of shaly sands and complex lithology, oil-shale yield determination and the calculation of overburden pressure and rock mechanical properties.

2.2.4 Resistivity Logs (Induction Log)

Resistivity logs are electric logs (Fig. 8) that are used to determine hydrocarbon versus water-bearing zones, indicate permeable zones, and determine resistivity porosity.



A_0 is the central electrode, A_1, A'_1, A_2, A'_2 are the current electrodes, M_1, M'_1, M_2, M'_2 are the potential electrodes, and i_o and i_a are the current emitting from the electrodes.

Figure 8: Dual Laterolog (Modified from Schlumberger Wireline Tools, 2016)

The most important use of resistivity logs is the determination of hydrocarbon versus water-bearing zones. Because the rock's matrix or grains are non-conductive, the ability of the rock to transmit a current is almost entirely a function of water in the pores. Hydrocarbons, like the rock's matrix, are non-conductive; therefore, as the hydrocarbon saturation of the pores increases, the rock's resistivity also increases.

The induction log was developed to measure formation resistivity in boreholes containing oil-based mud because the electrode device does not work in these non-conductive muds. Induction logging devices focus the current in the formation in order to minimize the influence of borehole and of the surrounding formations. They are designed for deep investigation and reduction of the influence of the invaded zone

2.3 BASIC SEISMIC METHODS

Seismic method is the most extensively used geophysical tool of petroleum exploration. It provides the largest amount of information about subsurface geology. Most importantly, are the high accuracy, high resolution and greater depth of penetration (Dobrin and Savit 1988). Seismic reflection work thus includes field design and data acquisition, processing, and interpretation of the processed data. The seismic method involves measurement of the travel times of seismic waves at the interface between media having different velocities and/or densities. The operative physical properties are the density and elastic constants. The travel time depends on the velocity. There are two main seismic methods -refraction and the reflection. Essentially, seismic refraction is used for engineering site investigation and groundwater exploration because of the shallow depth of investigation, while reflection seismology involves the use of acoustic energy sources that are made to travel into the subsurface while travel times of reflected waves generated are measured by acoustic detecting transducer placed at a reasonable distance from the source.

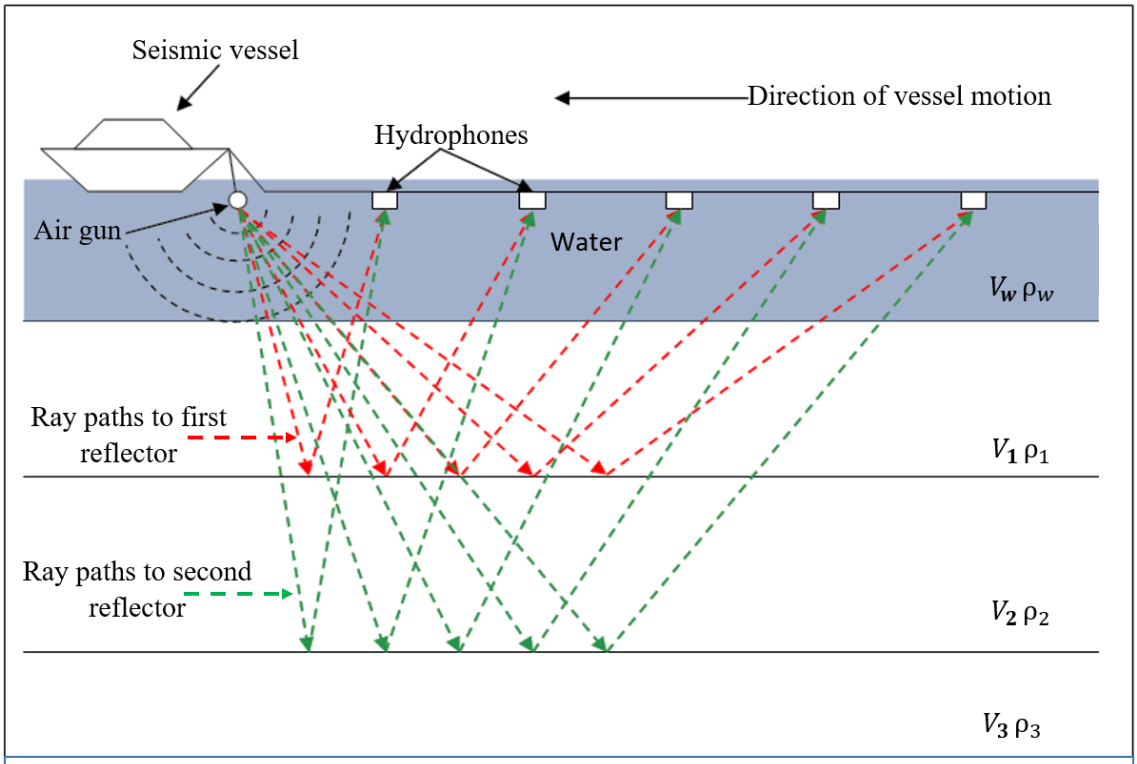
The principles of seismic exploration are based on the propagation of elastic waves. During the elastic wave propagation, the particle of the medium, vibrate to transmit energy from one particle to another. The wave propagation is based on some principles and laws (Huygens, Fermat's and Snell's). Waves are categorized as compressional, dilatational, longitudinal or primary waves (p-waves), Shear, transverse or secondary waves (S–waves), Ground roll, surface waves or Rayleigh waves, Love waves and Stoneley waves (Telford et al. 1990).

2.3.1 Seismic Data Acquisition

Seismic data acquisition could be on either land/swamp (onshore) or water (offshore). Literature review, which involves a study of the geological and geophysical data of the area is important to know the depth of the target zone, vertical resolution, spatial resolution, type of reservoir (structural or stratigraphic), desired signal to noise ratio, effect of near-surface conditions (weathering layer) and fold or coverage of target horizons. In seismic surveys,

sources and receivers are along multiple parallel lines, where source lines are perpendicular to the receiver lines. In 3-D surveys, the source and receiver lines enclosing the CDP locations are scattered over a "bin" which is the smallest rectangle or square with different azimuths for proper imaging of 3-D structure.

Seismic energy sources can be land or marine sources (Fig. 9) depending on the area of investigation. Land sources include explosives (e.g dynamite), vibroseis (hydraulic vibrator), dinoseis (propane and oxygen) and thumper or weight dropping. Marine sources include air gun, vapor choc or steam gun (superheated stream), maxipulse (involving a cylindrical charge of nitrocarbonitrate – explosive), water gun (a variety of air gun) and sleeve exploder or aqua pulse (a mixture of propane and oxygen).



Impedance (Z) = $V_i\rho_i$, Such that, ρ = the bulk density of the rock, and V = the velocity of seismic wave propagated through water and the stratified of rocks.

Figure 9: A typical array of a Marine Seismic Survey Reflection Seismology [Marine Seismic Survey Diagram by Nwhit, 2012]

Acoustic detecting transducers used on the land are called geophones (also referred to as jugs or seismometers). They are electromagnetic detectors that measure particle motion by conversion into electrical energy. Hydrophones are marine detectors, which operate on the principle of application of pressure to certain piezoelectric ceramics substances producing an electrical potential difference between two surfaces of the materials. Each receiver converts pressure or

ground disturbances to electrical impulses. The digitally recorded electrical pulses of an array or group of receivers are summed for each station and transmitted, via cable or telemetry to recording computers. The hydrophones are usually mounted on a long streamer tied behind the ship and lowered to a depth of between 10 and 20m.

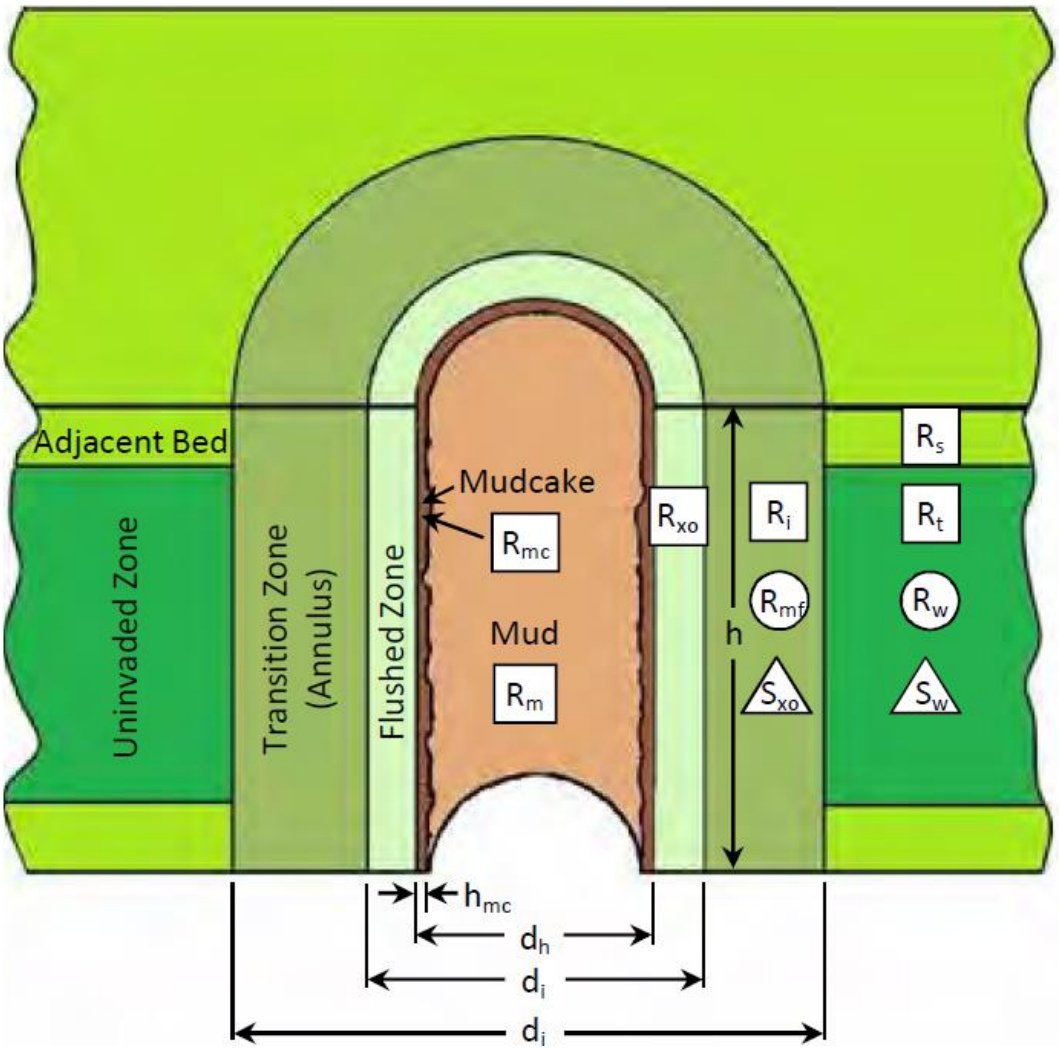
2.3.2 Seismic Data Processing

Seismic data processing involves the conversion or development of acquired seismic data into a format suitable for geological interpretation. In addition, it involves the statistical manipulation of a large amount of data using the workstation and mathematical models. It also involves the conversion of field data into a suitable state for processing, data analysis to determine optimum processing of parameter (e.g. weathering correction and seawater velocity) and processing to remove multiple reflectors in order to enhance primary reflector. Some of the data processing activities also include:

- ✓ **De-multiplexing**, which is the arrangement of seismic data, such that, the order of samples is changed from time sequential order to trace sequential order.
- ✓ **Static Corrections** are applied to seismic field data in order to compensate for the travel time differences due to elevation changes, as to lateral fluctuations of the weathering velocities and weathering thickness. This weathered layer is also referred to as the unconsolidated layer or the low-velocity layer (LVL)**.**
- ✓ **Normal move out (NMO) correction**, which is time adjustment that involves the changes in the reflection arrival time, from the shot point due to the variation in the source–receiver offsets.
- ✓ **Deconvolution** is an analytical procedure to remove (suppressed) the effect of the previous filtering that arises from convolution.
- ✓ **Stacking**, which is a noise reduction and signal enhancement technique that separates coherent signals from incoherent noise.
- ✓ **Migration or Imaging** helps to moves dipping reflections into their true subsurface positions and collapses diffraction, thereby delineating detailed subsurface features such as fault planes. Migration helps to ensure that the stacked section appears similar to the geologic cross section along the seismic line.

2.4 BOREHOLE ENVIRONMENT

A borehole environment (Fig. 10) is typically where a hole is drilled into a formation, in order to exploit the subsurface natural resources (hydrocarbons in this case). The formation includes the rock and the fluid contained in it, which are usually altered near the borehole. The essence of this is that the drilling mud always contaminates a well's borehole and the surrounding rock. This, largely, often affects logging measurements. It shows a porous and permeable formation, which has been penetrated by a borehole filled with drilling mud.



d_i = Diameter of invaded zone (outer boundary invaded zone), d_t = Diameter of transition zone h_{mc} = Mud-cake thickness, d_h = Hole diameter, R_m= Drilling mud resistivity, R_s = Adjacent bed Resistivity (usually shale), R_{mc} = Mud-cake resistivity, R_{mf} = Mud filtrate resistivity, R_t = True resistivity (resistivity of uninvaded zone), R_w = Formations water resistivity, R_{xo} = Flushed zone resistivity, S_W = Uninvaded zone water saturation, S_{xo} = Flushed zone water saturation. (R_i) = Resistivity of transition zone, h = Bed thickness

Figure 10: Typical borehole condition [Allied Horizontal Wireline Services, 2015]

The diameter of the hole (d_h) is dependent on the diameter of the drill bit, but sometimes hole diameter may be larger or smaller than the bit diameter. This is because at times, wash out and/or collapse of shale and poorly cemented porous rocks, or build-up of mud cake on a porous and permeable formation. Caliper log is used to measure the diameter of a borehole. Borehole diameters range from about 7.8 inches (19.8 cm) with modern logging tool designed to operate within this range. The invaded zone is an area invaded by mud-filtrate. It consists of the flushed zone (R_{xo}) and a transition or annulus zone uninvaded (R_i), on the other hand, is the area beyond the invaded zone where formation fluids are uncontaminated by mud-filtrate. The degree of invasion is depending upon the permeability of the mud cake and the time, which the well is left before the commencement of logging. The flushed zone forms part of the invaded zone. It extends only a few centimetres from the wellbore.

3 CASE STUDY

3.1 Problem Definition

This research hopes to identify and evaluate some areas regarding data interpretation that can help to improve the integrity of the deductions made with the use of some methods and selected parameters for qualitative estimations, especially in the absence of core data. These parameters are essentials in the evaluation of reservoirs' flow units. Therefore, equations were modified to aid the evaluation of the selected sandstone hydrocarbon reservoirs in Ritchie's Oil Block and Osland Oil and Gas Field, within the Niger Delta offshore were engaged (Fig. 11). Ritchie's block occupies an area enclosed by the geographical grids of Latitude 3.6^{0}N and 3.8^{0}N, and longitude 7.1^{o}E and 7.3^{0}E, while Osland oil and gas field is located within latitude 5.5^{0}N and 5.7^{0}N, and longitude 5.0^{0}E and 5.2^{0}E. Similarly,

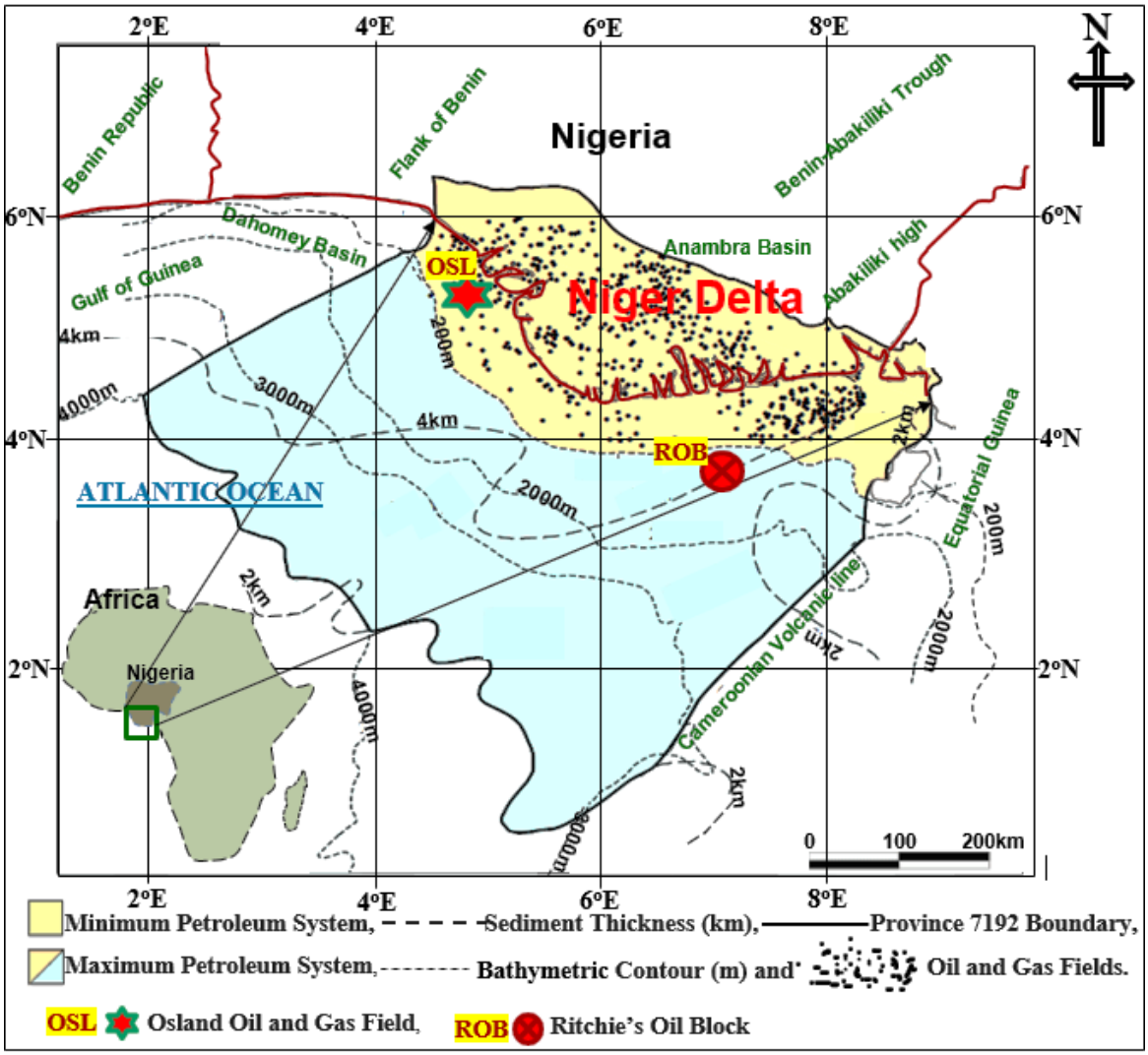


Figure 11: Niger Delta map showing study locations with oil and gas fields. [Modified from Petroconsultants, 1996]

estimation of the volumes of hydrocarbon in places must be carried out with absolute care involving the appropriate methods to ensure that underestimation or overestimation is averted. Herein, some ways to minimise possible errors involving volumes estimations (quantitative estimations) were addressed. The preference for technical expertise in data acquisition and interpretation were also outlined.

3.2 Preamble

Over the years, geological and/or geophysical evaluations have been fundamental to the exploration and production of hydrocarbons. Petrophysics and seismic methods have been proving useful for qualitative and quantitative evaluation of hydrocarbon reservoirs. These methods have been used in the Niger Delta for various purposes (Richardson, 2013; Ajisafe, and Ako, 2013; Richardson, 2014; Oyeyemi and Aizebeokahi, 2015; Adagunodo et at., 2017) and are very useful as decision-making tools regarding oil and gas exploration and production. Herein the geophysical evaluations are categorised into three steps: preliminary, confirmatory and volumes estimation. These steps are all within the pre-production stage, range between data acquisition and the interpretation of data

3.2.1 Preliminary evaluation

This could include a feasibility study, especially when the studied area has never been explored. The literature review, which includes the previous works on that field or on related fields, is very significant. The topography of the terrain, which includes accessibility, drainages, undulations, dips, and strikes, is also very relevant to aid the preparedness and good exploration instincts. Sometimes, the local geography of the area is also needed. This helps to determine the best time of the year to embark upon exploration activities. However, if otherwise, there is no time to wait, it will also aid the geologist/geophysicists gets prepared for the prevailing weather/climatic conditions. This could also include safety measures and the consciousness of the sensitivity of the equipment, which could later suggest the kind of filtering that, will be applied during the data processing. The estimated area of land or the limit of the study area within the offshore or onshore is also very important. This information, when combined with the time of the delivering of the project, it will help to determine the workforce, considering the number of persons (skilled, semi-skilled and unskilled) and the choice of equipment. The final phase of the preliminary approach is the acquisition of data. Data acquisition is the root of the entire exploration activity. Any error that is not noticed and taken care of at this stage will definitely reflect on the whole process and may remain unknown to

the interpreter. Therefore, absolute care must be ensured during data acquisition and computation in order to avert interpretations that will inform wrong decisions at the end of the day. Geologist or geophysicists must not necessarily be engaged in the aspect of data acquisition. A well-trained and experienced physicist or mathematician or instrumental engineer can also handle this aspect.

3.2.2 Confirmatory evaluation

This aspect includes qualitative data interpretations, usually petrophysics and seismic evaluations. There were times in the past when these evaluations were carried out, basically, with the use of analog data and interpretation methods based on generated charts. Nowadays, workstations such as Petrel and Kingdom suite (SMT) have been in use and are proving very dependable. The quality of the acquired data and the competency of the interpreter (geologist/geophysicist) are not negligible in the use of the software. It is better if a geologist who is upskilled in geophysical methods and/or vice versa completes the petrophysics and seismic interpretations. It is one thing to have very good data with nice petrophysics and seismic sections. But it entirely another thing to be able to make use of the quality and quantity of the geologic information that explains the actual condition of the reservoir to make accurate or near accurate deductions. Hence, it is not advisable to engage the services of an engineer or a physicist that is trained in geophysics alone to carry out this function. Allowing this, may be very risky and hence, put the integrity of the results and deductions at stake.

Evaluation of sand/shale lithology, identification of hydrocarbon/non-hydrocarbon bearing zones, fluid type's identification, net hydrocarbon sand (NHS) and gas bearing sand (GBS) are mostly evaluated using wireline logs. Information derived from wireline logs are also effectively combined with core data (when available) for the evaluation of some intrinsic parameters such as porosity (Φ), permeability (K), formation resistivity factor (F) among others during petrophysical evaluations. The mapping of hydrocarbon reservoir traps (structural and stratigraphic) is carried out using 2-D and/or 3-D seismic methods. Faults are delineated using both wireline logs and seismic sections, but the relationships between these faults and the hydrocarbon are better-estimated using seismic sections. Such relationships include the geometry of the source rock, reservoir rock geometry and trap types, faults orientations and migration paths and the reservoirs' area extents.

Both methods (seismic and petrophysics) will be engaged for these evaluations, by tying well logs to seismic data for reservoir identification and time to depth conversion. CSEG (2011) in its final report acknowledged that the rock and fluid characterization are based on

seismic attributes such as amplitudes and seismic inversion and are usually tied to elastic properties calculated from well logs. Usually, the surface areas of the depths identified (normally with wireline logs) to have hydrocarbon are mapped (on the Isodepth /Isopach) and used as inputs for volumetric estimations. For this reason, well to seismic tie (W-S_T) must be done with possible zero error. Tying the correct wells on the wireline logs to their appropriate times and depths on the corresponding seismic sections must be ensured. This will help to avoid overestimation or underestimation of the probable areas.

This study modified (Richrdson and Taioli, 2017) some traditional equations to help confirm the hydrocarbon potential of some wells in Ritchie's Oil Block and Osland Oil and Gas Field, both in the Niger Delta with the aim of avoiding errors of underestimation and/or overestimation with the use of the selected expressions in the absence of core. In Osland Oil and Gas Field, correct time/depth correlation and enhanced velocity analysis of the two wells in some selected reservoirs are carried out. The evaluation looks at the influence of W-S_T on the integrity of the results and the boost on the confidence of the interpretation. Very clear and didactic images highlighting the times and depths to the tops and the bottoms of the selected reservoirs contribute to the quality of the interpretation. In the same vein, useful information such as reservoirs' trap types, pay thickness (Pt) and drainage areas (A_d) that aid the recommendation of possible points for siting developmental wells are also evaluated.

3.2.3 Volume Estimations

The whole exploration activity pays off if at the end it is confirmed that there are established and probable reservoirs in commercial volumes. This later calls for the estimation of the hydrocarbons in places and the recoverable volumes of oil and gas. In some cases, the anticipated volumes of water cut (C_w) in the reservoirs are also predicted. Herein the equations for fluids relative permeability [water relative permeability (K_{wr}) and oil relative permeability (K_{or})] are modified and use to predict the percentages of C_w that will be associated with the production of the recoverable volumes of hydrocarbon in two reservoirs mapped across two wells in Osland Oil and Gas field (Richardson and Taioli, 2018). The fact that P_t and A_d are essential inputs in the estimation of the recoverable volume of hydrocarbons has called for the importance attached to W-S_T herein. Overestimation or underestimation of these two parameters (P_t and A_d) could result in wrong computation and misinformation on the volumes of hydrocarbons in the reservoirs. Therefore, the confidence on the estimated volume of hydrocarbons in places and/or recoverable volume of hydrocarbons depends on the degree of correctness of the results obtained from the confirmatory (qualitative) evaluations.

3.3 Materials and Methods

Gamma-ray log (GR), deep laterolog (LLD), water saturation log (SW), neutron porosity log (NPHI) and density tool (ROHB) were engaged in this work. The evaluated parameters are free fluid index (FFI), permeability (K), reservoir quality index (RQI), flow zone indicator (FZI), water relative permeability (K_{wr}) and oil relative permeability (K_{or}). The basic methods herein are:

(a) Modification of the equations for the free fluid index (FFI), permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) and water relative permeability (K_{wr}) and oil relative permeability (K_{or}) for use in sandstone units.

(b) Sensitivity analysis on the expressions in (a) above using different values of tortuosity factor to help verify the influence of its change on the selected parameters.

(c) Redefinition of the selected equations using the idea derived from (b) above.

(d) Determination of porosity from well logs to aid the computation of the parameters across of the selected reservoirs with the aid of the equations as in (c) above.

(e) Generation of curves showing permeability/porosity (K/Φ), reservoir quality index/porosity (RQI/Φ) and flow zone indicator/porosity (FZI/Φ) relationships based on the results as in (d) above.

(f) Determination of $RQI_{average}$ and $FZI_{average}$ based on the three expressions for each of them.

(g) Generation of a combined quick-look model for the estimation of the reservoirs RQI and FZI to aid the prediction of flow units.

(h) Evaluation of lithologic units, depths to hydrocarbon reservoirs and fluids contacts;

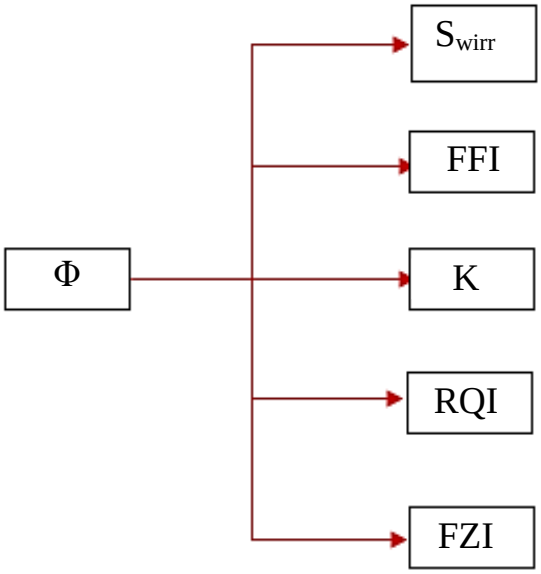
(i) Evaluation of reservoirs flow (hydraulic) units, transmissibility and prediction of primary recovery in the selected reservoirs.

(j) Estimation of the recoverable volumes of hydrocarbons with the associated water cuts (C_w) production in some selected wells and

(k) Well to Seismic Tie (W-S_T) to aid correct time/depth correlations and enhanced velocity analysis for petrophysics and seismic interpretations to aid the recommendation of the points for siting developmental wells.

3.3.1 The layout of the use of the expressions

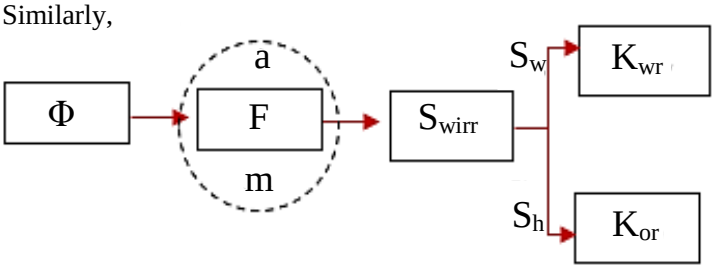
Conventional use of the selected expressions for flow units' estimations.



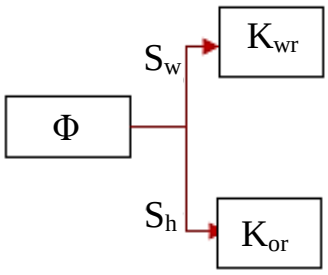
Φ = Porosity
F = Formation factor
FFI = Free Fluid Index
K= Permeability
RQI = Reservoir Quality Index
FZI = Flow Zone Indicator
S_w = Water Saturation
S_h = Hydrocarbon saturation
K_{wr} = Water Relative Permeability
K_{or} = Oil Relative Permeability
a = Factor of tortuosity
m = Factor of cementation
S_{wirr} = Irreducible Water Saturation

The use of the selected expressions for flow units' estimations in this study.

Similarly,



Conventional use of the selected expressions for the prediction of fluids relative permeability.



The use of the selected expressions for the prediction of fluids relative permeability in this study.

4. RESULTS AND DISCUSSION

The results of this research are presented in form of charts, tables, maps, and related figures. The results also included publications and presentations in relevant Journals and Conferences respectively. The research has four objectives and each serves as a base for a publication. Similarly, the two extended abstracts in conferences were based on the objectives as well.

Core data were not available for this evaluation; hence, an alternative approach involving the modification of some expressions to help predict the desired parameters was embarked upon. The modified equations for irreducible water saturation (S_{wirr}) and free fluid index (FFI) were used to redefine permeability (k) equations based on Timur, Tixier and Coates ideas. Such that, three different expressions; K_{mtx}, K_{mtm} and K_{mc} (K modified from Tixier's, Timur's and Coates' idea respectively) were presented. Three alternative expressions for reservoir quality index (RQI); RQIaa, RQI_{ab} and RQI_{ac} (alternative **a**, **b** and **c**) were presented based on K_{mtx}, K_{mtm} and K_{mc}. In the same vein, alternative expressions **a**, **b** and **c** (FZI_{aa}, FZI_{ab} and FZI_{ac}) were presented for flow zone indicator (FZI). Consequently, in Ritchie Oil Block, two reservoirs (R-N and R-M) were delineated across three wells ($R\text{-}D_a$, $R\text{-}D_b$ and $R\text{-}D_c$). The estimated average porosity (Φ) of the two reservoirs is 0.24; consequently, the values of averaged K were estimated at 1721mD, 2343mD and 1969mD for K_{mtx}, K_{mtm} and K_{mc} respectively. Similarly, the corresponding values of RQI and FZI were estimated at 2.66µm, 3.10µm and 2.84µm (RQI_{aa}, RQI_{ab} and RQI_{ac}) and 8.42µm, 9.82µm and 9.01µm (FZI_{aa}, FZI_{ab} and FZI_{ac}).

The evaluation of Osland Oil and Gas Field includes fluid differentiation and hydraulic units 'and primary recovery prediction. The equation of K by Coates and Denoo was modified and used to redefine RQI and FZI for the evaluation of a reservoir across Well D_1 and Well D_2. The reservoir, in well D_1, is about 90ft (27m) thick, with the upper 30ft (9m) occupied by gas, the next 28ft (8.5m) is filled with oil and the remaining 32ft (9.8m) is water filled. The reservoir, in well D2, is about 110ft (33.5m) thick and it is oil saturated. Within D_1 reservoir, average Φ, FFI, K, RQI, and FFI are 0.2, 0.18, 1256mD, 2.5µm and 10.1µm respectively. Within D_2 reservoir, average Φ, FFI, K, RQI, and FFI are 0.25, 0.23, 5166mD, 4.5µm and 13.5µm respectively. In addition, the equations for water relative permeability (K_{wr}) and oil relative permeability (K_{or}) were redefined and used to predict the water cut (C_w) in some reservoirs in Osland Oil and Gas Field. The volumes of C_w in the evaluated reservoirs are within the acceptable rates. The evaluation herein provided handy equations. The drudgery, time consumption and possible computational errors that are normally associated with the use

of traditional equations were all avoided. Hence, the methods adopted in the evolution has helped to reduce the doubts concerning the integrity of the results.

Furthermore, in Osland Oil and Gas Field, correct time/depth correlation and enhanced velocity analysis were carried out to aid petrophysical and seismic interpretations. Well to Seismic Tie (W-S_T) was carried to aid high-resolution imaging in the evaluated wells (Osl-1 and Osl-2) and complex geological structures associated with the reservoirs. Wellbore position recommendation for the developmental purpose was also involved. Down the well, each of Reservoir A-horizon (R-A_h) and Reservoir B-horizon (R-B_h) is about 70ft. (21m) in Osl-1. In Osl-2, R-A_h is about 70ft. (21m) while R-B_h is 100ft. (30m). Across the wells, R-A_h has a total value of 171.944 acres (67×10^4 m^2) for $A_{d,}$ with 80.767acres (33×10^4 m^2), 45.110acres (18×10^4 m^2) and 46.067acres (19×10^4 m^2) for $A_{d-1,}$ A_{d-2} and A_{d-3} respectively. Similarly, R-B_h has a total value of 206.387acres (83.5×10^4 m^2) for A_d with 94.204acres (38×10^4 m^2), 24.320 acres (1×10^4 m^2) and 87.863 acres (36×10^4 m^2) for $A_{d-1,}$ A_{d-2} and A_{d-3} respectively. The sum of the drainage areas (A_{d-1} + A_{d-2} + A_{d-3}) on R-A_h is 172acres (69.6×10^4 m^2) and that of R-B_h is 206acres (83.4×10^4 m^2).

Herein the alternative approaches involving the use of redefined equations and quick-look models (charts) have assisted to simplify the evaluation for the prediction of flow units, transmissibility/primary recoveries and water cut production in the sandstone hydrocarbon reservoirs. Furthermore, the evaluation has presented ways of increasing the integrity of evaluating flow units in sandstone hydrocarbon reservoirs, in the absence of core data. In addition, the uncertainty that may arise because of the doubt involving water cut (C_w) production and volume estimations in the sandstone units' are reduced. The idea herein is to publish the four objectives.

5. CONCLUSION

Hydrocarbon potentials evaluation involving a new simplified approach has been carried out in some selected sandstone reservoirs within Ritchie's Oil Block and Osland Oil and Gas. Due to the limitation of data and core sample unavailability, alternative methods are needed to estimate some fundamental reservoir parameters. The study involving maximising porosity in sandstone units (A Case Study of Ritchie's Block, Offshore Niger Delta), has been carried out. It has presented alternative expressions for K, RQI and FZI, modified for use mainly in sandstone units. The evaluated reservoirs (R-M and R-N), were correlated across three wells (R-Da, R-Db and R-Dc) and are confirmed to contain hydrocarbon. An average porosity of 0.24 was estimated for the reservoirs and it can be considered as a good value. From the combined quick-look model, the porosity of 0.24 corresponds to RQI value of 2.95µm and FZI value of 9.00µm. Hence, the evaluated reservoirs can be said to have good values of RQI and FZI. This suggests that the sandstone reservoirs are well-sorted, coarse-grained with little shale contents and present good pore throats. Therefore, the pores are expected to be interconnected within these reservoirs and as such, good hydraulic conductivity and significant recovery factors are anticipated within the studied wells. Porosity range of sandstones is usually within the limits of the RQI and FZI curves presented herein. This work has showcased a way to maximise porosity based on the modified expressions. The expressions and curves can be recommended for use in formation evaluation. The combined model can be used for the estimations of the values of RQI and FZI in sandstone units, provided porosity values derived from logs or core data are available. Similarly, if in any case, someone is interested in the use of any of the Tixier's, Timur's or Coates' idea alone, the respectively modified expressions (K_{mtx}, K_{mtm} and K_{mc}) with their corresponding equations for RQI and FZI and the curves are recommendable. The study has showcased porosity dependent expressions for the evaluated parameters and also provided a way of avoiding the approximation of porosity over a range of equations before the parameters herein are fully expressed. This work has emphasised the relevance of the use of the direct relationship between porosity and the evaluated parameters in the prediction of reservoirs flow units. Maximising porosity for formation evaluation as presented herein can help to minimise risk and reduce uncertainty in the evaluations of sandstone hydrocarbon reservoirs.

Similarly, the prediction of the hydrocarbon viability of two reservoirs (one in Well D_1 and the other in Well D_2) in "Osland" oil and gas field, Offshore Niger Delta, Nigeria was evaluated using a simplified approach. The evaluation involved the identification of

hydrocarbons in the reservoirs, differentiation of fluids and prediction of flow units. The traditional expressions for the free fluid index (FFI), permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) were modified for this evaluation. In the absence of core data, the equations herein provided quick access to the prediction of the flow units of the reservoirs with the aid of porosity (Φ) values derived from wire-line logs. The computation of formation factor (F) and irreducible water saturation (S_{wirr}) was bypassed. The use of the alternative expressions for the selected parameters herein makes the evaluation easier. Φ, FFI, K, RQI, and FZI were computed at intervals of 10ft. (3m) each within the reservoirs to aid the evaluation of hydraulic (flow) units. The average values for K in both reservoirs are above 1,000mD, while Φ is 0.20 in D_1 and 0.25 in D_2. FFI, RQI, and FZI are significant and are indicative of reservoirs with good transmissibility and recovery rate. The sensitivity analysis suggests that changes in tortuosity factor may not have a significant influence on FFI and K. Hence, the FFI, K, RQI and FZI equations developed herein are usable as alternative expressions for evaluations in reservoir sands. In the same vein, the generated plots are also usable for the quick prediction of FFI, RQI, and FZI in sandstone reservoir units. Therefore, drudgery and possible errors that may come with the computation of other dependent parameters are avoided. The results can help to reduce doubts and uncertainties, regarding the viability of the identified reservoirs in terms of availability of hydrocarbons, the measure of the ability of the reservoirs to transmit the fluids and rate of recoveries of oil and gas. Further exploration activities can be encouraged to help identify other reservoirs within “Osland” oil and gas field and to aid the estimations of the volumes of recoverable hydrocarbons in place when the need arises. In the absence of core data, this evaluation has highlighted a simplified approach involving the use of handy equations for the evaluation of flow units in hydrocarbon reservoirs with the aid of wireline logs.

In the same vein, the relationship between porosity (Φ) and fluids (oil and water) saturations has been used to predict the water cut (C_w) in Reservoirs X and Y correlated across Wells D_1 and D_2 in Osland oil and gas field, Niger Delta, Nigeria. Alternative expressions for the estimation of oil relative permeability (K_{or}) and water relative permeability (K_{wr}) in sandstone units were presented. These equations were used to estimate the water-cut in each of the reservoirs. Reservoir X shows approximately 18.8% and 1.7% of water-cut (C_w) in Wells D_1 and D_2 respectively, while the values are relatively low and negligible in Reservoir Y. Considering the range of values it can be concluded that Reservoir X is within the acceptable water-cut range. The total recoverable volumes of hydrocarbons from the two wells are

estimated at 7.7×10^9cu. ft for gas and at 2.54×10^7bbl for oil. About 5.04×10^5 bbl of estimated water-cut is expected to be associated with the production of the total recoverable volume of oil in the reservoirs in both wells. More wells within the field and its environs could reveal better reservoirs compared to the two evaluated here in this research. In addition, the depths of occurrence and trapping of the hydrocarbons within the reservoirs blocks and good migration pathways provided by the faults among others factors, are readily available to support the accumulation and producibility of the reservoirs. One can, therefore, conclude that the area is potentially viable, with reservoirs containing manageable or little-associated water production. In view of this, more exploratory activities can be carried out in other to establish more or less prolific hydrocarbon reservoirs prior to the draining of the field. Reservoir Y has very little water saturation (S_w) with corresponding higher values of hydrocarbon saturation (S_h) across the two wells, this could also indicate that higher depths may have more established reservoirs with little or no water saturations, such that associated water production may not be a thing to worry about. The results of the evaluation suggest that high Φ with corresponding high S_w accounted for high K_{wr} with the corresponding high associated C_w in Reservoir X. Within sandstone units, especially when water saturation log and porosity tool are present, the redefined equations can be quickly used to predict K_{or}, K_{wr} and C_w whenever it is required.

Finally, 3-D seismic sections with wire-line logs have been used as complementary tools to successfully evaluate the hydrocarbon viability of Osl-1 and Osl-2 in Osland oil and gas field. The didactic figures of the well to seismic tie (W-S_T) presented herein has assisted to amplify the hydrocarbon horizons and provide high-resolution images of the reservoirs. W-S_T shows that the depth of occurrence and the travel times of seismic waves at the interface between media having different velocities/densities are the same both on the well logs and on seismic sections. The structural maps helped in delineating the drainage area (A_d) of the fields, but qualitative evaluation of the formation using well logs provided the vertical extent (thickness) of the reservoir. The sum of the pay thicknesses calculated for Osl-1 and Osl-2 is 310ft. (94.5m) for both reservoirs across the wells, and the sum of the drainage areas (A_{d-1}, A_{d-2}, and A_{d-3}) is 378.331acres (153×104 m^2). These values are significant. The two tools are quite distinct yet complementary in the evaluation of the studied field. When they are both available, it is important they are engaged for the evaluation of formation in other to minimize risk. There may be little or no doubts about the percentages of the correctness of each of the A_d calculated for each of the delineated portions, but the depths of occurrences of the pay thicknesses of the other points recommended for developmental wells may not be accurate. This is because; until

those portions are penetrated by wells, one cannot say for sure the thicknesses of the reservoir sands in those areas. Therefore, there are possibilities that the reservoirs are thicker (or otherwise) in those portions. In the same vein, this work is not establishing that the developmental wells must be sited at the recommended points herein. The points are recommended based on the delineated drainage areas and the structural highs. Therefore, under field/technical conditions the wells can be sited at other points taken to be more convenient within the highlighted drainage areas. Furthermore, the two exploratory wells (Wildcats) (Osl-1 and Osl-2), can also function as developmental wells. This work has assisted to increase the confidence concerning the hydrocarbon viability of the selected reservoirs, hence, reducing uncertainty regarding the portions of the field that are saturated with hydrocarbons, pay thicknesses and drainage areas.

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APPENDIXES

A. ***Maximising porosity for flow units' evaluation in sandstone hydrocarbon reservoirs, a Case Study of Ritchie's Block, Offshore Niger Delta***. IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG). 3:2, pp 06-16 ***(2017).***

B. ***Redefining fluids relative permeability for reservoir sands. (Osland oil and gas field, Offshore Niger Delta, Nigeria),*** Journal of African Earth Sciences (JAES) in **Elsevier**. 10: 024 pp 1-8 ***(2018).***

C. ***Hydrocarbon Viability Prediction of Some Selected Reservoirs in Osland Oil and Gas Field, Offshore Niger Delta, Nigeria.*** Journal of Marine and Petroleum Geology (JMPG) in Elsevier. Vol. 100. 195-203.

D. ***Asserting the Pertinence of the Interdependent Use of Seismic Images and Wireline Logs in the Evaluation of Some Selected Reservoirs in the south Atlantic Passive Margin. (Osland oil and gas field, Offshore Niger Delta, Nigeria),*** **[**Under review by the paired reviewers in Brazilian Journal of Geology**]**.

E. ***The relevance of porosity in the evaluation of hydrocarbon reservoirs.*** Conference paper (Oral presentation 44027), 9th Congress of the Balkan Geophysical Society 5-9 November 2017, Antalya, Turkey.

F. ***A simplified approach to hydraulic units' evaluations using wire-line logs.*** Conference paper ***(***Oral presentation) "**3rd International Convention on Geosciences and Remote Sensing"**, October 19-20, 2018, Ottawa, Canada.

APPENDIX A

Maximising porosity for flow units evaluation in sandstone hydrocarbon reservoirs (A Case Study of Ritchie's Block, Offshore Niger Delta)

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Maximising porosity for flow units evaluation in sandstone hydrocarbon reservoirs (A Case Study of Ritchie's Block, Offshore Niger Delta)

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Abstract: *Herein the relationships between porosity (Φ) and permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) were further verified and used to evaluate the selected reservoirs. This work is aimed at presenting porosity dependent equations for formation evaluation, through; (a) modification of traditional equations and (b) generation of curves/models for the estimation of K, RQI and FZI based on three fundamental ideas to aid the evaluation of the reservoirs flow units. Two reservoirs (R-M and R-N) were correlated across three wells (R-D_a, R-D_b and R-D_c) in Ritchie's Block, offshore Niger Delta. The equations (Tixier's, Timur's and Coates') for K determination and the expressions for RQI and FZI were modified and used for the evaluation of hydrocarbon potential of the two reservoirs mapped across the selected wells. Three porosity dependent equations suggested for use in sandstone units were presented for each of K, RQI and FZI. These equations were used to evaluate and compare these parameters each in three different ways and suggest that the reservoirs have good flow units. The estimated average porosity of the two reservoirs is 0.24, consequently, the values of averaged K were estimated at 1721mD, 2343mD and 1969mD for K_{mtx}, K_{mtm} and K_{mc} respectively. Similarly, the corresponding values of RQI and FZI were estimated at 2.66µm, 3.10µm and 2.84µm (RQI_{aa}, RQI_{ab} and RQI_{ac}) and 8.42µm 9.82µm and 9.01µm (FZI_{aa}, FZI_{ab} and FZI_{ac}) respectively. Models in form of curves that show the relationships between the evaluated parameters and porosity were presented. In a way to combine the three expressions for each of the parameters, the average of the values for RQI_{aa}, RQI_{ab} and RQI_{ac} and the average of the corresponding values for FZI_{aa}, FZI_{ab} and FZI_{ac} were determined. Hence, $RQI_{average}$ and $FZI_{average}$ were plotted against porosity to help generate a combined quick-look model for RQI and FZI prediction. With this model, the porosity of 0.24 corresponds to RQI of 2.95µm and FZI of 9.00µm respectively. Overall, the evaluated reservoirs were confirmed to have hydrocarbon with very good values of K, RQI and FZI. Significant rates of hydraulic conductivity and hydrocarbon recoveries are anticipated within the reservoirs (R-M and R-N) across the three wells and as such, hydrocarbon volumetric estimation is encouraged. A sensitivity analysis was carried out and shows that the change in tortuosity factor does not seem to have a significant influence on the results. Therefore, an averaged tortuosity factor of 0.8 was used in the equations. The expressions were also tested and compared with the results computed using the traditional equations and similar values were obtained.*

Keywords: *Hydrocarbon potential, Permeability (K), Reservoir Quality Index (RQI), Flow Zone Indicator (FZI)*

I. Introduction

The relationship between porosity and flow units in the sandstone reservoirs in Ritchie's oil block, located in the offshore part of the southern Niger Delta, Nigeria has been evaluated. Porosity is an influential parameter in the petrophysical and volumetric evaluation and the majority of the reservoirs physical characteristics are not completely expressed without the use of porosity. The relationship between porosity and reservoir's flow units is very effective for explaining reservoirs' geological attributes such as grain sizes and sorting, shale content, cementation, consolidation of rocks, pore sizes and interconnectivity among others [1; 2; 3]. In most cases involving qualitative evaluations, a few other parameters such as formation factor (F), irreducible water saturation (S_{wirr}) and free fluid index (FFI) are calculated first using porosity and a few other factors as inputs before calculating permeability and other parameters.

This work presents modified expressions with which permeability (K), reservoir quality index (RQI) and flow zone indication (FZI) were evaluated. Essential parameters for reservoirs qualitative evaluations are derivable from wire-line logs [3; 4] and porosity is always incorporated with other information from the seismic analysis for volumetric estimations [5; 6; 7]. Therefore, it is very important that porosity be carefully estimated before it is optimised for formation evaluation. The determination of the reservoirs porosity was done with the aid of density log (RHOB) and the values obtained were corrected for the influence of shale before they were used for the evaluation of other dependent parameters. The correction for shale influence on the porosity of the reservoirs' sand is very important [8; 9] because any error in the evaluation or computation of porosity could result in either exaggeration or reduction of the actual value of the dependent parameters. Since whole lots of parameters use for

formation evaluation are directly or indirectly dependent upon porosity, when it is well calculated and properly harnessed, it will present a way of minimising risk. In volumetric estimations, for instance, every other parameter been alright, 0.05 to 0.1 (5 – 10%) increase or decrease in porosity value could result in a notable increase or decrease in the computed volumes of hydrocarbons in place. As such, the actual volume is either reduced or exaggerated and could affect the final decision. Similarly, in qualitative evaluations, the expression for RQI [2] is dependent upon K, K is dependent upon S_{wirr} and/or FFI, both S_{wirr} and FFI are dependent upon F while F is dependent upon Φ. If one must follow the computation in steps from the determination of F, Φ will be approximated over a range of equations, because most of these equations never give their results in whole figures. Errors due to estimation are always undesirable, especially when it comes to volumetric analysis and other decision dependent calculations, where overestimation or underestimation error as low as ±0.05 can result in a notable difference. This can bring about risk and uncertainty.

Therefore, this work tends to look at the use of equations that are involving direct computation of porosity for the evaluation of some of the reservoirs intrinsic parameters in sandstone units. The possibility of using porosity as the only variable in these expressions was fundamental because it assisted in drawing a direct relationship between porosity and the evaluated parameters (K, RQI and FZI). Curves showing the relationship between porosity and each of K, RQI and FZI based on the three different ideas (Tixier's, Timur's and Coates') were presented. A single model for the determination of RQI and FZI based on the modified expressions was also presented. These curves are recommendable for use as quick-look models in the estimation of these parameters, provided porosity values are available.

II. Study location and geology

The study location (Latitude 3.6^0N and 3.8^0N and longitude 7.1^oE and 7.3^0E) is within the offshore region of the southern Niger Delta (Fig. 1). The offshore boundary of the Niger Delta province is bound by the Cameroon volcanic line to the east, the Dahomey basin to the west and the 2km sediment thickness contour or the 4000m bathymetric contour to the south and south-west [10; 11].

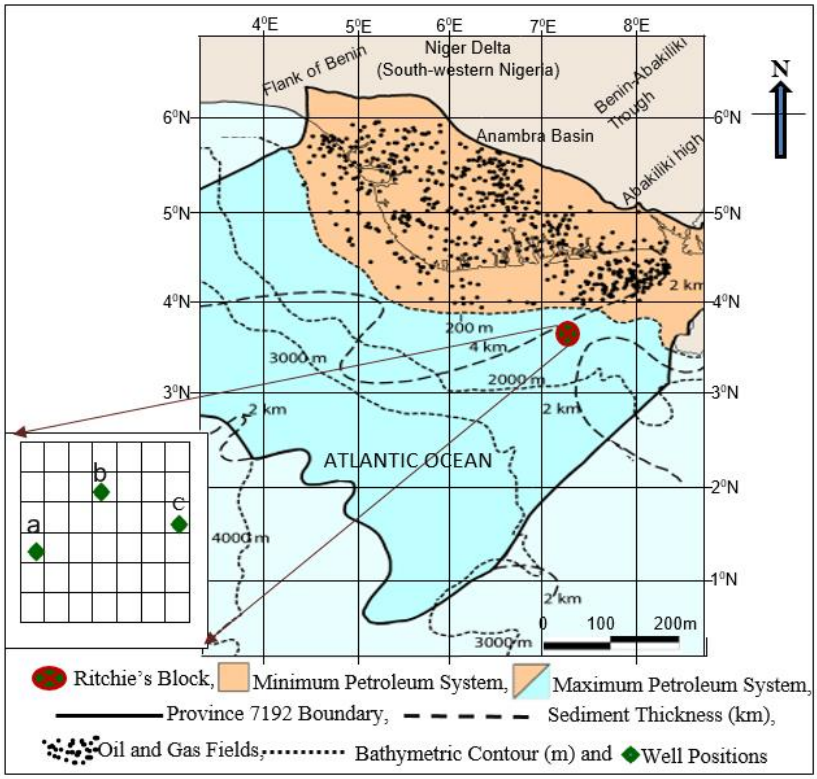


Figure 1. Index map of study location and map of Niger Delta showing the petroleum systems and oil and gas fields, modified from Petroconsultant [10]

Deep-sea landscapes and related structural alterations are believed to have emerged due to activities involving erosion, sedimentation and gravity influenced tectonics [12; 13; 14; 15]. These events have assisted in redefining the seabed bathymetry and the collective petroleum pattern of the region. The rollovers structures collapsed crests, faults with back-to-back features and the marine shale diapers which provided the sealing mechanism for the reservoirs are also linked with these structural deformations [16; 17; 18; 19]. Although, stratigraphic traps are not impossible but most known traps in Niger Delta fields are structural and they believed

to have developed during synsedimentary deformation of the Agbada parallel [17; 20]. The onshore Province is delineated by the geology of southern Nigeria and southwestern Cameroon. The northern boundary is the Benin flank, an east-northeast trending hinge line south of the West Africa basement massif [11]. The northeastern boundary is defined by outcrops of the Cretaceous on the Abakaliki High and further southeast by the Calabar flank. The province covers 300,000 km^2 and includes the geologic extent of the Tertiary Niger Delta (Akata-Agbada) Petroleum System [11; 16].

The Niger Delta is characterised by three geologic formations; Benin, Agbada and Akata. Benin Formation consists of highly porous continental sands and gravels with very little hydrocarbon. The abundance of hydrocarbon in Niger Delta is mostly associated with the Agbada and Akata Formations. Agbada Formation is between the Benin and the Akata Formations and consists of a sandy part, which serves as the main hydrocarbon reservoir of the delta and shale as the cap rock. The Akata Formation is believed [16; 20; 21] to have the highest field with the lowest gas to oil ratio. The Agbada Formation has intervals that contain organic carbon contents sufficient to be considered good source rocks [22; 23]. But Evamy et al [20] and Starcher [17] believe that the intervals, rarely reach thickness sufficient to produce a world-class oil province and are immature in various parts of the delta. Similarly, the marine interbedded shale in the Agbada Formation, the marine Akata shale, and Cretaceous shale are also suspected to be contributing source rocks [20; 24; 25; 26]. Evamy et al. [20] supported the marine shale (Akata Formation) and the shale interbedded with paralic sandstone (lower Agbada Formation) as the source rocks for the Niger Delta oils.

III. Materials and Methods

Gamma-ray log (GR), deep laterolog (LLD), water saturation log (SW), neutron porosity log (NPHI) and density tool (ROHB) were engaged in this work. The basic methods herein are:

(a) modification of traditional (Timur's Tixier's and Coates') permeability (K) equations to help provide alternative expressions in sandstone units;
(b) sensitivity analysis on the expressions in (a) above using different values of tortuosity factor to help verify the influence of its change on permeability;
(c) redefinition of the permeability (K) equations using the idea derived from (b) above and modification of reservoir quality index (RQI) and flow zone indicator (FZI);
(d) determination of porosity from well logs to aid the computation of K, RQI and FZI of the selected reservoirs with the aid of the equations as in (c) above;
(e) generation of curves showing permeability/porosity, reservoir quality index/porosity and flow zone indicator/porosity relationships based on the results as in (d) above and
(f) determination of $RQI_{average}$ and $FZI_{average}$ based on the three expressions for each of them, to help generate a combined model for the estimation of the reservoirs flow units.

3.1 Modification of Timur's, Tixier's and Coates' permeability (K) expressions for use in sandstone units

The normal expression for irreducible water saturation is given by equation 1.

$$(S_{wirr})^2 = \frac{\mathrm{F}}{2000} \tag{1}$$

Where; 2000 = formation constant and F = formation factor which is expressed by equation 2.

$$\mathrm{F} = \frac{\mathrm{a}}{\Phi^{\mathrm{m}}} \tag{2}$$

[a = tortuosity factor (usually within the range of 0.6 to 1), Φ = porosity and m = porosity exponent]
Hence, the expression for irreducible water saturation can be written as equation 3.

$$(S_{wirr})^2 = \frac{a}{2000\Phi^m} \tag{3}$$

But porosity exponent (m) is usually taken as 2 in sandstone units. Therefore;

$$(S_{wirr})^2 = \frac{a}{2000\Phi^2} \tag{4}$$

Such that irreducible water saturation in sandstone units can be expressed by equation 5.

$$s_{wirr} = \frac{a^{0.5}}{44.72\Phi} \tag{5}$$

Where 44.72 is the square root of 2000.
This equation was then used to modify Tixier's, Timur's and Coates' equations for permeability.

The Tixier's equation [1] for permeability is given by equation 6.

$$K^{0.5} = 250\ \frac{\Phi^3}{s_{wirr}} \tag{6}$$

S_{wirr} is substituted in equation 6 using equation 5 such that, the expression becomes;

$$K^{0.5} = 250\ \frac{\Phi^3}{1} \div \left[\frac{a^{0.5}}{44.72\Phi}\right] \tag{7}$$

Hence,

$$K^{0.5} = 250\ \frac{\Phi^3}{1} \times \left[\frac{44.72\Phi}{a^{0.5}}\right] \tag{8}$$

Therefore, the Tixier's permeability expression is modified for use in sandstone units as equation 9.

$$(K_{mtx})^{0.5} = \frac{11180\Phi^4}{a^{0.5}} \tag{9}$$

[K_{mtx} is permeability modified from Tixier's expression].

The expression for permeability [1] given by Timur is written as;

$$K^{0.5} = 100\ \frac{\Phi^{2.25}}{s_{wirr}} \tag{10}$$

Similarly, s_{wirr} is substituted such that, the Timur's permeability expression is modified for use in sandstone units as equation 11.

$$(K_{mtm})^{0.5} = \frac{4472\Phi^{3.25}}{a^{0.5}} \tag{11}$$

[K_{mtm} is permeability modified from Timur's expression].

Schlumberger [1] stated Coates' expression for permeability as equation 12.

$$K^{0.5} = 70\ \frac{\Phi^2(1-s_{wirr})}{s_{wirr}} \tag{12}$$

and

$$K^{0.5} = 70\ \Phi^2 \left[1 - \frac{a^{0.5}}{44.72\Phi}\right] \div \left[\frac{a^{0.5}}{44.72\Phi}\right] \tag{13}$$

Such that

$$K^{0.5} = 70\ \Phi^2 \left[\frac{44.72\Phi - a^{0.5}}{44.72\Phi}\right] \div \left[\frac{a^{0.5}}{44.72\Phi}\right] \tag{14}$$

Consequently,

$$K^{0.5} = 70\ \Phi^2 \left[\frac{44.72\Phi - a^{0.5}}{44.72\Phi}\right] \times \left[\frac{44.72\Phi}{a^{0.5}}\right] \tag{15}$$

Hence, the Coates' permeability expression is modified for use in sandstone units as equation 16.

$$(K_{mc})^{0.5} = \frac{3130.4\Phi^3 - 70\Phi^2 a^{0.5}}{a^{0.5}} \tag{16}$$

[K_{mc} is permeability modified from Coates' expression].

3.2 Sensitivity analysis

A simulation was carried out by doing a sensitivity analysis on K_{mtm}, K_{mtx} and K_{mc} considering the possible range (0.6 to 1.0) of tortuosity factor (a) and a porosity range of 0.05 to 0.75. The results of K using each of 0.6, 0.7, 0.8, 0.9 and 1.0 with the three equations herein were plotted against porosity to help verify the influence of the change in the factor of tortuosity on permeability. The three expressions show approximately the same results as shown in Figure 2.

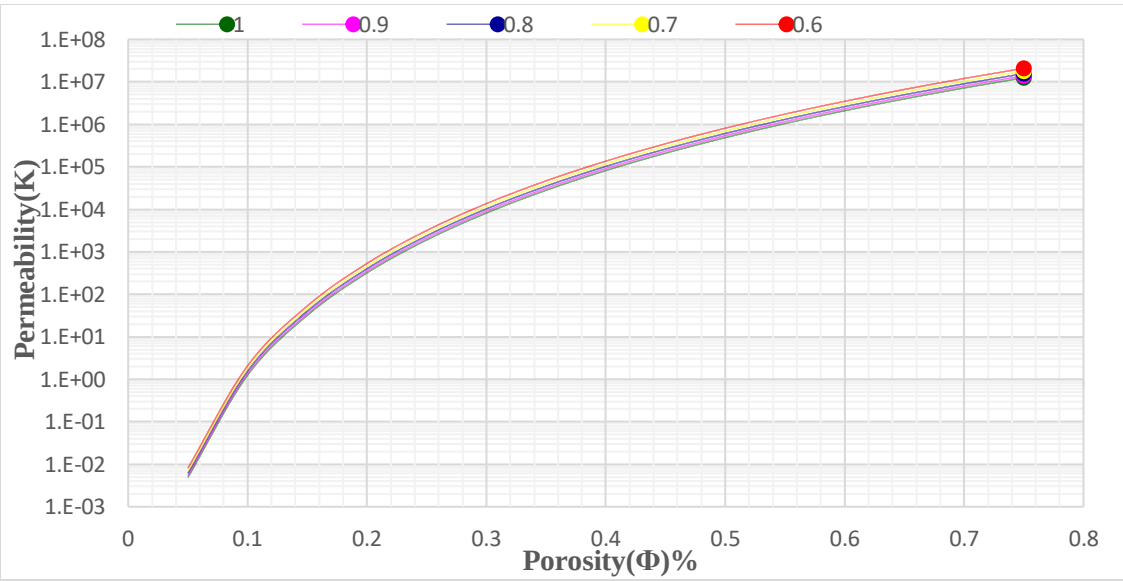


Figure 2: Curves showing the influence of the change in tortuosity factor (a) on permeability (k)

The evaluation shows that change in tortuosity factor seems not to have a significant influence on the permeability values**.** Therefore, the average (0.8) of the range (0.6 to 1) of tortuosity factor was used to redefine the equations for the reservoirs, such that only porosity dependent expressions were presented as shown in equations 15 to 18.

$$(K_{mtx})^{0.5} = \frac{11180\Phi^4}{(0.8)^{0.5}} \tag{17}$$

$$(K_{mtx})^{0.5} = \frac{11180\Phi^4}{0.894} \tag{18}$$

Similarly,

$$(K_{mtm})^{0.5} = \frac{4472\Phi^{3.25}}{0.894} \tag{19}$$

and

$$(K_{mc})^{0.5} = \frac{3130.4\Phi^3 - 62.58\Phi^2}{0.894} \tag{20}$$

3.3 Modification of equations for reservoir quality index (RQI) and flow zone indicator (FZI) for the reservoirs sandstone units

The equation for RQI [2] is given by equation 21.

$$RQI = 0.0314\left(\frac{K}{\Phi}\right)^{0.5} \tag{21}$$

This equation was redefined by substituting the value of K using equations 18, 19 and 20 respectively, such that;

$$RQI_{aa} = \frac{351\Phi^4}{0.894\Phi^{0.5}} \tag{22}$$

Hence;

$$RQI_{ab} = \frac{140.4\Phi^{3.25}}{0.894\Phi^{0.5}} \tag{23}$$

and

$$RQI_{ac} = \frac{98.29\Phi^3 - 1.965\Phi^2}{0.894\Phi^{0.5}} \tag{24}$$

Where; RQI_{aa}, RQI_{ab} and RQI_{ac} are alternative expressions a, b and c for RQI, modified with K_{mtx}, K_{mtm} and K_{mc} respectively.

In the same vein, FZI was redefined in three different ways by using the three alternative expressions for RQI in equations 22, 23 and 24. The expression for FZI [2] is given by equation 25.

$$FZI = \frac{RQI}{\Phi_r} \tag{25}$$

Such that

$$FZI_{aa} = \frac{351\Phi^4}{(0.894\Phi^{0.5})\Phi_r} \tag{26}$$

Similarly,

$$FZI_{ab} = \frac{140.4\Phi^{3.25}}{(0.894\Phi^{0.5})\Phi_r} \tag{27}$$

$$FZI_{ac} = \frac{(98.29\Phi^3 - 1.965\Phi^2)}{(0.894\Phi^{0.5})\Phi_r} \tag{28}$$

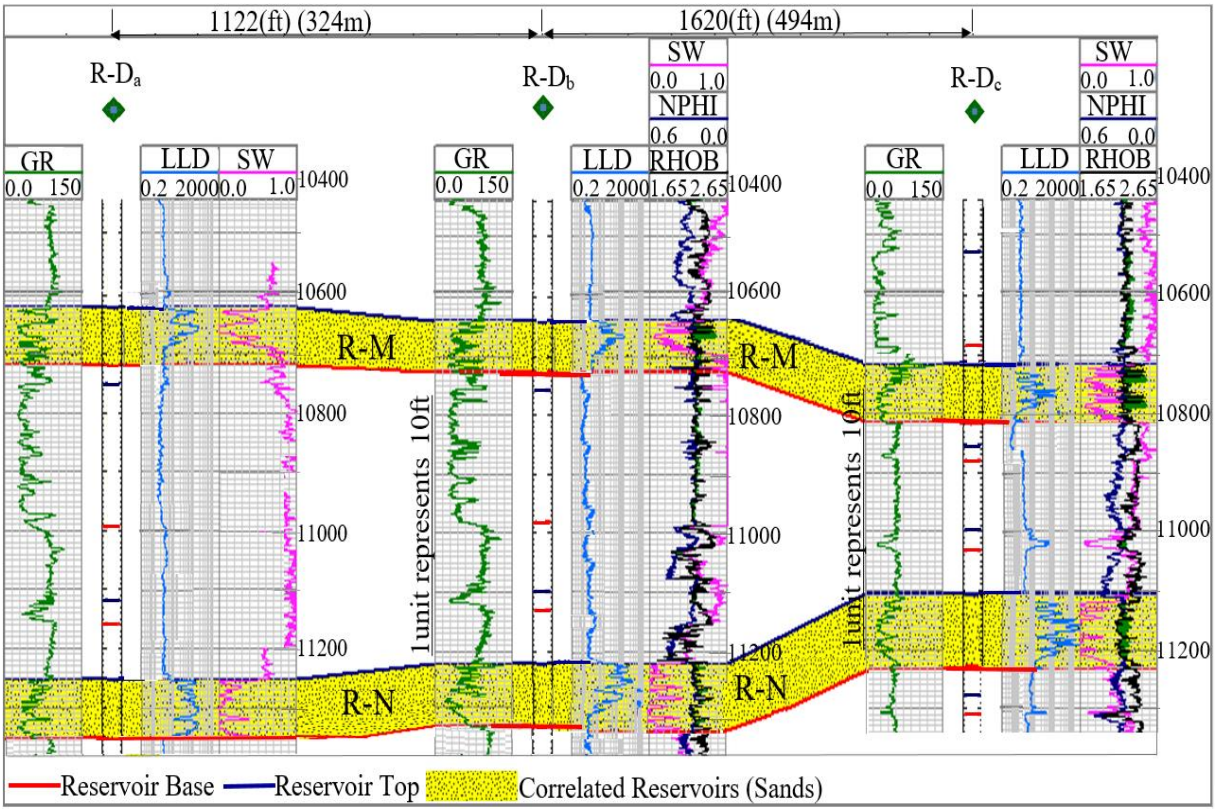
Where; FZI_{aa}, FZI_{ab} and FZI_{ac} are alternative expressions a, b and c for FZI, modified with RQI_{aa}, RQI_{ab} and RQI_{ac} respectively. Φ_r is the ratio of the derived porosity and the difference between the maximum derivable value (100%) of porosity and the derived porosity, it is expressed by equation 29.

$$\Phi_r = \frac{\Phi}{1-\Phi} \tag{29}$$

3.4 Determination of porosity and computation of parameters (K, RQI and FZI) across the selected reservoirs

This aspect started with log interpretation to help determine the average porosity of each of the reservoirs. Two reservoirs (R-M and R-N) were correlated across the three wells (R-D_a, R-D_b and R-D_c) (Fig.3). Gamma-ray log (GR) was used to identify sandstone units while deep laterolog (LLD) was used to delineate hydrocarbon units within the sandstone reservoirs. Well R-Da does not have porosity tool but the signatures of GR, LLD and water saturation (SW) within the reservoirs in this well are in similar patterns with those in other selected wells (R-D_b and R-D_c). Similarly, NPHI and RHOB also show similar responses within each of the correlated reservoirs in

wells R-D_b and R-D_c (Fig.3) as such, it is assumed that the porosity values within the reservoir R-M and R-N in R-D_a should be within the same range as the other wells. In addition, the reservoirs in each of the wells are correlated across the same formation.



GR = Gamma-ray log, LLD = Deep laterolog, NPHI = Neutron Porosity log, ROHB = Density tool, and SW = Water Saturation Log.

Figure 3. Well logs with correlated reservoirs

Therefore, porosity (Φ) values were obtained directly from density log (RHOB) at intervals of 10 feet and corrected for shale influence within each of the reservoirs using equation 30.

$$\Phi_D = \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_f} - V_{sh}\left[\frac{\rho_{ma}-\rho_{sh}}{\rho_{ma}-\rho_f}\right] \quad (30)$$

[V_{sh} = volume of shale, Φ_D = density derived porosity corrected for shale, ρ_{ma} = matrix density of formation (2.65gcc for sandstone), ρ_b= bulk density of formation, ρ_f= fluid density of formation (1.0gm/cc) and ρ_{sh}= bulk density of adjacent shale].

Averaged porosity values within each reservoir were used as inputs to compute the reservoir permeability (K), reservoir quality index (RQI) and Flow Zone Indicator (FZI).

3.5 Permeability (K)/Porosity (Φ), Reservoir Quality Index (RQI)/Porosity (Φ) and Flow Zone Indicator (FZI)/ Porosity (Φ) Curves

With the aid of the expressions herein a range of values from 0 to 50% (0 to 0.50) was used for porosity to compute K, RQI and FZI. The averaged values of these parameters across the selected reservoirs were extracted from the results, considering the averaged porosity values calculated for each reservoir. Based on the results, curves were generated by plotting each of the evaluated parameters against porosity. Similarly, the values of RQI_{aa}, RQI_{ab} and RQI_{ac} were averaged with the corresponding values FZI_{aa}, FZI_{ab} and FZI_{ac}. $RQI_{average}$ and $FZI_{average}$ were plotted against porosity to help generate curves that can serve as a combined model for RQI and FZI estimations within sandstone units.

IV. Results

The results obtained for K, RQI and FZI using averaged porosity within each of the reservoirs are presented in Tables 1 and 2.

Table 1: Results of the evaluated parameters across reservoir R-M

Wells	Φ	a	$K_{(mtx)}$ (mD)	$K_{(mtm)}$ (mD)	K_{mc} (mD)	RQI_{aa} (µm)	RQI_{ab} (µm)	RQI_{ac} (µm)	FZI_{aa} (µm)	FZI_{ab} (µm)	FZI_{ac} (µm)
R-D$_a$	0.24	0.80	1721	2343	1969	2.66	3.10	2.84	8.42	9.82	9.01
R-D$_b$	0.23	0.80	1225	1776	1513	2.29	2.76	2.55	7.67	9.24	8.53
R-D$_c$	0.24	0.80	1721	2343	1969	2.66	3.10	2.84	8.42	9.82	9.01

Table 2: Results of the evaluated parameters across reservoir R-N

Wells	Φ	a	$K_{(mtx)}$ (mD)	$K_{(mtm)}$ (mD)	K_{mc} (mD)	RQI_{aa} (µm)	RQI_{ab} (µm)	RQI_{ac} (µm)	FZI_{aa} (µm)	FZI_{ab} (µm)	FZI_{ac} (µm)
R-D$_a$	0.24	0.80	1721	2343	1969	2.66	3.10	2.84	8.42	9.82	9.01
R-D$_b$	0.24	0.80	1721	2343	1969	2.66	3.10	2.84	8.42	9.82	9.01
R-D$_c$	0.25	0.80	2386	3054	2534	3.07	3.47	3.16	9.20	10.41	9.48

The curves generated according to the equations herein are as shown in Figures 4, 5 and 6.

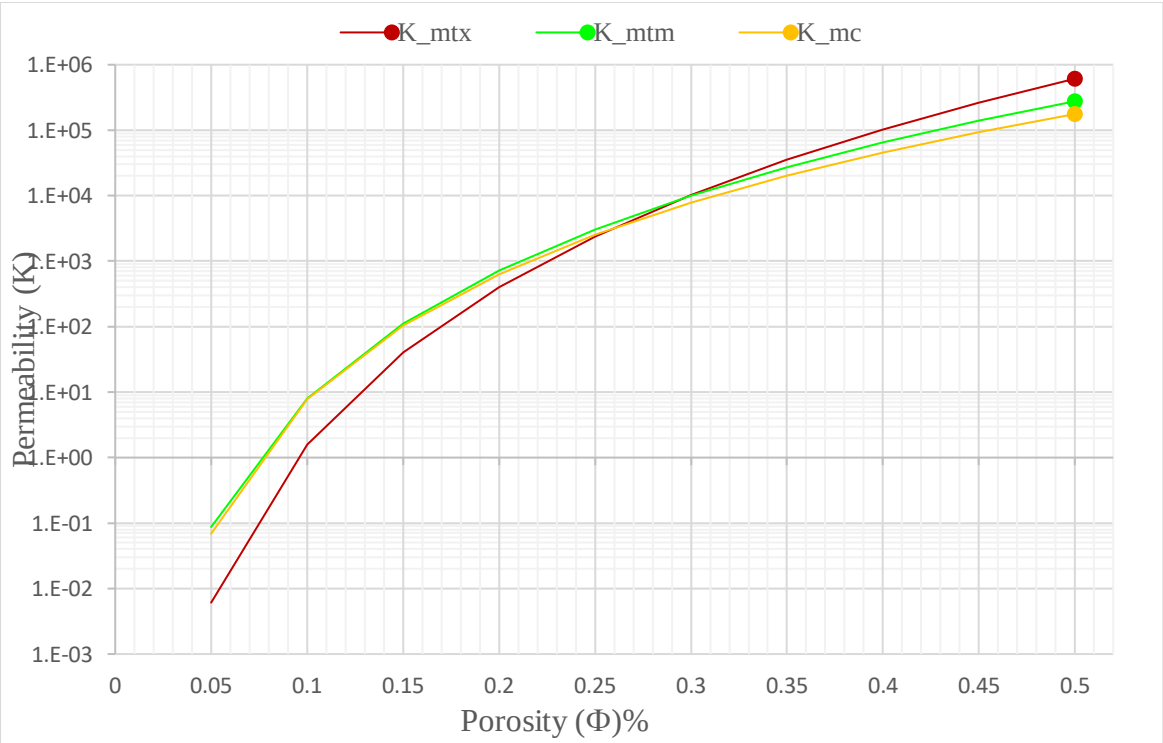


Figure 4: Permeability (K)/Porosity (Φ) curves

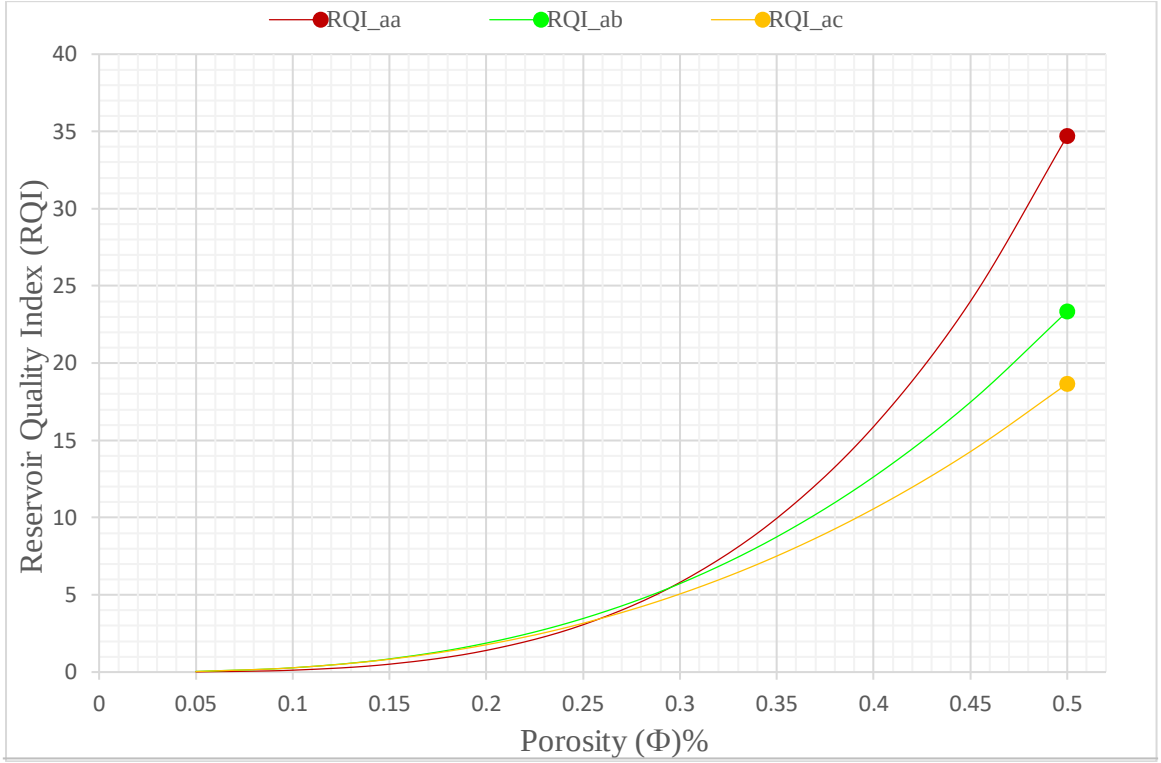


Figure 5: Reservoir Quality Index (RQI)/Porosity (Φ) curves

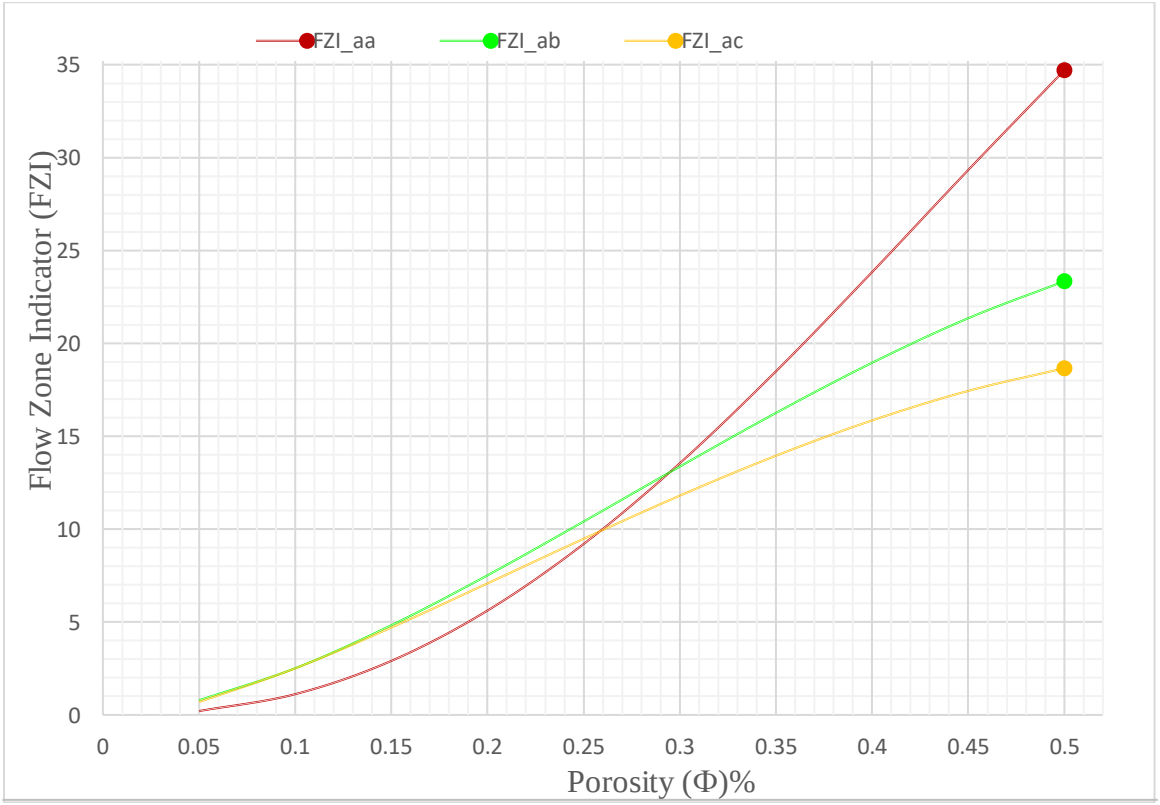
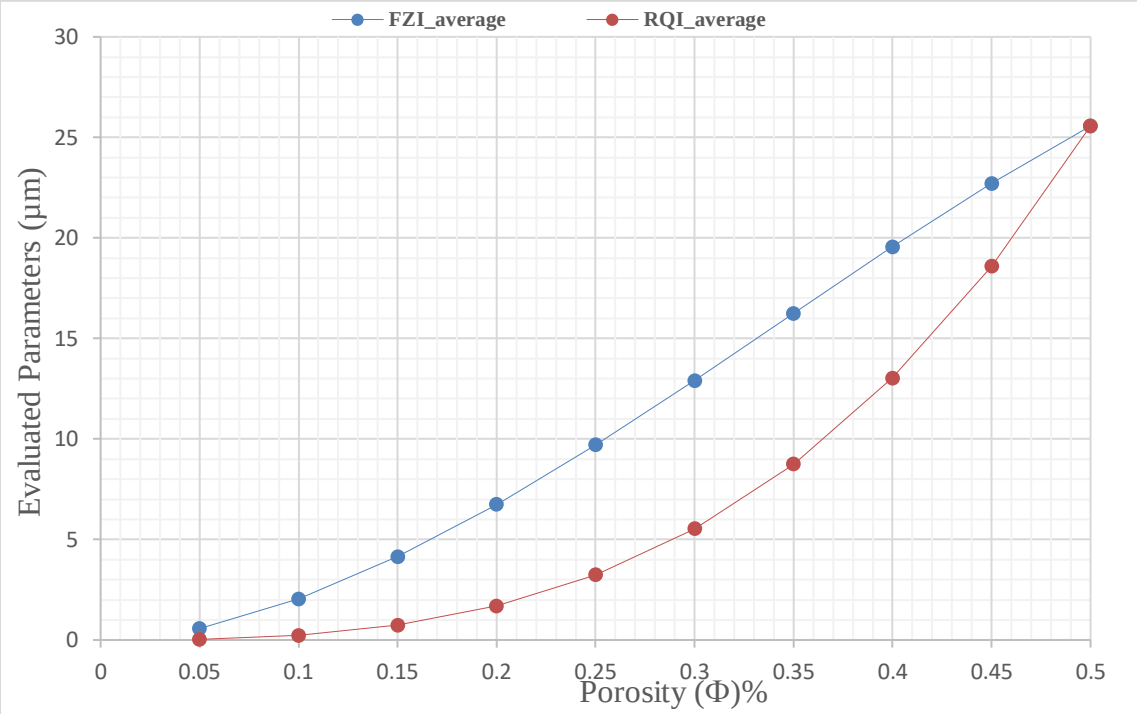


Figure 6: Flow Zone Indicator (FZI)/Porosity (Φ) curves

The combined model for the estimation of reservoir quality index (RQI) and flow zone indicator (FZI) to aid the evaluation of the reservoirs flow units is as shown in Figure 7.



$RQI_{average}$ = Average of the values of RQI_{aa}, RQI_{ab} and RQI_{ac}
$FZI_{average}$ = Average of the values of FZI_{aa}, FZI_{ab} and FZI_{ac}

Figure 7: Combined quick-look model for the prediction of RQI and FZI.

V. Discussion

Two hydrocarbon-bearing reservoirs (R-M and R-N), were identified and correlated across three wells (R-Da, R-Db and R-Dc). This study presents porosity dependent expressions for permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI). Curves were generated based on these expressions and were used for the estimation of RQI and FZI to help predict flow units across the selected reservoirs. R-M shows averaged porosity of 0.24, 0.23 and 0.24 in R-D_a, R-D_b and R-D_c, while R-N shows 0.24, 0.24 and 0.25 in R-D_a, R-D_b and R-Dc respectively. Such that, the average porosity of the two reservoirs across the three wells is 24%. Based on this value, the average permeability values of the two reservoirs are 1721mD, 2343mD and 1969mD for K_{mtx}, K_{mtm} and K_{mc} respectively. Permeability above 1000mD (1Darcy) is very good and indicative of a formation with good flow units. Averaged values for reservoir quality index across the two reservoirs are 2.66µm, 3.10µm and 2.84µm for RQI_{aa}, RQI_{ab} and RQI_{ac} respectively. Similarly, average values for the flow zone indicator are 8.42µm 9.82µm and 9.01µm for FZI_{aa}, FZI_{ab} and FZI_{ac} respectively. However, with the aid of the combined model, at the porosity of 0.24 RQI is 2.95µm while FZI is 9.00µm.

FZI is directly proportional to RQI; therefore, significant values of RQI indicate good values of FZI. This implies that the sandstone reservoirs can be considered coarse-grained and well sorted with little volumes of shales. Consequently, the reservoirs are expected to present good pore throats. From the curves, the increase in porosity corresponds to increase in K, RQI and FZI, considering all the scenarios. Reservoirs with very good RQI and/or FZI usually seem to have significant hydraulic conductivity and very good recovery rates. The curves for the three expressions (K_{mtx}, K_{mtm} and K_{mc}) show similar trends. K_{mtm} and K_{mc} trend very close to each other and are almost the same until at about the porosity value of 30% where the curves start separating from each other but consistently maintaining the same trend with each other and K_{mtx}. Reservoir quality index/porosity curves with the three expressions show the same trend for RQI_{aa}, RQI_{ab} and RQI_{ac}. The three variables show almost the same pattern up to about 30% of porosity value where separation began, but still maintain the same trend. Similarly, flow zone indicator/porosity curves show almost exactly the same response like their corresponding permeability values. FZI_{ab} and FZI_{ac} trend very close to each other and are almost the same at the lower limits of the curves and consistently maintaining the same trend with the corresponding K_{mtx}. Most important of all are that the three expressions, each for the parameters (K, RQI and FZI) follow similar trends and within the same range up to porosity of above 35%. Porosity range in sandstones is usually between 0.1 and 0.4 (10 to 40%) [27].

VI Conclusion and Recommendations

The study involving maximising porosity in sandstone units (A Case Study of Ritchie's Block, Offshore Niger Delta), has been carried out. This work has presented alternative expressions for K, RQI and FZI, modified for use mainly in sandstone units. The evaluated reservoirs (R-M and R-N), were correlated across three wells (R-Da, R-Db and R-Dc) and are confirmed to contain hydrocarbon. An average porosity of 0.24 was estimated for the reservoirs and it can be considered as a good value. From the combined quick-look model, the porosity of 0.24 corresponds to RQI value of 2.95µm and FZI value of 9.00µm. Hence, the evaluated reservoirs can be said to have good values of RQI and FZI. This suggests that the sandstone reservoirs are well-sorted, coarse-grained with little shale contents and present good pore throats. Therefore, the pores are expected to be interconnected within these reservoirs and as such, good hydraulic conductivity and significant recovery factors are anticipated within the studied wells. Porosity range of sandstones is usually within the limits of the RQI and FZI curves presented herein. This work has showcased a way to maximise porosity based on the modified expressions.

The expressions and curves can be recommended for use in formation evaluation. The combined model can be used for the estimations of the values of RQI and FZI in sandstone units, provided porosity values derived from logs or core data are available. Similarly, if in any case, someone is interested in the use of any of the Tixier's, Timur's or Coates' idea alone, the respectively modified expressions (K_{mtx}, K_{mtm} and K_{mc}) with their corresponding equations for RQI and FZI and the curves are recommendable. The study has showcased porosity dependent expressions for the evaluated parameters and also provided a way of avoiding the approximation of porosity over a range of equations before the parameters herein are fully expressed. This work has emphasised the relevance of the use of the direct relationship between porosity and the evaluated parameters in the prediction of reservoirs flow units. Maximising porosity for formation evaluation as presented herein can help to minimise risk and reduce uncertainty in the evaluations of sandstone hydrocarbon reservoirs.

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APPENDIX B

Redefining fluids relative permeability for reservoir sands (Osland oil and gas field, offshore Niger Delta, Nigeria)

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Redefining fluids relative permeability for reservoir sands. (Osland oil and gas field, offshore Niger Delta, Nigeria)

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ABSTRACT

Redefining oil and water relative permeability for the evaluation of reservoir sands, a case study of Osland oil and gas field, Offshore Niger Delta, Nigeria has been carried out. The aim of this study is to modify water relative permeability (K_{wr}) and oil relative permeability (K_{or}) equations in sandstone units. The objectives are to provide alternative expressions for K_{wr} and K_{or} in sandstone units, use the equations as inputs in a simplified water cut (C_w) equation to predict the volume of water that will be associated with the recoverable volume of oil (V_{Ro}) in penetrated reservoirs. The relationship between porosity (Φ) and water saturation (S_w), with the relationship between porosity and hydrocarbon saturation (S_h), were used to evaluate K_{Wr} and K_{or} in order to predict C_w in the selected reservoirs. Reservoir X in Well D_1 shows about 2.0×10^6bbl for V_{Ro} and 18.78% for C_w but in D_2 it shows about 7.4×10^6bbl and 1.73% for V_{Ro} and C_w respectively. Similarly, in Reservoir Y, D_1 has about 6.8×10^6bbl of V_{Ro} and 0.034% of C_w, but in D_2 it has about 9.3×10^6 bbl of V_{Ro} and 0.015% of C_w. The results suggest that high Φ with corresponding high S_w resulted in high associated C_w in Reservoir X. The evaluation also confirmed that the decrease in the ratio of oil relative permeability to water relative permeability (K_{or}/K_{wr}) corresponds to the increase in C_w. The total recoverable volumes of hydrocarbons from the two wells are estimated at 7.7×10^9cu.ft for gas and at 2.54×10^7bbl for oil. With the present conditions of the two reservoirs, the values of C_w in Reservoir X are low and are extremely low and negligible in Reservoir Y. Reservoir X in Well D_1 has a smaller volume of V_{Ro} but the C_w is higher than others. Nonetheless, the C_w in Reservoir X is still within acceptable range.

1. Introduction

This study focuses on the Osland oil and gas field, offshore Niger Delta, Nigeria. One of the evaluated reservoirs has a significant percentage of water saturation. This raised questions on the reservoir's water cut (C_w) because sometimes it could be problematic, especially when the transition zone is reached.

Water cut is defined as the ratio of water produced compared to the total volume of fluid produced (Schlumberger, 2016). Wire-line logs with 3-D data were engaged in this work. Previous works (Emujakporue et al., 2012: Richardson, 2014: Nwankwo et al., 2015: Adagunodo et al., 2017) have shown successes with the use of petrophysics and seismic interpretation in the region for different objectives.

Herein, information from logs and seismic models were combined with redefined expressions for oil relative permeability (K_{or}) and water relative permeability (K_{wr}) to aid the estimation of C_w. Water viscosity (μ_w) and oil viscosity (μ_o) are also important parameters in this evaluation. According to Schlumberger (1989), the rate of water production is dependent upon relative permeability ratio (K_{or}/ K_{wr}) and viscosity ratio (μ_w/μ_o).

Crain's Petrophysics (2015) stressed that interest is always in the volume of oil that can be pumped out of reservoirs, possibly without any associated water production. Oilfield Review (Spring, 2000), also stated that in some depleting reservoirs, for every one barrel of hydrocarbon produced, 3 barrels of associated water is also produced. The technologies for water control are quite expensive and tedious, therefore, there is need to be aware of the volume of water that will be associated with hydrocarbon production in the reservoirs before exploitation activities began.

Schlumberger (1989) and Crain's Petrophysics (2015) have shown equations involving irreducible water saturation (S_{wirr}) and reservoir water saturation (S_w) for the estimation K_{or} and K_{wr}. S_{wirr}

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is dependent upon porosity (Φ) which is fundamental to qualitative and quantitative evaluations. Hence, when Φ it is not approximated over a range of equations, it could present a way of optimising it relevance and reducing errors concerning overestimation and/or underestimation of the dependent parameters (Richardson and Taioli, 2017). Therefore, in this research work, the expressions for K_{or} and K_{wr} were modified for sandstone units, such that equations involving Φ with water saturation (S_w) and hydrocarbon saturation (S_h) were presented.

These equations were engaged with the direct computation of Φ, to predict K_{or}, K_{wr} and the associated volumes of C_w in the reservoirs across the wells. Apart from the suggestion of alternative expressions for some of the relevant parameters (K_{or} and K_{wr}) herein to aid the determination of C_w in sandstone units, the results of this research will help the decision to go ahead with exploitation activities in the studied field. This can serve as a way to reduce risk and uncertainty because oil and gas ventures are usually not undertaken without attaining levels of certainty, regarding the occurrence and recoverable volumes of hydrocarbons and associated water production in the selected reservoirs. Qualitative and quantitative evaluation of reservoirs using integrated wire-line logs and seismic data were carried out.

2. Study location and brief geology

The location of study (Osland) is within Latitude 5.5°N and 5.7°N and Longitude 5.0°E and 5.2°E, in the offshore area of southwestern Niger Delta (Fig. 1). Niger Delta is defined by three lithostratigraphic units; Benin, Agbada and Akata Formations (Weber and Daukoru, 1975: Evamy et al., 1978: Ejedawe, 1981).

Faulting and other deformations in the Niger Delta are linked with the continental breakup and rifting of the African and South American plates (Genik, 1993; Michael and Ronald, 2006). Rifting in the region took effect from Late Jurassic to late Cretaceous, after then; gravity tectonism emerged as a principal force and induced other forms of structural alterations (Lehner and De Ruiter, 1977; Genik, 1993; Michele et al., 1999; Rowan et al., 2004). The Gravity tectonics was active within the Akata formation, but it stopped prior to the deposition of the Benin Formation. Diapirs, rollover anticlines, collapsed crests and faults are closely associated with this gravity tectonics (Doust and Omatsola, 1990; Stacher, 1995; Brownfield, 2016).

Freddy et al. (2005) confirmed that the structures are exemplary of an extensional rift system with faults juxtaposing against each other. The diapiric shale within the Niger Delta basin provides the trap (seal and cap rock) in the region (Doust and Omatsola, 1990). The shale also provides three sealing mechanisms; clay smear along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting and vertical seals (Doust and Omatsola, 1990; Freddy et al., 2005). The degrees of overpressure in the region are also closely related to the inability to de-water because of the rapid sedimentation of fine-grained sediments.

3. Materials and methods

3.1. Materials

Seismic Micro-Technology (SMT) software was used for the interpretation of data. The set of data for this study comprised 3-D seismic data, a suite of geophysical wire-line logs: gamma ray(GR), deep laterolog (LLD), shallow laterolog (LLS), water saturation (S_w), neutron (NPHI) and bulk density (RHOB) logs from two wells. SEG – Y data comprising of 38 in-lines and 32 cross-lines was engaged. Check shot data was used to convert seismic travel time values to depths and to tie well logs to seismic sections.

3.2. Methods

The major steps involved are;

(a) modification of the relevant equations for sandstone units,
(b) log and seismic interpretation to help derive porosity, water saturation reservoirs thicknesses, and drainage areas which are essential inputs for the expressions in (a) above and volumetric estimations and

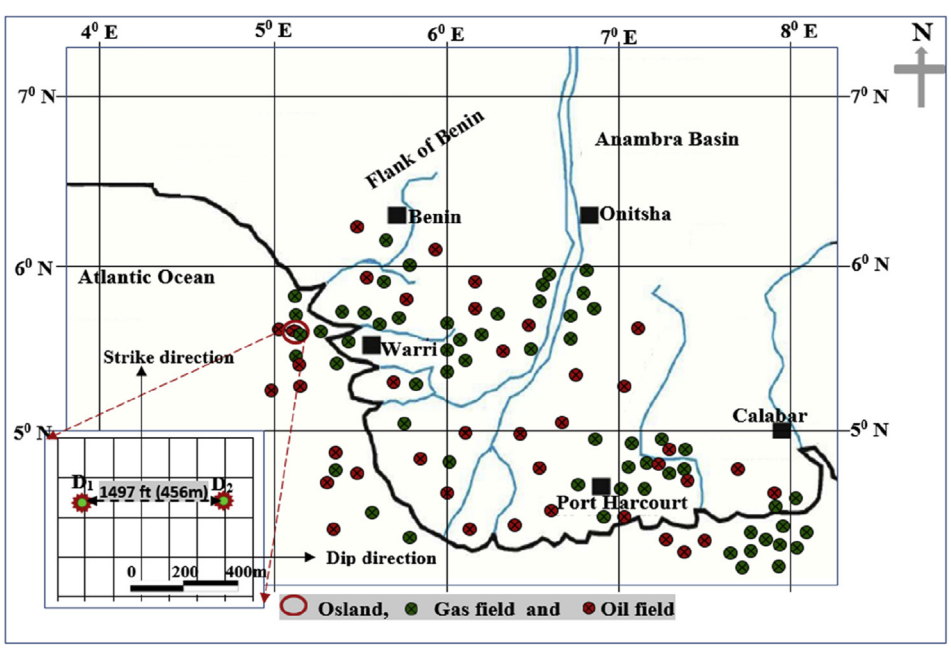


Fig. 1. Map of Niger Delta showing oil and gas fields and study location.

(c) computation of fluids relative permeability, percentage water cut and prediction of associated water volumes.

3.2.1. Modification of the relevant expressions for sandstone units

The general expression for irreducible water saturation is given by Equation (1).

$$(s_{wirr})^2 = \frac{a}{2000\Phi^m} \tag{1}$$

However, porosity exponent (m) is usually taken as 2 in sandstone units. Therefore;

$$(s_{wirr})^2 = \frac{a}{2000\Phi^2} \tag{2}$$

where 'a' is the tortuosity factor (ranges from 0.6 to 1) such that in sandstone units Equation (3) below gives the expression for irreducible water saturation

$$s_{wirr} = \frac{a^{0.5}}{44.72\Phi} \tag{3}$$

where 44.72 is the square root of 2000 (formation constant).

Equation (3) was used to modify water relative permeability (K_{wr}) and oil relative permeability (K_{or}) for sandstone units. The equation for water relative permeability according to Schlumberger (1989) is given as Equation (4).

$$K_{wr} = \left[\frac{S_w - S_{wirr}}{1 - S_{wirr}}\right]^3 \tag{4}$$

[S_w =water saturation].

By substituting for S_{wirr} in Equation (4) using Equation (3), water relative permeability becomes;

$$K_{wr} = \left[\left(S_w - \frac{a^{0.5}}{44.72\Phi}\right) \div \left(1 - \frac{a^{0.5}}{44.72\Phi}\right)\right]^3 \tag{5}$$

Such that

$$K_{wr} = \left[\left(\frac{44.72\Phi S_w - a^{0.5}}{44.72\Phi}\right) \div \left(\frac{44.72\Phi - a^{0.5}}{44.72\Phi}\right)\right]^3 \tag{6}$$

and

$$K_{wr} = \left[\left(\frac{44.72\Phi S_w - a^{0.5}}{44.72\Phi}\right) \times \left(\frac{44.72\Phi}{44.72\Phi - a^{0.5}}\right)\right]^3 \tag{7}$$

Hence, water relative permeability expression for sandstone unit is given as Equation (8);

$$K_{wr} = \left[\frac{44.72\Phi S_w - a^{0.5}}{44.72\Phi - a^{0.5}}\right]^3 \tag{8}$$

Similarly, the equation for oil relative permeability is given by Schlumberger (1989) as;

$$K_{or} = \frac{(1 - S_w)^{2.1}}{(1 - S_{wirr})^2} \tag{9}$$

But

$$1 - S_w = S_h \tag{10}$$

[S_h = hydrocarbon saturation].

Such that

$$K_{or} = \left[S_h^{2.1} \div \left(1 - \frac{a^{0.5}}{44.72\Phi}\right)^2\right] \tag{11}$$

When the denominator is resolved by finding the difference of two squares, the expression becomes;

$$K_{or} = S_h^{2.1} \div \left(1 - \frac{a}{2000\Phi^2}\right) \tag{12}$$

Consequently,

$$K_{or} = S_h^{2.1} \div \left(\frac{2000\Phi^2 - a}{2000\Phi^2}\right) \tag{13}$$

Such that

$$K_{or} = S_h^{2.1} \times \left(\frac{2000\Phi^2}{2000\Phi^2 - a}\right) \tag{14}$$

In this study, the equation for oil relative permeability in sandstone units was used as Equation (15);

$$K_{or} = \frac{2000\Phi^2 S_h^{2.1}}{2000\Phi^2 - a} \tag{15}$$

Recall, formation factor (F) is given as;

$$F = \frac{a}{\Phi^m} \tag{16}$$

When m is 2 for sandstone units, the equation becomes;

$$F = \frac{a}{\Phi^2} \tag{17}$$

Therefore, an alternative expression can also be given by substituting for F in Equation (12) as shown in Equation (18).

$$K_{or} = S_h^{2.1} \div \left(1 - \frac{a}{2000\Phi^2}\right) = S_h^{2.1} \div \left(1 - \frac{F}{2000}\right) \tag{18}$$

This shows that the definition of irreducible water saturation is not in any way altered in these expressions. Therefore;

$$K_{or} = S_h^{2.1} \div \left(\frac{2000 - F}{2000}\right) \tag{19}$$

and

$$K_{or} = S_h^{2.1} \times \left(\frac{2000}{2000 - F}\right) \tag{20}$$

Such that oil relative permeability can also be defined by equation (21);

$$K_{or} = \frac{2000 S_h^{2.1}}{2000 - F} \tag{21}$$

Equation (21) can also be used to compute the values of K_{or}, but this work focuses on the direct computation of porosity values, as such, equation (15) was preferred.

3.2.2. Logs and seismic models

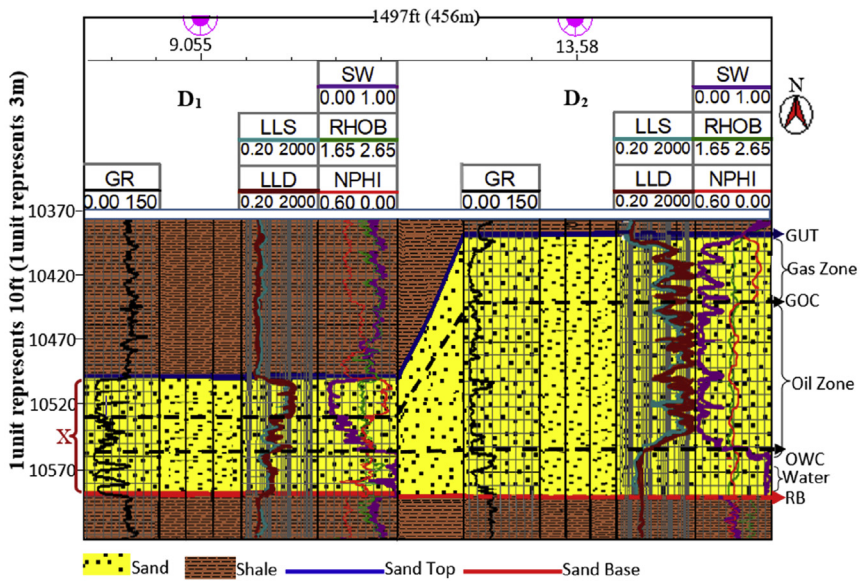
Logs evaluation includes lithologic units' identification using gamma ray log (GR) and reservoirs correlation/thicknesses evaluation using GR, deep laterolog (LLD) and shallow laterolog (LLS). Water saturation log (SW) was used to estimate the percentage of water in each of the reservoirs, while the mapping of fluids contacts

was carried out with the neutron (NPHI) and bulk density (RHOB) logs. Porosity (Φ) was estimated using RHOB. Two Reservoirs (X and Y) were correlated across the two Wells (D_1 and D_2). In Well D_1, Reservoir X (Fig. 2) is tracked between 10,500 ft (3200.m) and 10,590 ft (3227 m) and it is about 90 ft (27 m) with estimated thicknesses of 30 ft (9 m) of gas, 28 ft (8 m) of oil and 32 ft (10 m) of water.

Reservoir X is tracked between 10,390ft (3167m) and 10,590ft (3228m) in Well D_2, it is about 200ft (60m) with estimated thicknesses of 50ft (15m) of gas, 110ft (33m) of oil and 40ft (12m) of water.

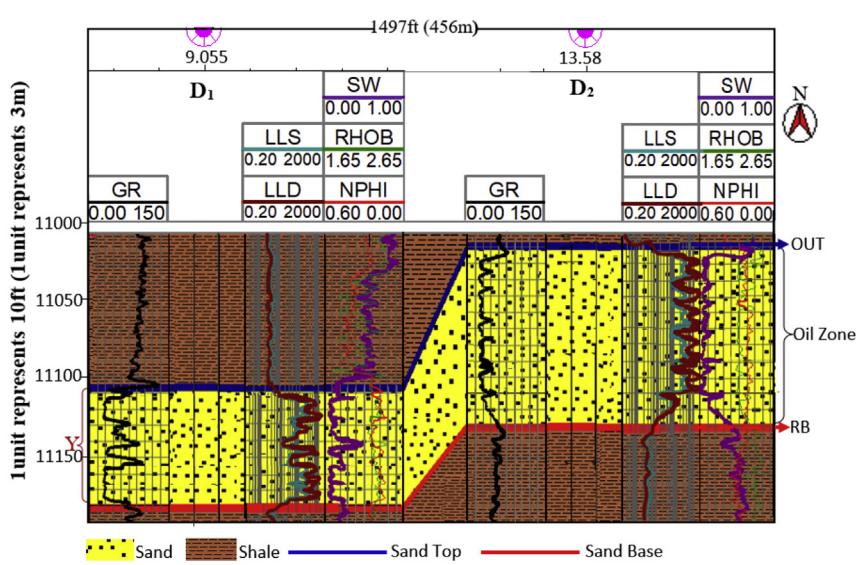
Reservoir Y (Fig. 3) is tracked between 11,110ft (3386m) and 11,180ft (3412m) and is about 70ft (21m) thick in Well D_1. Similarly, in Well D_2, it is tracked between 11,020ft (3359m) and 11,130ft (3392m), the thickness is about 110ft (33m). The reservoir shows no gas indication but proves to be oil-saturated.

The seismic analysis was carried out in order to evaluate the drainage areas needed to determine the recoverable volume of gas (V_{Rg}) and recoverable volume of oil (V_{Ro}). The seismic interpretation involved mapping of horizons and evaluation of faults orientation in order to understand the geometry of the reservoir rocks and trapping mechanisms. Seismic lines (38 in-lines and 32



GR = Gamma-ray Log, **LLD** = Deep Laterolog, **LLS** = Shallow Laterolog, **NPHI** = Neutron Porosity Log, **RHOB** = Density Log and SW = Water Saturation Log. **GUT** = Gas-Up-To, **GOC** = Gas-Oil-Contact, **OUT** = Oil-Up-To, **OWC** = Oil-Water-Contact, **RB** = Reservoir Base.

Fig. 2. Log models showing Reservoir X and fluids contact across Wells D_1 and D_2.



GR = Gamma ray Log, **LLD** = Deep Laterolog, **LLS** = Shallow Laterolog, **NPHI** = Neutron Porosity Log, **RHOB** = Density Log, SW = Water Saturation Log, **OUT** = Oil-Up-To and **RB** = Reservoir Base.

Fig. 3. Log models showing Reservoir Y across Wells D_1 and D_2.

cross-lines) were interpreted at every ten-meter intervals. Well to seismic tie was carried out in order to further identify and compare events interpreted on the seismic sections with the wire-line logs. Therefore, the times and depths of occurrence of these reservoirs as reflected on the selected wells were tied with the mapped horizons on the seismic sections and aided to generate the structural maps.

Two horizons were consistently tracked on the selected reservoir sands. Faults were picked considering up-thrown with relative down-thrown, abrupt changes in dip directions and distortion of reflections. Two major faults (F_a and F_b) were identified and a minor fault (f) was also found closing in on F_a. Consequently, Areas with collapsed crests and rollover anticlinal structures that are sandwiched between these faults were suspected to hold the volumes of hydrocarbon in-place. Therefore, such areas were identified as structural closures (traps) and the extent of the surfaces of these regions were mapped as drainage areas.

The drainage area (A_d) derived from the seismic evaluation was combined with other parameters from well logs [porosity (Φ), reservoir thickness (h), and hydrocarbon saturation (S_h)] and used as inputs for the estimation of the volumes of oil in place (OIP) and gas in place (GIP). The volumes in place of oil and gas were later used as inputs to estimate V_{Rg} and V_{Ro}. The corresponding percentages of water cut [c_w (%)] expected to be associated with V_{Ro} in the reservoirs were also predicted.

The first horizon (Fig. 4) is identified below 10,500 ft (3200 m) on the depth structure map and on the wire-line log in Well D_1. The horizon is tracked below 10,390 ft (3167 m) in Well D_2.

The second horizon (Fig. 5) corresponds to the top of Reservoir Y. The horizon is identified below 11,110ft (3386m) on the depth structure map and on the wire-line log in Well D_1. In Well D_2 is tracked below 11,020ft (3359m).

Volume of Oil-In-Place (OIP) and Gas-In-Place (GIP), were calculated using equations (22) and (23) (Modified from Bateman and Fessler, 1990: Asquith and Krygowski, 2004);

$$OIP = [Cc \times A_d \times h \times S_h \times \Phi]bbl \tag{22}$$

$$GIP = [Cc \times A_d \times h \times S_h \times \Phi]cu.\ ft \tag{23}$$

Cc = conversion constant (7758 converts oil volume from acres to bbl and 43560 converts gas volume acres to cubic feet), A_d = drainage area, h = reservoir thickness, S_h = hydrocarbon saturation and Φ = porosity.

The volume of recoverable volumes of oil and gas was computed using Equations (24) and (25);

$$V_{Ro} = \frac{OIP}{FVF} \times R.f \tag{24}$$

$$V_{Rg} = \frac{GIP}{FVF} \times R.f \times \frac{P_{f_2}}{P_{f_1}} \tag{25}$$

Where; R.F = recovery factor,

P_{f_2} = reservoir pressure,
P_{f_1} = surface pressure (15 atm) and
FVF = formation volume factor which is calculated using Equation (26);

$$FVF = 1.05 + 0.5 \times \frac{GOR}{100} \tag{26}$$

Gas-to-Oil Ratio (GOR) is the ratio of the volume of gas in cubic feet to that of the volume of oil in barrels.

Similarly,

$$\frac{P_{f_2}}{P_{f_1}} = \frac{0.43 \times depth}{15} \tag{27}$$

Where; 0.43 is a universal average pressure gradient (Asquith and Krygowski, 2004) and depth corresponds to Gas-Up-To (GUT).

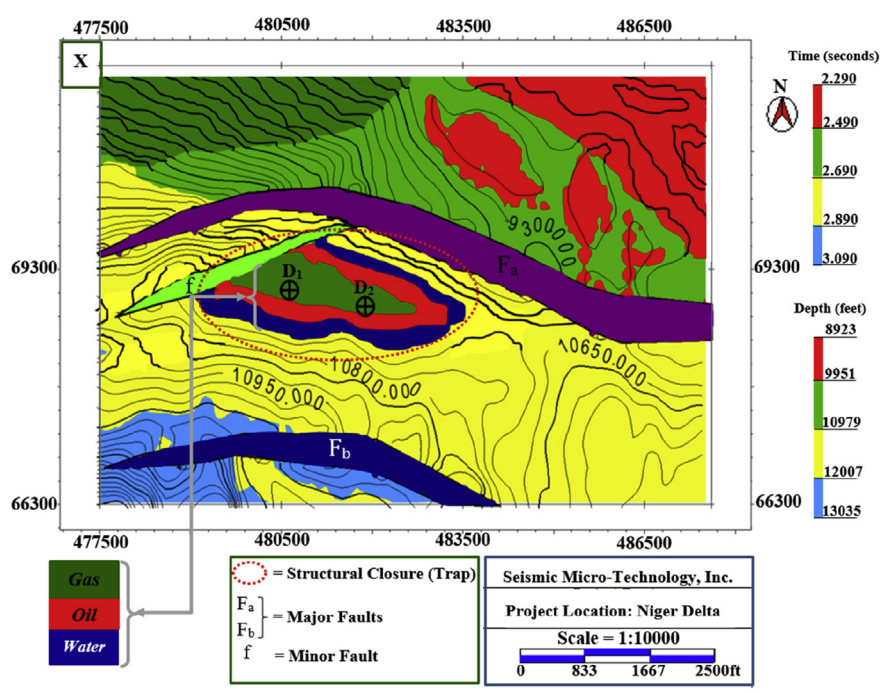


Fig. 4. Depth Structure Map showing the trapping mechanism and drainage area (A_d) of Reservoir X.

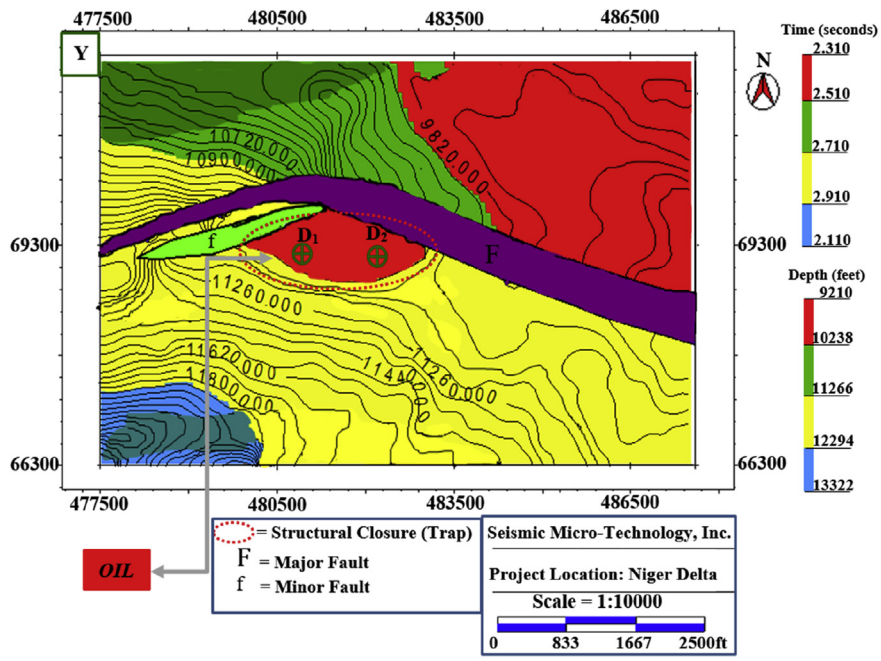


Fig. 5. Depth Structure Map showing the trapping mechanism and drainage area (A_d) of Reservoir Y.

3.2.3. Determination of water cut (c_w)

Instead of having reservoir's water saturation and irreducible water saturation dependent expressions for both parameters, this work presents water saturation and porosity dependent equations for K_{or} and K_{wr} within sandstone units, as previously shown in Equations (8) and (15).

The equation for water cut (c_w) as given by Schlumberger (1989), is as shown in Equation (28);

$$c_w = \left[\frac{1}{1 + \frac{K_{or}}{K_{wr}} \times \frac{\mu_w}{\mu_o}}\right] \tag{28}$$

where $\frac{\mu_w}{\mu_o}$ is the ratio of water viscosity(μ_w) to oil viscosity (μ_o)

Equation (28) was redefined in this work as Equation (29);

$$c_w = \frac{K_{rw}\mu_o}{K_{rw}\mu_o + K_{or}\mu_w} \tag{29}$$

Therefore, Equation (29) was used to compute and predict the water cut in this study. The viscosity of 2.9 (mm^2/s) for light crude (Bonny light is associated with the field) was used for μ_o and μ_w was taken as 1. Consequently, the percentage of water cut [c_w (%)] that is expected to be associated with the recoverable volume of oil was estimated for each of the reservoirs.

4. Results

Volumes in place of oil and gas [Gas-In-Place (GIP) and Oil-In-Place (OIP)] estimated for the reservoirs are as presented in Tables 1 and 2 below. Similarly, the results of oil relative permeability (K_{or}), water relative permeability (K_{wr}) and water cut (c_w) are as shown in Table 3.

The parameters and their corresponding values, which were used as inputs for the estimation of the recoverable volumes of oil and gas, are as shown below;

- Gas-to-Oil Ratio (GOR) is 3.8 for Reservoir X in Well D_1 and 2.4 in Well D_2.
- Recovery factor (FR) = 0.32 (provided by the data source)
- Formation volume factor (FVF) is 1.07 for Reservoir X in Well D_1 and 1.06 in Well D_2
- Reservoir Y has no gas indications, therefore; FVF is 1.05 for both wells.
- Depth corresponds to Gas-Up-To (GUT) and it is 10, 480ft for D_1 and 10, 370ft for D_2 in Reservoir X.
- $\frac{P_{f_2}}{P_{f_1}}$ is 302 for Reservoir X in Well D_1 and 299 in Well D_2.

The total recoverable volume of gas (V_{Rg}) in Reservoir X is estimated at 7.7 $\times 10^9$cu.ft. Well D_1 holds 2.3×10^9 cu.ft of the estimated volume while Well D_1 holds about 5.4×10^9cu.ft. The total recoverable volume of oil is estimated at 9.4×10^6bbl in Reservoir X and at 1.6×10^7bbl in Reservoir Y.

Similarly, the recoverable volumes of oil (V_{Ro}) with the corresponding percentages of water cut [c_w (%)] of the reservoirs across the wells are as shown in Table 4.

5. Discussion

The use of the redefined equations involving direct computation of porosity seems to make the evaluation less tedious and the results are good. One of the objectives of this work is to predict the water cut in Reservoir X. This is because the water saturation in Reservoir X is 36% in Well D_1 and 21% in Well D_2, but in Reservoir Y, about 10% water saturation is estimated across the two wells for each of the reservoirs. With the equations, the increase in the values of porosity (Φ) with a corresponding increase in the values of water saturation (S_w) resulted in a decrease in values of oil relative permeability (K_{or}) with a corresponding increase in water relative permeability (K_{wr}). Similarly, the increase in the values of K_{wr} with a corresponding decrease in the values of K_{or} resulted in the increase in the values of water cut (C_w). Consequently, Reservoir X in Well D_1 with the highest value of S_w and high value of Φ has a higher value of K_{wr} and lower value of K_{or} when compared with

Table 1
OIP and GIP for reservoir X across wells D_1 and D_2.

Wells	h(ft.) × Cc	A_d(acres)	Φ	S_w	S_h	Volumes in place
$D_{1GIP(cu.ft)}$	30.0 × 43560	112.72	0.27	0.36	0.64	25,453,871.31cu.ft
$D_{1OIP(bbl)}$	28.0 × 7758	176.81	0.27	0.36	0.64	6,636,794.48bbl
$D_{2GIP(cu.ft)}$	50.0 × 43560	128.63	0.27	0.21	0.79	59,757,304.66cu.ft
$D_{2OIP(bbl)}$	100.0 × 7758	152.14	0.27	0.21	0.79	25,175,844.22bbl

Table 2
OIP and GIP for reservoir Y across wells D_1 and D_2.

Wells	h(ft.) × Cc	A_d(acres)	Φ	S_w	S_h	Volumes in place
$D_{1GIP(cu.ft)}$	0 × 43560	nil	0.26	0.11	0.89	–
$D_{1OIP(bbl)}$	70.0 × 7758	176.81	0.26	0.11	0.89	22,218,666.69 bbl
$D_{2GIP(cu.ft)}$	0 × 43560	nil	0.26	0.10	0.90	–
$D_{2OIP(bbl)}$	110.0 × 7758	152.14	0.26	0.10	0.90	30,380,976.57 bbl

Table 3
K_{wr}, K_{or} and c_w for reservoirs X and Y across wells D_1 and D_2.

Reservoirs	Φ	S_h	S_w	S_w/S_h	K_{or}	K_{wr}	K_{or}/K_{wr}	c_w
XD_1	0.27	0.64	0.36	1:1.8	0.39334	0.03136	12.54238	0.187794
XD_2	0.27	0.79	0.21	1:3.8	0.61208	0.00372	164.7224	0.017301
YD_1	0.26	0.89	0.11	1:8.1	0.78641	0.00009	8431.445	0.000344
YD_2	0.26	0.90	0.10	1:9.0	0.80508	0.00004	19395.56	0.000149

Table 4
V_{Ro} and c_w (%) across Wells D_1 and D_2.

Reservoirs	V_{Ro} bbl	c_w (%)
XD_1	1,984,835.73	18.780
XD_2	7,391,073.53	1.730
YD_1	6,771,403.18	0.034
YD_2	9,258,964.29	0.015

their corresponding values in Reservoir Y.

Furthermore, the ratios of water saturation to hydrocarbon saturation (S_w/S_h) are approximately 1:2 and 1:4 in Reservoir X and 1:8 and 1:9 in Reservoir Y across the two wells. Where the difference between the ratio of the fluids (water and oil) is not too much, the reservoirs show low values of K_{or} and high values of K_{wr} with corresponding high values of C_w. It can be confirmed from these results that the higher the ratio of S_h in a well, the lower the C_w. In the same vein, the decrease in the ratio of oil relative permeability to water relative permeability (K_{or}/K_{wr}) corresponds to the increase in C_w.

The estimated recoverable volume of oil (V_{Ro}) in Reservoir X is about 2.0×10^6bbl in Well D_1 and 7.4×10^6bbl in Well D_2. In Reservoir Y, V_{Ro} is estimated at 6.8×10^6 bbl for Well D_1 and at 9.3×10^6bbl for Well D_2. Reservoir X has about 18.8% (0.18779) of C_w in Well D_1 and 1.7% (0.01730) in D_2. In the same vein, Reservoir Y has about 0.034% (0.00034) of C_w in D_1 and 0.015% (0.00015) in D_2. The total recoverable volumes of hydrocarbons from the two wells are estimated at 7.7×10^9cu.ft for gas and at 2.54×10^7bbl for oil. With the present conditions of the two reservoirs, the values of C_w in Reservoir X are low and are very low in Y. Reservoir X in Well D_1 holds a smaller volume of V_{Ro} when compared with others and the C_w is also higher than others. Nonetheless, the percentage of C_w in Reservoir X is still within acceptable range.

6. Conclusion

The relationship between porosity (Φ) and fluids (oil and water) saturations has been used to predict the water cut (C_w) in Reservoirs X and Y correlated across Wells D_1 and D_2 in Osland oil and gas field, Niger Delta, Nigeria. Alternative expressions for the estimation of oil relative permeability (K_{or}) and water relative permeability (K_{wr}) in sandstone units were presented. These equations were used to estimate the percentages of water cut [c_w (%)] in each of the reservoirs.

Reservoir X shows approximately 18.8% and 1.7% of C_w in Wells D_1 and D_2 respectively, while the values are relatively low and negligible in Reservoir Y. Considering the range of values it can be concluded that Reservoir X is within the acceptable water cut range. The total recoverable volumes of hydrocarbons from the two wells are estimated at 7.7×10^9cu.ft for gas and at 2.54×10^7bbl for oil.

More wells within the field and its environs could reveal better reservoirs compared to the two evaluated here in this research. In addition, the depths of occurrence and trapping of the hydrocarbons within the reservoirs blocks and good migration pathways provided by the faults among others factors, are readily available to support the accumulation and producibility of the reservoirs. One can, therefore, conclude that the area is potentially viable, with reservoirs containing a manageable or little volume of associated water production. In view of this, more exploratory activities can be carried out in other to establish more or less prolific hydrocarbon reservoirs prior to the draining of the field.

Reservoir Y has very little water saturation (S_w) with corresponding higher values of hydrocarbon saturation (S_h) across the two wells. This could indicate that higher depths may have more established reservoirs, with each having little or no water saturation, such that associated water production may not be a thing to worry about. The results of the evaluation suggest that high Φ with corresponding high S_w accounted for high K_{wr} with the corresponding high associated C_w in Reservoir X. Within sandstone units, especially when water saturation log and porosity tool are present, the redefined equations can be quickly used to predict K_{or}, K_{wr} and C_w whenever it is required.

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APPENDIX C

Hydrocarbon Viability Prediction of Some Selected Reservoirs in Osland Oil and Gas Field, Offshore Niger Delta, Nigeria

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Research paper

Hydrocarbon viability prediction of some selected reservoirs in Osland Oil and gas field, Offshore Niger Delta, Nigeria

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ABSTRACT

An alternative approach involving the use of modified expressions for the free fluid index (FFI) permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI), was used to predict the viability of hydrocarbon in some selected reservoirs. The aim of this work is to predict flow units, transmissibility and primary recovery through porosity (Φ) derived from wire-line logs. In the absence of core data, Φ values derived from the density log (RHOB) were optimised herein. Alternative expressions for the FFI, K, RQI, and FZI were suggested. A simplified approach with the use of only porosity dependent expressions for these parameters (FFI, K RQI, and FZI) that lies within the scope of the study was used for the evaluation of the reservoirs. Quick-look models for the prediction of RQI an FZI based on these the redefined equations were presented. Drudgery and computational errors that may come with the use of a range of other dependent parameters [irreducible water saturation (S_{wirr}), formation factor (F), tortuosity factor (a) and cementation exponent (m)] were avoided. The reservoir, in well D_1, is about 90 ft (27 m) thick, with the upper 30 ft (9 m) occupied by gas, the next 28 ft (8.5 m) is filled with oil and the remaining 32 ft (9.8 m) is water filled. The reservoir, in well D_2, is about 110 ft (33.5 m) thick and it is oil saturated. Within D_1 reservoir, average Φ, FFI, K, RQI, and FFI are 0.2, 0.18, 1256mD, 2.5 μm and 10.1 μm respectively. Within D_2 reservoir, average Φ, FFI, K, RQI, and FFI are 0.25, 0.23, 5166mD, 4.5 μm and 13.5 μm respectively. Significant transmissibility and good rates of hydrocarbons recoveries are anticipated within the evaluated reservoirs.

1. Introduction

At times, the evaluation of hydrocarbon reservoirs is not precise due to the limitation of data and unavailability of core samples. Often, wire-line logs are more available for use and to evaluate some of the desired parameters, equations are mostly engaged. The use of a range of traditional equations for the evaluation of hydrocarbon reservoirs could come with drudgery that can result in some computational errors. It becomes a bit cumbersome when some specific parameters are to be evaluated at close intervals of depths within a formation for detail analysis. The quality of a reservoir is dependent upon the availability of significant volumes of the hydrocarbons and the ability to produce larger percentages of these fluids from the reservoir. This has called for the prediction of the viability of two reservoirs in two wells (D_1 and D_2), with the aid of wire-line logs. Logs are typically employed in establishing the viability of reservoirs, determination of porosity, hydraulic conductivity and other intrinsic rock properties. Related works (Richardson and Taioli, 2018; Ajisafe, and Ako, 2013; Richardson, 2013; Magara, 1993) have also confirmed that reservoir models derived from log data often provide excellent vertical resolution and are useful in the determination of pay thickness, porosity (Fic and Pedersen, 2013) and in the identification of gas, oil and water contacts (Ofoma et al., 2008).

This study tends to introduce alternative expressions for some intrinsic parameters to evaluate the flow units of the reservoirs. The confirmation of the availability of hydrocarbons in the reservoirs, delineation of fluids contact and prediction of the transmissibility and primary recovery of the selected reservoirs were also evaluated. Flow units evaluation includes the presentation of a simplified equation for the free fluid index (FFI). Thereafter, the expressions for permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) are modified for easy access to the evaluation of the transmissibility and recoverability of hydrocarbon from the selected sandstone hydrocarbon reservoirs. FFI is used as a measure of the moveable hydrocarbon, while RQI and FZI are models used to explain other reservoirs' attributes such as sand texture, structure, and shale content and their relationships to fluid flow. The signatures of gamma ray log (GR), deep laterolog (LLD), shallow laterolog (LLS), water saturation log (S_w), neutron porosity log

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(NPHI) and RHOB, were closely analysed. This evaluation also looks at optimising porosity for the evaluation of the selected reservoirs. As such, FFI, K, RQI and FZI expressions will be modified herein to help present only porosity dependent expressions in order to reduce the drudgery and computational errors that may come with the use of other dependent parameters such as irreducible water saturation (S_{wirr}), formation factor (F), tortuosity factor (a) and cementation exponent (m). Most studies (Samuel and Kevin, 2014; Okwoli et al., 2015; Oyeyemi and Aizebeokahi, 2015), have used Timur and Tixier equations. The authors have computed other dependent parameters and irreducible water saturation directly in the respective permeability equations for the evaluation of some fields in the Niger Delta. Herein equations for FFI and K based on Schlumberger (1989) and Coates and Denoo (1981) respectively, will be simplified to provide alternative and handier expressions for the evaluation of the selected reservoir sand units. Similarly, reservoir quality index (RQI) and flow zone indicator (FZI) expressions based on Tiab and Donaldson (2012) will be modified to provide only porosity dependent equations for quick evaluation.

FFI can be used to determine the ability of a reservoir to hold free and moveable fluid (Schlumberger, 1989). Similarly, RQI and FZI values can be used to predict other reservoirs' properties such as cementation, grains, and pores sizes, sorting and shale content among others (Tiab and Donaldson, 2012). These flow units are very important reservoir parameters. They are used for the evaluation of Formations relevant geologic attributes (Tiab and Donaldson, 2012; Amir and Nahla, 2015) and the ability of the reservoir to transmit its fluids and primary recovery are in so many ways dependent on the flow units. A sensitive evaluation using different scenarios of the tortuosity factor to verify the influence of it changes on FFI and K was also carried out. The values obtained for FFI were used for the computation of permeability. Consequently, RQI and FZI were evaluated to help predict the transmissibility of the selected reservoirs. Reservoir hydraulic flow unit can be defined as laterally and vertically continuous reservoir zones with similar bedding characteristics; permeability and porosity (Hear et al., 1984). The determinations of permeability and porosity are typically essentials in the evaluation of the hydraulic conductivity of reservoirs. Hydraulic flow unit is also seen as a consistent body with a defined reservoir volume, having regular fluid and petrophysical properties (Tiab and Donaldson, 2012). This unit is consistently correlative, recognizable and mappable on wire-line logs. Therefore, in this paper, wireline logs were used for the evaluation of two reservoirs in well D_1 and D_2 respectively. The study has also provided ways to minimize some fundamental risks; hence, it will encourage the determination of the volume of the transmittable hydrocarbons in places and further exploitation in Osland oil and gas field.

2. Geology of the study area

Osland Oil and gas field is located within latitude 5.0°N and 5.4°N and longitude 4.4°E and 4.8°E, in the offshore area of Southwestern Niger Delta (Fig. 1). The emergence of the Niger Delta basin is consequent upon a series of events. According to Burke (1972), the prevailing Southwestern wind and the regular pattern of longshore currents resulted in the geomorphology of the Niger Delta. Some of the river deposits are picked up by longshore currents in the coastal plain, while the rest is deposited in the coast.

Consequently, a larger percentage of the sand accretes along the front of barrier bars, but a minor portion moves down the slope along submarine channels (Burke, 1972). The Niger Delta basin is believed to have emerged from a failed rift junction because of the separation of the South American and African plates in the late Jurassic to mid-Cretaceous. These depositional and tectonic events have brought about ranges of evolutional trends that have been in use for explaining the general and petroleum geology of the area. The structural and stratigraphic styles that are in use for predicting the availability of hydrocarbons in place are directly related to these events.

The Niger Delta consists of the regressive wedge of clastic sediments of maximum thickness of about 12 km (Doust and Omatsola, 1990). There are three lithostratigraphic units in the region; Benin, Agbada and Akata Formations (Fig. 2). The Benin Formation consists of mostly continental sands with a thickness ranging from 0.7ft. to over 656ft. (0.2m to over 200m). It is also documented (Avbovbo, 1978) that it has a maximum thickness up to 6560ft. (2000m). The sands in the Benin Formation are coarse to fine, granular in texture, highly porous and generally freshwater bearing formation (Short and Stauble, 1967). Therefore, very little hydrocarbon accumulation has been associated with it. The Agbada Formation consists of interbedded sands and shale with a thickness of about 1000ft. to 15000ft. (300m – 4500m).

The Agbada Formation is made up of five sub-environments: Fluviatile, backswamp and lagoonal sediments, barrier bar sand, barrier foot (interbedded sand, silt, and clays); marine clay; and transgressive deposits (Weber and Daukoru, 1975). It is a transitional environment between the upper continental Benin Formation and the underlying Akata Formation. The Akata Formation ranges from 2000 ft. to over 20000 ft. (600 m to over 6000 m) in thickness. It is made up of mainly marine shale with restricted sandy and silty beds. This shale is overpressured and this provides the mobile base for subsequent growth faulting associated with the deposition of the overlaying Paralic sequence. The common stratigraphic succession consist of the sand and shale alternation and the production of hydrocarbons is associated with reservoirs in the units. There were several debates on the source rock in the region. Some have proposed that the Agbada Formation is the main source rock (Lambert – Aikhionbare and Ibe, 1984). Others proposed that the collective Akata and Agbada acted as source rocks (Doust and Omatsola, 1990; Nwachukwu and Chukwurah, 1986), based on the organic matter content in the shales of both the paralic and open marine sequences associated with them. The maximum extent of the Tertiary Niger Delta (Akata–Agbada) Petroleum System lies within the province boundaries and the minimum extent of the system is characterised by the areal extent of fields (Michele et al., 1999; Kulke, 1995; Ekweozor and Daukoru, 1984). The Niger Delta reservoir development is associated with the sandy regressive off lap sequence of the Agbada Formation (Haack et al., 2000). Some of the reservoirs in the Niger Delta are juxtaposed against faults within this formation (Freddy et al., 2005). This accounts for the structural traps that permitted the accumulation of hydrocarbons. The maturity of the associated hydrocarbons and reservoir quality are directly linked with depth and overpressure (Weber and Daukoru, 1975; Evamy et al., 1978). The rapid loading of the compacted shale of the Akata Formation by the sandy Agbada and Benin Formations (Reijers et al., 1997) resulted in the overpressures in the Niger Delta. Hence, fluids expelled from the over-pressured Akata shale could inflate the pressures in the adjacent sands. Compaction creates upward and downwards fluid potential gradients from the more compactable units to the more permeable units. Fluids may be expelled upwards and downwards into the adjacent reservoir rocks. The downward potential gradient makes the shale a perfect barrier and seals to upward migrating fluids (Weber and Daukoru, 1975; Reijers, 1995).

3. Materials and method

The well log data acquired were entered into the Kingdom Suite software to enable a comprehensive log evaluation. Log curves were generated; gamma-ray log (GR), deep laterolog (LLD), shallow laterolog (LLS), water saturation log (SW), neutron porosity log (NPHI) and density tool (ROHB) were engaged in this work. Derived parameters were based on characteristic log signatures and reservoir physical models. The basic steps include:

- Evaluation of litho-units and hydrocarbon bearing sands,
- Fluids differentiation
- Evaluation of flow (hydraulic) units,
- Sensitivity evaluation and

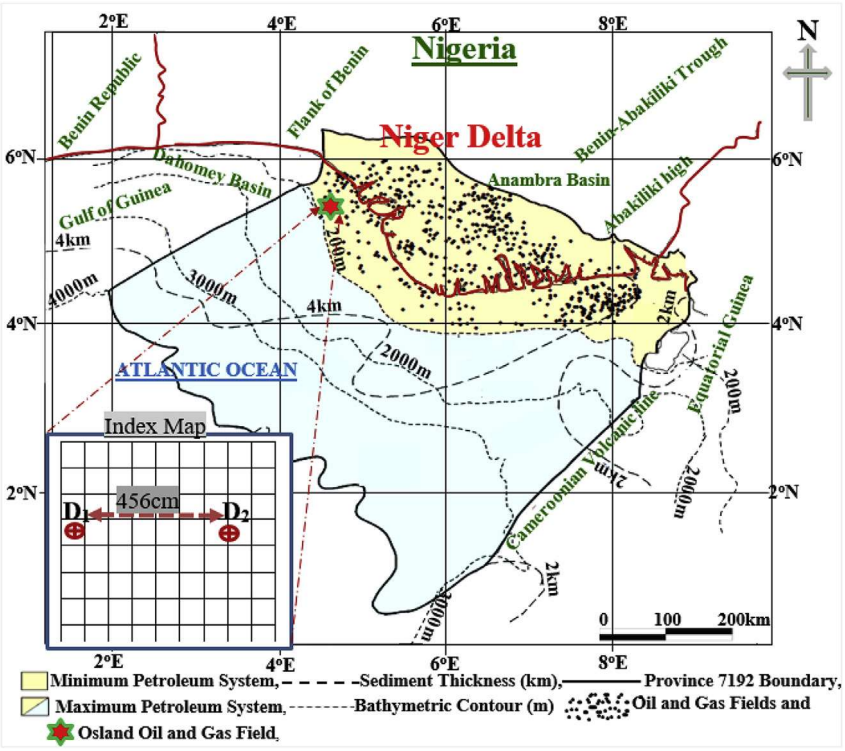

Fig. 1. Niger Delta map showing study location with oil and gas fields.
[Modified from Petroconsultants (1996)(a)].

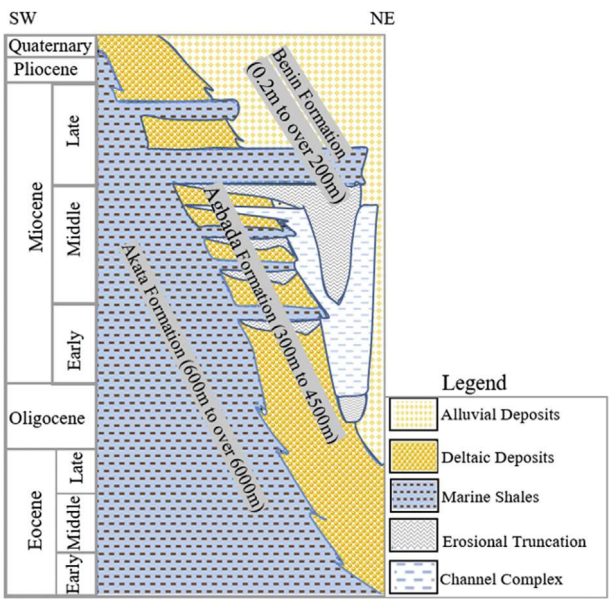

Fig. 2. Niger Delta Lithostratigraphic Succession.
[Modified from Shannon and Naylor (1989) and Doust and Omatsola, 1990].

- Modification and presentation of alternative expressions for the free fluid index (FFI), permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI)

The decision to go ahead with further exploration/exploitation activities depends on the outcome of this evaluation, reducing risk and uncertainty.

3.1. Evaluation of litho-units and hydrocarbon bearing sands

The gamma ray log used in the project is scaled from 0 to 150API units, increasing from left to right and was responsible for the identification of shale lithology in well D_1 and D_2. Shale has a reasonable concentration of radioactive substances (Schlumberger Oil Field Glossary, 2016) such as potassium, thorium, and uranium; thus, gamma ray response is expected to be relatively high within shale and exhibit maximum deflections. Hence, segments with maximum deflections to the right were mapped as shale units. It follows from this deduction that when there are little or no radioactive materials in the penetrated formation, the log shows a very low response (Ahammod et al., 2014). Such low responding zones were mapped as sand units. Gamma ray log was combined with a resistivity log to differentiate between portions with fluids and to identify the pay thickness (PT) within the reservoir sands (Fig. 3). Where total volume of the reservoir is suspected to be hydrocarbon saturated, the Reservoir Thickness (RT) was picked as the (PT) (Fig. 4).

3.2. Fluids differentiation

Formation density compensated and neutron logs were used for the differentiation of the reservoir fluids types. The neutron porosity log is scaled from 0.00 to 0.60 in porosity units (p.u), increasing from right to left and the density tool (RHOB) is scaled from 1.65 to 2.65 in g/cm^3, increasing from left to right. Gas in the pores causes the density log to record very high porosity and causes the neutron log to record a normally low porosity. The combination of neutron-density logs was effectively used to differentiate between gas and oil. The increase in RHOB along with a decrease in NPHI was noted as a gas indication, while a decrease in contrast in the porosity of density and neutron logs indicates oil-bearing zones. Furthermore, the water saturation log (SW) was used with the resistivity logs (LLS and LLD), to confirm water-bearing units. Points with maximum deflections to the right of the water saturation signature with corresponding minimum deflections to

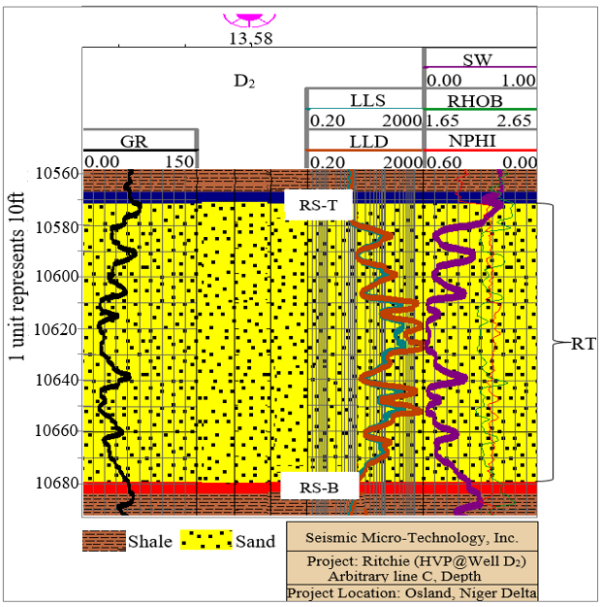

Fig. 3. Well D_1 showing log curves, the selected reservoir and identified pay thickness.
GR = Gamma ray log, **LLD** = Deep laterolog, **LLS** = Shallow laterolog, **NPHI** = Neutron Porosity log, **ROHB** = Density tool, and **SW** = Water Saturation Log. **RS-T** = Reservoir Sand Top and **RS-B** = Reservoir Sand Base. **PT** = Pay Thickness, **HUT** = Hydrocarbon-Up-To & **HDT** = Hydrocarbon-Down-To.

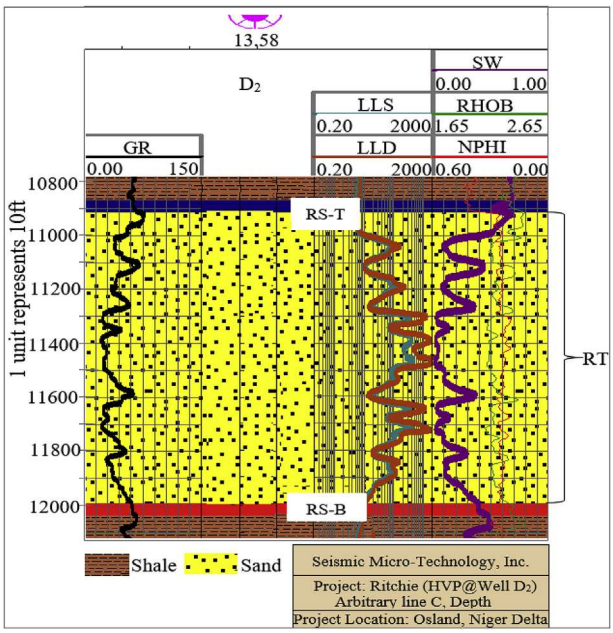

Fig. 4. Well D_2 showing log curves, lithologic units and identified Pay thickness.
GR = Gamma-ray log, **LLD** = Deep laterolog, **LLS** = Shallow laterolog, **NPHI** = Neutron Porosity log, **ROHB** = Density tool and **SW** = Water Saturation Log. **RT** = Reservoir Thickness, **RS-T** = Reservoir Sand Top and **RS-B** = Reservoir Sand Base.

the left of the resistivity logs were mapped and confirmed as water. Well D_1 is a gas-bearing reservoir, therefore, Hydrocarbon-Up-To (HUT), corresponds to Gas-Up-To (GUT). GUT was mapped at the point on the reservoir's top where NPHI and RHOB cross each other. Similarly, the point where LLD still maintains maximum deflection but with NPHI and RHOB crossing each again, within the hydrocarbon-bearing reservoir sand was picked as the Gas-Down-To (GDT). The enclosed area between these log curves (Fig. 5) was shaded with green

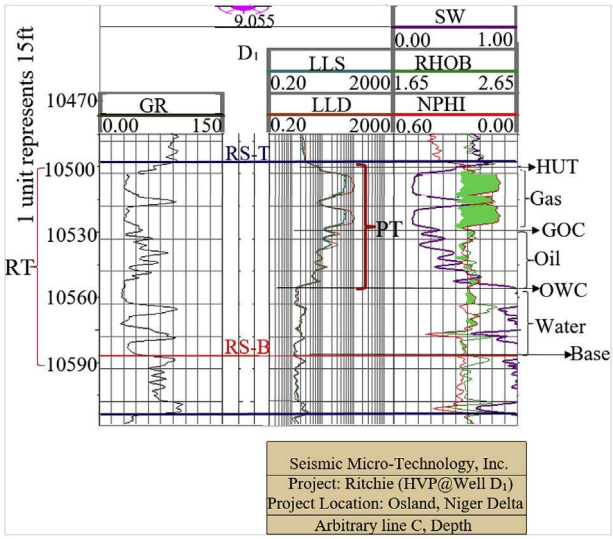

Fig. 5. Log curves showing reservoir vertical extent with available fluids and their contacts.
GR = Gamma ray log, **LLD** = Deep laterolog, **LLS** = Shallow laterolog, **NPHI** = Neutron Porosity log, **ROHB** = Density tool, and **SW** = Water Saturation Log. **RT** = Reservoir Thickness, **PT** = Pay Thickness, **HUT** = Hydrocarbon-Up-To, **GOC** = Gas-Oil-Contact, and **OWC** = Oil-Water-Contact. **RS-T** = Reservoir Sand Top and **RS-B** = Reservoir Sand Base.

colour to represent the gas unit in accordance with the usual colour code for gas fields in the Niger Delta.

Gas-Oil-Contact (GOC) is the base of the gas layer and it corresponds to the top of the oil layer. Oil-Water-Contact (OWC) is the base of the oil layer and the corresponding top of the water zone within the reservoir. Overall, the vertical extent of the reservoir was identified. Similarly, well D_2 seemed to be oil filled; therefore, the reservoir top corresponds to the Hydrocarbon-Up-To (HUT).

3.3. Evaluation of flow (hydraulic) units

The ability of fluids to be transmitted through the reservoir rock is dependent upon the rock permeability (K), porosity (Φ) and fluid's viscosity. Porosity is normally directly proportional to permeability and both are related to the reservoir's capillaries, geometry, pore connectivity and fracture network (Schlumberger Oilfield Review Autumn, 2014). Therefore, the evaluation of Fluid Free Index (FFI), K, Reservoir Quality Index (RQI) and Flow Zone Indicator (FZI) was initiated with the computation of the porosity. FFI is a measure of moveable fluids and it is the product of porosity and hydrocarbon in the reservoirs at irreducible water saturation (Tiab and Donaldson, 2012). RQI is a measure of pore integrity and grain distribution (Amaefule et al., 1993) and FZI is a measure of texture, shale content, grain sizes and tortuosity factor (Tiab and Donaldson, 2012). Hence, significant values of RQI and FZI indicate reservoir sands that are interconnected with well-sorted grains and less shaly. In this study, the equation for (FFI) was modified for the reservoirs sands, by incorporating the formation Factor (F) and Irreducible Water Saturation (s_{wirr}) equations. The FFI and permeability (K) relationship (Coates and Denoo, 1981) was used to compute values for the formation K. RQI and FZI were calculated using the values of K and Φ as inputs. These parameters were computed at 10 ft (3 m) intervals each with the selected reservoirs.

Porosity (Φ) was determined by obtaining values directly from density log (RHOB). Maximum and minimum deflections of the log within hydrocarbon bearing units were read and the average of the sum was taken as the formation bulk density (ρ_b). The same thing was done within the adjacent shale to obtain the values of bulk density of shale (ρ_{sh}). The values were later put into equation (1);

$$\Phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{sh}\left[\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f}\right] \quad (1)$$

[V_{sh} = volume of shale, Φ_D = density derived porosity corrected for shale, ρ_{ma} = matrix density of formation (2.65gcc for sandstone), ρ_b = bulk density of formation, ρ_f = fluid density of formation (1.0 gm/cc) and ρ_{sh} = bulk density of adjacent shale]. This equation was used to correct for shale influence (Mian, 1992).

Free fluid index (FFI) equation was redefined herein, to avoid direct computation of irreducible water saturation (s_{wirr}) for the purpose of this work. The s_{wirr} expression is given by equation (2);

$$(s_{wirr})^2 = \frac{F}{2000} \quad (2)$$

Where; F = Formation factor and it is given by equation (3).

$$F = \frac{a}{\Phi^m} \quad (3)$$

Where; Φ = porosity, m = porosity exponent (usually 2 for sands) a = tortuosity factor (ranges from 0.6 to 1).

Combining equations, (2) and (3), irreducible water saturation (s_{wirr}) becomes;

$$(s_{wirr})^2 = \frac{a}{2000\Phi^m} \quad (4)$$

However, free fluid index (FFI) (Schlumberger, 1989) is defined as equation (5).

$$FFI = \Phi(1 - s_{wirr}) \quad (5)$$

From equation (4), porosity exponent (m) is usually taken as 2 for sandstones. Hence, s_{wirr} becomes;

$$(s_{wirr})^2 = \frac{a}{2000\Phi^2} \quad (6)$$

Such that

$$s_{wirr} = \frac{a^{0.5}}{44.72\Phi} \quad (7)$$

Where; 44.72 is the square root of 2000 (Formation constant).

Such that equation (5) becomes;

$$FFI = \Phi\left[1 - \frac{a^{0.5}}{44.72\Phi}\right] \quad (8)$$

It follows that

$$FFI = \Phi - \left[\frac{\Phi a^{0.5}}{44.72\Phi}\right] \quad (9)$$

Therefore, the reservoirs' sand free fluid index was calculated using equation (10).

$$FFI = \Phi - \left[\frac{a^{0.5}}{44.72}\right] \quad (10)$$

3.4. Sensitivity evaluation

Tortuosity factors (a) usually range from 0.6 to 1 (Schlumberger, 1989; Asquith and Krygowski, 2004). Therefore, a kind of simulation was carried out using tortuosity factors of 0.6, 0.7, 0.8 and 0.9 each, with a porosity range of 0.05 – 0.5, to compute FFI. This was done to help verify the influence of the change in tortuosity factor on FFI and K. The results are presented in tables, curves and line graphs. The results obtained for FFI using the different tortuosity factors with the derived porosity range (0.14 – 0.27) within the reservoirs herein, were extracted from the sensitivity analysis and they are as presented in Table 1.

Free fluid index/porosity plots were generated using the different scenarios of tortuosity factor and the FFI equation herein, considering porosity range of 5%–50%. Fig. 6 shows the relationship between the changes in tortuosity factor (a) with free fluid index (FFI).

Table 1
Sensitivity analysis using different scenarios of tortuosity factor.

Φ	FFI (a = 0.6)	FFI (a = 0.7)	FFI (a = 0.8)	FFI (a = 0.9)	FFI (a = 1)
0.14	0.123	0.121	0.120	0.119	0.118
0.15	0.133	0.131	0.130	0.129	0.128
0.16	0.143	0.141	0.140	0.139	0.138
0.18	0.163	0.161	0.160	0.159	0.158
0.19	0.173	0.171	0.170	0.169	0.168
0.20	0.183	0.181	0.180	0.179	0178
0.21	0.193	0.191	0.190	0.189	0.188
0.22	0.203	0.201	0.200	0.199	0.198
0.23	0.213	0.211	0.210	0.209	0.208
0.24	0.223	0.221	0.220	0.219	0.218
0.25	0.233	0.231	0.230	0.229	0.228
0.26	0.243	0.241	0.240	0.239	0.238
0.27	0.253	0.251	0.250	0.249	0.248

Curves showing permeability/porosity (Fig. 7) and permeability/free fluid index ((Fig. 8) relationships were generated using the different scenarios of tortuosity factor and Coates and Denoo (1981) permeability expression, considering porosity range of 5% – 50%.

3.5. Alternative expressions for the selected parameters

The analysis shows that, if each of the free fluid index (FFI) values is approximated to the nearest 0.00 considering all the scenarios (0.6, 0.7, 0.8, 0.9 and 1.0) with any derived porosity, FFI is consistently 0.02 less than the corresponding porosity (Φ) value. Similarly, if the average (0.8) of 0.6, 0.7, 0.8, 0.9 and 1.0 is considered, FFI equation becomes;

$$\text{FFI} = \Phi - \left[\frac{0.\ 8^{0.5}}{44.72}\right] \quad (11)$$

Such that

$$\text{FFI} = \Phi - 0.02 \quad (12)$$

The expression (equation (13)) for permeability (K) by Coates and Denoo (1981)

$$K = 10^4\,\Phi^4\,\frac{FFI^2}{(\Phi - FFI)^2} \quad (13)$$

becomes;

$$\text{K} = 10^4\Phi^4\frac{(\Phi - 0.02)^2}{0.0004} \quad (14)$$

The reservoir quality index (RQI) and flow zone indicator (FZI) (Tiab and Donaldson, 2012) are given as equations (15) and (16) respectively.

$$RQI = 0.0314\sqrt{\frac{K}{\Phi}} \quad (15)$$

$$FZI = \frac{RQI}{\Phi_r} \quad (16)$$

Φ_r is porosity ratio (the ratio of the derived porosity and the difference between the maximum derivable value (100%) of porosity and the derived porosity. It is expressed as equation (17).

$$\Phi_r = \frac{\Phi}{1 - \Phi} \quad (17)$$

Therefore, RQI and FZI are redefined as equations (18) and (19);

$$\text{RQI} = \frac{3.14\Phi^2(\Phi - 0.02)}{0.02\Phi^{0.5}} \quad (18)$$

$$\text{FZI} = \frac{3.14\Phi^2(\Phi - 0.02)}{(0.02\Phi^{0.5})\Phi_r} \quad (19)$$

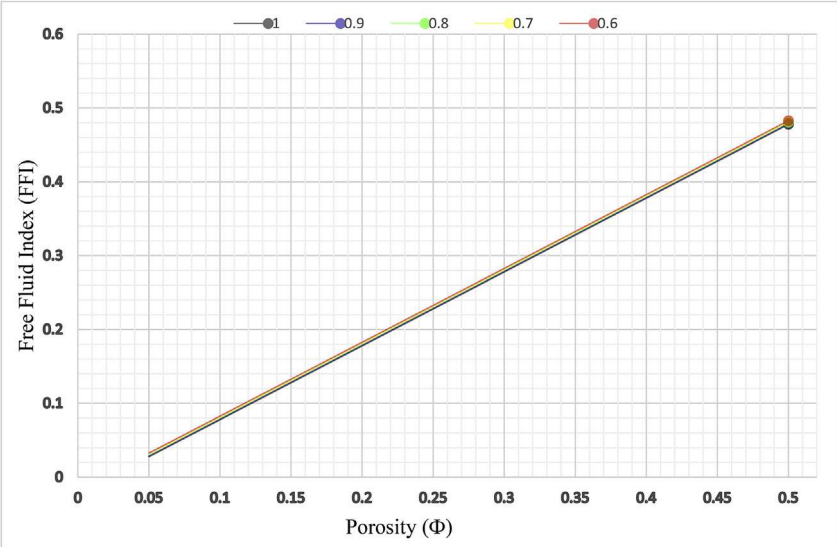

Fig. 6. Free fluid index/porosity plots.

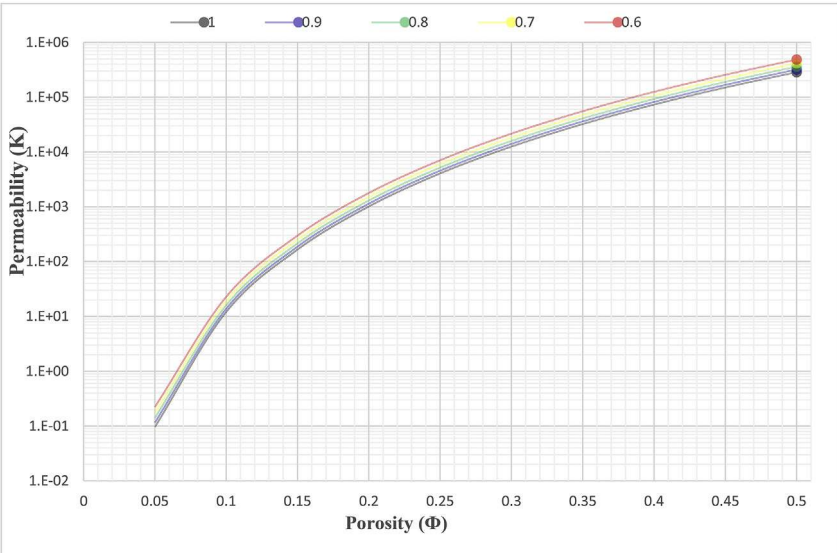

Fig. 7. Permeability/Porosity curves.

With these equations, porosity derived from the density tool (RHOB) was used as the only variable input for the computation of FFI, K RQI and FZI. Hence, provided quick access to the evaluation of the hydraulic units of the selected sandstone hydrocarbon reservoirs.

4. Results

Porosity (Φ), free fluid index (FFI), permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) were computed at 10 ft. (3 m) intervals within the reservoirs in the two wells with a tortuosity factor of 0.8 and the results are shown in Tables 2 and 3;

Average values of Φ and FFI in well D_1 are 0.20 and 0.18. These values were used to compute the average values of K, RQI and FZI, within the reservoir in this well and the results are 1256mD, 2.5 μm and 10.1 respectively. Similarly, the average values of Φ and FFI in well D_2 are 0.25 and 0.23. With these values, average values of K, RQI and FZI within the reservoir in this well are 5166mD, 4.5 μm and 13.5 respectively. RQI/Φ (Fig. 9) and FZI/Φ (Fig. 10) plots were also generated based on the modified equations herein.

5. Discussions

Core data were not provided for this evaluation, therefore, an alternative approach involving the modification of some expressions to help predict the selected parameters was embarked upon. The modified and alternative equations suggested herein, fit the scope of the study. Computational errors and possible drudgery that may come with the use of other dependent parameters such as irreducible water saturation (S_{wirr}), formation factor (F), tortuosity factor (a) and cementation exponent (m) are believed to have been avoided.

The evaluated reservoir in well D_1 occurs between 10,500 ft. and 10,590 ft. The total reservoir thickness is about 90 ft., and approximate in the upper 58 ft. is filled with hydrocarbons. The top 30 ft. of the 58 ft. (10,500 ft. to 10,530 ft.) of the reservoir in well D_1 is gas filled. Between 10,530 ft. to about 10,558 ft. (28 ft.) is the oil. The remaining 32 ft. of the 90 ft., down to the base is believed to be filled with water. Similarly, in well D_2 the reservoir is between 10,570 ft. and 10,680 ft., it appears to be mostly oil saturated. In well D_1, about 40 ft. (12 m) from the top has K range of 1,755mD to 6,580mD while the remaining 50 ft. (15 m) below shows a range of 214mD to 941mD. Within well D_2, a low value

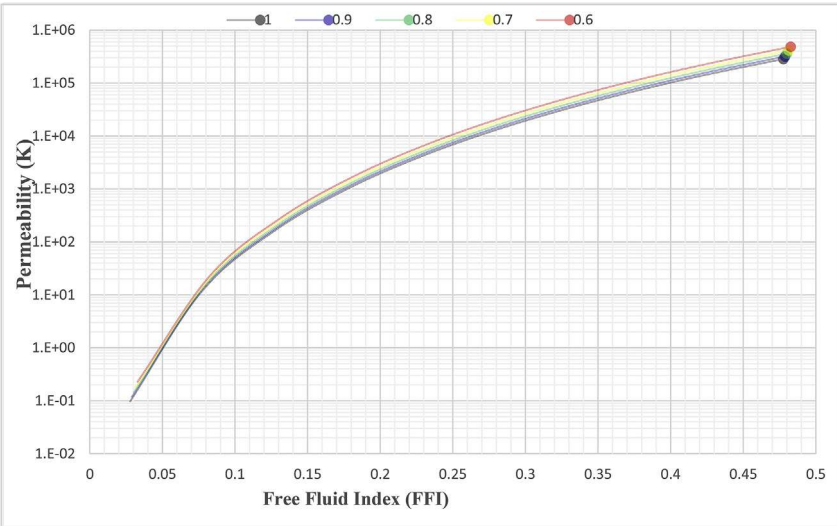

Fig. 8. Permeability/Free Fluid Index curves.

Table 2
Derived parameters of the reservoir across in D_1.

Depth	Φ	FFI	K (mD)	RQI (μm)	*FZI* (μm)
10500 ft (3200 m)	0.26	0.24	6580	5.0	14.2
10510 ft (3203 m)	0.25	0.23	5166	4.5	13.5
10520 ft (3206 m)	0.25	0.23	5166	4.5	13.5
10530 ft (3209 m)	0.21	0.19	1755	2.9	10.7
10540 ft (3212 m)	0.19	0.17	941	2.2	9.4
10550 ft (3215 m)	0.18	0.16	671	1.9	8.7
10560 ft (3218 m)	0.15	0.13	214	1.2	6.7
10570 ft (3221 m)	0.16	0.14	321	1.4	7.4
10580 ft (3224 m)	0.18	0.16	671	1.9	8.7

Table 3
Derived parameters of the reservoir in well D_2.

Depth	Φ	FFI	K (mD)	RQI (μm)	*FZI* (μm)
10570 ft (3221 m)	0.14	0.12	138	1.0	6.1
10580 ft (3224 m)	0.27	0.25	8303	5.5	14.9
10590 ft (3227 m)	0.20	0.18	1256	2.5	10.1
10600 ft (3230 m)	0.22	0.20	2342	3.2	11.5
10610 ft (3233 m)	0.26	0.24	6580	5.0	14.2
10620 ft (3236 m)	0.27	0.25	8303	5.5	14.9
10630 ft (3239 m)	0.24	0.22	4014	4.1	12.9
10640 ft (3242 m)	0.25	0.23	5166	4.5	13.5
10650 ft (3246 m)	0.26	0.24	6580	5.0	14.2
10660 ft (3249 m)	0.25	0.23	5166	4.5	13.5
10670 ft (3252 m)	0.22	0.20	2342	3.2	11.5
10680 ft (3255 m)	0.20	0.18	1256	2.5	10.1

of 138mD was computed in the first 10 ft. (3 m) and the remaining 100 ft. (30 m) has K range of 1,256mD to 8,303mD. Permeability can be up to 10,000mD and permeability above 1,000mD is very good (Electric Logs, 2016: Schlumberger, 1989). Baker (1992), referred to permeability above 1,000mD as excellent. Herein, the averaged value of K is 1,256mD in well D_1 and 5,166mD in D_2. Therefore, K can be termed significant within the reservoirs. Okwoli et al. (2015), obtained values up to 6,000mD and above with Tixier's equation, Oyeyemi and Aizebeokahi (2015) computed values up to about 10,000mD with Timur's equations and Adaeze et al. (2012), also calculated up to 5,000mD and above with the use of core data in an adjacent oil field within the Niger Delta. The computed values for reservoir quality index (RQI) and flow zone indicator (FZI) with the evaluated K are good. The average value of RQI is 2.5 μm in D_1 and 4.5 μm in D_2, while FZI is 10.1 μm in D_1 and 13.5 μm in D_2.

It is observed from the calculations that higher the porosity, the higher is FFI. High values obtained for porosity and FFI, resulted in significant values for K, RQI, and FZI. Significant RQI values indicate a reservoir with well-sorted grain distribution and good pore-throats. Pore-throat size is an important factor that can be used for the evaluation of reservoir quality and its ability to transmit it fluids (Tiab and Donaldson, 2012; Fic and Pedersen, 2013; Kelai et al., 2016). In the same vein, significant values obtained for FZI shows that the reservoirs consist of less shaly and interconnected sands, coarse-grained and well-sorted sands (Tiab and Donaldson, 2012). Significant values for RQI and FZI indicate reservoirs with good flow units and are expected to have good hydrocarbon transmissibility and significant recovery rates. The sensitivity evaluation shows that different scenario of tortuosity factor has very little and negligible influence on FFI and K. The curves showing the relationships between K and Φ, and K and FFI look quite similar. Nevertheless, a closer look at the K/FFI curves seems to show that the results appear smoothened a little bit, especially at the lower values of K/FFI cross plots when compared with the K/Φ cross plots considering the range of values that were computed in the research. This could be in agreement with Schlumberger (1989), which suggested that FFI is the formation's effective porosity and that is a measure of the moveable hydrocarbon. With the range (0.6 – 1) of values of the tortuosity factor (a) considered in the sensitivity analysis to check the influence of it changes on FFI, the suggested equations might just be useful for the prediction of the selected parameters within any sandstone reservoir. It might be useful as well in carbonate rocks because cementation factor (m) could be within a range of 1.90 – 2.15 (Carothers, 1968; Asquith and Gibson, 1982; Schlumberger, 1989) and the factor of tortuosity (a) is still within the considered range.

6. Conclusion

Due to the limitation of data and core sample unavailability, alternative methods are needed to estimate some fundamental reservoir parameters. Therefore, the prediction of the hydrocarbon viability of two reservoirs (one in Well D_1 and the other in Well D_2) in "Osland" oil and gas field, Offshore Niger Delta, Nigeria was evaluated using a simplified approach. The evaluation involved the identification of hydrocarbons in the reservoirs, differentiation of fluids and prediction of flow units. The traditional expressions for the free fluid index (FFI), permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) were modified for this evaluation. Core data were not available; therefore, the equations herein provided quick access to the prediction of the flow units of the reservoirs with the aid of porosity (Φ) values

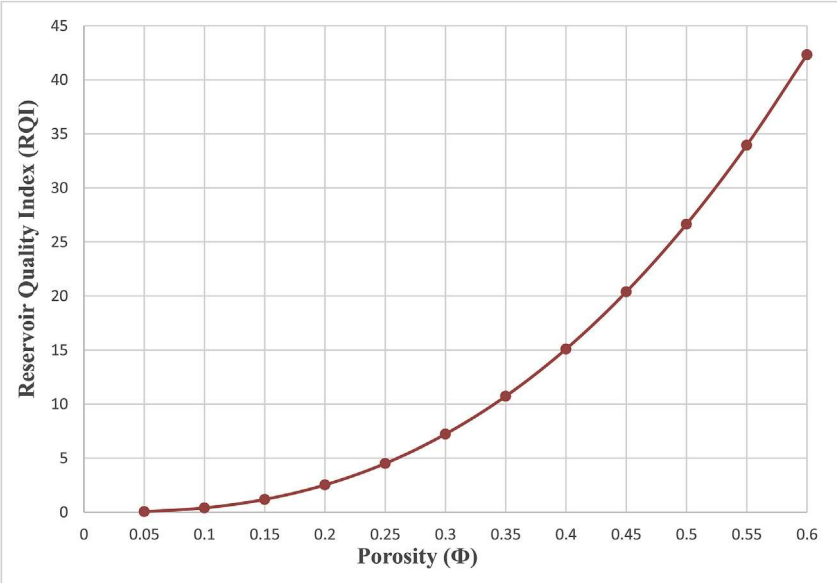

Fig. 9. Reservoir quality index (RQI)/Porosity (Φ) relationship.

derived from wire-line logs. The computation of formation factor (F) and irreducible water saturation (S_{wirr}) was bypassed. The use of the alternative expressions for the selected parameters herein makes the evaluation easier. Φ, FFI, K, RQI, and FZI were computed at intervals of 10 ft. (3 m) each within the reservoirs to aid the evaluation of hydraulic (flow) units. The average values for K in both reservoirs are above 1,000mD, while Φ is 0.20 in D_1 and 0.25 in D_2. FFI, RQI, and FZI are significant and are indicative of reservoirs with good transmissibility and recovery rate. The sensitivity analysis suggests that changes in tortuosity factor may not have a significant influence on FFI and K. Hence, the FFI, K, RQI and FZI equations developed herein are usable as alternative expressions for evaluations in reservoir sands. In the same vein, the generated plots are also usable for the quick prediction of FFI, RQI, and FZI in sandstone reservoir units. Therefore, drudgery and possible errors that may come with the computation of other dependent parameters are avoided. The results can help to reduce doubts and uncertainties, regarding the viability of the identified reservoirs in terms of availability of hydrocarbons, the measure of the ability of the reservoirs to transmit the fluids and rate of recoveries of oil and gas. Further exploration activities can be encouraged to help identify other reservoirs within "Osland" oil and gas field and to aid the estimations of the volumes of recoverable hydrocarbons in place when the need arises. In the absence of core data, this evaluation has highlighted a simplified approach involving the use of handy equations for the evaluation of flow units in hydrocarbon reservoirs with the aid of wireline logs.

Acknowledgement

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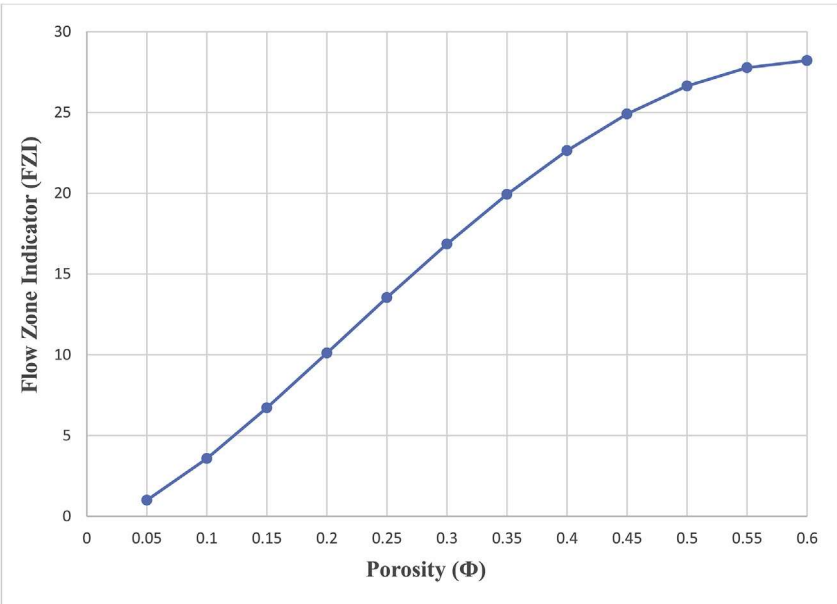

Fig. 10. Flow zone indicator (FZI)/Porosity (Φ) relationship.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.marpetgeo.2018.11.007.

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APPENDIX D

Asserting the Pertinence of the Interdependent Use of For Review Only Seismic Images and Wireline Logs in the Evaluation of Some Selected Reservoir in the South Atlantic Passive Margin (Osland Oil and Gas Field, Offshore Niger Delta, Nigeria)

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Asserting the Pertinence of the Interdependent Use of Seismic Images and Wireline Logs in the Evaluation of Some Selected Reservoir in the South Atlantic Passive Margin (Osland Oil and Gas Field, Offshore Niger Delta, Nigeria)

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Keyword:	Times/Depths Correlations, High-resolution Imaging, Developmental Wells, Pay Thickness/Drainage Area, Risk/Uncertainty Reduction

Highlights

- Correct Time/Depth Correlation
- High-resolution imaging in wells
- Developmental Well Points Recommendation
- Pay Thicknesses/Drainage Areas Evaluations
- Risk/Uncertainty Reduction

Asserting the Pertinence of the Interdependent Use of Seismic Images and Wireline Logs in the Evaluation of Some Selected Reservoir in the South Atlantic Passive Margin (Osland Oil and Gas Field, Offshore Niger Delta, Nigeria)

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ABSTRACT

This study presents the correct time/depth correlations and enhanced velocity analysis for petrophysics and seismic interpretations. It involves high-resolution imaging in the selected wells (Osl-1 and Osl-2) and complex geological structures associated with the reservoirs to aid the evaluation of the pay thicknesses (P_t), drainage areas (A_d) and developmental wellbore positions recommendation. It shows the influence of well to seismic tie (W-S_T) and the boost on the confidence of the interpretation. W-S_T shows that the depth of occurrence and the travel times of seismic waves at the interfaces between media having different velocities/densities are the same on the seismic sections and on the wireline logs. Reservoir A-horizon (R-A_h) is mapped below 9550ft. and at 2.460sec. in Osl-1 and 9510ft. at 2.450sec. in Osl-2. Reservoir B-horizon (R-B_h) is mapped below 10550ft. and at 2.655sec. in Osl-1, and 10520ft. at 2.650sec. in Osl-2. Reservoir A is about 70ft. thick across Ols-1 and Osl-2. Reservoir B is 70ft. thick in Osl-1 and 100ft. thick in Osl-2. The sum of the drainage areas on R-A_h is 172acres (69.6×104m^2) and that of R-B_h is 206acres (83.4×104m^2). Total pay thickness is 310ft. (94.5m) for both reservoirs and Ad is 378acres (153×104 m^2) on the two horizons.

Keywords: Times/Depths Correlations, Pay Thickness/Drainage Area, High-resolution Imaging Developmental Wells. Risk/Uncertainty Reduction.

I. INTRODUCTION

Hydrocarbon exploration and production usually commence with data acquisition, either on the onshore or offshore. In any case, risk and uncertainty management habits are advisable to be inculcated in the whole process, from the planning of the survey to the preparation of equipment and human labour, through to the field processes and data processing and interpretation. Every instrument in use (equipment, technical knowledge, and proper planning) contributes to the quality of the data acquired. The exploration and production of hydrocarbons involve lots of risk and uncertainties (Suslick et al., 2009). It is true that geological/geophysical concepts are uncertain with respect to structure, reservoir seal, and availability of hydrocarbon. Furthermore, pay thickness (P_t) and drainage area (A_d) are necessary parameters for the estimation of the volumes of hydrocarbon in places and recoverable volumes (Richardson and Taioli, 2018; Asquith and Krygowski, 2004; Bateman and Fessler, 1990). Therefore, a painstaking attention given to the evaluation of P_t and A_d will help to minimize errors, such that overestimation or underestimation of hydrocarbon volumes is avoided. This work tends to show high-resolution images of the well to seismic ties to help amplify the interpretation and to boost the confidence on the results thereafter. Most times, scholars and experts who are never there during the acquisition of the issued data does the analysis either for educational purpose and/or to meet the needs of the oil and

gas companies. Therefore, during interpretation, the interpreter is left alone with no other option than to carefully interpret the data and presents the results in the best ability. Without ignoring the fact that there are several other means of possible errors, this work tends to emphasis the relevance of paying attention to the way seismic structures are tied to well logs during formation evaluation. Correct time/depth correlation and enhanced velocity analysis of the two wells (Osl-1 and Osl-2) are carried out. Furthermore, the evaluation looks at the influence of well to seismic tie (W-S_T) on the integrity of the results and the boost on the confidence of the interpretation. The decision to go ahead with developmental activities in Osland oil and gas field, Niger Delta depends largely on the conclusion of this evaluation. Two horizons that are consistent on the reservoir sands are selected. Herein very clear and didactic images highlighting the times and depths to the tops and the bottoms of the selected reservoirs are mapped and presented. In the same vein, other useful information such as reservoirs' trap types, drainage areas (A_d) and possible points recommended for siting developmental wells are highlighted. Hence, the relevance of the evaluation to the case study (Osland oil and gas field) are discussed.

Well logs and 3-D seismic data were engaged in this study. The measurement of the variations in the physical properties of hydrocarbon reservoirs with depths in wells across oil and gas fields is usually carried out with the aid of corresponding suites of wireline logs. Well logs are used to correlate zones suitable for hydrocarbon accumulation, identify productive zones, determine depth and thickness of zones, distinguish between gas, oil, and water in a reservoir and to estimate hydrocarbon reserves (Asquith and Krygowski, 2004; Tiab and Donaldson, 2012; Richardson and Taioli 2018). Seismic interpretation entails the process of determining information about the earth from seismic data. 3-D seismic interpretations are used to image subsurface structures capable of harbouring hydrocarbon (Hamed, and Kurt, 2008; Richardson and Taioli, 2018). 3-D seismic data comprises a set of numerous closely spaced seismic lines that provide a high spatially sampled measure reflectivity and typical receiver line spacing could range from 300m (1000ft) to over 600m (2000ft) (Coffeen, 1986; Tom, 2002; Schlumberger Oilfield Glossary; 2018). The original seismic lines are called the in-lines, and the lines displayed perpendiculars to them are called cross-lines. A range of these lines was engaged in this evaluation. Each of these seismic lines depicts a seismic section. Seismic data with well logs have been used in several ways for locating and evaluating the geometry of structures that harbours hydrocarbon. According to Wang Qin (1995), a geologic trap is a combination of rock structures that harbour hydrocarbon and is able to prevent the lateral or vertical escape of oil and gas to the surface. These hydrocarbon traps are categorized as either stratigraphic (i.e. unconformity, reef, or pinch out), structural (i.e. folded or faulted) or a combination of structural and stratigraphic traps (Lines and Newrick, 2004). Lines and Newrick, (2004) defined a stratigraphic trap as a hydrocarbon trap caused by lithologic changes. In this case, a reservoir unit is surrounded by an impermeable unit or is thinned out against a seal. Structural traps, on the other hand, are caused by folding, faulting or other deformities. The geologic trap that is a common feature in the evaluated field is the structural type. All the delineated A_d are faults dependent. This work is expected to boost the confidence regarding the availability of hydrocarbon in the reservoirs prior to the commencements of exploitation activities.

2. PETROLEUM GEOLOGY

The study area is located in the offshore rifted continental margin of south-west Niger Delta. Rifting in the Niger Delta started from Late Jurassic to late Cretaceous as part of the Benue trough, a NE-SW-oriented basin (probably a failed arm of the of a triple-junction) related to the separation

of the African and South American plates (Olade, 1975). Thereafter, gravity tectonism took over as a major force and influenced other structural changes (Lehner and Ruiter, 1977; Genik 1993; Michele et al.1999; Michael and Ronald, 2006). Structural deformation commences when the potential of gravity is good enough to overcome the overburden internal strength and resistance to slip along the basal detachment (Rowan et al., 2004). The resultant movement brings about vertical and/or lateral displacement and influences rock deformation, such that different structures are produced. diapirs, rollover anticlines, collapsed crests and faults are closely associated with this gravity tectonics (Doust and Omatsola, 1990; Stacher, 1995; Brownfield, 2016). Some faults are synthetic and cut across the field while others are antithetic, but are terminated right on top of other faults. Freddy et al., (2005) also confirmed that the structures are exemplary of an extensional rift system with faults juxtaposing against each other. Niger Delta basin is characterized by diapiric shale that provides the trap (seal and cap rock) in the region (Doust and Omatsola, 1990). The shale also provides three sealing mechanisms; clay smear along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting and vertical seals (Doust and Omatsola, 1990; Freddy et al., 2005). Hydrocarbons are held in places in the Niger Delta because of the enormous structural traps. These traps exist due to the availability of closely distributed faults as seen in Osland Oil and Gas Field.

The study area is bounded by the geographical grids of latitude 5.00N and 5.20N and longitude 4.80 and 5.00E (Fig. 1). 5,100 barrels of oil production per day was a huge success by Shell-British Petroleum in 1958 but then, the Biafra War had to put a stop to further developmental activities. Later, after Nigeria became independent and a republic, exploration, and production increased.

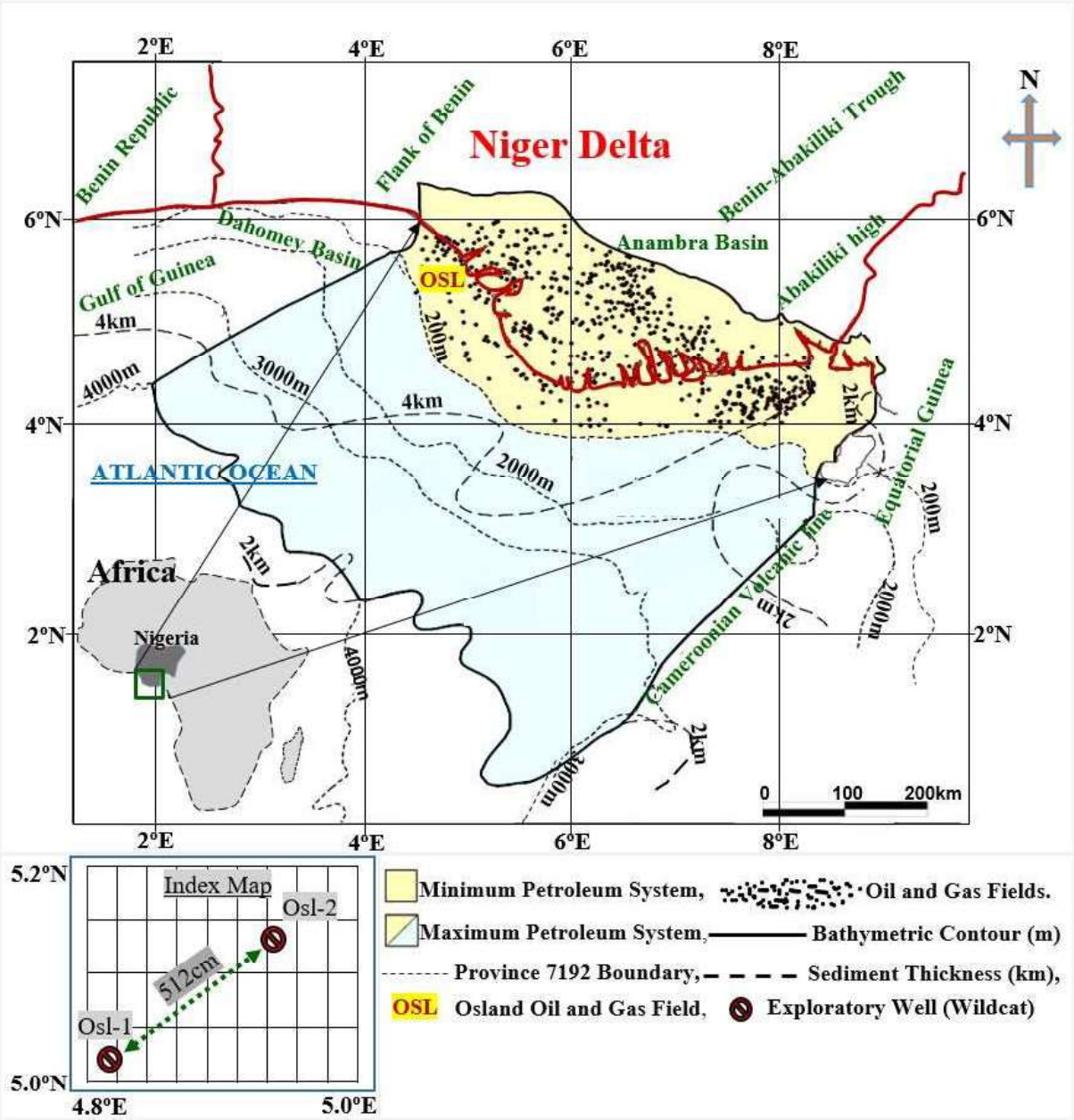


Figure 1: Niger Delta map showing study location with oil and gas fields.

[Modified from Petroconsultants, 1996]

The relevance of hydrocarbon to the Nigeria economy gained a massive recognition by the end of 1970 when world oil prices began to rise. This is fundamental to the involvement of other key players (Total, ExxonMobil, Chevron, Halliburton, etc) that are operating in the region. The Delta is rich in both oil and gas. Three lithostratigraphic units; Benin, Agbada and Akata Formations exist in the Niger Delta (Weber and Daukoru, 1975: Evamy et al., 1978: Ejedawe, 1981). Source rocks are sedimentary rocks that are normally very rich in organic content and are generating or have the tendency to generate petroleum (Tissot and Welte, 1984; Akinlua et al., 2016). The general consensus is that the most effective source rock, in the Niger Delta sequence is the marine

shale of the Akata Formation and the shale interbedded with the paralic sandstones of the Agbada Formation and that they have both yielded oil and gas. The undiscovered resources of the Tertiary Niger Delta (Akata-Agbada) Petroleum System is estimated at 40.5 billion barrels of oil and 133 trillion cubic feet of gas (Michael et al., 2006). Ejedawe et al., (1984), suggested that the Agbada shale sources the oil while the Akata shale sources the gas. On the other hand, Doust and Omatsola (1990) suggested that the Agbada and Akata Formations are both source rocks and that the Agbada Formation should be producing more. 34.5 billion barrels of recoverable oil and 93.8 trillion cubic feet of recoverable gas have been discovered in the Niger Delta (Michele, 1999). This indicates that the undiscovered volumes in places in the Niger Delta are more than the discovered volumes. The faults, rollover and collapsed structures observed within the studied reservoirs in Osland Oil and Gas Field are exemplary of the Niger Delta. These structures are possible aftermaths of the continental breakup and rifting of the African and South American plates (Weber and Daukoru, 1975; Genik, 1993; Stacher, 1995, Antonio et al., 2000; Byami et al., 2016).

The production of Petroleum in the Niger Delta is associated with the unconsolidated reservoir sands largely in the Agbada Formation. These reservoir sands are controlled by depth of burial and by depositional environment and they are Eocene to Pliocene in age (Michele et al., 19990). Furthermore, the reservoirs are normally stacked up and are vary in thicknesses and the thicker reservoirs are most likely to represent composite bodies of stacked channels (Evamy et al., 1978; Doust and Omatsola, 1990). Similarly, Kulke (1995) describes the significant reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels, considering the quality and geometry of reservoir. The Niger Delta reservoirs are described as Miocene paralic sandstones with significant flow units and thicknesses (Edwards and Santogrossi, 1990). It is also suggested that potential reservoirs are very likely to be created by the combined effort of deep-sea channel sands, low-stand sand bodies, and proximal turbidites (Beka and Oti, 1995). Growth faults determines the lateral variation in reservoir thickness and lithofacies, as such, the reservoir thickens towards the fault within the down-thrown block. (Weber and Daukoru, 1975; Smith-Rouch et al., 1996).

3. MATERIALS AND METHODS

3-D seismic data with integrated wireline logs consisting of Gamma ray log (GR), Resistivity logs (LLS and LLD) Water Saturation log (SW) Neutron log (NPHI) and Density log (RHOB) were used for the research. The methods include;

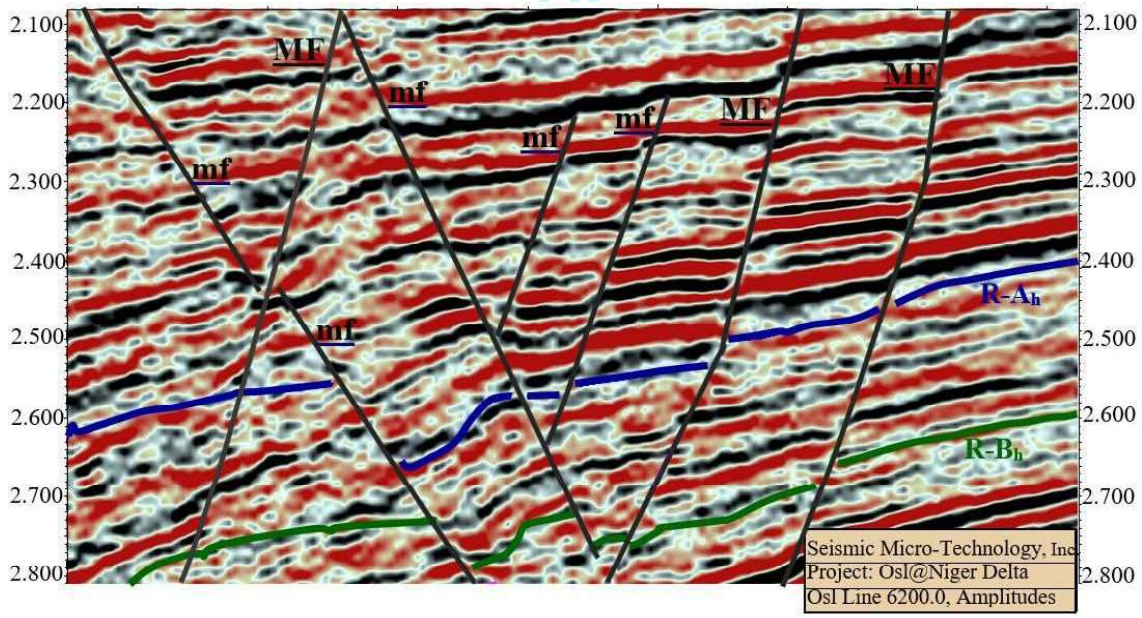
(a) The use of well logs to correlate zones suitable for hydrocarbon accumulation, identify productive zones, and determine depth and thickness of zones,
(b) Generation of Seismic sections to aid the mapping of faults and horizons and development of time and depth structural maps and
(c) Correct time/depth correlations based on well to seismic tie (W-S_T), for the evaluation of the times and depths of occurrences of these reservoirs as reflected on the well logs data and on the seismic sections

3.1. Logs

GR was engaged for litho-units identification, as such, the potential reservoir sands were differentiated from the shale units. In Osl-1, LLS and LLD were combined to delineate portions within the reservoir that are hydrocarbon saturated. Osl-1 has SW, NPHI, and RHOB which are used to further confirm the presence of hydrocarbons and can later be engaged in further studies for fluids differentiation whenever the need arises. In Osl-2, LLD alone was used for the identification of hydrocarbon bearing sands.

3.2. Seismic

Qualitative and volumetric hydrocarbon reservoirs evaluation are normally done with seismic sections and maps. Herein faults and horizon delineation (Fig.2) was fundamental and was carried out with a distinct attention to; abrupt endings of reflections, up-throw with relative down-throw and abrupt changes in dip directions, distortion and/or displacement of reflections and disappearance of reflection below suspected faults lines. These points were carefully looked out for because the region Osland oil and gas field is characterised by multiple faults with collapsed and rollover structures. Two consistent horizons [Reservoir A-horizon (R-A_h) and Reservoir B-horizon (R-B_h)] where picked respectively on both inlines and crosslines. Timing was done by reading reflection time on the horizon picked at intervals. The values for the time obtained were, therefore, posted at appropriate points on the seismic situation maps. The top and bottom of the horizon picked were timed at every change. This represents the arrival time of the reflection from the sea level. Faults were posted to their corresponding location on the depth structure map. Prior to contouring, the horizon times were gridded and smoothed then converted to depth grids.



MF = Major Fault, **mf** = Minor Fault, **R-A_h** = Reservoir A-horizon, and **R-B_h** = Reservoir B-horizon

Figure 2: Inline 6200 Showing Structure with Multiple Growth Faults, Collapsed Structures, Structural Traps and Selected Horizons (Osland Oil and Gas Field).

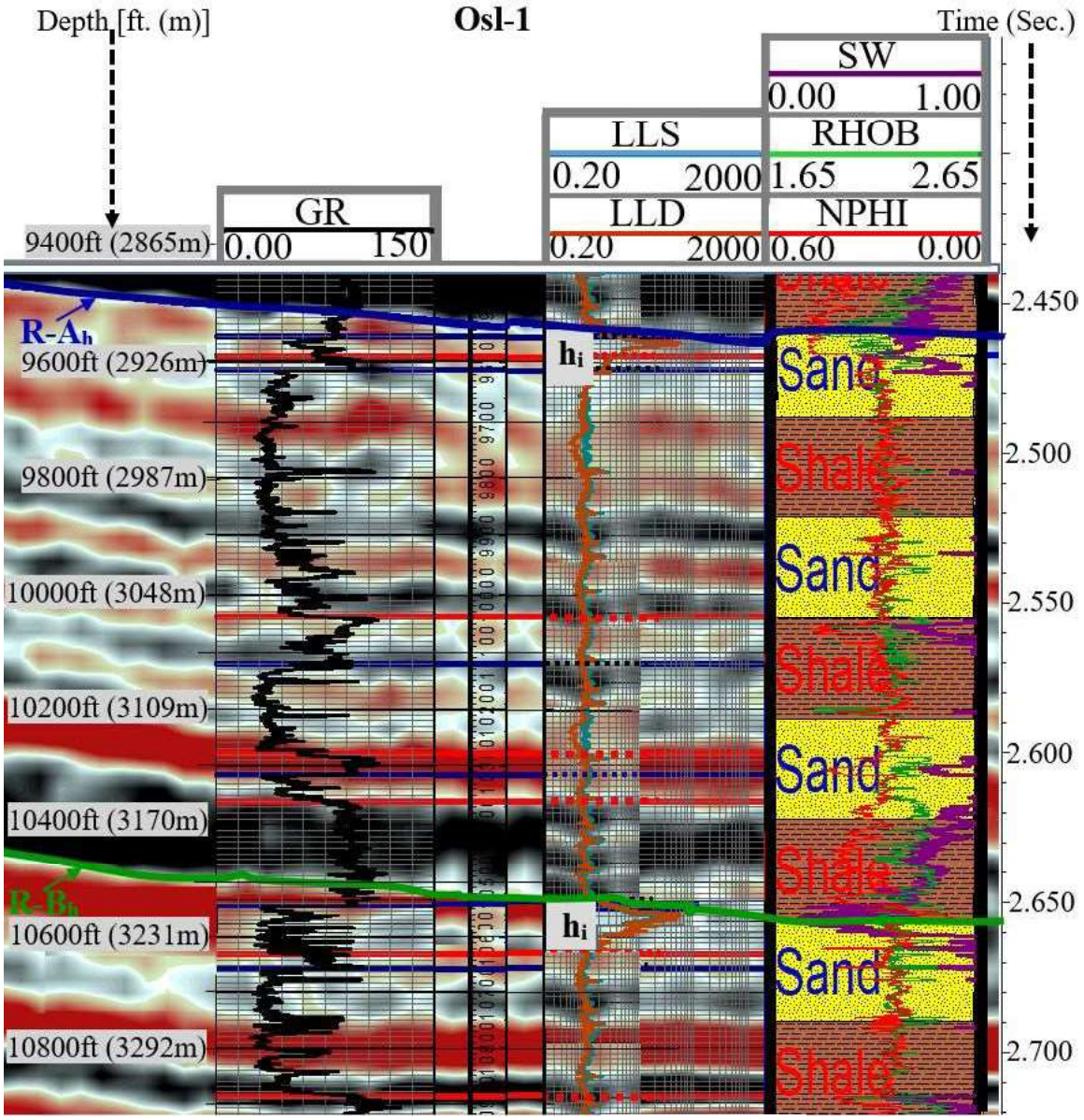
The grids serve as distinguishing factors between the different horizons picked as each horizon has a different grid. It was therefore convenient for the preparation of time and depth contour maps. Times to depths conversion was carried out using T-D conversion (check shot survey). It involves the conversion of the acoustic wave travel time to actual depth, based on the acoustic velocity of the subsurface medium. This conversion permits to produce depth and thickness maps of subsurface layers interpreted on seismic reflection data. These maps are crucial in hydrocarbon exploration because they permit the volumetric evaluation of oil or gas-in-place.

3.3. Well to Seismic Tie (WS_T)

Check shot data, of Osl-1 and Osl-2, was used in the conversion of seismic travel time values to depth, and to tie well log to seismic section within the evaluated reservoirs. Usually, Check shot includes a direct measure of the travel time from an energy source at the surface down to various depths in the reservoir of interest. It helps to check if the seismic travel times are averaged at the same depths and at interfaces between media with different velocities on the well logs information and the on the seismic sections.

4. RESULTS

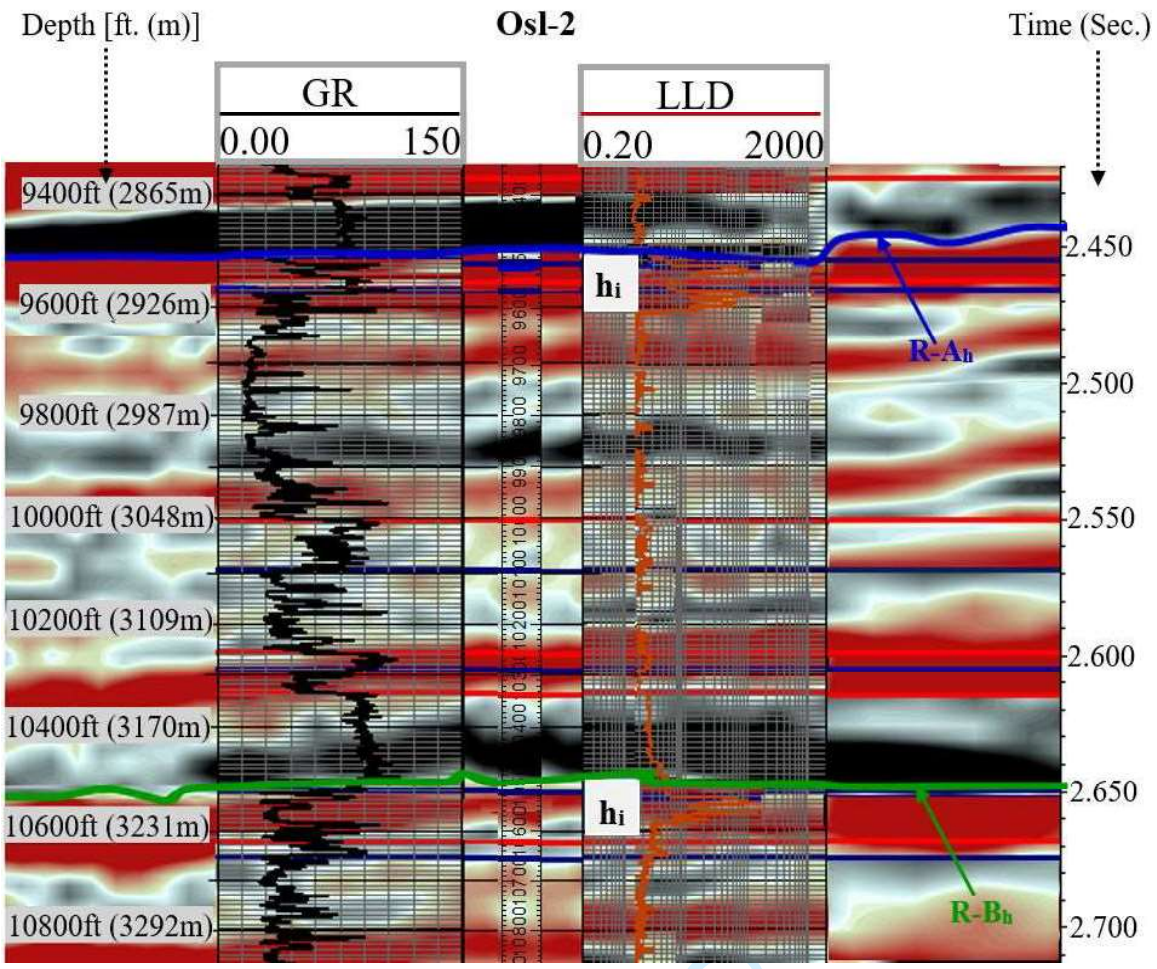
Figure 3 shows the first well (Osl-1) tied to the seismic section prior to the generation of the time and depth structure map. The two horizons were consistent on the reservoir sand. The thickness of the portion occupied by the hydrocarbon below the Reservoir A- horizon (R-A_h) is about 70ft. (9550ft. to 9620ft.) and timed between 2.46 and 2.48 seconds. Below the Reservoir B-horizon (R-B_h), the thickness of the hydrocarbon zone is about 70ft. (10530ft. to 10600ft.) and timed between 2.65 and 2.67 seconds.



GR = Gamma ray log, **LLD** = Deep laterolog, **LLS** = Shallow laterolog, **NPHI** = Neutron Porosity log, **ROHB** = Density tool, and **SW** = Water Saturation Log. **R-A$_h$** = Reservoir A-horizon, **R-B$_h$** = Reservoir B-horizon and **h$_i$** = Hydrocarbon Indication

Figure 3: Well to Seismic Tie (W-S$_T$) of Osl-1.

Figure 4 shows the first well (Osl-2). The thickness of the portion occupied by the hydrocarbon below Reservoir A-horizon (R-A$_h$) is about 100ft. (9510ft. to 9610ft.) and timed between 2.45 and 2.48 seconds. Below the Reservoir B-horizon (R-B$_h$), the thickness of the hydrocarbon zone is 70ft. (10520ft. to 10590ft.) and timed between 2.65 and 2.67 seconds.



GR= Gamma ray log, **LLD** = Deep laterolog, **R-A$_h$** = Reservoir horizon A. **R-B$_h$** = Reservoir horizon B and **h$_i$** = Hydrocarbon Indication.

Figure 4: Well to Seismic Tie (W-S$_T$) of Osl-2.

The structural maps (contoured in time and depth) of the two selected horizons show the two-way travel time of the mapped horizon, the geometry of the reflector, probable areas considering structural highs and depths and faults orientation. These maps reflect geological information such as anticline with their respective syncline and the geometry of the faults as they relate to migration and accumulation of hydrocarbon.

The delineated as drainage areas (A_{d-1}, A_{d-2} and A_{d-3}) were mapped out on each of the depth structure maps. The depth of occurrence of these zones corresponds to the depth of the reservoir as mapped on the wireline logs. The time structural map of Reservoir A-horizon (R-A$_h$) (Fig. 5) reveals a travel time tracking between 2.097 and 2.704 seconds amplitude time. The portions delineated as hydrocarbon saturated track between 2.45 and 2.50 seconds. This apparently agrees with the results of the W-S$_T$. The depth structural map of A-Reservoir horizon (R-A$_h$) (Fig. 6) reveals a depth between 7770ft and 10764ft. The thicknesses of the portions delineated as hydrocarbon saturated in both wells is between 9450ft and 9700ft. This apparently agrees with the results of the well logs

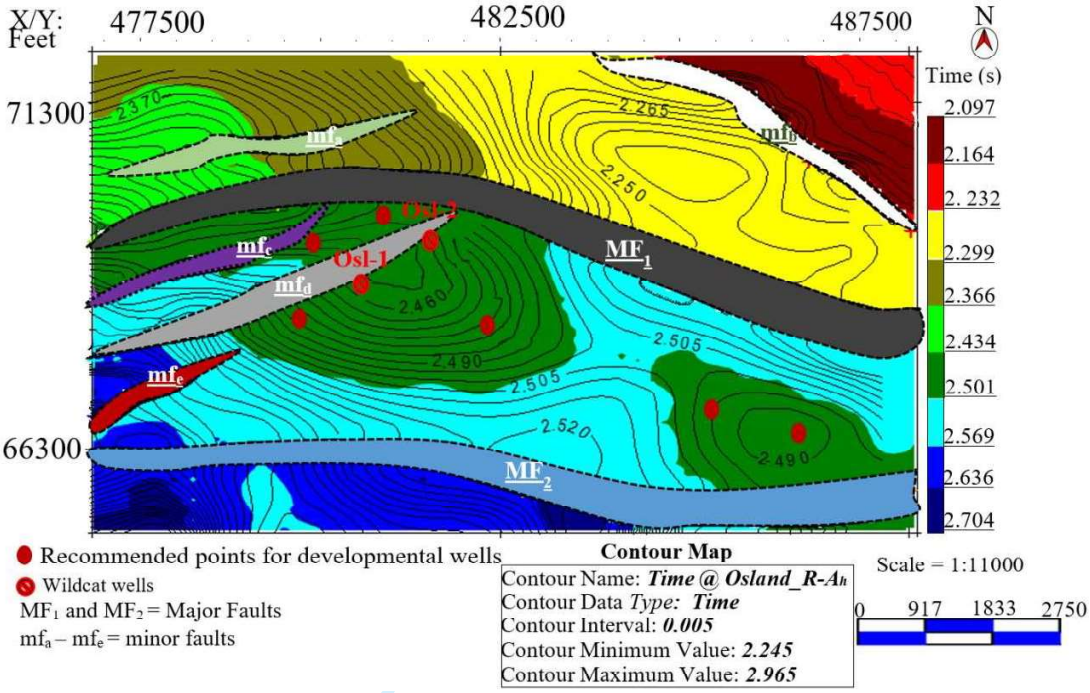


Figure 5: Time Structural Map of Reservoir A-horizon (R-A_h)

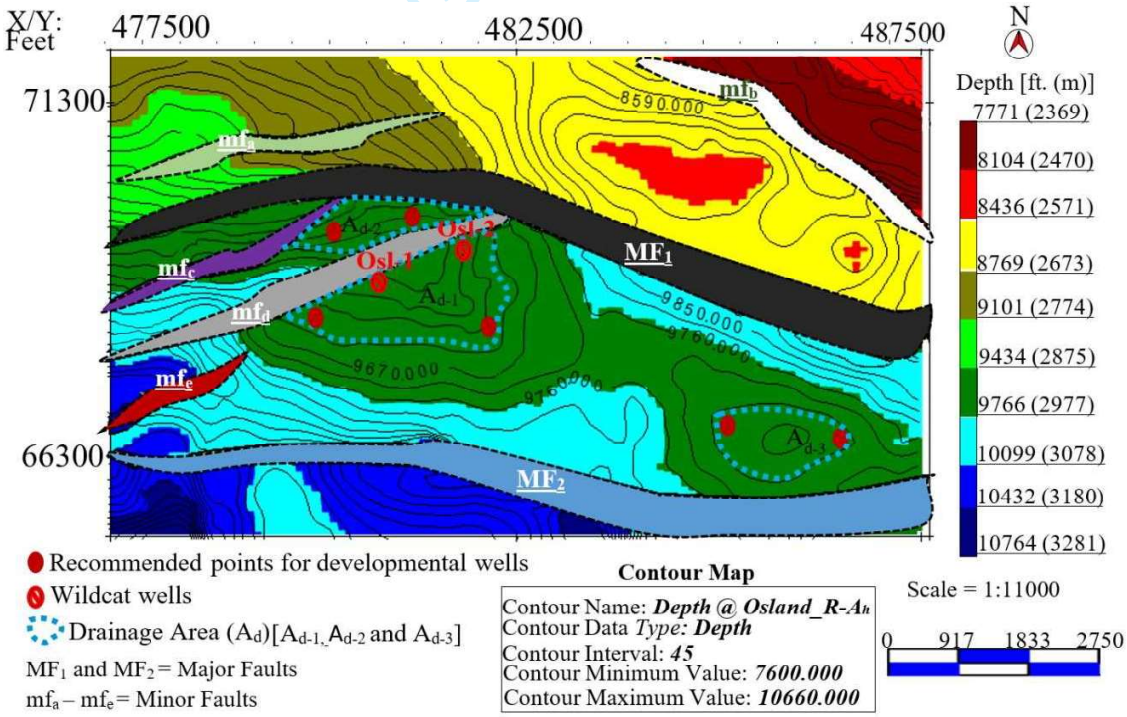


Figure 6: Depth Structural Map of Reservoir A-horizon (R-A_h)

Similarly, the time structural map of Reservoir B-horizon (R-B_h) (Fig. 7) reveals a travel time tracking between 2.223 and 2.995 seconds amplitude time. The portions delineated as hydrocarbon saturated track between 2.65 and 2.70 seconds. The depth structural map of Reservoir A-horizon (R-A_h) (Fig. 8) reveals a depth between 8359ft and 12299ft. The thicknesses of the portions

delineated as hydrocarbon saturated in both wells is between 10450ft and 10610ft. and the respective values of the drainage areas (A_{d-1}, A_{d-2} and A_{d-3}) are 94.204 acres (38 $\times 10^4$ m^2), 24.320 acres (1×10^4 m^2) and 87.863 acres (36×10^4 m^2)

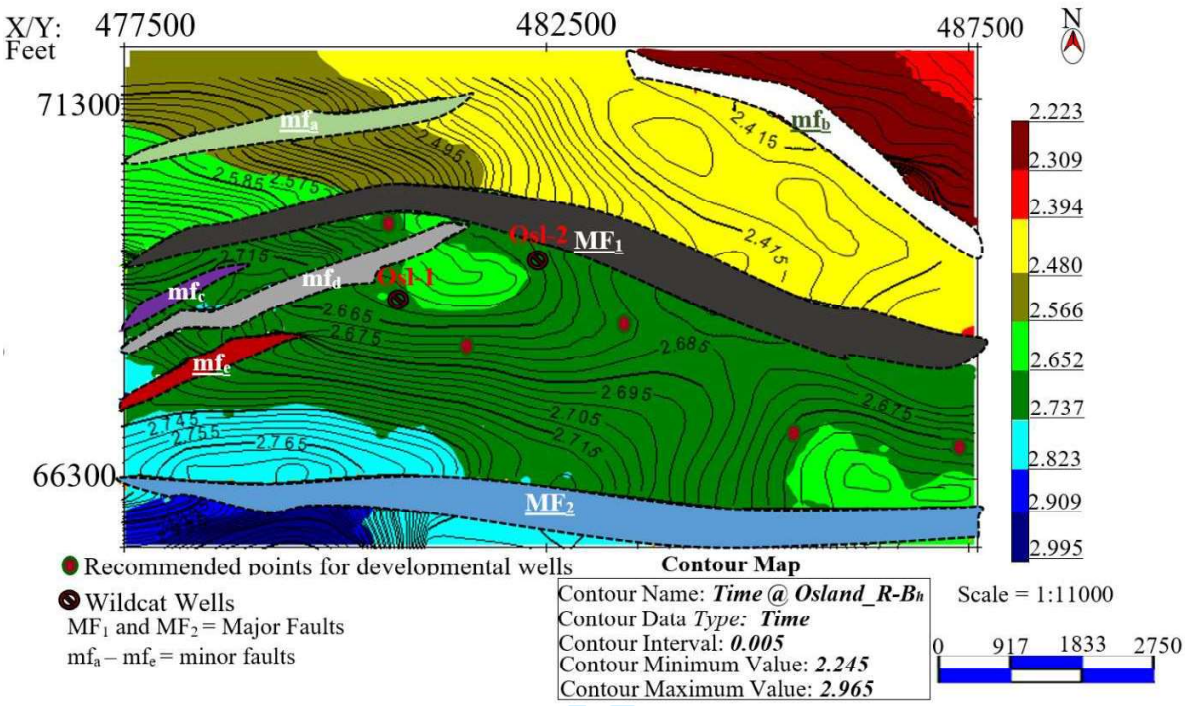


Figure 7: Time Structural of Reservoir A-horizon (R-B_h)

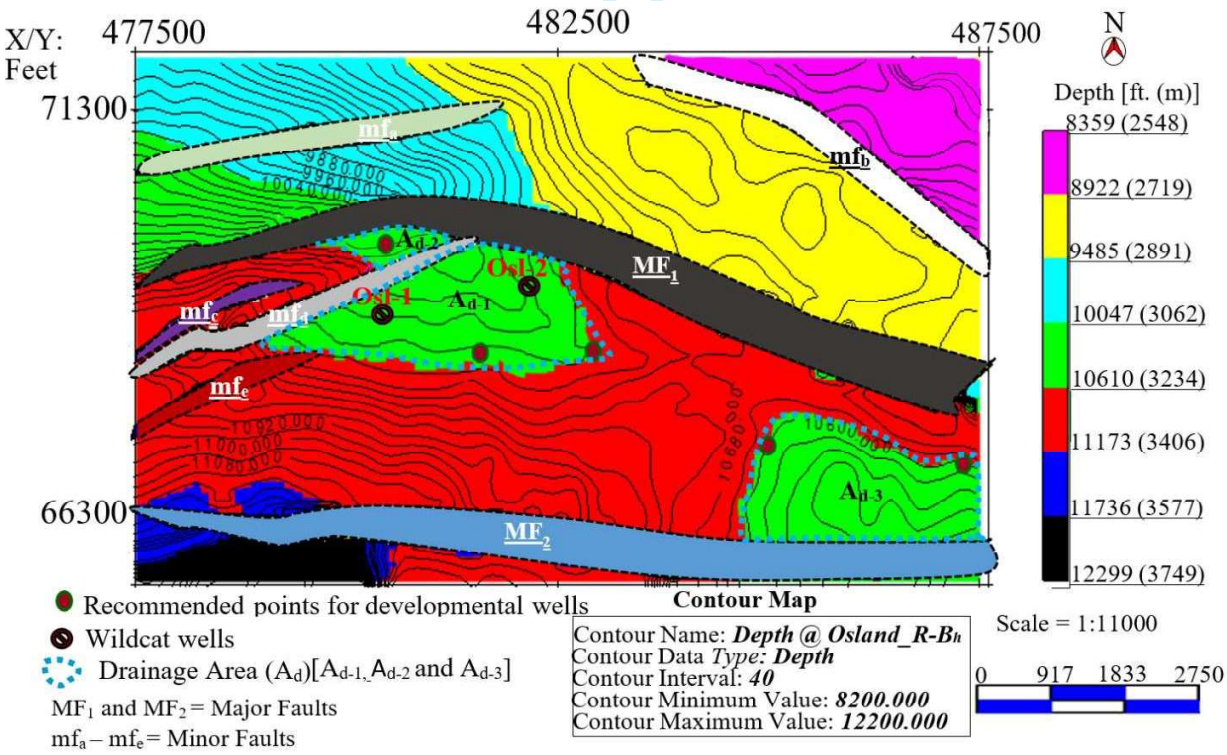


Figure 8: Depth Structural of Reservoir A-horizon (R-B_h)

Table 1: Showing Reservoirs' Thickness and Drainage Area

Reservoir horizon	Thickness [Ft. (m)]		Drainage Area (A_d)		
	Osl-1	Osl-2	A_{d-1} [acre. (m^2)]	A_{d-2}[acre. (m^2)]	A_{d-3} [acre. (m^2)]
R-A_h	70 (21)	100(30)	80.767 (33 ×10^4)	45.110(18×10^4)	46.067 (19 ×10^4)
R-B_h	70 (21)	70 (21)	94.204 (38 ×10^4)	24.320 (1×10^4)	87.863 (36 ×10^4)

5. DISCUSSION

Wellbore positions recommendation for developmental purposes was carried in this study. It has shown the correct time/depth correlation and enhanced velocity analysis for seismic processing in the evaluated wells. Herein, high-resolution imaging in Osl-1 and Osl-2 and complex geological structures associated with the reservoirs are presented. The results of this evaluation are to further confirm the viability of the hydrocarbon reservoirs. Therefore, the didactic images of both the wireline logs and structural maps herein provided high-resolution pictures that show the details of the reservoirs' conditions. The orientation of the faults aids the structural traps within the field. The major growth faults (MF_1 and MF_2) cut across the entire portion covered in this evaluation. Minor faults (mf_a, mf_b, mf_c, mf_d, and mf_e) mostly on the western portion of the field provided the structural closure needed to keep any possible fluid in place within the field. The shale markers and the fault seals are common in the Niger Delta. The shale markers form the basis of the predictions of most hydrocarbon seal because of the uniqueness of biostratigraphy constituents and they provide three types of seals; vertical seal, clay smears through faults and interbedded sealing units against which reservoir sands are juxtaposed due to faulting (Doust and Omatsola, 1990). The fault seals consist of main faults that display growth faults. However, whenever clay smears are sufficient and/or if reservoirs are juxtaposed against shale, they provide the required seals good enough as migration paths or to hold the hydrocarbons in places. The orientation of the mapped faults across the Osland oil and gas field is exemplary in these explanations.

Some of the minor faults (mf_c, and mf_d) are antithetical to MF_1. This, combined with the depth at the central portion makes it very dependable as a hydrocarbon trap. The wildcat (Osl-1 and osl-2) are located within this portion. This is a very good positioning because it enables the firsthand interpretation of that portion of the field and as such, the level of certainty regarding the availability of hydrocarbon, reservoir thickness and drainage area (A_d) in that portion is greatly increased. At the southeastern portion where MF_2 is edging out on the field, there is a structural high supported by the fault. This portion corresponds (by correlation) to the central portion of the field in times and depths. Therefore, it may not be misleading if that portion is delineated as pay zone. Other points (at the central portion and at the southeastern portion) are suggested for developmental wells based on; times and depth occurrences, structural highs and fault assisted trap. Well to seismic tie (W-ST) aided to confirm that the depths of occurrences and the travel times of seismic waves at the interfaces between media (shale/sand and oil saturated sands/water saturated sands) having different velocities as interpreted on the seismic sections and structural maps corresponds the times and depths on the wireline logs. The points recommended for the siting of developmental wells herein are just any points within the confines of the delineated drainage areas, therefore, under field/technical conditions, engineers can decide to place these developmental wells at any

convenient portion, within the mapped drainage areas. Down the well, each of Reservoir A-horizon (R-A_h) and Reservoir B-horizon (R-B_h) is about 70ft. (21m) in Osl-1. In Osl-2, R-A_h is about 70ft. (21m) while R-B_h is 100ft. (30m). Across the wells, R-A_h has a total value of 171.944acres (67×104m^2) for Ad, with 80.767acres (33 ×104m^2), 45.110acres (18×104m^2) and 46.067acres (19 ×104m^2) for A_{d-1}, A_{d-2} and A_{d-3} respectively. Similarly, R-Bh has a total value of 206.387acres (83.5×104 m^2) for Ad with 94.204acres (38 ×104 m^2), 24.320acres (1×104 m^2) and 87.863acres (36 ×104m^2) for A_{d-1}, A_{d-2} and A_{d-3} respectively. The sum of the drainage areas (A_{d-1} + A_{d-2} + A_{d-3}) on R-A_h is 172acres (69.6×104 m^2) and that of R-B_h is 206 acres (83.4×104 m^2). After all, the way the well logs were carefully tied to the seismic sections to generate didactic images of the reservoirs' depths and drainage areas have assisted to boost the confidence of the interpretation. Hence, the doubt regarding the availability of hydrocarbon, depths to the top and bottom of the hydrocarbon reservoirs and the drainage areas is reduced.

6. CONCLUSION

The 3-D seismic sections with wire-line logs have been used as complementary tools to successfully evaluate the hydrocarbon viability of Osl-1 and Osl-2 in Osland oil and gas field. The didactic figures of the well to seismic tie (W-S_T) presented herein has assisted to amplify the hydrocarbon horizons and provide high-resolution images of the reservoirs. W-S_T shows that the depth of occurrence and the travel times of seismic waves at the interface between media having different velocities/densities are the same both on the well logs and on seismic sections. The structural maps helped in delineating the drainage area (A_d) of the fields, but qualitative evaluation of the formation using well logs provided the vertical extent (thickness) of the reservoir. The sum of the pay thicknesses calculated for Osl-1 and Osl-2 is 310ft. (94.5m) for both reservoirs across the wells, and the sum of the drainage areas (A_{d-1}, A_{d-2}, and A_{d-3}) is 378.331acres (153×104 m^2). These values are significant. The two tools are quite distinct yet complementary in the evaluation of the studied field. When they are both available, it is important they are engaged for the evaluation of formation in other to minimize risk. There may be little or no doubts about the percentages of the correctness of each of the A_d calculated for each of the delineated portions, but the depths of occurrences of the pay thicknesses of the other points recommended for developmental wells may not be accurate. This is because; until those portions are penetrated by wells, one cannot say for sure the thicknesses of the reservoir sands in those areas. Therefore, there are possibilities that the reservoirs are thicker (or otherwise) in those portions. In the same vein, this work is not establishing that the developmental wells must be sited at the recommended points herein. The points are recommended based on the delineated drainage areas and the structural highs. Therefore, under field/technical conditions the wells can be sited at other points taken to be more convenient within the highlighted drainage areas. Furthermore, the two exploratory wells (wildcats) (Osl-1 and Osl-2), can also function as developmental wells. This work has assisted to increase the confidence concerning the hydrocarbon viability of the selected reservoirs, hence, reducing uncertainty regarding the portions of the field that are saturated with hydrocarbons, pay thicknesses and drainage areas.

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APPENDIX E

The Relevance of Porosity in the Evaluation of Hydrocarbon Reservoirs

Conference paper (Oral presentation 44027), 9th Congress of the Balkan Geophysical Society 5-9 November 2017, Antalya, Turkey.

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44027

The Relevance of Porosity in the Evaluation of Hydrocarbon Reservoirs

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Summary

This work is intended to encourage the direct computation of porosity (Φ) in the equations for the permeability (K), fluid flow index (FFI), reservoir quality index (RQI) and flow zone indicator (FZI). These parameters are always determined with aid of other expressions that are initially calculated based on one or two other factors and porosity. Porosity is a very important parameter, it is advisable to avoid approximating it over a range of equations before it is indirectly engaged. This could help to minimise underestimation/overestimation errors. Porosity was optimised by using it as the only variable among other inputs in the modified FFI, K, RQI and FZI expressions to help evaluate the hydrocarbon potential and flow units of two reservoirs. The equations for relative water permeability (Kwr) and relative oil permeability (Kor) were modified and used to predict the water cut (Cw) of another reservoir. A sensitivity analysis shows that the change in tortuosity factor does not have a significant effect on the results. Therefore, alternative equations were presented for these parameters for use mainly in sandstone units. The curves were generated based on these expressions and are recommendable for use as quick-look models.

Introduction

Porosity is an influential parameter in the petrophysical and volumetric evaluation and the majority of the reservoirs physical characteristics are not completely expressed without the use of porosity. The relationship between porosity and reservoir's flow units is very effective for explaining reservoirs' geological attributes such as grain sizes and sorting, shale content, cementation, consolidation of rocks, pore sizes and interconnectivity among others [Schlumbeger 1989; Asquith and Krygowski. 2004; Tiab and Donaldson 2012]. The predictability of the occurrence of hydrocarbon in the reservoirs and recoverability of hydrocarbon from the reservoirs are dependent on these attributes. Free fluid index (FFI), permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) are the parameters with which the stated attributes are evaluated. These parameters are directly or indirectly dependent upon porosity and one another.

Porosity plays a major role in formation evaluation and when it is well calculated and harnessed, it could present a way of reducing risk. This work suggests a way of optimising porosity for formation evaluation by presenting equations (FFI, K, RQI and FZI) that have the porosity as the only variable. The relevance of the optimisation of porosity for formation evaluation cannot be overemphasised. In volumetric estimations, for instance, every other parameter been all right, 0.05 to 0.1 (5 – 10%) increase or decrease in porosity value could result in a notable increase or decrease in the computed volumes of hydrocarbons in place. Similarly, in qualitative evaluations the expression for FZI is dependent upon RQI, which is dependent upon K. In the same vein, K is dependent upon S_{wirr} and/or FFI, both S_{wirr} and FFI are dependent upon F while F is dependent upon Φ. If one must follow the computation in steps from the determination of F, Φ will be approximated over a range of equations, because most of these equations never give their results in whole figures. Errors due to estimation are always undesirable, especially when it comes to volumetric analysis and other decision dependent calculations, where overestimation or underestimation error as low as ±0.05 can result in a notable difference. This can bring about risk and uncertainty. As such, traditional expressions (FFI, K, RQI and FZI) were modified for use in sandstone hydrocarbon reservoirs unit. Similarly, the equations for water relative permeability (K_{wr}) and oil relative permeability (K_{or}) were modified and used to predict the anticipated volumes of water-cut (C_w), which will be produced with the hydrocarbon in the reservoir. Two other factors associated with these equations are the exponent of porosity (m) and the factor of tortuosity (a). Usually, the exponent of porosity is taken as 2 in sandstones and the factor of tortuosity has a range of 0.6 to 1.0. This evaluation looks at presenting equations and models involving porosity as the only variable input. Therefore a sensitivity analysis to investigate the change in tortuosity factor was carried out. It showed that the change does not have a significant effect on the results. Hence, alternative equations with porosity as the only variable input were presented for these parameters for use mainly in sandstone units. Curves were generated based on these expressions and are recommendable for use as quick-look models for the estimation of these parameters.

Materials and Methods

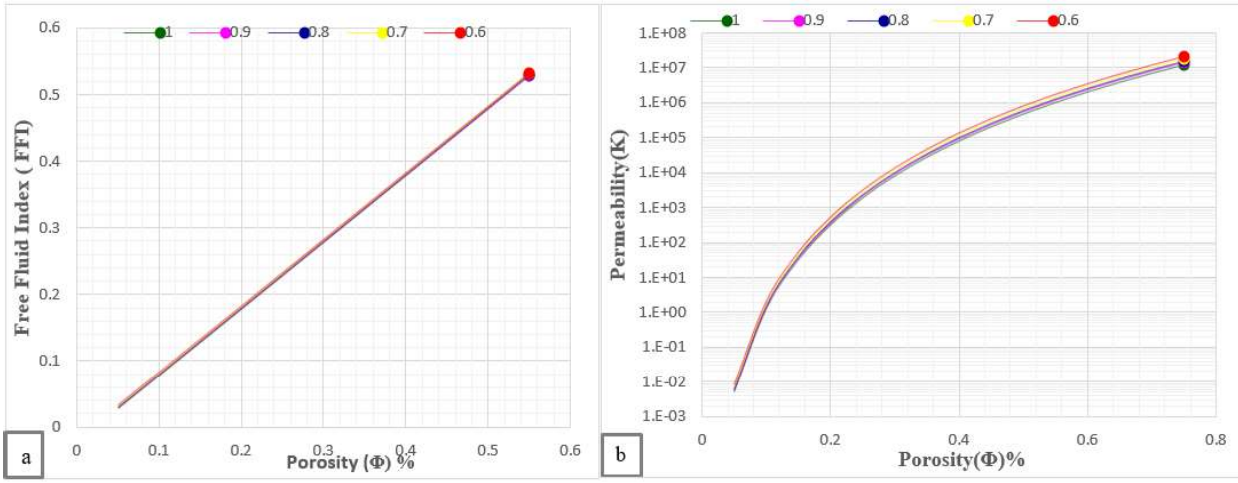
Gamma-ray log (GR), deep laterolog (LLD), water saturation log (SW), neutron porosity log (NPHI) and density tool (ROHB) were engaged in this work. The evaluated parameters are; free fluid index (FFI), permeability (K), reservoir quality index (RQI), flow zone indicator (FZI), water relative permeability (K_{wr}) and oil relative permeability (K_{or}).The basic methods herein are:

(a) modification of traditional equations for the relevant parameters to help provide alternative expressions in sandstone units;
(b) sensitivity analysis on the expressions in (a) above using different values of tortuosity factor to help verify the influence of its change on parameters;
(c) redefinition of the equations using the idea derived from (b) above;
(d) determination of porosity from well logs to aid the computation of parameters across of the selected reservoirs with the aid of the equations as in (c) above;
(e) generation of curves showing permeability/porosity, reservoir quality index/porosity and flow zone indicator/porosity relationships based on the results as in (d) above and

(f) determination of $RQI_{average}$ and $FZI_{average}$ based on the three expressions for each of them, to help generate a combined model for the estimation of the reservoirs flow units.

The traditional equations (Schlumbeger 1989; Tiab and Donaldson 2012) for FFI, K, RQI, FZI, and relative fluids permeability *(K_{wr} and K_{or}),* were modified such that, expressions having tortuosity factor (a) and porosity (Φ) were initially presented for each of them. Three alternative expressions were presented for each of RQI and FZI based on Tixier, Timur and Coates permeability equations

Sensitivity analysis on FFI and K (K_{mtm}, K_{mtx} and K_{mc}) considering the possible range (0.6 to 1.0) of tortuosity factor (a). This analysis shows that the change in the factor tortuosity has no significant influence on FFI and K values as shown in Figures 1a and 1b.



Figures 1 (a): The influence of the change in the factor of tortuosity on FFI
(b): The influence of the change in the factor of tortuosity on K.

The results of the sensitivity analysis coupled with the fact that the reservoirs present some shale influences at regular intervals, the average (0.8) of the range (0.6 to 1) of tortuosity factor was used to redefine the equations for the reservoirs, such that only porosity dependent expressions were presented as shown in equations 1 to 10.

Free fluid index (FFI); FFI = Φ – 0.02 (1)

Permeability (K); $(K_{mtx})^{0.5} = \frac{11180\Phi^4}{0.894}$ (Based on Tixier's idea) (2)

$$(K_{mtm})^{0.5} = \frac{4472\Phi^{3.25}}{0.894} \text{ (Based on Timur's idea)} \quad (3)$$

$$(K_{mc})^{0.5} = \frac{3130.4\Phi^3 - 62.58\Phi^2}{0.894} \text{ (Based on Coates'idea)} \quad (4)$$

Reservoir quality index (RQI); $RQI_{aa} = \frac{351\Phi^4}{0.894\Phi^{0.5}}$ (Based on Tiab and Donaldson idea) (5)

$$RQI_{ab} = \frac{140.4\Phi^{3.25}}{0.894\Phi^{0.5}} \quad (6)$$

$$RQI_{ac} = \frac{98.29\Phi^3 - 1.965\Phi^2}{0.894\Phi^{0.5}} \quad (7)$$

[RQI_{aa}, RQI_{ab} and RQI_{ac} are alternative expressions for RQI, modified with K_{mtx}, K_{mtm} and K_{mc}]

Flow zone indicator (FZI); $FZI_{aa} = \frac{351\Phi^4}{(0.894\Phi^{0.5})\Phi_r}$ (Based on Tiab and Donaldson idea) (8)

$$FZI_{ab} = \frac{140.4\Phi^{3.25}}{(0.894\Phi^{0.5})\Phi_r} \quad (9)$$

$$FZI_{ac} = \frac{(98.29\Phi^3 - 1.965\Phi^2)}{(0.894\Phi^{0.5})\Phi_r} \quad (10)$$

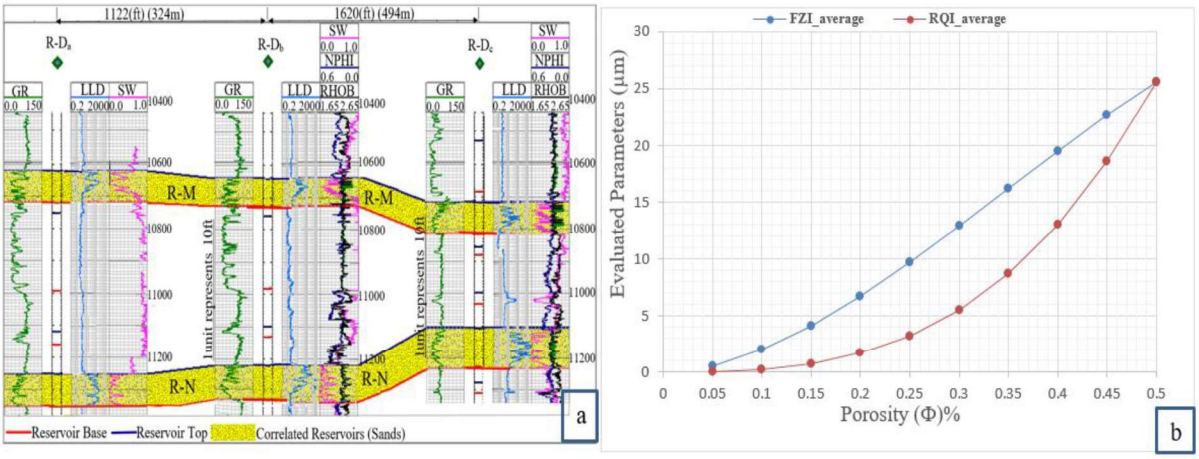
[FZI_{aa}, FZI_{ab} and FZI_{ac} are alternative expressions for FZI, modified with RQI_{aa}, RQI_{ab} and RQI_{ac}]
Where; a = the factor of tortuosity, Φ = porosity, Φ_r = ratio of the derived porosity and the difference between the maximum derivable value (100%) of porosity and the derived porosity.

These modified expressions herein were tested and compared with the results computed using the traditional equations and similar values were obtained.

Estimation of porosity (Φ), free fluid index (FFI) Permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI).
The objective of this aspect is to predict the flow units of Reservoirs (R-M and R-N) mapped across Wells R-D_a, R-D_b and R-D_c (Fig. 2a) via the evaluation of FFI, K, RQI and FZI. Φ values were obtained from density log (RHOB) at intervals of 10ft and corrected for the influence of shale using equation 11.

$$\Phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{sh}\left[\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f}\right] \quad (11)$$

A range of values from 0 to 50% (0 to 0.50) was used for porosity to compute FFI, K, RQI and FZI, such that the values of these parameters across the selected reservoirs were extracted from the results. The values of RQI_{aa}, RQI_{ab} and RQI_{ac} were averaged with the corresponding values FZI_{aa}, FZI_{ab} and FZI_{ac}. $RQI_{average}$ and $FZI_{average}$ were plotted against porosity to help generate curves (combined model) for RQI and FZI estimations of the wells (Fig. 2b).



$RQI_{average}$ = Average of the values of RQI_{aa}, RQI_{ab} and RQI_{ac}
$FZI_{average}$ = Average of the values of FZI_{aa}, FZI_{ab} and FZI_{ac}
Figure 2 (a): Correlated reservoirs across the wells.
(b): Combined quick-look model for the prediction of RQI and FZI

Results; Φ = 0.24, FFI = 0.22, K = 1721mD, 2343mD, and 1969mD for K_{mtx}, K_{mtm} and K_{mc} respectively, RQI =2.95µm and FZI = 9.00µm.

Volumetric estimations
Volumetric estimations were carried out in another reservoir (X) selected across the two wells (D_1 and D_2). The seismic data and a recovery factor of 32% of these wells were provided by the data source. The objective of this aspect is to calculate the water-cut (C_w) anticipated to be produced with the oil in Reservoir X. Equations 12 and 13 were used for the estimation of recoverable volumes of oil and gas.

$$V_{Ro} = \frac{OIP}{FVF} \times R.f \quad (12)$$

$$(V_{Rg}) = \frac{GIP}{FVF} \times R.f \times \frac{0.43 \times depth}{15} \quad (13)$$

[OIP = Oil in place, GIP = Gas in place, FVF = Formation volume factor and RF = Recovery factor]
The modified relative water and oil permeability (K_{wr} and K_{or}) equations (14 and 15) were used as inputs in a simplified water cut (C_w) equation (16) to help predict the associated water production.

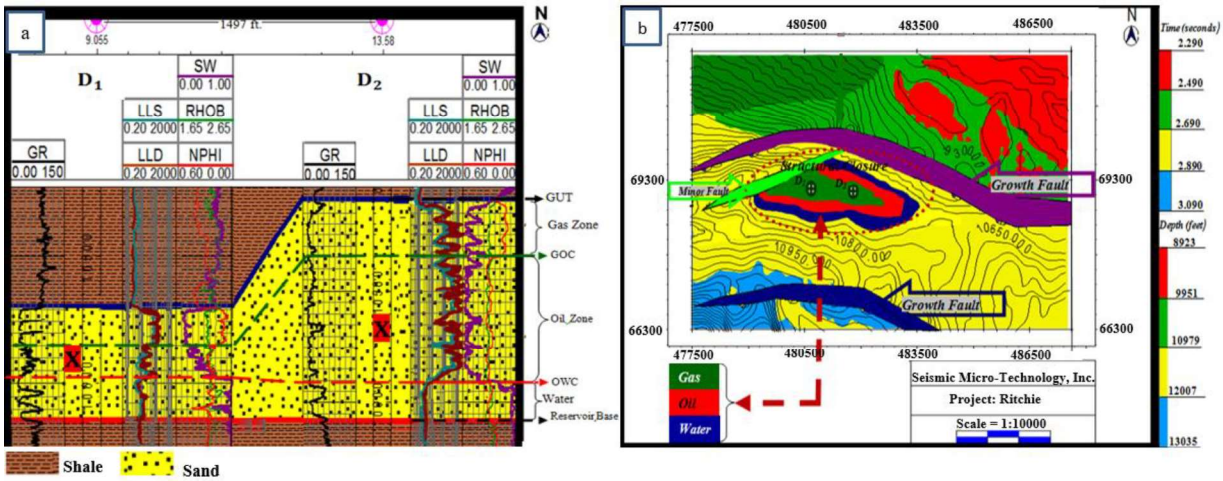
Fluids relative permeability; $K_{wr} = \left[\frac{44.72\Phi S_w - a^{0.5}}{44.72\Phi - 0.8^{0.5}}\right]^3$ (14)

$$K_{or} = \frac{2000\Phi^2 S_h^{2.1}}{2000\Phi^2 - 0.8} \quad (15)$$

Water-cut; $c_w = \frac{K_{rw}\mu_o}{K_{rw}\mu_o + K_{or}\mu_w}$ (16)

[μ_w = water viscosity and μ_o = oil viscosity]

Volumes of recoverable oil and gas (V_{Ro} and V_{Rg}) were estimated in another reservoir (X) that was selected across two wells (D_1 and D_2) as shown in Figures 3a and 3b.



Figures 3 (a); Correlated wells showing suites of wire-line logs, reservoir thickness and fluids contact (b); Depth structural map showing reservoir area extent, fluids contact and trapping mechanism.

Results;

Reservoirs	V_{Ro} *bbl*	V_{wc} *bbl*
XD_1	1,984,835.73	372,740.20
XD_2	7,391,073.53	127,873.00
Total	**9,375,909.26**	**499,513.20**

Reservoirs	V_{Rg} *cu.ft*
XD_1	**2,298,936,564.00**
XD_2	**5,393,942,368.00**

Conclusion

It is believed that this work has presented a way of optimising porosity to aid the qualitative and volumetric estimations herein. The estimation of FFI, K, RQI and FZI were all computed involving the use of porosity as the only variable. This has helped to avoid the approximation of porosity over a range of equations. Possible errors of underestimations and/or overestimations of porosity with the use of traditional equations are presumed to have been avoided. The results suggested that the reservoirs (R-M and R-M) across wells ($R\text{-}D_a$, $R\text{-}D_b$ and $R\text{-}D_c$) show significant values for the evaluated parameters. Therefore, the flow units are expected to be good and significant recovery rates are anticipated within the reservoirs. The volumes of water-cuts in Reservoir X across Well D_1 and Well D_2 are within the acceptable range.

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APPENDIX F

A Simplified Approach to Hydraulic Units' Prediction with the aid of Wireline Logs

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A Simplified Approach to Hydraulic Units' Prediction with the aid of Wireline Logs

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Abstract

Wireline logs data are quite handy and can be preserved over a longer period when compared with core samples, as such; they are readily available for researchers. Nonetheless, the choice of the values of the factor of tortuosity **(a)** and cementation factor **(m)** when using wireline logs alone for evaluation could vary, depending on the discretion of one researcher to the other. Hence, with the same data for any evaluation by different researchers, there are possibilities of seeing slightly-notableto-notable differences in the results. This work tries to review the uses of the values of a and m over time, and suggest modified equations that are not dependent on the direct computation of formation factor **(F)** and irreducible water saturation **(S_{wiir}).** For details studies, **F**, **S_{wiir},** free fluid index **(FFI)** and porosity **(Φ)** are usually evaluated at some intervals of depths. This study is intended to reduce the variation in the results that may come with the choice of the values of these factors (**a** and **m**) within the same formation and minimize drudgery. The direct relationship between porosity and other parameters, such as permeability **(K)**, reservoir quality index **(RQI)** and flow zone indicator **(FZI**) was helpful to simplify the equation for each of them. **FFI** is a measure of the moveable hydrocarbon, and **RQI** and **FZI** are used to predict the reservoirs flow units. A simplified approach involving the suggestion of handier equations for **FFI, K, RQI,** and **FZI**, with quick-look models for the prediction of flow units, was presented.

Introduction

Many scholars/geoscientists do not truly believe in the use of wireline logs alone for the evaluation of hydrocarbon reservoirs. Most people normally trust the use of laboratory core data and wireline logs for comparative studies. This perhaps is because it is believed that most of the fundamental parameters are best estimated by laboratory core analysis. Having this in mind, this presentation will try to suggest ways by which flow units can be easily predicted with the use of wireline logs and the choice of the use of the values of the factor of tortuosity **(a)** and cementation factor **(m)** will also be discussed. However, this could also ensure that some steps that normally make the approach quite monotonous and often result in drudgery are avoided. Most times, in the petrophysical evaluation, some basic parameters are calculated before others. It becomes quite tedious if this parameter must be manually computed at intervals of some depths (e.g. at every 5ft or 10ft intervals) within formations for detail evaluations.

It is true that workstations (e.g Petrel and Kingdom Suite Software) can also be used for the computation of petrophysical parameters. However, most of these workstations will effectively average these parameters for the whole formation. Therefore, when details studies (Petrophysical, and other related studies) are required, such that some basic parameters [formation factor **(F),** irreducible water saturation **(S_{wiir}),** free fluid index **(FFI)** and porosity (Φ)] are needed to be computed, it is usually recommended that they are computed manually at desired intervals based on the purpose of the evaluation. The need for the use of the direct relationships between porosity and other parameters such as permeability **(K),** reservoir quality index **(RQI)** and flow zone indicator **(FZI)** might be helpful to simplify most of these equations. **FFI** is a measure of the moveable hydrocarbon (Schlumberger 1989). **RQI** and **FZI** are used to explain other reservoirs' attributes such as grain sizes and sorting, shale content, cementation, consolidation of rocks, pore sizes and interconnectivity (Tiab and Donaldson, 2012).

However, the choice of the values of the factor of tortuosity **(a)** and cementation factor **(m)** must be properly addressed. If this is investigated, there is a good possibility that handy equations can be suggested. Such that, simplified expressions for hydraulic units prediction will be presented. As such, drudgery that may come with the use of several equations before the investigated parameters are computed and computational errors will be reduced. This work will further stress the need for the computation of these parameters, by assuming certain range of values of **a** and **m** for sandstone and carbonate reservoir rocks. It is intended herein to review the concept of the use of **a** and **m.** The influence of the changes in these factors on other parameters will be compared over a range of equations for flow units' evaluation in consolidated, unconsolidated and carbonate reservoir rocks. In the end, suggestions to the use of simplified equations for some considered parameters within these reservoir rocks would be presented.

Correlation between formation factors (F), cementation exponent (m) and tortuosity factor (a)

Generally, Formation factor (F) is given as;

$$\mathbf{F} = \frac{\mathbf{a}}{\Phi^{\mathbf{m}}} \qquad (1)$$

Where; porosity (Φ) can be derived from laboratory core analysis or suitable wireline logs.

Carothers (1968) suggested that factor of tortuosity **(a)** and cementation factor **(m)** should be taken as 1.45 and 1.54 for average sands, 1.45 and 1.70 for shaly sands, 1.65 and 1.33 for calcareous sands and as 0.85 and 2.14 for carbonate rocks respectively. Keller (1987) based on the degree of cementation, suggested that the respective values for **a** and **m** should be taken as 0.88 and 1.37 in weakly detrital cemented rock, 0.62 and 1.72 in moderately well cemented and 0.62 and 1.95 in well-cemented rocks. In the same vein, Asquith and Gibson (1982) believe that **a** and **m** should be taken as 1.0 and 2.0 for carbonate rocks, 0.81 and 2 for consolidated sands and 0.62 and 2.15 for unconsolidated sandstones respectively. Others, including a more recent author (Schlumberger, 1989: Tiab and Donaldson, 2012) did not really put more emphasis on the choice of the values for **a** and **m**. They simply refer to equation 2 and 3 as Archie equation and Humble formula respectively.

$$\mathbf{F} = \frac{1}{\Phi^2} \qquad (2)$$

$$\mathbf{F} = \frac{0.62}{\Phi^{2.15}} \qquad (3)$$

Similarly, it is also taken (Schlumberger, 1989: Tiab and Donaldson, 2012) that in a way to eliminate the fractional numerator in the equation 3, the Humble formula is given as;

$$\mathbf{F} = \frac{0.81}{\Phi^2} \qquad (4)$$

Supposing, cementation factor mostly varies from 1.90 to 2.15, while tortuosity factor ranges from 0.6 to 1.0 in both consolidated and unconsolidated rocks. It is, therefore; assumed herein that **m** should be 2.15 in unconsolidated rock and 1.90 in carbonates and consolidated sands. Such that;

$$\mathbf{F} = \frac{\mathbf{a}}{\Phi^{2.15}} \text{ (Unconsolidated rocks)} \qquad (5)$$

$$\mathbf{F} = \frac{\mathbf{a}}{\Phi^{1.90}} \text{ (Carbonates and Consolidated)} \qquad (6)$$

Such that irreducible water saturation **(S_{wirr})** is given as;

$$s_{wirr} = \frac{a^{o.5}}{\sqrt{2000\Phi^{2.15}}} \text{ (Unconsolidated rocks)} \qquad (7)$$

$$s_{wirr} = \frac{a^{o.5}}{\sqrt{2000\Phi^{1.9}}} \text{ (Carbonates and Consolidated)} \qquad (8)$$

Considering a range of porosity (Φ) values (0.05 to 0.6), factor of tortuosity **(a)** values (0.6 to 1.0) and cementation factor **(m)** of 1.90 and 2.15. Irreducible water saturation (S_{wirr})/ porosity (Φ) plots were generated to check the effect of the change in the factor of tortuosity considering, when **m** is 1.90 (Figure 1) and when **m** is 2.15 (Figure 2). In the evaluation, the scenarios seem to be approximately the same, especially at lower values of S_{wirr} with the corresponding higher values of Φ.

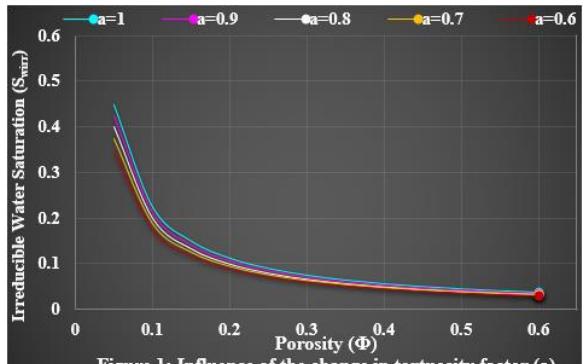

Figure 1: Influence of the change in tortuosity factor (a) on s_{wirr} using a cementation factor of 1.90

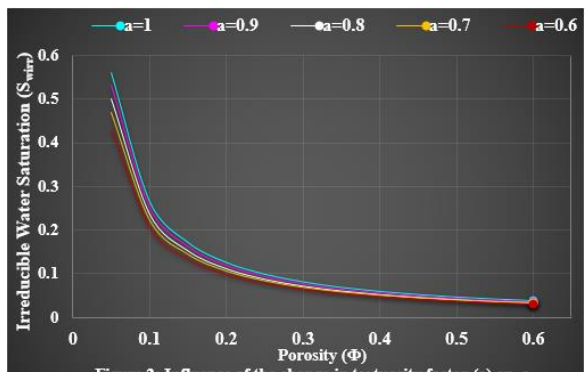

Figure 2: Influence of the change in tortuosity factor (a) on s_{wirr} using a cementation factor of 2.15

At higher values of S_{wirr} with the corresponding lower values of Φ, there are notable differences between the curves considering the range of values (0.6 to 1.0) for each of the scenarios (1.90 and 2.15). The curves with the use of 1.90 are also different a bit from those with the use of 2.15 at higher S_{wirr} values with the corresponding lower values of Φ.

The values for **S_{wirr}** with the use of 1.90 and 2.15 for cementation factor were averaged for each of the scenarios. Such that single correlation plots, one for unconsolidated rocks and the other for consolidated rocks were presented (Figure 3). The irreducible water saturation (S_{wirr})/porosity (Φ) plots show that below 0.1 values of S_{wirr} and above 0.2 of Φ, the curves are approximately the same. Porosity values for limestone and sandstone are usually within the range of 0.1 to 0.45.

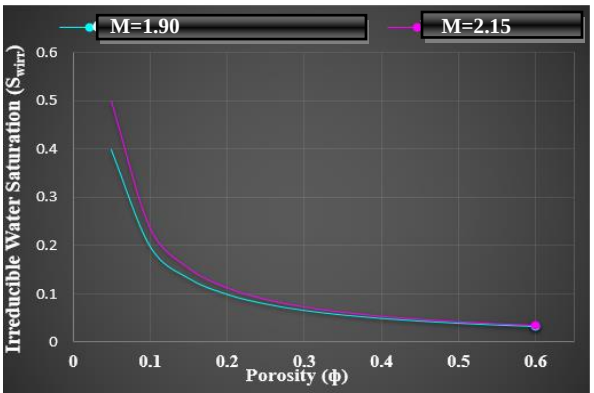

Figure 3: Averaged s_{wirr}/ϕ correlation plots

It was observed (Richardson and Taioli, personal communication, 2017) that there were no significant changes in the values of K when tortuosity factor was varied from 0.6 to 1.0, considering a cementation factor of 2 and tortuosity factor of 8 (Figure 4).

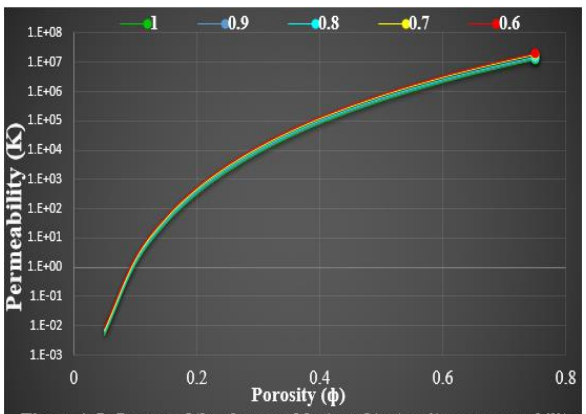

Figure 4: Influence of the change of factor of tortuosity on permeability

Therefore, modified expressions for permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) based on Timur (1968) and Tiab and Donaldon (2012) expressions were suggested as shown in equation 9, 10 and 11 respectively.

$$(K_{mt})^{0.5} = \frac{4472\Phi^{3.25}}{0.894} \quad (9)$$

$$RQI_m = \frac{140.4\Phi^{3.25}}{0.894\Phi^{0.5}} \quad (10)$$

$$FZI_m = \frac{140.4\Phi^{3.25}}{(0.894\Phi^{0.5})\Phi_r} \quad (11)$$

Where; K_{mt} = permeability modified from Timur (1968)
RQI_m = reservoir quality index modified from Tiab and Donaldon (2012) based on K_{mt}
FZI_m = flow zone indicator modified from Tiab and Donaldon (2012) based on RQI_m and
Φ_r = porosity ratio, it is expressed by;

$$\Phi_r = \frac{\Phi}{1-\Phi} \quad (12)$$

In the same vein, comparative analysis was carried out with cementation factor of 1.90 and 2.15 using a range of values (1, 0.9, 0.8, 0.7 and 0.6) of the factor of tortuosity (a) for each in the equations (13 and 14) for free fluids index (FFI) modified from Schlumberger (1989).

$$FFI = \Phi\left(1 - \frac{a^{o.5}}{\sqrt{2000\Phi^{2.15}}}\right) \quad (13)$$

(Carbonates and Consolidated)

$$FFI = \Phi\left(1 - \frac{a^{o.5}}{\sqrt{2000\Phi^{1.90}}}\right) \quad (14)$$

(Unconsolidated)

FFI values were plotted against Φ (Figure 5), based on these equations.

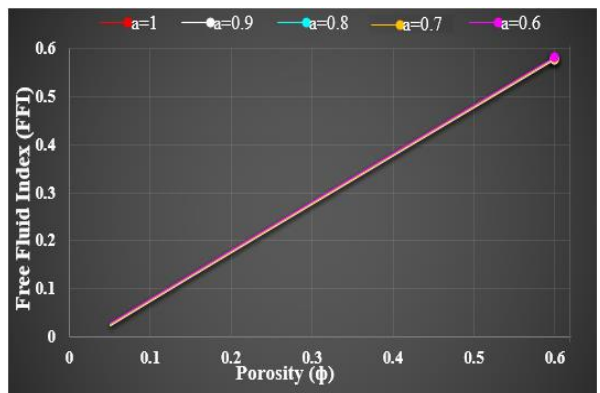

Figure 5: Influence of the change in the factor of tortuosity on FFI considering a range of values (1.90-2.15) of cementation factor

There were no notable differences in the plots considering each of the two equations for FFI. The results were the same with the use of cementation factor of 1.90 and 2.15 each with varied values (1.0 to 6.0) of tortuosity factor (a). The analysis above suggests that, if each of the free fluid index (FFI) values is approximated to the nearest 0.00 in all the scenarios, FFI is consistently about 0.02 less than the corresponding Φ value. Therefore, the equation for FFI can be simplified as;

$$\mathbf{FFI = \Phi - 0.02} \quad (15)$$

Such that an alternative expression for permeability (K) modified from Coates and Denoo (1981) is given as;

$$K_{cd} = 10^4 \Phi^4 \frac{(\Phi - 0.02)^2}{0.0004} \quad (16)$$

Consequently, RQI and FZI can therefore, be expressed as;

$$RQI_{ma} = \frac{3.14\Phi^2(\Phi - 0.02)}{0.02\Phi^{0.5}} \quad (17)$$

$$FZI_{ma} = \frac{3.14\Phi^2(\Phi - 0.02)}{(0.02\Phi^{0.5})\Phi_r} \quad (18)$$

Where; K_{cd} = Alternative expression for permeability modified from Coates and Denoo (1981)

RQI_{ma} = Alternative expression for reservoir quality index modified from Tiab and Donaldon (2012) based on K_{cd}

FZI_{ma} = Alternative expression for flow zone indicator modified from Tiab and Donaldon (2012) based on RQI_{ma} and

Φ_r = porosity ratio

With these equations, porosity value derived from wireline logs can easily be used to calculate each of these parameters. Hence, the drudgery and computational errors that may come with the use of the traditional expressions could be reduced. More so, the approximation of other dependent parameters before K, RQI and FZI are computed will be avoided.

Quick-look models were generated based on these equations to facilitate the prediction of flow units.The RQI/Φ relationship is shown in Figure 6, while the FZI/Φ relationship is shown in Figure 7.

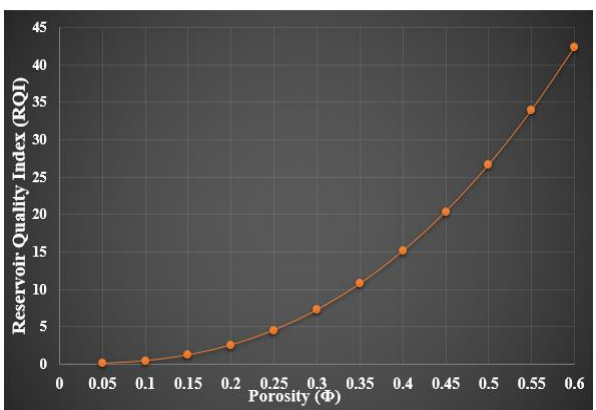

Figure 6: Reservoir Quality Index (RQI)/ Porosity (Φ) Relationship.

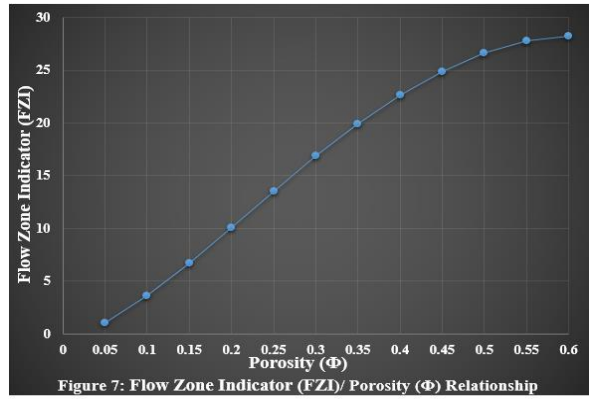

Figure 7: Flow Zone Indicator (FZI)/ Porosity (Φ) Relationship

Conclusion

In an attempt to suggest ways by which the drudgery and computational errors that could result from the use of some equations, a simplified approach to hydraulic units' evaluations was studied. Cementation factor **(m)** of 1.90 for unconsolidated rocks and 2.15 for carbonates and consolidated rocks, and tortuosity factor range of 0.6 to 1.0 were considered herein. The evaluations show that the use of the different values within the selected ranges of values of each of the parameters, do not show significant influences on the results of the free fluid index (FFI), permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI). However, the changes in the use of **a** and **m** show notable differences at the higher values of irreducible water saturation (S_{wirr}) with the corresponding lower values of Φ. The results are almost the same at lower values of S_{wirr} with the corresponding higher values of porosity (Φ). Therefore, it is assumed herein that when an investigation ends with the evaluation of S_{wirr} alone with the use of wireline alone, one can worry a bit about the choice of the values of **a** and **m** depending on the type of rocks that are being evaluated. Nonetheless, for quick prediction, any value within the ranges of values considered herein (0.6 to 1.0 for tortuosity factor and 1.90 to 2.15 for cementation factor) could yield estimated results in both consolidated and unconsolidated sands. The equations and RQI/Φ and FZI/Φ plots presented in this evaluation are quite handy for the prediction of flow units both in consolidated and unconsolidated rocks. It is supported herein that this evaluation has suggested a simplified approach to the use of wireline logs for the prediction of flow units in carbonates and sandstones hydrocarbon reservoirs.

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Biography

Richardson M. Abraham-A. (Ritchie) has completed his M.Tech (Exploration Geophysics) and at the time of writing this abstract, he is completing his PhD (TWAS/CNPq scholarship), under the supervision of Prof. Fabio Taioli at the Institute of Energy and Environment (IEE), University of Sao Paulo (USP), Brazil. He published two papers before he got the TWAS/CNPq Scholarship. During the PhD period, he published three additional articles in reputed journals and two conference papers. The paired reviewers (Brazilian Journal of Geology) are reviewing his fourth paper (also from his PhD work) for possible publication. His main area of interest is petroleum geology/geophysics with the bias for petrophysics and seismic methods for hydrocarbon exploration. He is also knowledgeable in the areas of environmental/engineering geophysics and groundwater geophysics.