Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278
https://dx.doi.org/10.4314/sa.v22i1.22
© Faculty of Science, University of Port Harcourt, Printed in Nigeria
ISSN 1118 – 1931

HYDROCARBON EVALUATION AND DISTRIBUTION IN WELL-X AND WELL-Y IN THE NIGER DELTA BASIN: FINDINGS AND VALIDATION THROUGH POROSITY COMPARISON

[*] **Maju-Oyovwikowhe, E.G. and Osayande, A.D.**
[*]Department of Geology, University of Benin, P. M. B 1154, Benin City, Edo State, Nigeria.
Geology and Mining Technology, University of PortHarcourt, PortHarcourt, Rivers State, Nigeria
[*]Corresponding author email: efetobore.maju@uniben.edu

Received: 16-03-2023
Accepted: 28-04-2023

ABSTRACT

The aim of this study is to integrate well logs and core data to identify reservoir characteristics and determine the reservoir's petrophysical properties in order to improve the understanding of the reservoir and provide valuable information for reservoir management. Wells X and Y of the 'SCOJAS' Field in the Niger Delta Basin of Nigeria were analyzed using Gamma ray logs, Resistivity logs, Sonic, Neutron and Density Logs. The obtained results were compared with core data from the wells to verify their accuracy. Porosity values for Wells X and Y fall within the range typically observed in sedimentary rocks, with Well Y having higher values. Hydrocarbons were detected in all reservoirs except reservoir zone 1b in both Well-X (12 reservoirs) and Well-Y (7 reservoirs). In Well-X, oil was identified in 5 reservoir zones while in Well-Y, oil was present in 2 reservoir zones. The remaining zones in both wells contained gas. To validate the results further, a comparison was made with the porosity of selected fields in the Niger Delta Basin and the general porosity of the Basin. Well X has a porosity range of 2.7% to 20.8%, which is generally lower than the reported porosity range Well Y has a porosity range of 19.90% to 24.38%, which falls at the upper end of the reported porosity range. Comparing previous works and data from other fields provides important validation for the findings of the study, which is crucial in the oil and gas industry for making informed decisions about exploration and production.

Keywords: Hydrocarbons, Reservoirs, Well logs, Core data, Porosity, Validation

INTRODUCTION

This study involves the analysis of two wells, Well-X and Well-Y, in the Niger Delta Basin of Nigeria to determine the presence and distribution of hydrocarbons in the reservoirs. The Niger Delta Basin is one of the largest hydrocarbon-bearing basins in the world, with significant oil and gas reserves. The exploration and production of these hydrocarbons require accurate evaluation of the subsurface geology, which can be done through well logging and core analysis.

Well logging is a technique used to measure various parameters of a wellbore, such as the electrical, nuclear, acoustic, and seismic properties of the rocks. These measurements are used to identify the lithology, porosity, permeability, fluid saturation, and other characteristics of the subsurface formations. Core analysis involves the examination and testing of rock samples extracted from the wellbore to provide further insight into the properties and composition of the reservoir. Well logs and core data provide essential information about subsurface formations and their properties, including lithology, porosity, and permeability, which are crucial in determining hydrocarbon distribution.

Studies have shown that the combination of well logs and core data provides a more accurate and reliable evaluation of hydrocarbon reservoirs in the Niger Delta Basin. For instance, a study by Uko and Ekwere (2017) used well logs and core data to evaluate the hydrocarbon potential of a field in the basin. The study found that the reservoirs were composed of sandstones, shales, and siltstones with good porosity and permeability, and that the hydrocarbons were of good quality. In another study by Oyeyemi et al. (2020), well logs and core data were used to evaluate the hydrocarbon distribution in a field in the Niger Delta Basin. The study found that the reservoirs were composed of sandstones and shales with varying degrees of porosity and permeability. The study also found that the hydrocarbon distribution in the field was affected by structural traps, lithology, and diagenesis.

Ukuedojor and Maju-Oyovwikowhe (2019), used wireline logs (gamma-ray, resistivity, neutron and density) to carry out a study of the volumetric reserve estimate for the D-3 reservoir in the Niger Delta. Results from the study shows that the reservoir contains 15.8 million barrels of oil and 32 billion cubic feet of gas. This study therefore, suggests that there is more gas than oil in the reservoir. In a study by Olasehinde et al. (2019), well log and core data were used to evaluate the hydrocarbon potential of a field in the Niger Delta Basin. The study found that well logging data provided information on the lithology, porosity, permeability, and fluid content of the reservoir, while core data helped to validate the findings and provide additional information on the rock properties and fluid characteristics. Similarly, in a study by Eze et al. (2018), well logging data were used to evaluate the hydrocarbon distribution in a field in the Niger Delta Basin. The study found that the reservoirs were mainly composed of sandstone with varying levels of porosity and permeability. The well logs also showed the presence of hydrocarbons in the reservoirs, with different zones having varying amounts of oil and gas.

Afolabi et al. (2018) used well logs and core data to evaluate the petrophysical properties of reservoirs in the basin, including porosity and permeability. The study found that porosity varied significantly across different reservoirs, with some reservoirs having high porosity and others having low porosity. The study also showed that permeability is closely related to porosity, with high porosity reservoirs exhibiting high permeability. In another study, Oluwasegun et al. (2020) used well logs and core data to evaluate the hydrocarbon potential of the Niger Delta Basin. The study focused on the identification of hydrocarbon-bearing formations and the estimation of hydrocarbon reserves. The study found that hydrocarbon-bearing formations are present in various depths in the basin and that reserves vary significantly across different formations.

Furthermore, the integration of well logs and core data with seismic data has also been utilized in evaluating hydrocarbon distribution in the Niger Delta Basin. For example, Akpabio et al. (2019) used well logs, core data, and seismic data to evaluate the reservoir properties and hydrocarbon distribution in the basin. The study found that the integration of these data sets provided a more accurate and reliable evaluation of reservoir properties and hydrocarbon distribution. Ojo et al. (2020) used well log and core data to evaluate the hydrocarbon potential of the Akata Formation in the Niger Delta Basin. They found that the Akata Formation is a potential source rock for hydrocarbon accumulation in the basin.

Another study by Ayinde et al. (2018) used well log and core data to investigate the reservoir properties of the Agbada Formation in the Niger Delta Basin. The study revealed that the Agbada Formation has high porosity and permeability, making it a good reservoir rock for hydrocarbon accumulation. Similarly, Nwosu et al. (2018) used well log and core data to evaluate the reservoir properties of the Nkporo Formation in the Niger Delta Basin.

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 *https://dx.doi.org/10.4314/sa.v22i1.22*
 ISSN 1118 – 1931

The study showed that the Nkporo Formation has good reservoir properties, with high porosity and permeability, making it a potential hydrocarbon reservoir rock in the basin. Ukuedojor and Maju-Oyovwikowhe (2019) carried out petrophysical evaluation and reservoir geometry analysis of the D-3 sandstone in Idje field of the Niger Delta region using well log suites from ten wells. The study found that the reservoir had a very good porosity and excellent permeability, with an average porosity value of 0.25 and an average permeability value of 3393.69m.

Overall, the use of well log and core data provides valuable information on the hydrocarbon potential and distribution in the Niger Delta Basin. The accuracy of these evaluations can be further improved by comparing the results with data from other fields in the basin, as well as by integrating other geologic and geophysical data.

This study is relevant in the oil and gas industry as it provides important information on the presence and distribution of hydrocarbons in the reservoirs of Well-X and Well-Y. The identification of oil in several reservoir zones indicates the potential for oil production and exploration in these areas. The comparison with the porosity of other fields in the Niger Delta Basin adds further support to the findings of the study and enhances the reliability of the information obtained from well logs.

The contribution to knowledge of this study lies in the validation of the results obtained from well logs and the confirmation of the presence of hydrocarbons in the studied reservoirs. This information can be used by oil and gas companies to make informed decisions on exploration and production activities, which can have significant economic and environmental impacts. Additionally, the comparison with other fields' data provides a broader understanding of the geology and reservoir characteristics of the Niger Delta Basin. This could contribute to advancements in the field of hydrocarbon exploration and production. This, in turn, could have implications for the oil and gas industry and the economy of the region. The aim of this study is to integrate well logs and core data to identify reservoir characteristics and determine the reservoir's petrophysical properties, such as porosity, permeability, and water saturation in order to improve the understanding of the reservoir and provide valuable information for reservoir management.

Location and Geology of the Study Area

The study wells (Well-X and Well-Y) are located in the swamp region of the Niger Delta province, which is situated in the southern part of Nigeria, along the coastline of the Gulf of Guinea. The Niger Delta province is a sedimentary basin that covers an area of about 75,000 km² and is bounded by the Benin flank to the west, the Cameroon flank to the east, and the coastline of the Gulf of Guinea to the south (Ojo and Adekeye, 2019). The province is characterized by a complex network of channels, estuaries, and mangrove swamps, and is known for its high hydrocarbon potential.

Well-X and Well-Y are located in close proximity to the coastline of Niger Delta, with Well-X located about 8 km away from the coastline and Well-Y located about 10 km away (Ako et al., 2016). The proximity of the wells to the coastline is significant, as it influences the depositional environment and sedimentation history of the Niger Delta province. The deltaic sediments that constitute the hydrocarbon-bearing formations in the study area were deposited in a shallow marine environment, which was influenced by the transgressive-regressive cycles of the sea level (Ejedawe, 1991).

The geographical location of the study wells (Figure 1) is important in understanding the hydrocarbon potential of the Niger Delta. The region is known for its prolific hydrocarbon reserves, including both oil and gas, which have been exploited since the discovery of oil in 1956. The study of the geological and geophysical characteristics of the region, including the location of the wells relative to the coastline, helps to identify potential reservoirs and inform exploration and production strategies.

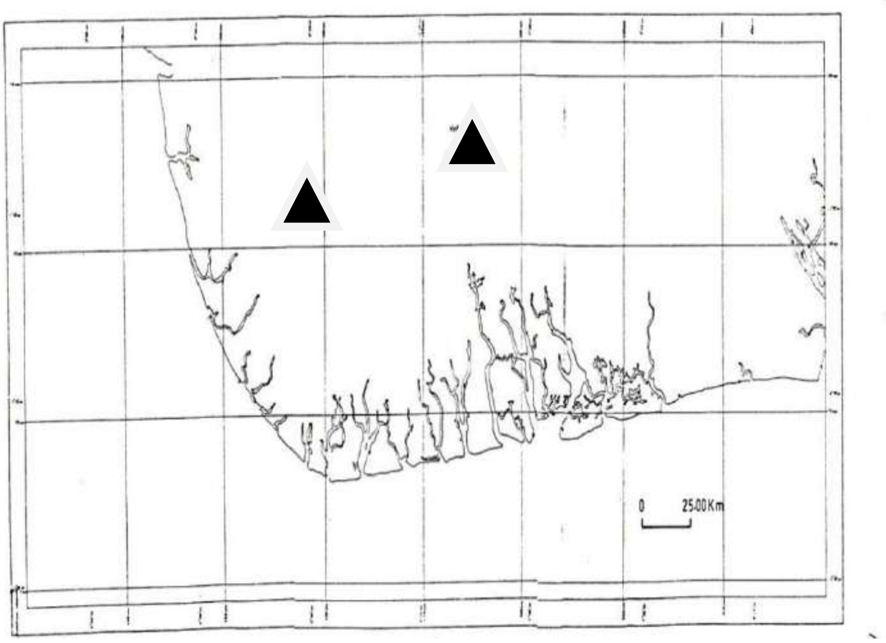


Figure 1: The Geographical Location of the study wells relative to the coastline of Niger Delta. Modified after (Okiotor, 2020)

The Niger Delta Basin is a sedimentary basin located in Nigeria and is known for its extensive hydrocarbon reserves (Onwuka et al., 2019). The basin is characterized by a thick sequence of sedimentary rocks, including sandstones, shales, and siltstones, which were deposited in a deltaic environment (Siren et al., 2018). The sedimentary rocks in the Niger Delta Basin have been found to contain high-quality source rocks, reservoir rocks, and seals, making it a prolific area for oil and gas production (Onwuka et al., 2019).

Lithostratigraphy of Niger Delta*:*

The Niger Delta Basin is a complex depositional environment that has undergone multiple phases of sedimentation, tectonic activity, and erosion (Figure 2). The lithostratigraphy of the Niger Delta Basin can be divided into several units based on their lithology, sedimentary structures, and depositional history (Short and Stauble, 1967).

The oldest unit in the Niger Delta Basin is the Benin Formation, which consists of claystones, sandstones, and shales that were deposited in a shallow marine environment during the Late Cretaceous period (Edet et al., 2017). The Benin Formation is overlain by the Agbada Formation, which is the thickest unit in the Niger Delta Basin and consists of predominantly sandstones, interbedded with shales and lignites (Evamy et al., 1978). The Agbada Formation was deposited in a deltaic environment during the Paleocene to early Eocene epoch.

The uppermost unit in the Niger Delta Basin is the Akata Formation, which consists of shale, mudstone, and siltstone with intercalated sandstones (Ojo and Adegoke, 2014). The

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 *https://dx.doi.org/10.4314/sa.v22i1.22*
© Faculty of Science, University of Port Harcourt, Printed in Nigeria *ISSN 1118 – 1931*

Akata Formation was deposited in a deep marine environment during the late Eocene to early Oligocene epoch.

Between the Agbada Formation and the Akata Formation lies the Paralic and Deltaic Sandstones, which consist of sandstones, shales, and siltstones that were deposited in a transition zone between the deltaic and marine environments (Short and Stauble, 1967).

The lithostratigraphy of the Niger Delta Basin has been studied extensively due to its importance for hydrocarbon exploration and production. Understanding the distribution and characteristics of the different lithostratigraphic units can help identify potential reservoir rocks and seals, as well as provide insights into the depositional history of the basin.

The Geology of the Niger Delta and its surroundings is a complex mixture of sedimentary rocks that have been deposited in a variety of environments over millions of years. This has resulted in a unique geological setting that is rich in petroleum resources and has significant economic and environmental importance.

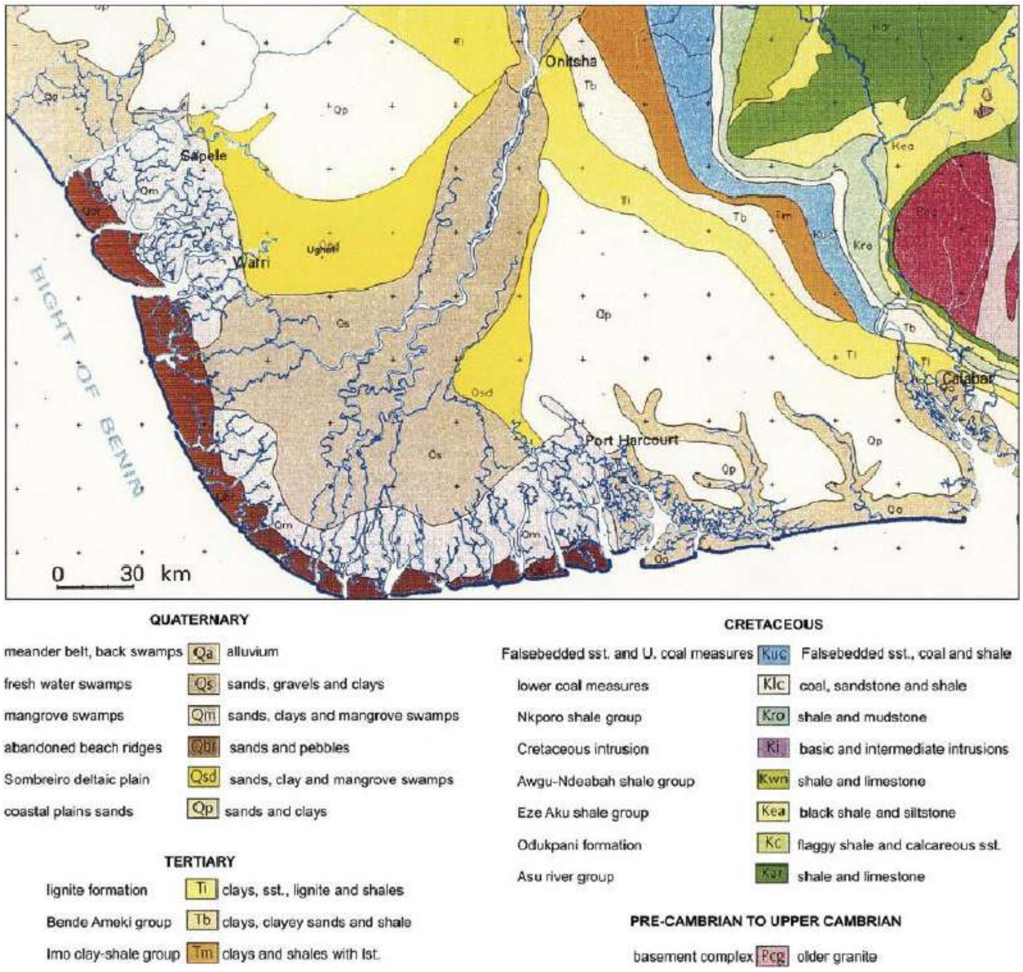


Figure 2: Geological map of the Niger Delta and surroundings (Reijers, 2011)

MATERIALS AND METHOD

The tools, equipment, and procedures used in this study to obtain data and achieve research objectives are discussed. The materials used are clearly specified in this study to ensure that the results can be reproduced. The procedures or techniques used in the study to collect data or information are also discussed. This is an essential part of this study.

Brief Review of Wireline Logs Used for the Study

Gamma Ray, Density, Sonic, and Neutron logs were used for this study. They are commonly used in the oil and gas industry for formation evaluation (Zhang et al., 2021). Gamma Ray logs measure the natural gamma radiation emitted by subsurface rocks to correlate stratigraphic units, identify shale and non-shale intervals, estimate mineralogy and porosity, and detect hydrocarbons (Ghosh and Sharma, 2014). Density logs, on the other hand, use a strong gamma ray source to bombard the rock with medium-energy gamma rays, and the count rate of the scattered gamma rays at a fixed distance from the source is inversely proportional to the electron density of the formation, which is used to calculate porosity in layers of known lithology (Guo et al., 2018). Sonic logs measure the time it takes for sound pulses to travel through the formation and are used in the calibration of seismic data, in calculating porosity in layers of known lithology, and in the evaluation of secondary porosities in combination with the Neutron and/or Density tools (Kumar and Tiwary, 2019). Neutron logs use a source and two detectors to count returning thermal neutrons to determine porosity in the formation (Joshi et al., 2019).

By using these logs in combination, a more complete understanding of the subsurface formations can be achieved (Zhang et al., 2021).

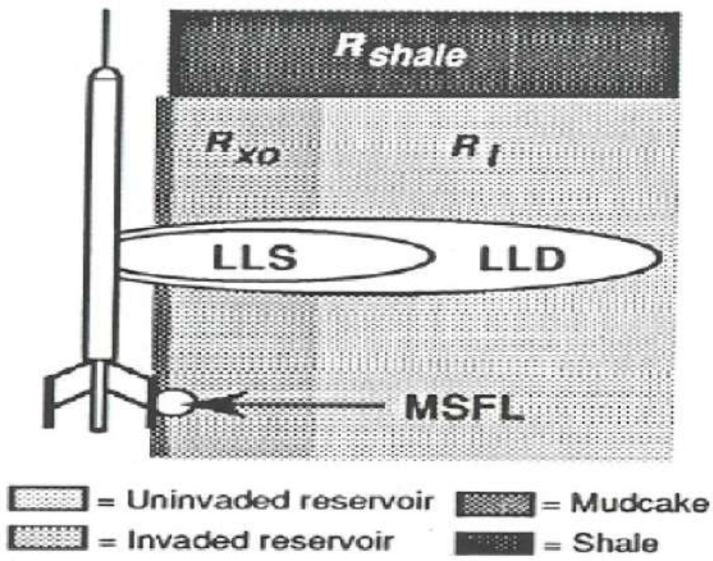


Figure 3: Schematic diagram showing the lateral extent of resistivity logs (Doveton,1999)

Methods (Evaluation Techniques)

Lithology Identification

The gamma ray log was used to identify lithology by reading the GR level of the thickest shale bed to represent 100% shale and constructing a shale line (Figure 4). Similarly, an average GR level of thick sands was used to construct the sand line. A cut-off line was constructed between the shale and sand line for initial evaluation, and intervals on the left side of the GR log are assumed to be sandstone. Neutron-density X-plots were used to confirm the lithology type and check consistency. The level of GR within a reservoir interval is a measure of its shaliness, which affects effective porosity. The sand line and shale line values were 21 API and 150 API, respectively, in well X, and 30 API and 150 API, respectively, in well Y.

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 https://dx.doi.org/10.4314/sa.v22i1.22
© Faculty of Science, University of Port Harcourt, Printed in Nigeria ISSN 1118 – 1931

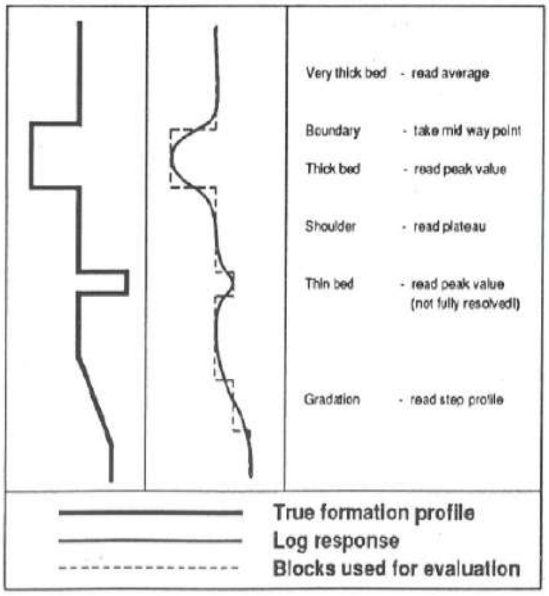


Figure 4: Typical log showing how values are read (Doveton, 1999)

Porosity Determination

Porosity was determined for well X using the sonic log (Figure 5) and for well Y using both the density and neutron logs (Figure 6). The Neutron-Density log was used to check consistency and correct for gas-bearing reservoirs. The X-plot was used to identify lithologic units and estimate porosity for each unit. Using multiple methods to cross-check results is common practice for increased confidence in interpretation. The Neutron-Density log and X-plot are powerful tools for petrophysical analysis, improving the accuracy and consistency of porosity estimates.

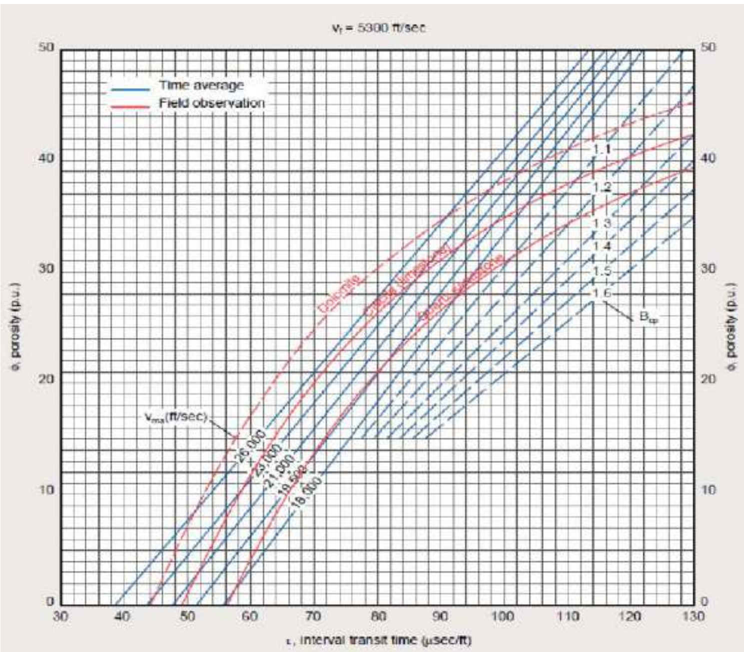


Figure 5: Porosity evaluation from Sonic Log. Modified after (Kiakojury et.al., 2018)

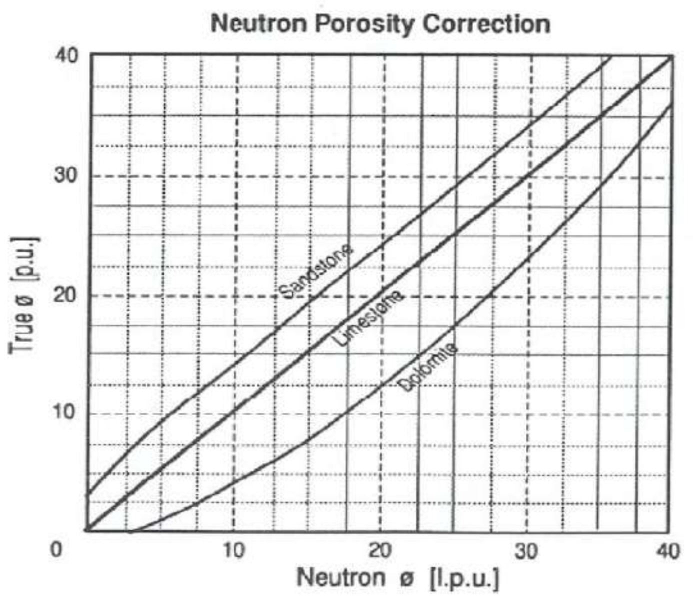


Figure 6: Neutron-Density Cross plot. Modified after (O'Connor et. al., 2019)

Hydrocarbon Detection

To identify potential reservoir intervals in Well X and Well Y, resistivity, GR, and porosity logs were used. The first Archie formula was used to relate resistivity to porosity and fluid saturation. The GR log helped identify shale and sandstone intervals, while the porosity log indicated the presence of reservoir fluids. The balloon effect due to gas was used to identify gas-bearing reservoirs. By combining these different logs and techniques, potential reservoir intervals were identified in both wells.

Petrophysical Characters of the Reservoirs

Porosity (ø)

This is the ratio of the voids in the formation to the total rock volume, corrected for shale

- *Density Porosity:*

$Ø_D = (ρma – ρb / ρma – ρfl)$

$Ø_D$ = Density porosity

Pb = Bulk density (read from log)

Pma = Matrix density (2.65g/cm^3 for sandstones)

Pfl = Fluid density (1.0g/cm^3 for water)

- *Total Porosity*

$Ø_T = Ø_N^2 - Ø_D^2 / 2$

$Ø_T$ = Total porosity

$Ø_D$ = Density porosity

$Ø_N$ = Neutron porosity (read from log)

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 https://dx.doi.org/10.4314/sa.v22i1.22
© Faculty of Science, University of Port Harcourt, Printed in Nigeria ISSN 1118 – 1931

- *Effective Porosity*

$Ø_e = Ø_T (1 – V_{sh})$

$Ø_e$ = Effective porosity

V_{sh} = Volume of shale

- *Sonic Porosity*

$Ø_s = \Delta t_{log} - \Delta t_{ma} / \Delta t_{fl} - \Delta t_{ma}$

$Ø_s$ = Sonic porosity

Δt_{log} = Interval transit time (read from log)

Δt_{ma} = Interval transit time for matrix

Δt_{fl} = Interval transit time for fluid

Volume of Shale (v_{sh})

$V_{sh} = Gr_{log} – Gr_{min} / Gr_{max} – Gr_{min}$

V_{sh} = Volume of shale

Gr_{log} = Gamma ray value for the reservoir (read from log)

Gr_{min} = Minimum gamma ray value for the well

Gr_{max} = Maximum gamma ray value for the well

Resistivity (R)

$Rw = Ro*Ø^m$

Rw = Resistivity of water

Ro = Resistivity of water bearing reservoir (read from the water leg in the reservoir)

m = Cementation factor (1.8)

Water Saturation (Sw)

$Sw = (a \times Rw / Ø^m \times Rt)^{1/n}$

Sw = Water saturation

Rw = Resistivity of water

Rt = Resistivity of hydrocarbon bearing reservoir (read from log)

a = 1

n = Saturation exponent (2)

Hydrocarbon Saturation (Shc)

Shc = 1 - Sw

Bulk Volume Water (BVW)

BVW = Ø x Sw

Bulk Volume Hydrocarbon (BVH)

BVH = Ø x (1-Sw)

Hydrocarbon Effect

For Oil

$Ø = Ø_s \times 0.9$

For Gas

Ø = Øs x 0.7

3D Seismic and Depth Structure Map

Seismic exploration is a crucial part of the hydrocarbon evaluation process, as it provides valuable information about the subsurface geology and structures. Seismic waves are generated using a seismic source, such as a vibrating plate or explosive charge, and these waves travel through the subsurface and bounce back off different layers and structures. The reflected waves are recorded by sensors, called geophones or hydrophones, and the data is processed and analyzed to create a seismic section (Figures 7 and 8) which is a two-dimensional representation of the subsurface.

To identify potential reservoir intervals in Well X and Well Y, resistivity, GR, and porosity logs were used. The first Archie formula was used to relate resistivity to porosity and fluid saturation. The GR log helped identify shale and sandstone intervals, while the porosity log indicated the presence of reservoir fluids. The balloon effect due to gas was used to identify gas-bearing reservoirs. By combining these different logs and techniques, potential reservoir intervals were identified in both wells.

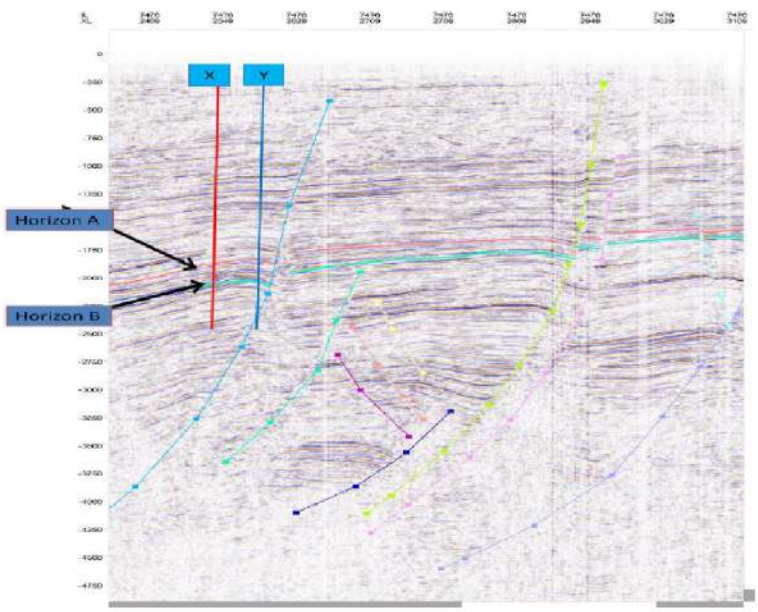


Figure 7: Horizons Interpretation on 3D seismic Inline showing Two Horizons and Growth Faults in the subsurface.

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 https://dx.doi.org/10.4314/sa.v22i1.22
© Faculty of Science, University of Port Harcourt, Printed in Nigeria **ISSN 1118 – 1931**

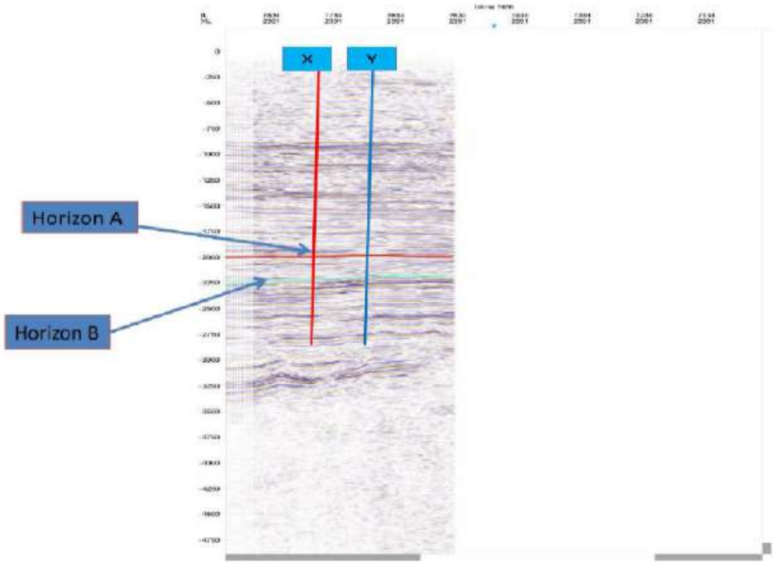


Figure 8: Horizons Interpreted on 3D seismic X-line

Depth structure maps and subsurface structure maps (Figure 9) are important tools in hydrocarbon exploration and production. Depth structure maps show the contours of a particular horizon, while subsurface structure maps depict the 3D geometry of different horizons and structures. Accurate structural interpretation is crucial in identifying potential hydrocarbon traps and determining the best location for drilling wells. By understanding the surface and subsurface geology, informed decisions can be made to optimize production and minimize risks and costs, while ensuring safety and environmental protection.

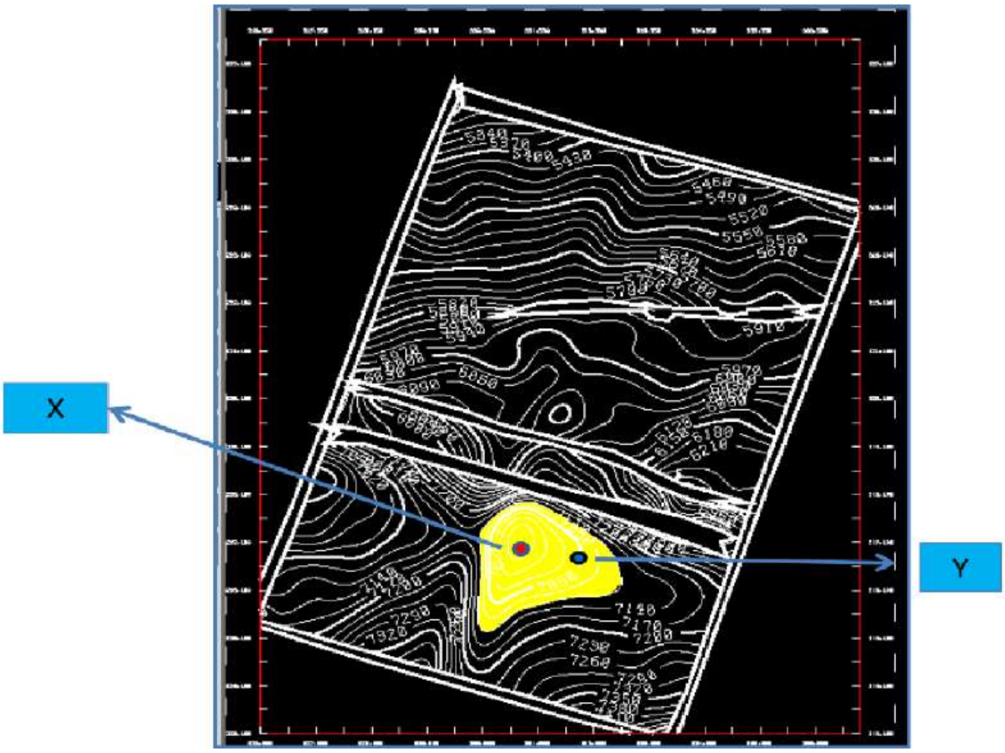


Figure 9: Depth Structural Map with Identified Hydrocarbon Closure

Well Correlation

The well tie process helps to ensure that the subsurface data collected from different wells is consistent and accurate, which is crucial for making informed decisions about reservoir development and production. By comparing the petrophysical characteristics of different wells, geoscientists and engineers can identify potential reservoir intervals and develop a better understanding of the subsurface geology and fluid flow. This information can then be used to optimize well placement, completion, and production strategies.

RESULTS

Results of the analysis from the study are given in the tables below:

Table 1 Well Y Neutron Density Log

RESERVOIR	DEPTH INTERVAL (m)	THICKNESS (m)	LITHOLOGY	FLUID PRESENT	ILD RT (Ωm)	TNPL (v/v)	AV. TOTAL POROSITY Ø (%)	Vsh (%)	EFFECTIVE POROSITY Ø (%)	Rw	Sw (%)	Shc (%)	BVW (%)	BVH (%)
1a	2920 - 2925	5.0	Sand	Gas	200	10	24.38	25.0	18.3	0.36	11.5	88.5	2.10	13.54
1b	2925-2926.5	1.5	Sand	Gas	100	17	24.38	35.0	15.8	0.36	17.7	82.3	2.79	13.00
2a	2941.3-2943.8	2.5	Sand	Gas	180	6	21.60	5.8	20.3	0.36	13.2	86.8	2.67	17.62
2b	2943.8-2949.8	5.5	Sand	Gas	120	12	20.80	33.3	13.9	0.36	17.8	82.2	2.47	11.42
3	2961.3-2971.8	10.5	Sand	Gas	60	13	19.90	22.5	15.4	0.36	27.0	73.0	4.15	11.24
4a	2993.8-3004	10.2	Sand	Gas	80	12	22.10	25.0	16.5	0.01	3.4	96.6	0.56	15.93
4b	3004-3009	5.0	Sand	Oil	8	21	23.60	25.0	17.7	0.01	11.9	88.1	2.10	15.59
5	3070-3083.8	13.8	Sand	Gas	80	10	21.60	19.0	17.4	0.01	3.4	96.6	0.59	16.80
6a	3119.2-3130	10.8	Sand	Gas	80	15	21.80	17.5	17.9	0.02	5.1	94.9	0.91	16.98
6b	3130-3146.2	16.2	Sand	Oil	8	21	22.50	25.0	18.0	0.02	18.1	81.9	3.25	14.74
7a	3198.8-3203.6	4.8	Sand	Gas	100	14	21.50	45.0	11.8	0.02	4.6	95.4	0.54	11.25
7b	3203.6-3209.4	5.8	Sand	Gas	140	10	21.60	30.8	20.0	0.02	3.6	96.4	0.72	19.28

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 *https://dx.doi.org/10.4314/sa.v22i1.22*
© Faculty of Science, University of Port Harcourt, Printed in Nigeria *ISSN 1118 – 1931*

Table 2 Well X Sonic Log

RESERVOIR	DEPTH INTERVAL (m)	THICKNESS (m)	LITHOLOGY	FLUID PRESENT	DT μsm	μsft	ILD RT (Ωm)	Øs (%)	Vsh (%)	Rw	Sw (%)	Shc (%)	BVW (%)	BVH (%)	HC EFFECT Ø (%)
1a	2900-2912.5	12.5	Sand	Gas	236	72	80	11.9	22.4	0.006	5.8	94.2	0.69	11.20	8.3
1b	2912.5-2930	17.5	Sand	Water	196	60	4	2.7	30.2	0.006	100	-	2.7	-	-
2	2932.5-2962.5	30	Sand	Gas	203	62	100	4.3	26.3	0.006	13.1	86.9	0.56	3.73	3.0
3a	2971.3-2978.8	7.5	Sand	Gas	262	80	80	17.8	10.8	0.006	4.0	96.0	0.71	17.08	12.4
3b	2978.8-2987.5	8.7	Sand	Gas	209	64	40	5.7	30.2	0.006	16.1	83.9	0.91	4.78	3.9
4a	3005 - 3015	10	Sand	Gas	223	68	100	8.9	26.3	0.033	16.0	84.0	1.42	7.47	6.2
4b	3015- 3020	5	Sand	Oil	236	72	10	11.9	26.3	0.033	39.0	61.0	4.64	7.25	10.7
5	3035-3047.5	12.5	Sand	Gas	242	74	80	13.3	10.8	0.033	12.4	87.6	1.64	11.65	9.3
6a	3060-3063.8	3.8	Sand	Gas	275	84	120	20.8	3.1	0.003	2.0	98.0	0.41	20.38	14.5
6b	3063.8 - 3067.5	3.7	Sand	Oil	229	70	16	10.3	41.8	0.003	10.5	89.5	1.08	9.21	9.2
7	3075 - 3105	30	Sand	Gas	236	72	60	11.9	26.3	0.003	4.8	95.2	0.57	11.32	8.3
8	3107.5-3121.3	13.8	Sand	Oil	255	78	16	16.2	37.9	0.003	7.0	93.0	1.13	15.06	14.5
9	3128.8-3138.8	10	Sand	Gas	262	80	80	17.8	14.7	0.003	2.7	97.3	0.48	17.31	12.4
10	3140-3160	20	Sand	Oil	236	72	10	11.9	34.1	0.003	11.7	88.3	1.39	10.50	10.7
11	3165-3222.5	57.5	Sand	Oil	242	74	8	13.3	37.9	0.003	11.9	88.1	1.58	11.71	11.9
12	3265-3277.5	12.5	Sand	Gas	229	70	40	10.3	34.1	0.509	87.2	12.8	8.98	1.31	7.2

Key Reservoir Characteristics and Properties Summary for Oil and Gas Exploration and Production for well X and well Y is presented in Tables 3 and 4 respectively.

Table 3 Reservoir Characteristics and Properties Summary of Well X

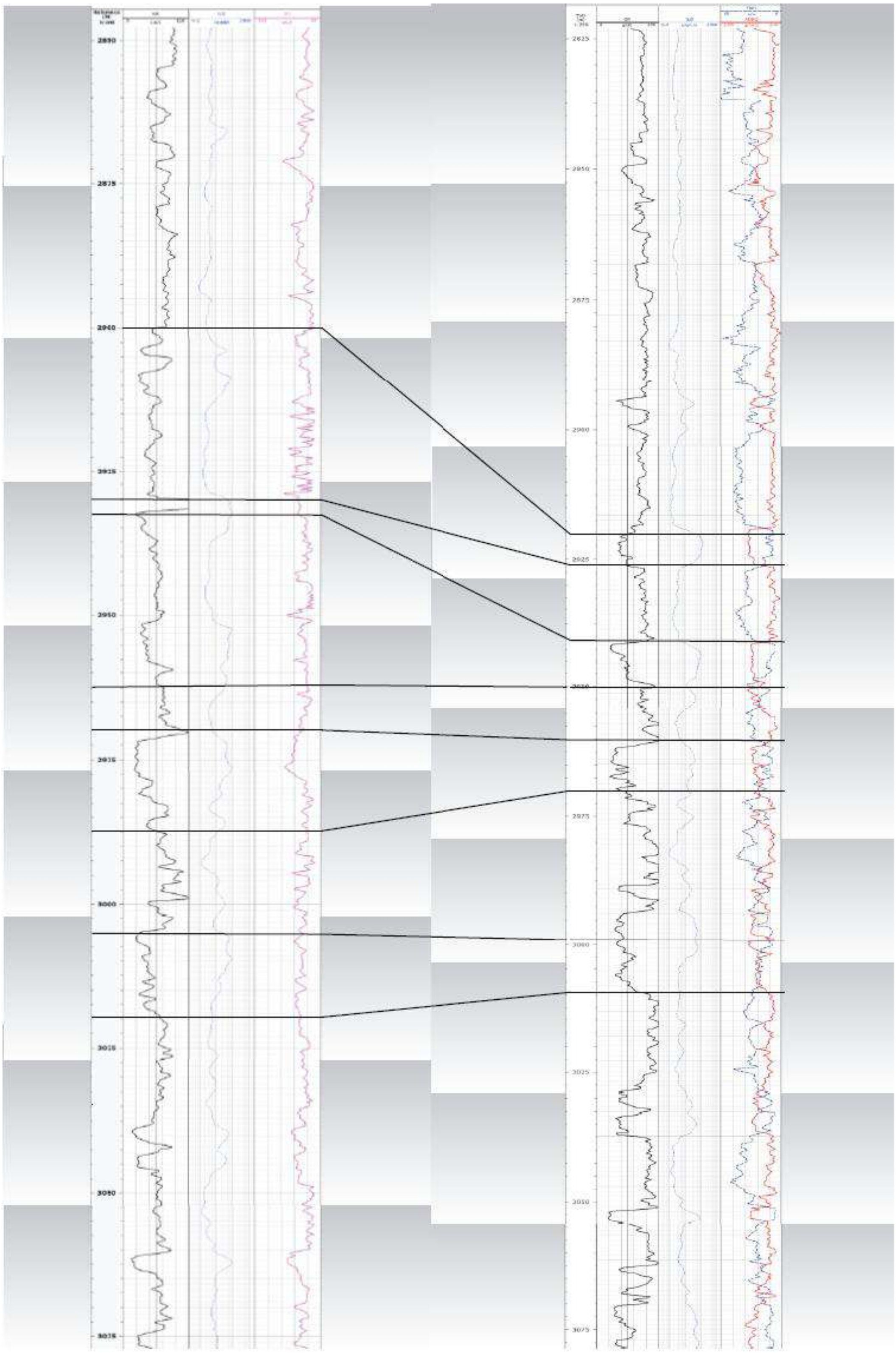
WELL X	
NET SAND THICKNESS	255m
NET / GROSS (255m/377.5m)	0.67
GOC	3015m, 3063.8m
GWC	2912.5m
$Ø_S$	2.7% - 20.8%
S_W	2.0% - 87.2%
S_h	12.8% - 98.0%
V_{sh}	3.1% - 41.8%
BVW	0.41% - 8.98%
BVH	1.31% - 20.38%
HC EFFECT	9.2% - 14.5% (FOR OIL)
	3.0% - 14.5% (FOR GAS)
NET PAY THICKNESS	137.5m (FOR GAS), 100m (FOR OIL)

Table 4 Reservoir Characteristics and Properties Summary of Well Y

WELL Y		
NET SAND THICKNESS	91.6m	
NET / GROSS (91.6m/ 289.4m)	0.31	
GOC		3004m, 3130m
Ø		19.90% - 24.38%
$Ø_e$		11.8% - 20.3
S_W		3.4% - 27.0%
S_h		73.0% - 96.6%
V_{sh}		5.8% - 33.3%
BVW		0.54% - 4.15%
BVH		11.24% - 19.28
NET PAY THICKNESS		70.4m (FOR GAS), 21.2m (FOR OIL)

Well Correlation

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 *https://dx.doi.org/10.4314/sa.v22i1.22*
© Faculty of Science, University of Port Harcourt, Printed in Nigeria *ISSN 1118 – 1931*



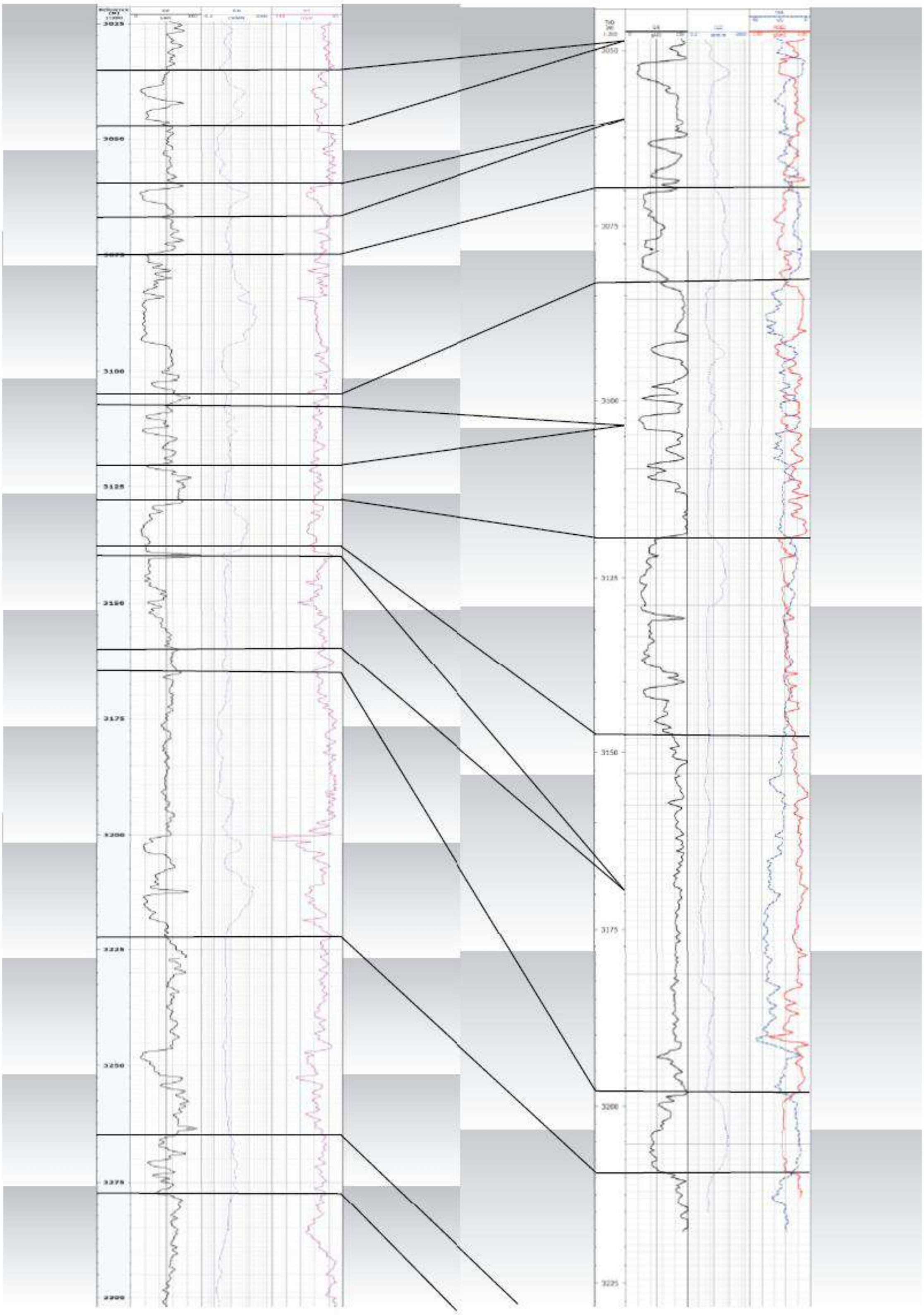


Figure 10: Well Correlation of Well X and Well Y

Core Data

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 https://dx.doi.org/10.4314/sa.v22i1.22
© Faculty of Science, University of Port Harcourt, Printed in Nigeria ISSN 1118 – 1931

Table 5 Core Data Values Collected for Well Y.

SAND	SAMPLE No.	DEPTH (M)	Swi (frct)	HORIZONTAL POROSITY (%)	VERTICAL POROSITY (%)	HORIZONTAL PERMEABILITY (mD)	VERTICAL PERMEABILITY (mD)	HORIZONTAL BULK DENSITY (gr/cc)	VERTICAL BULK DENSITY (gr/cc)	HORIZONTAL APPAR. DENSITY (gr/cc)	VERTICAL APPAR. DENSITY (gr/cc)
Y	1	2951.6		22.9	26.8	235	349	2.66	2.69	2.05	1.97
Y	2	2951.9		23		714		2.69		2.07	
Y	3	2952.15		22.8	22.4	1292		2.66	2.69	2.06	2.08
Y	4	2952.5		25	25.4	395	149	2.66	2.68	1.99	2
Y	5	2952.6		24.7	26.1	475	392	2.66	2.69	2	1.99
Y	6	2952.9		25.5	26.3	583	421	2.67	2.69	1.98	1.98
Y	7	2953.05		25.1	26.2	481	245	2.67	2.7	2	1.99
Y	8	2953.3		24.1	25.1	255	169	2.66	2.68	2.02	2.01
Y	9	2953.5		24.5	24.4	608	70.9	2.66	2.69	2.01	2.03
Y	10	2953.9		24.5	24.2	354	52.4	2.65	2.68	2	2.03
Y	11	2954.25		24	25.4	412	56.9	2.66	2.68	2.02	2
Y	12	2954.5		24.2	24.7	1013	132	2.67	2.69	2.02	2.02
Y	13	2954.8		23.9	23.3	206	14.4	2.65	2.68	2.02	2.05
Y	14	2955		24.1	25.3	329	92.4	2.65	2.68	2.01	2
Y	15	2955.35		19.6	18.1		62.5	2.67	2.69	2.14	2.2
Y	16	2955.5		24	24.8	238	220	2.66	2.68	2.02	2.02
Y	17	2855.8		24	24.6	183	30.1	2.65	2.68	2.01	2.02
Y	18	2956.1		24.8	20.8	127	4.2	2.65	2.64	1.99	2.09
Y	19	2956.5		19		337		2.67		2.16	
Y	20	2956.7		23.9	24.2	160	34.4	2.64	2.67	2.01	2.02
Y	21	2957		24.9	24.9	317	72.9	2.65	2.67	1.99	2.01
Y	22	2957.2		24.5	25.6	311		2.65	2.67	2	1.98
Y	23	2959.9		22.3	21.6	213	11	2.68	2.69	2.08	2.11
Y	24	2960.3		24.1	25.2	283	121	2.65	2.68	2.01	2.01
Y	25	2960.45		25.5	24.9	683	121	2.67	2.68	1.99	2.01
Y	26	2960.5		23.9	22.7	252	24.5	2.67	2.68	2.03	2.07
Y	27	2960.55		24.2	25.8	302	111	2.66	2.68	2.02	1.99
Y	28	2960.6		26	25.9	893	443	2.67	2.68	1.97	1.99
Y	29	2968.3		5.8	12.9	0.04		3.23	2.7	3.05	2.35
Y	30	2968.5	0.36	15.9	21.3	6.3	6.3	2.86	2.7	2.41	2.12
Y	31	2968.8		21.1	20.6	18	16.7	2.71	2.81	2.13	2.23
Y	32	2969.2		11.1	17.9	1.6	10.3	2.93	2.69	2.6	2.21
Y	33	2969.4		23.9	27.5	542	1081	2.66	2.68	2.02	1.94
Y	34	2969.8		22.6	23.9	360	211	2.66	2.67	2.05	2.03
Y	35	2970	0.24	25	24.4	473	310	2.65	2.67	1.99	2.02
Y	36	2970.3		23.3	21.4	543	117	2.66	2.68	2.04	2.1
Y	37	2970.5	0.08	22	23.2	652	589	2.66	2.68	2.08	2.06
Y	38	2970.75		18.7	18.5	237	7	2.73	2.7	2.22	2.2
Y	39	2970.95		22.8	22.8	674	156	2.65	2.67	2.05	2.06
Y	40	2971.1		22.7	24.9	973	1022	2.67	2.7	2.07	2.03
Y	41	2971.35		23.2	23.4	473	80.9	2.65	2.7	2.04	2.06
Y	42	2971.6		23.1	22.9	580	273	2.67	2.7	2.05	2.08
Y	43	2971.8		24.1	23.3	955	173	2.65	2.7	2.01	2.07
Y	44	2972.1		24.3	25.7	1138	903	2.68	2.72	2.03	2.02
Y	45	2972.4		24.9	24.7		789	2.67	2.7	2.01	2.03
Y	46	2972.6	0.06	22.9	25	946	493	2.67	2.73	2.06	2.05
Y	47	2973		19.3	19.9			2.68	2.69	2.17	2.15
Y	48	2973.3		20.5	20.5	467		2.73	2.84	2.17	2.25
Y	49	2973.5		21.5	22.3	422	452	2.66	2.7	2.09	2.09
Y	50	2973.75		19.3	19.9	809	589	2.66	2.71	2.15	2.17
Y	51	2974.1		20.7	21.8	2210		2.67	2.68	2.11	2.1
Y	52	2974.3	0.04	19	19.7	2002	1491	2.66	2.7	2.16	2.16
Y	53	2974.6		16.9	19	702	3	2.66	2.68	2.21	2.17
Y	54	2974.8			21.4				2.68		2.1
Y	55	2974.95		21.8	21.2	1012	396	2.67	2.68	2.08	2.11
Y	56	2975.25		20.1	20.7	919	336	2.66	2.68	2.13	2.13
Y	57	2975.4		23.9	23.9	2214	564	2.66	2.68	2.03	2.04
Y	58	2975.6	0.06	20.8	20.2	351	68.7	2.66	2.67	2.1	2.13
Y	59	2976	0.19	24.7		1904		2.67		2.01	
Y	60	2976.25		23.5	25.6	969	490	2.67	2.67	2.04	1.99
Y	61	2976.4		17.3	20.2			2.77	2.71	2.29	2.16
Y	62	2976.6		10.2	8.4			2.66	2.66	2.39	2.43
Y	63	2976.8		24.8	25.8	203	47.7	2.66	2.66	2	1.98
Y	64	2977.3	0.33	26.9	26.9	611	183	2.65	2.68	1.94	1.96
Y	65	2977.6	0.07	26.4	21.6	367	38.2	2.67	2.66	1.96	2.09
Y	66	2977.9		8.4	10.2			2.64	2.64	2.41	2.37
Y	67	2978.1		10.9	12.8			2.63	2.63	2.34	2.29
Y	68	2978.3									

Y	69	2978.6										
Y	70	2978.61										
Y	71	2980.65	0.08	22.7	23.1	757	11.1	2.72	2.71	2.1	2.08
Y	72	2980.95										
Y	73	2981.3		18.6	19.5	13.9	0.41	2.67	2.69	2.17	2.17
Y	74	2981.7		15.6	17.3			2.65	2.68	2.24	2.21
Y	75	2982			13.9		0.6		2.72		2.34
Y	76	2982.3		15.1	15.8			2.72	2.75	2.31	2.31
Y	77	2982.6									
Y	78	2983	0.2	27.1	27.7	172	131	2.67	2.68	1.95	1.94
Y	79	2983.3		26.1	26.8	162	77.6	2.65	2.66	1.96	1.95
Y	80	2983.5		25.5	25	98.7	27.9	2.65	2.66	1.97	2
Y	81	2983.7		24.2	25.9	106	104	2.65	2.66	2	1.97
Y	82	2983.95	0.35	25.9	26	273	138	2.65	2.67	1.96	1.97
Y	83	2984.25	0.26	23.3	24.9	74.8	23.3	2.65	2.66	2.03	2
Y	84	2984.5		24.4	24.4	131	42.2	2.64	2.66	2	2.01
Y	85	2984.7	0.11	24.4	23.5	309	62.8	2.65	2.67	2	2.04
Y	86	2985.05		22.4	23.5	81.8	32.1	2.66	2.68	2.06	2.05
Y	87	2985.2	0.16	23.4	27.5	86.9	304	2.65	2.66	2.03	1.93
Y	88	2985.5	0.24	18.9	21.9	17.5	2.5	2.66	2.67	2.16	2.08
Y	89	2985.7		25.2	25.7	94.1	38.2	2.65	2.67	1.98	1.98
Y	90	2985.9		16.7	17.7		0.99	2.66	2.68	2.21	2.2
Y	91	2986.1			8.8				2.65		2.42
Y	92	2986.3		15.7	13		0.06	2.61	3.04	2.2	2.64
Y	93	2986.5	0.25	24	24.9	47	1.7	2.67	2.69	2.03	2.02
Y	94	2986.6		21.6	22.1		0.49	2.66	2.68	2.09	2.09
Y	95	2986.9		21.5	22	8	5.8	2.7	2.67	2.12	2.08
Y	96	2987.05									
Y	97	2987.45		7.5	9.8			2.77	2.65	2.56	2.39
Y	98	2987.55		10.9				2.43		2.16	
Y	99	2987.8			12.4				2.66		2.33
Y	100	2988		16.5	13.6	1.7	0.09	2.65	2.68	2.21	2.32
Y	101	2988.3		17.2	17.7	1.2	0.39	2.65	2.67	2.19	2.19
Y	102	2988.7		13.8	13.2		1.6	2.64	2.81	2.27	2.44
Y	103	2989		17.4	18.5	2.2	1.8	2.65	2.67	2.19	2.17
Y	104	2989.2		16.1	14.9		24.3	2.65	2.67	2.22	2.27
Y	105	2989.5		13	14.1	2.3		2.66	2.67	2.31	2.29

DISCUSSION

Petrophysical Properties

From the result of the Petrophysical analysis (Tables 1 and 2), Well X has a reservoir zone (1b) that contains water, while the other reservoir zones contain hydrocarbons. Specifically, zones 1a, 2, 3, 4a, 5, 6a, 7, 9, and 12 contain gas, while zones 4b, 6b, 8, 10, and 11 contain oil (Table 2). In contrast, all reservoir zones investigated in Well Y contain hydrocarbons, with oil occurring in reservoir zones 4b and 6b and gas occurring in the reservoir zones 1, 2, 3, 4a, 5, 6a, and 7 (Table 1). The volume of shale in each reservoir has a direct effect on both total and effective porosity. Specifically, zones with high volumes of shale tend to have reduced porosity. Overall, this information suggests that there are differences in the hydrocarbon and water content of the reservoir zones in Well X and Well Y, and that the total and effective porosity of the reservoir zones is influenced by the volume of shale present. For well X, Net sand thickness is 255m. This refers to the total thickness of the reservoir that consists of sand. Net to gross ratio (N/G) is 0.67. This indicates that out of the total reservoir thickness of 377.5m, only 67% (255m) is composed of sand. Gas-oil contact (GOC) is at 3015m for oil and 3063.8m for gas. This refers to the depth at which the transition from oil to gas occurs in the reservoir. Gas-water contact (GWC) is at

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 https://dx.doi.org/10.4314/sa.v22i1.22
© Faculty of Science, University of Port Harcourt, Printed in Nigeria ISSN 1118 – 1931

2912.5m. This refers to the depth at which the transition from gas to water occurs in the reservoir. Porosity (Ø) ranges from 2.7% to 20.8%. This refers to the percentage of the total rock volume that is comprised of void space or pores. Water saturation (S¬W) ranges from 2.0% to 87.2%. This refers to the percentage of pore space that is filled with water. Hydrocarbon saturation (S¬h¬) ranges from 12.8% to 98.0%. This refers to the percentage of pore space that is filled with hydrocarbons. Volume of shale (V¬sh¬) ranges from 3.1% to 41.8%. This refers to the percentage of the total rock volume that is composed of shale. Bulk volume of water (BVW) ranges from 0.41% to 8.98%. This refers to the total volume of water present in the reservoir. Bulk volume of hydrocarbons (BVH) ranges from 1.31% to 20.38%. This refers to the total volume of hydrocarbons present in the reservoir. Hydrocarbon effectivity (HC EFFECT) ranges from 9.2% to 14.5% for oil and 3.0% to 14.5% for gas. This refers to the percentage of the total hydrocarbon volume that is expected to be recoverable based on the reservoir characteristics and recovery methods. Net pay thickness is 137.5m for gas and 100m for oil. This refers to the thickness of the reservoir that has properties (such as porosity, permeability, and saturation) that are favourable for hydrocarbon production (Table 3).

For well Y, Net sand thickness is 91.6m. This refers to the total thickness of the reservoir that consists of sand. Net to gross ratio (N/G) is 0.31. This indicates that out of the total reservoir thickness of 289.4m, only 31% (91.6m) is composed of sand. Gas-oil contact (GOC) is at 3004m for oil and 3130m for gas. This refers to the depth at which the transition from oil to gas occurs in the reservoir. Porosity (Ø) ranges from 19.90% to 24.38%. This refers to the percentage of the total rock volume that is comprised of void space or pores. Effective porosity (Ø¬e¬) ranges from 11.8% to 20.3%. This refers to the percentage of the total rock volume that contributes to fluid flow. Water saturation (S¬W) ranges from 3.4% to 27.0%. This refers to the percentage of pore space that is filled with water. Hydrocarbon saturation (S¬h¬) ranges from 73.0% to 96.6%. This refers to the percentage of pore space that is filled with hydrocarbons. Volume of shale (V¬sh¬) ranges from 5.8% to 33.3%. This refers to the percentage of the total rock volume that is composed of shale. Bulk volume of water (BVW) ranges from 0.54% to 4.15%. This refers to the total volume of water present in the reservoir. Bulk volume of hydrocarbons (BVH) ranges from 11.24% to 19.28%. This refers to the total volume of hydrocarbons present in the reservoir. Net pay thickness is 21.2m for oil and 70.4m for gas. This refers to the thickness of the reservoir that has properties (such as porosity, permeability, and saturation) that are favorable for hydrocarbon production (Table 4).

Well Correlation

A correlation between Well X and Y (Figure 10) was used to identify areas of the reservoir that are more likely to contain hydrocarbons. The 'SCOJAS'-X Well has twelve major reservoirs identified at varying depths with varying thicknesses. The 'SCOJAS'-Y Well has seven identified reservoirs. This information can be used to optimize well placement and increase the likelihood of successful production. By using well correlation to improve reservoir models and optimize well placement, drilling costs can be reduced by minimizing the number of dry holes and improving the efficiency of drilling operations.

A Comparison of Porosity Data from Well-X and Well-Y with Other Works in the Niger Delta Basin

The porosity values for Well X range from 2.7% to 20.8%, which is a fairly wide range. The lower end of this range is relatively low for reservoir rocks, while the upper end is more typical. The water saturation values for Well X range from 2.0% to 87.2%, which is also a wide range. The low end of this range suggests that the rock may be poorly saturated with water, while the high end suggests that there may be significant volumes of water present in the pore space.

The porosity values for Well Y range from 19.90% to 24.38%, which is a relatively narrow range. The effective porosity values for Well Y range from 11.8% to 20.3%, which is still relatively high compared to the total porosity values for Well X. The water saturation values for Well Y range from 3.4% to 27.0%, which is also a wide range. Overall, the porosity values for Wells X and Y are within the range of values typically observed in sedimentary rocks. However, the range of values for Well X is wider than that for Well Y, and the effective porosity values for Well Y are relatively high.

Well X has a porosity range of 2.7% to 20.8%, which is generally lower than the reported porosity range (Orajaka and Okoro, 2017). Well Y has a porosity range of 19.90% to 24.38%, which falls at the upper end of the reported porosity range (Asuquo and Isangedighi, 2014). According to Opuwari and Tari (2013), porosity values in the Niger Delta can range from as low as 5% to as high as 35%, depending on the lithology and depositional environment. Another study by Ola-Buraimo and Oni (2016) reported porosity values ranging from 12.80% to 23.20% in the Niger Delta. A study by Olorode and Olasehinde (2017) reported porosity values ranging from 7.24% to 28.29% in the Niger Delta, with variations observed across different geological formations. A study by Onyekuru et al. (2021) evaluated the porosity values of sandstone reservoirs in the Niger Delta using well logs and core data. The study found that porosity values ranged from 10% to 33%, with an average value of 20%. The authors also noted that porosity values were generally higher in the shallow marine and fluvio-deltaic depositional environments compared to the deep marine environment. Additionally, the study found that porosity values were strongly influenced by diagenesis, with compaction and cementation processes reducing porosity values in some reservoirs. A study by Edoho et al. (2022) investigated the porosity and permeability properties of reservoir rocks in the Niger Delta. The study found that porosity values ranged from 4.1% to 34.7%, with an average value of 19.6%. The authors also noted that porosity values were generally higher in sandstone reservoirs compared to shale reservoirs. The study concluded that understanding the porosity and permeability properties of reservoir rocks is crucial for effective hydrocarbon exploration and production in the Niger Delta. A study by Olarewaju et al. (2020) examined the porosity values of sandstone reservoirs in the Niger Delta using well log data. The study found that porosity values ranged from 4% to 31%, with an average value of 17.4%. The authors noted that porosity values were generally higher in the shallow marine depositional environment compared to the deep marine environment. The study also observed that porosity values were influenced by depositional facies, with sandstone facies generally having higher porosity values than shale facies.

A study by Omoniyi et al. (2021) investigated the porosity and permeability properties of reservoir rocks in the Niger Delta using well log and core data. The study found that porosity values ranged from 10% to 30%, with an average value of 18%. The authors noted that porosity values were generally higher in the shallow marine and fluvio-deltaic depositional environments compared to the deep marine environment. The study also observed that porosity values were influenced by diagenesis, with compaction and cementation processes reducing porosity values in some reservoirs. According to

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 https://dx.doi.org/10.4314/sa.v22i1.22
© Faculty of Science, University of Port Harcourt, Printed in Nigeria ISSN 1118 – 1931

Ukuedojor and Maju-Oyovwikowhe (2019), the reservoir in the Idje field, offshore Niger Delta, was shown to have a "very good porosity" with an average value of 0.25. The reservoir has an average porosity of 0.25, which is much higher than the porosity range of Well X (2.7% to 20.8%) and Well Y (19.90% to 24.38%). This suggests that the reservoir has significantly higher pore volume compared to the two wells.

CONCLUSION

The hydrocarbon evaluation and distribution in Well-X and Well-Y in the Niger Delta Basin can be influenced by several geological factors, including the depositional environment, lithology, porosity, permeability, and fluid properties of the reservoir rocks (Asquith and Krygowski, 2004). In this study, porosity comparison was used to validate the hydrocarbon distribution in Well-X and Well-Y. Porosity is an important property of reservoir rocks as it affects their ability to store and transmit fluids (Feng et al., 2016). The 'SCOJAS'-X Well has twelve major reservoirs identified at varying depths with varying thicknesses. The 'SCOJAS'-Y Well has seven identified reservoirs. With the exception of reservoir 12 in Well X, all hydrocarbon zones are producible, with hydrocarbon saturations greater than 61.0% and as high as 98.0%. Reservoir 12 in Well X has a low hydrocarbon saturation of 12.8%, a BVH of 1.31, and a thickness of 12.5m. The properties of the wells, particularly with respect to porosity, permeability, and other important properties, correlate well with established properties of the Niger Delta petroleum systems.

After conducting a comparison of the porosity values of Well X and Well Y with that of other wells in the Niger Delta basin and published works from renowned authors of literature on the porosity, permeability, and other important properties of the Niger Delta basin, it can be inferred that the well properties align with the established properties of the Niger Delta petroleum systems (Ukuedojor and Maju-Oyovwikowhe, 2019; Oluwajana et al., 2018). This suggests that the 'SCOJAS' field reservoir is consistent with the larger hydrocarbon system in the Niger Delta region, providing a promising opportunity for hydrocarbon exploration and production in the area.

The properties of the wells were found to align with the established properties of the Niger Delta petroleum system, indicating significant hydrocarbon potential. The field is promising for gas exploration, and crude oil exploration is also recommended. It is important to carry out a comprehensive evaluation of reservoir properties away from the well and provide opportunities for students to learn advanced methods of reservoir evaluation to develop a skilled workforce for sustainable and efficient exploitation of oil and gas reserves.

REFERENCES

Afolabi, B. R., Adetunji, A. R., and Nwosu, I. V. (2018). Petrophysical evaluation of reservoirs in the Niger Delta Basin using well logs and core data. Journal of Petroleum Exploration and Production Technology, 8(4), 1163-1174.

Ako, B. D., Isangedighi, I. A., and Okon, U. E. (2016). Sequence stratigraphy and sedimentology of reservoir sands in Well-X, Niger Delta, Nigeria. Journal of African Earth Sciences, 120, 105-114.

Akpabio, I. O., Okwueze, E. E., and Abodunrin, A. S. (2019). Reservoir properties and hydrocarbon distribution in the Niger Delta Basin: An integrated approach. Journal of African Earth Sciences, 151, 188-196.

Asquith, G.B., and Krygowski, D., 2004. Basic Well Log Analysis for Geologists, 2nd Edition. American Association of Petroleum Geologists.

Asuquo, F. E. and Isangedighi, I. A., 2014. Petrophysical evaluation of Akata

Formation reservoir in Afam field, Niger Delta. Journal of Petroleum Exploration and Production Technology, 4(2), pp. 115-126.

Avbovbo, A. A. and Osiberu, M. O., 1990. Petroleum prospects of the Nigerian continental margin: Sedimentary basins and petroleum geology of the continental margin of Nigeria. Geological Society of London, Special Publications, 50(1), pp. 187-204.

Ayinde, O., Adefisan, E., and Oluwole, A. (2018). Reservoir Properties Evaluation of Agbada Formation in Parts of Coastal Swamp Depobelt, Niger Delta Using Well Logs and Core Data. Journal of Applied Geology and Geophysics, 6(3), 18-28.

Doveton, J. H. (1999). Basics of oil and gas log analysis. Kansas Geological Survey, 510.

Edet, A.E., Essien, N.U., and Ekwere, S.J. (2017). Facies analysis and depositional environment of the Cretaceous Benin Formation, southeastern Nigeria. Journal of African Earth Sciences, 128, 43-55.

Edoho, S., Akpan, A., and Udo-Inyang, E. (2022). Evaluation of porosity and permeability properties of reservoir rocks in the Niger Delta, Nigeria. Arabian Journal of Geosciences, 15(2), 99. https://doi.org/10.1007/s12517-021-07388-1

Ejedawe, J. E. (1991). The Niger Delta petroleum system: Niger Delta Province, Nigeria, Cameroon, and Equatorial Guinea, Africa. American Association of Petroleum Geologists Bulletin, 75(5), 795-813.

Evamy, B.D., Haremboure, J., Kamerling, P., Knaap, W.A., and Molloy, F.A. (1978). Hydrocarbon habitat of Tertiary Niger Delta. AAPG Bulletin, 62(1), 1-39.

Eze, C. L., Egbule, C. L., and Okeke, P. O. (2018). Hydrocarbon distribution evaluation of a field in the Niger Delta basin, Nigeria using well log analysis. Arabian Journal of Geosciences, 11(15), 414.

Feng, Y., Liu, J., Han, X., and Zhang, L., 2016. A review of porosity evolution models for tight sandstone reservoirs. Journal of Petroleum Science and Engineering, 143, pp. 33-49.

Ghosh, S., and Sharma, S. (2014). Detection of hydrocarbon bearing sandstone reservoirs in Upper Assam Basin, India, using natural gamma radiation logs. Journal of Earth System Science, 123(4), 849-860.

Guo, Q., Guo, X., Liu, Z., Zhang, X., and Song, L. (2018). Research on density correction of gamma-gamma density logging based on wavelet transform. Journal of Applied Geophysics, 158, 42-48.

Joshi, A., Chandel, P., and Kumar, A. (2019). Interpretation of open hole log data for evaluation of formation parameters: A case study. Journal of Petroleum Science and Engineering, 173, 508-521.

Kiakojury, Mostafa and Zakariaei, Seyed and Riahi, Mohammad Ali. (2018). Investigation of Petrophysical Parameters of Kangan Reservoir Formation in One of the Iran South Hydrocarbon Fields. Open Journal of Yangtze Oil and Gas. 03. 36-56. 10.4236/ojogas.2018.31004.

Kumar, R., and Tiwary, A. K. (2019). Evaluation of petrophysical parameters from well logs for reservoir characterization: A case study of a gas field in India. Journal of Petroleum Exploration and Production Technology, 9(2), 1379-1392.

Nwosu, L. I., Okeugo, C., and Ugwu, S. (2018). Evaluation of Reservoir Properties of Nkporo Formation in a Niger Delta Oil Field Using Well Log and Core Data. Journal of Petroleum Technology and Alternative Fuels, 9(2), 25-36.

O'Connor*, S., Hoskin, E., Lahann, R., Lee, J., Ward, C., Gulli, V., and Clancy, S.

Scientia Africana, Vol. 22 (No. 1), April, 2023. Pp 255-278 https://dx.doi.org/10.4314/sa.v22i1.22
© Faculty of Science, University of Port Harcourt, Printed in Nigeria ISSN 1118 – 1931

(2015). Density/Neutron Cross-Plotting; Its Application as a Qualitative Basinal Tool for Pore Pressure Prediction: Case Study North Carnarvon Basin. In International Conference and Exhibition, Melbourne, Australia 13-16 September 2015 (pp. 427-427). Society of Exploration Geophysicists and American Association of Petroleum Geologists.

Ojo, A.O., and Adegoke, O.S., 2014. Sedimentology and sequence stratigraphy of the Akata Formation, offshore eastern Niger Delta Basin. Journal of African Earth Sciences, 99(Part 2), pp. 607-616.

Ojo, O. J., and Adekeye, O. A. (2019). Subsurface geology and hydrocarbon potential of Niger Delta basin: A review. Journal of Petroleum Exploration and Production Technology, 9(4), 3593-3613.

Ojo, T. J., Adepoju, O. T., Alawode, A. O., and Adepelumi, A. A. (2020). Hydrocarbon Potential of the Akata Formation in Parts of the Niger Delta Basin, Nigeria: An Integrated Approach. Journal of Earth Science and Geotechnical Engineering, 10(3), 35-48.

Okiotor, Michael. (2020). Reservoir Evaluation of Well A, Field Y, North-Eastern Niger Delta: A Case of a Problematic Sandstone. 2 (3). 114-126.

Olarewaju, A. J., Falebita, O. O., and Oyekan, S. O. (2020). Petrophysical evaluation of sandstone reservoirs in the Niger Delta: A case study. Journal of African Earth Sciences, 163, 103674. https://doi.org/10.1016/j.jafrearsci.2020.103674

Olasehinde, P. I., Olatunji, A. S., and Aladenika, A. F. (2019). Hydrocarbon evaluation of a field in the Niger Delta Basin, Nigeria using well log and core data. Petroleum Science and Technology, 37(3), 276-284.

Oluwasegun, K. M., Olajide, S. O., Ogunleye, P. O., and Akande, S. O. (2020). Hydrocarbon reserves estimation in the Niger Delta Basin using well logs and core data. Journal of Petroleum Exploration and Production Technology, 10(6), 2509-2521.

Omoniyi, O. O., Akintoye, A. E., and Akintoye, S. A. (2021). Petrophysical evaluation of sandstone reservoirs in the Niger Delta: Implications for hydrocarbon exploration and exploitation. Journal of Petroleum Exploration and Production Technology, 11(6), 3157-3173. https://doi.org/10.1007/s13202-021-01471-0

Onwuka, S.U., Okolie, C.N., and Oshodi, O.O., 2019. The Niger Delta Basin: A Tectonic Overview. In: A. Akujieze (ed.) Advances in Petroleum Exploration and Production, IntechOpen.

Onyekuru, S. O., Olabode, S. O., and Adeyemi, G. O. (2021). Porosity evaluation of sandstone reservoirs in Niger Delta using well logs and core data. Journal of Petroleum Science and Engineering, 200, 108683. https://doi.org/10.1016/j.petrol.2021.108683

Orajaka, I. P. and Okoro, A. U., 2017. Porosity and permeability distribution in the Imo shale formation, Niger Delta Basin, southeastern Nigeria. Journal of African Earth Sciences, 128, pp. 14-27.

Oyeyemi, K. D., Adekoya, J. A., and Okereke, C. S. (2020). Hydrocarbon distribution in an offshore Niger Delta field using well logs and core data. Journal of Petroleum Science and Engineering, 188, 106982.

Short, K. C., and Stauble, A. J. (1967). Outline of geology of Niger delta. AAPG bulletin, 51(5), 761-779.

Siren, G., Atakpo, E., and Ikwuetoghu, O.O., 2018. Sedimentary facies and depositional environments of the Niger Delta. In: H.C. Oyelami and O.O. Ikwuetoghu (eds.) The Niger Delta Region, Springer.

Uko, E. J., and Ekwere, S. J. (2017). Evaluation of hydrocarbon potential of a field in the Niger Delta Basin using well logs and core data. Journal of Petroleum Exploration and Production Technology, 7(1), 163-175.

Ukuedojor, K. O. and Maju-Oyovwikowhe, G. E. (2019) "Reservoir Geometry Determination and Volumetric Reserve Estimation of an Offshore, Niger Delta Basin Nigeria", Journal of Geography, Environment and Earth Science International, 23(2), pp. 1–15. doi: 10.9734/jgeesi/2019/v23i230164.

Ukuedojor, K.O. and Maju-Oyovwikowhe, G.E., 2019. Petrophysical Evaluation and Reservoir Geometry Deduction of Idje Field, Offshore Niger Delta Nigeria. Journal of Geosciences and Geomatics, 7(4), pp.157-171. doi: 10.12691/jgg-7-4-1.

Zhang, Z., Yang, H., Guo, B., and Wu, Z. (2021). An optimized method for predicting the reservoir properties of tight sandstones using logs and machine learning techniques: A case study in the Tarim Basin, NW China. Journal of Petroleum Science and Engineering, 204, 108865. [Original source: https://studycrumb.com/alphabetizer]