Original Scientific Article • DOI: 10.2478/rmzmag-2021-0020
Received: March 20, 2022
Accepted: April 05, 2022

Petrophysical Evaluation of H-field, Niger Delta Basin for Petroleum Plays and Prospects

Petrofizikalna ocena H-polja v bazenu delte reke Niger za scenarije ogljikovodikov in prospekcije

Thomas A. Harry[1], Camillus E. Etim[1], Agbasi E. Okechukwu[2,*]
[1]Department of Geology, Akwa Ibom State University, Mkpat-Enin, Nigeria
[2]Department of Physics, Michael Okpara University Agriculture, Umudike, Nigeria
*Corresponding author: E-mail: agbasi.okechukwu@gmail.com

Abstract in English

As a result of a combination of several methodologies, the H-Field, Niger-Delta, has been delineated. To identify probable reservoirs, seals, and source rocks in the study area, this study integrates sequence stratigraphy with petrophysical concepts through a comprehensive analysis of 3D seismic and well logging datasets. According to the 3D facies model, reservoirs are dominated by sand and are laterally extensive. They were then upscaled and stochastically distributed to create a 3D reservoir property model. On average, the porosity of these clastic reservoirs ranges from 22 to 28%. Reservoir net-to-gross (NTG) ratios range from 0.67 to 0.96. Water saturation ranges from 8% to 30%, while hydrocarbon saturation ranges from 70% to 92%. Four gas-bearing units and six oil-bearing units are present in reservoirs P 0.5 and P 1 compartments. All reservoir intervals' oil and gas volumes are evaluated based on the hydrocarbon distribution. Geological models of the subsurface, such as the one in this paper, are crucial for future reservoir development programs.

Keywords: Niger Delta, Nigeria, Petrophysics, Reservoir Quality Assessment

Abstract in Povzetek

Na podlagi različnih metodologij je opisano H-polje v delti reke Niger. V pričujoči študiji so z namenom identifikacije možnih rezervoarjev, zapornih plasti in izvornih kamnin na podlagi celovite analize 3D seizmičnih podatkov ter popisov vrtin integrirani sekvenčna stratigrafija in petrofizikalni koncepti. Glede na 3D faciesni model v rezervoarjih dominira pesek. Rezervoarji so lateralno širokega obsega. Za izdelavo 3D modela lastnosti rezervoarja so bili faciesni modeli razširjeni v vertikalni smeri in stohastično razporejeni. V povprečju poroznost klastičnih rezervoarjev znaša med 22 in 28%. Neto do bruto (NTG) razmerja rezervoarja so med 0,6 in 0,96. Nasičenost z vodo je med 8% in 30%, medtem ko je nasičenost z ogljikovodiki od 70% do 92%. V P 0,5 in P1 delih rezervoarja so prisotne štiri enote s plinom in šest enot z nafto. Prostornine intervalov z nafto in plinom so ocenjene glede na razporeditev ogljikovodikov. Geološki modeli podlage, kakršen je ta, ki je predstavljen v tem članku, so ključni za prihodnje programe razvoja rezervoarja.

Ključne besede: delta reke Niger, Nigerija, petrofizika, ocean kvalitete rezervoarja

Introduction

Recent research breakthroughs in the energy industry aim to improve subsurface resource utilization through increased output. This may be accomplished by accurately predicting physical and fluid properties in 3D space in order to increase production efficient resource recapture [1]. The essential aspect that governs reservoir appraisal and simulation for improved exploitation and successful development is three-dimensional (3D) modeling of hydrocarbon resources. Despite 3D geological simulation in oil and gas reservoirs is simple utilizing different available software, factors will lead remains a significant barrier that has a significant impact on the successful exploitation of gas resources [2–5]. Data from other sources may be included into the reservoir‘s 3D geologic feature models. Each cell is assigned properties by the modeling system, and numerical reservoir simulations are frequently cell-dependent. Such models impose much bigger loads on the geologist than conventional models do, because at any part of the reservoir‘s 3D volume, geology needs a complete explanation. Multi-integrated properties can be used to define a 3D geological model, which is critical for connecting data from a wellbore to a 3D geological model to create reservoir simulations [6–10].

The hydrocarbon prospective of the Niger Delta Basin‘s with its many fields and depobelts has yet to be completely realized. A thorough and correct fusion of petrophysical and sequence stratigraphic techniques will effectively provide a more accurate picture of reservoir attributes.

Identifying a field‘s depositional context is also crucial in determining reserves and designing optimal reservoir management strategies. Sands formed in various depositional conditions exhibit varying geometry in terms of its body patterns, form, size, and variability [11–12]. This indicates that the physical characteristics of sandstone reservoirs are the result of complex interplay of sedimentological processes. As a consequence, the reconstructing of sandstone successional sedimentological settings offers the ultimate framework for characterizing and evaluating reservoir character variation [13–15].

Given the existence of huge datasets of 2D/3D seismic lines, well logs, and biofacies from oil projects in the basin, the integration of sequence stratigraphy and petrophysics is still to be extensively utilised in the investigation of the Coastal Swamp depobelt. The success of peripheral field operators demonstrates the substantial opportunities of the Niger Delta basin‘s onshore sections. In other words, proper application of petrophysical investigations within those marginal fields would yield additional and greater deposits. This is due to the inclusive process of analysis being robust enough to scan the delta‘s diverse, different structural and stratigraphic features [16].

The current study aims to provide a new set of prospect evaluation in field optimistic parts for modeling reservoir characteristics in the Niger Delta Basin.

Geology of the study area

The study field is located in the Niger Delta Basin, south of the Atlantic, between latitudes 4°N and 6°N and longitudes 3°E and 9°E. It is a huge rift basin surrounded by several other basins in the offset region that have had comparable histories. The geologic setting of the Qua Ibo collapse summarizes the basin‘s tectonostratigraphic framework, which originated when a major piece of the southern margin of the Niger Delta underwent catastrophic failure and slid oceanward as a result of volcanism in the Cameroon hinterland [17].

The H-Field under investigation is located in the offshore depobelt region. Figure 1 depicts a schematic map of the research area, highlighting the possible locations of examined wells. From the bottom up, the

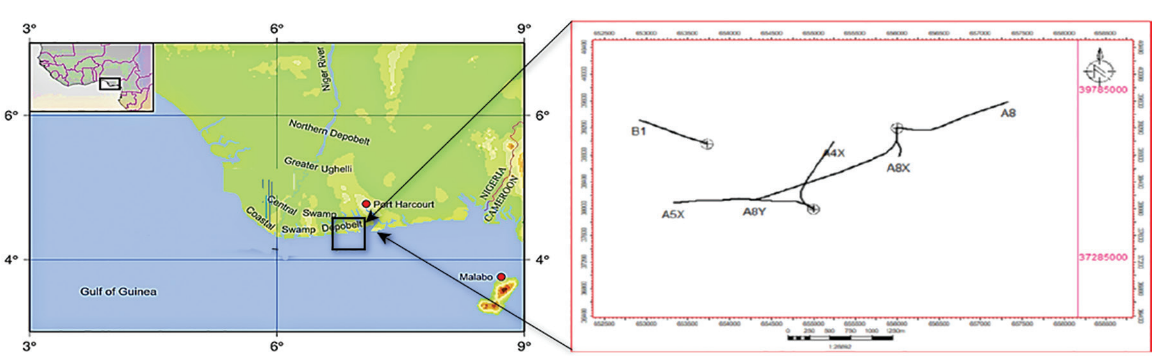

Figure 1: *This map depicts a generic location map of the research region as well as the basic concession map.*

basin comprises three thick, prominent lithostratigraphic units: the AKata Formation, the Agbada Formation, and the Benin Formation. The Paleocene Akata Formation is distinguished by marine shales with excellent source rock characteristics, and its maximum thickness can reach 20,000 feet in the delta's center region [18–20]. The largest source of hydrocarbons is the Eocene Agbada Formation, which formed in a deltaic to the fluvial-deltaic system directly above the Akata Formation. The Niger Delta Basin has a peak Agbada Formation thickness of around 9000 ft. The Benin Formation is the most recent stratigraphic unit, and it is composed mostly of fluviatile sediments [21].

The H-field is located in the Niger Delta's offshore region at a water depth of roughly 12 meters. The 3D seismic survey of H-field was completed in 1996 after being acquired in 1994. It covered approximately 400 km^2, and was conducted in shallow water using a land-type geometry. The inline and crossline processing spacing was 25m. The seismic data is generally of good quality and allows a reliable interpretation to be carried out over the major part of the field area. Before the start of the 2002 drilling campaign, a complete re-interpretation and mapping exercise of the top H3600 and top H3900 reservoirs was carried out using the reprocessed OPL98 3D seismic dataset, integrating all existing well data. Depth maps were generated using a complex depth conversion to account for a pull-down effect due to gas in the eastern part of the field. The 2002 drilled wells are largely used in seismic to well tie and confirming the interpreted structural.

The field structure is on a tilted horst in the central part of the macrostructure. Static reservoir models have been constructed for the H3600 and H3900 reservoirs for computing oil and gas volumes.

Materials and methods

Data sets

This study combines checkshot data, deviation data, geological reports, wireline logs (caliper, compressional sonic slowness, density, gamma-ray, neutron, and resistivity) and 3D seismic volume from H-field drilled wells. There were seven wells available: B1, A5X, A8Y, A4X, A8X, A8 and A1. The methodologies and workflow used in this work are represented in Figure 2.

Well log correlation

The correlation was performed across the wells, and suitable sand makers were identified to designate the reservoir units of significance [22–25]. The hydrocarbon-bearing sands were identified for examination of the field's reservoir potential and mapped at real vertical depth underwater [26–27]. The logs were used to delineate the parasequences and system tracts to determine the depositional settings [22]. The checkshot data has been used to match the depth and time of the seismic and well data (Well to seismic tie). This was also used to pick and determine the depth of the postulated horizons and faults.

Petrophysical analysis

The petrophysical analysis of logs was aimed mainly at determining the reservoir properties using a variety of qualitative and quantitative techniques. The GR logs were used for shale volume determination and lithology identification through discriminating between shale and non-shale beds. The resistivity logs were used in combination with the GR logs to distinguish among oil-gas and non-oil-gas bearing sections. By correlating equivalent intervals of log motif, the gamma-ray log was employed to achieve lithologic correlation of homologous strata among wells [14]. This was expanded to include the lateral extent of prospective hydrocarbon reserves calculated by connecting units across wells. Correlation panels are used to present the results. The well logs were used to construct many crossplots to identify the various correlations among reservoir rock properties characteristics and how they impact the reservoir's ability to retain or transfer fluid [28].

Shale volume estimation

The volume of shale (V_{sh}), which constitutes approximately of shale material in a sandstone or heterolith reservoir, was calculated using

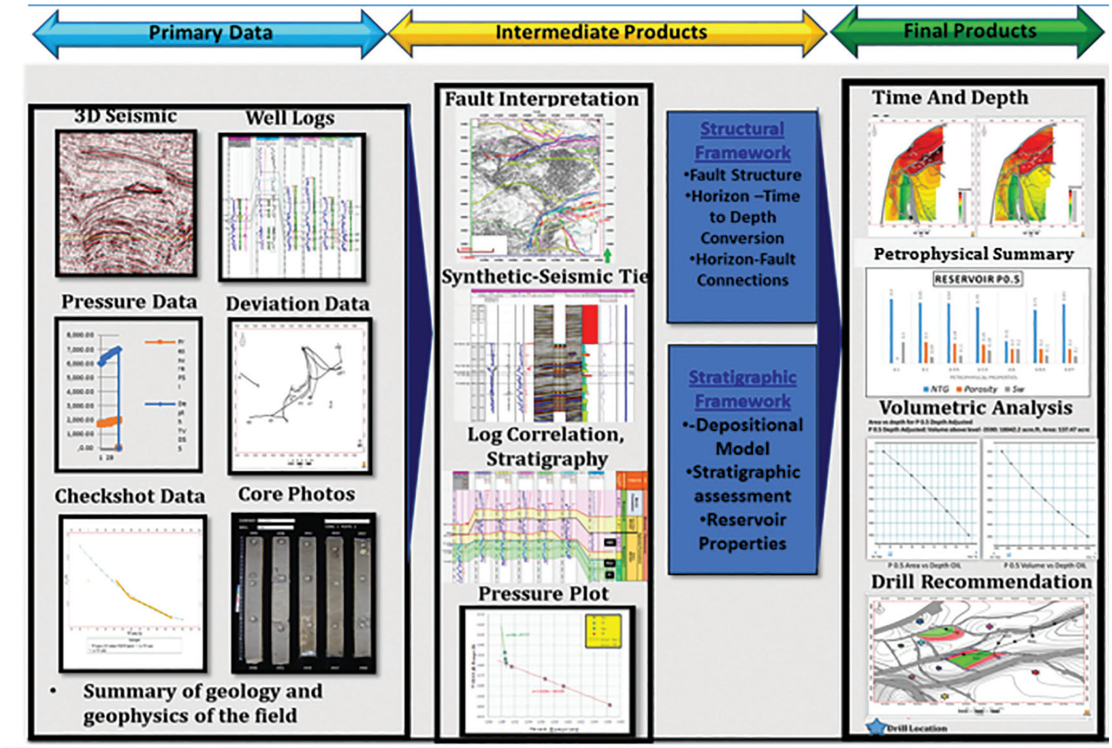

Figure 2: *Flowchart for the methodology utilized in the current study.*

equation 1 [29], that incorporates gamma-ray index (GR) estimates in equation 2.

$$V_{sh} = 0.083^{(2(3.7\times IGR))} \tag{1}$$

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \tag{2}$$

where I_{GR} = gamma-ray index, GR_{log} = chosen log value, and GR_{min} and GR_{max} are the values used for the sand and shale foundation lines.

Determination of porosity

Porosity is described as the proportion of cavities to overall amount of rock (Agbasi, et al. 2021). As shown in equation 3, this variable is calculated by using bulk density values obtained from the formation density log.

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \tag{3}$$

where ϕ = Apparent density porosity, ρ_{Ma}= Matrix density, ρ_b = Bulk density log reading, ρ_f = Fluid density.

Water and hydrocarbon saturation

To compute uninvaded region water saturation, a water resistivity (R_w) estimate at formation temperature calculated from porosity and resistivity records inside clean water zones is employed. To measure the saturation of the reservoir sands‘ fluid content, the formation water saturation was first calculated in equation 4 using Archie‘s water saturation equation:

$$S_w^n = \frac{FR_w}{R_t} \tag{4}$$

where n = saturation exponent, R_w = formation water resistivity, R_t = rock resistivity and F = formation factor.

Hydrocarbon Saturation (S_h) is the proportion of pore volume filled by hydrocarbon in a formation. As indicated in equation 5, it can be computed by deducting the number derived from water saturation from 100 percent.

$$S_h = (100 - S_w)\% \tag{5}$$

where S_h = Hydrocarbon Saturation.

Permeability determination

K denotes a rock's capacity to carry fluids. For each reservoir, permeability is evaluated using equation 6.

$$K = \sqrt{\frac{250 \times Ø^2}{S_{wir}}} \qquad (6)$$

where S_{wir} = irreducible water saturation.

Volumetric hydrocarbon estimation

The use of one or more mathematical models to characterize the petroleum porous structure in the reservoir and also the volumetric migration from of the reservoir to the surface was required for probabilistic hydrocarbon in situ assessment. The hydrocarbon in place was assessed using the net pay zone's average percentage hydrocarbon saturation [5]. The initial oil in situ (OIIP) is calculated as follows:

$$OIIP = GRV \times \frac{N}{G} \times \phi \times (1 - S_w) \qquad (7)$$

GRV = Gross Rock Volume, $\frac{N}{G}$ = Net-to Gross, ϕ = Porosity, S_w = Water Saturation.

Results and discussion

In the studied H-Field, a well tie between the wells was based on the motif sand model (Figure 3) and stratigraphic correlation (Figure 4). The identified reservoirs were classified as P 0.5 and P1. Variable hydrocarbon contact across reservoirs suggests compartmentalization. Reservoir ABC, P0.5, and P1 are Biafra sands, and Reservoir ABC is not widespread as it is frequently truncated by the Qua-Iboe Channel erosive unconformity. P0.5, and P1 are lowstand reservoir facies. As shown in Figure 5, faults and horizons are delineated in the seismic volume using well log-based inferences. Fault pillars were identified and structural modeling was implemented based on the seismic volume's horizon and fault mapping (Figure 6).

It is possible to see a network of faults in time (Figure 7) and depth (Figure 8) maps that cover up to 66% of the surveyed area. Syn-depositional listric faults and small antithetic faults dominate the whole map region. Normal faults have a NW-SE trend and a SW dip. As a result of these structural patterns, the H-Field was able to capture hydrocarbons.

Petrophysical research identified two primary reservoir intervals, P 0.5 and P 1, with

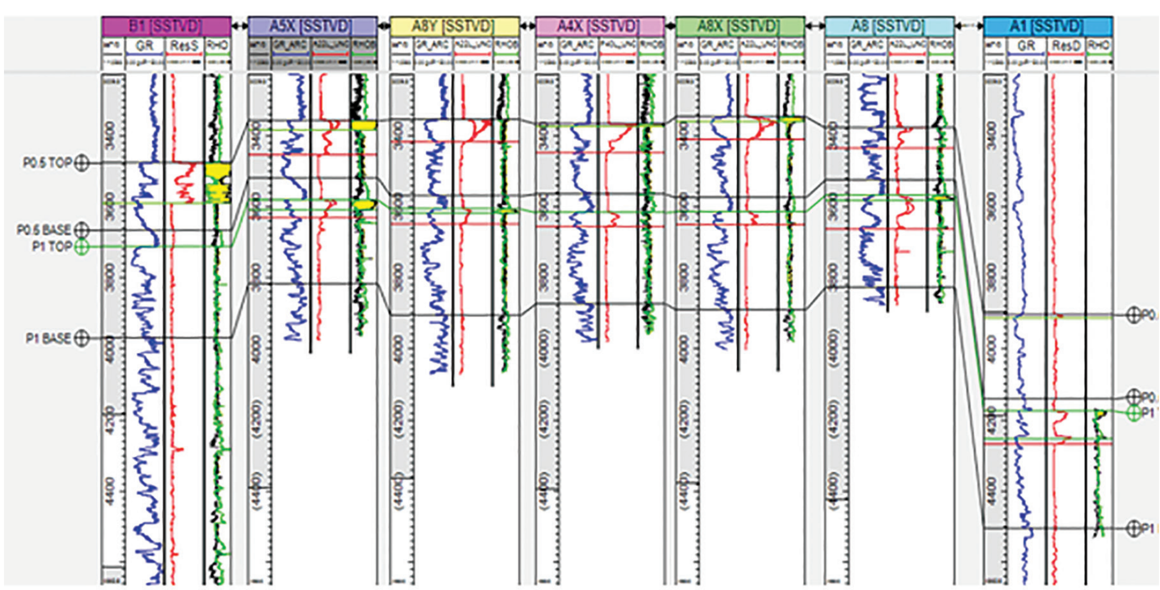

Figure 3: *Well log correlations between the wells analyzed.*

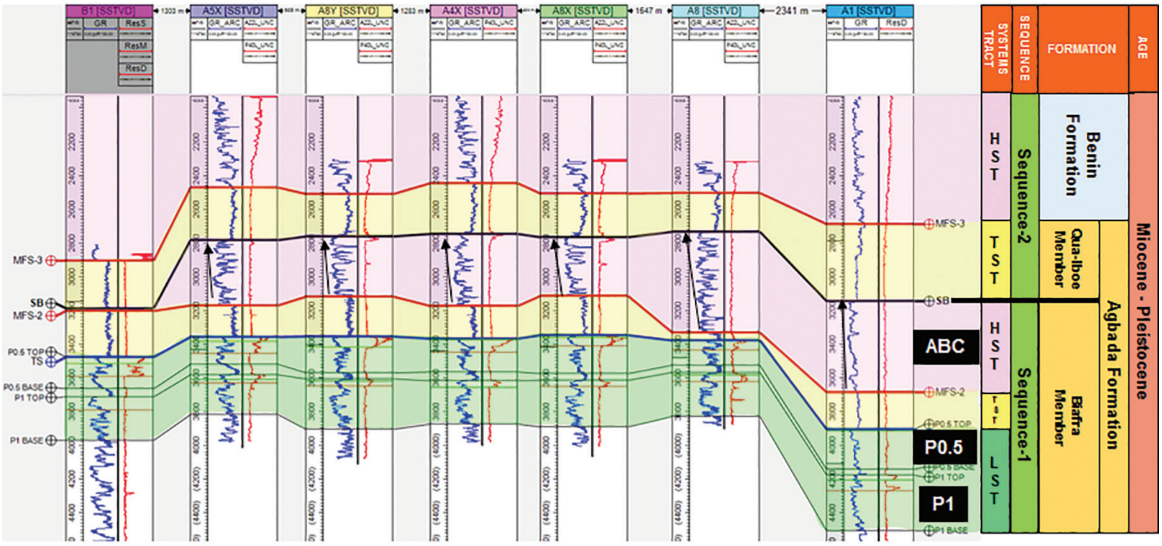

Figure 4: *Well log correlations between the studied wells with stratigraphic correlation.*

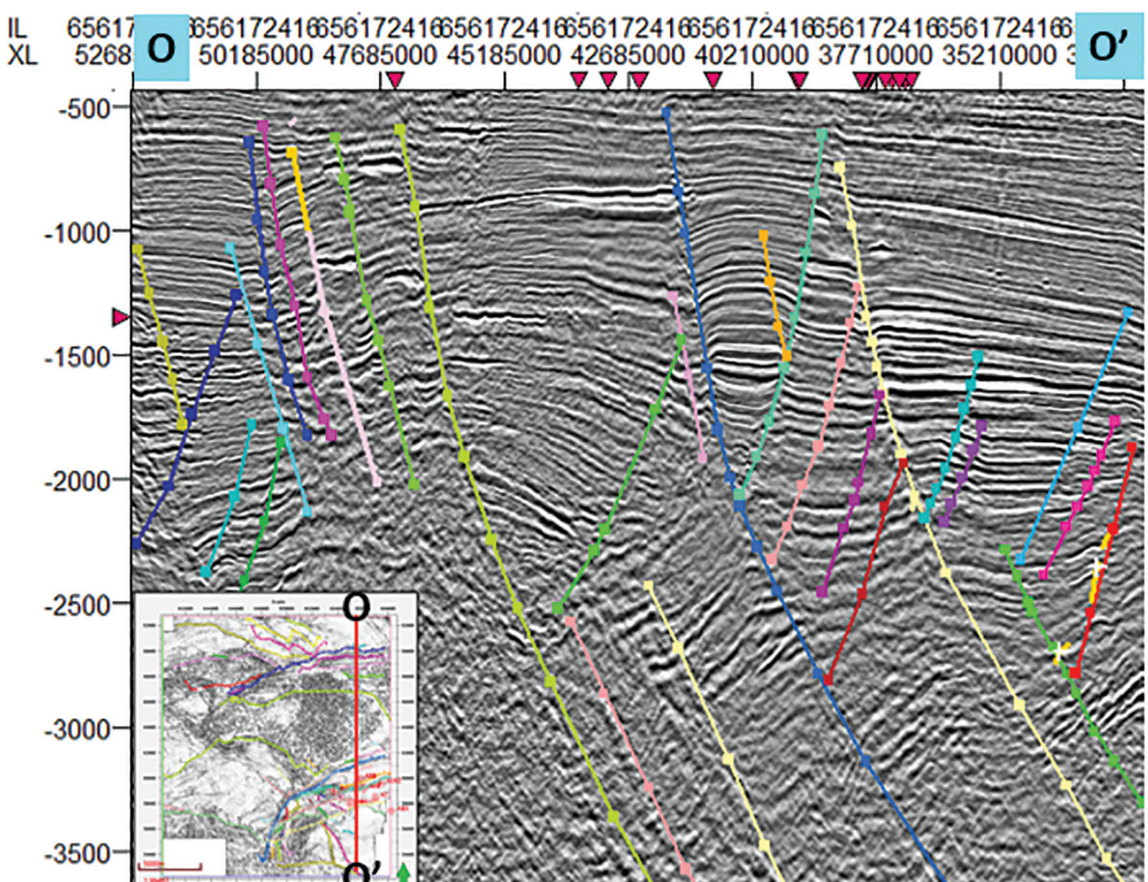

Figure 5: *Fault framework as delineated in the seismic sections.*

depths ranging from low to deeper. Well logs and seismic horizon modeling both demonstrate that all of these reservoirs are widely expansive throughout the simulated region and are impacted by the fault lines. The porosity in these reservoirs ranges between 22 and 29 percent on average. The reservoir net-to-gross (NTG) ratio varies from 0.67 to 0.96.

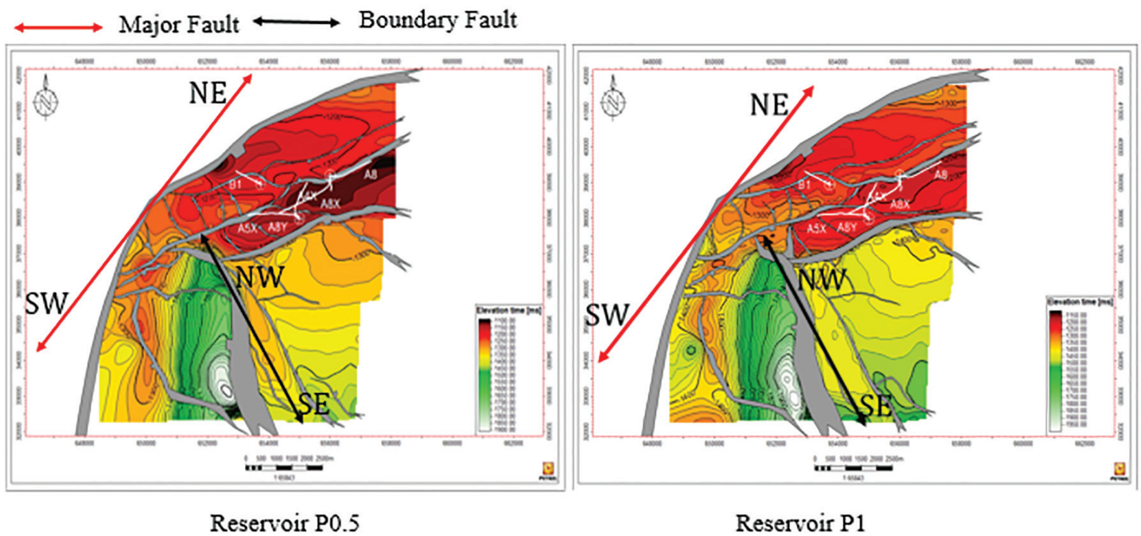

Figure 6: *Horizon and fault mapping for Reservoir P 0.5 and P 1.*

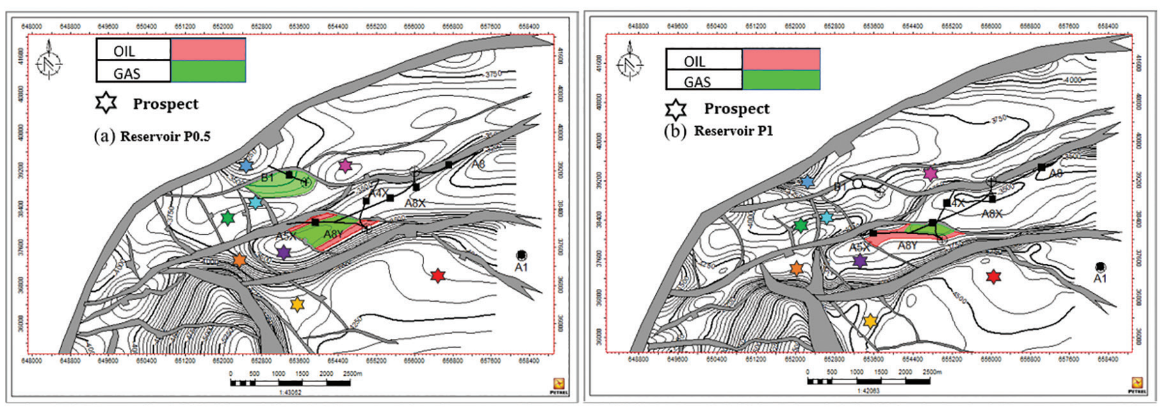

Figure 7: *Depth map for reservoir P 0.5 and P 1 showing GOC from both reservoirs.*

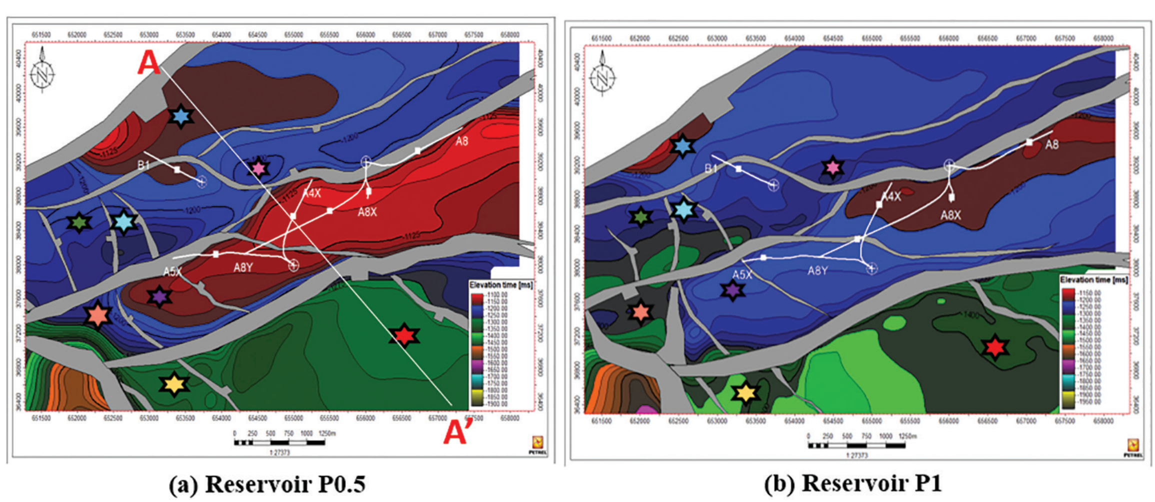

Figure 8: *Time attribute map for reservoir P 0.5 and P 1.*

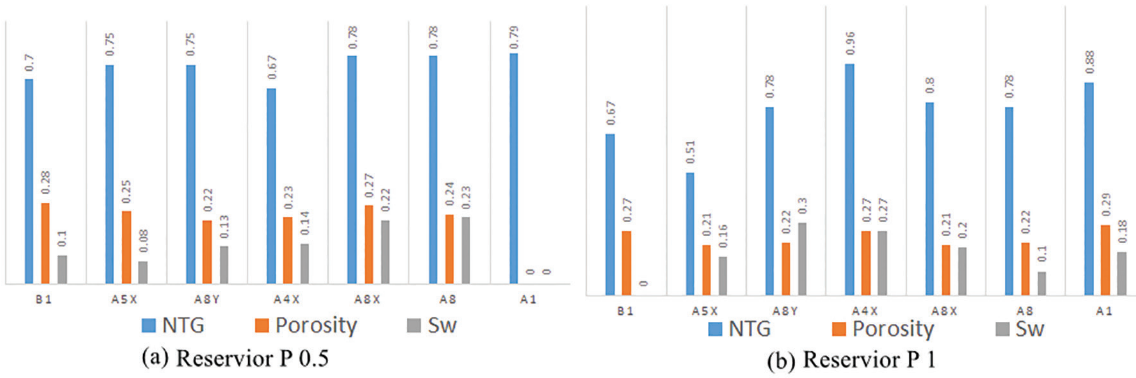

Figure 9: *Summary of the result of the petrophysical analysis from the studied wells for both Reservoir (a) P 0.5 and (b) P 1.*

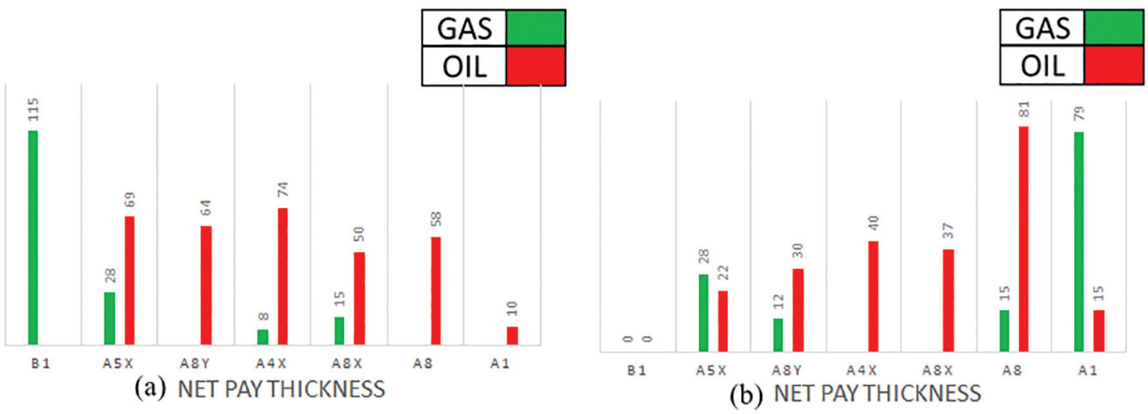

Figure 10: *Summary of the result of the net pay thickness for oil and gas in reservoirs P 0.5 and P 1.*

Water saturation varies from 8% to 30%, while hydrocarbon saturation values vary from 70% to 92%.

According to Figure 9a, well A1 has the greatest NTG value of 0.79 in reservoir P 0.5, whereas well A4X has the lowest NTG value of 0.67. Well B1 has a maximum effective porosity rating of 0.28, whereas well A8Y has the lowest mean value of 0.22. The hydrocarbon saturation is greatest in well A5X at 0.92 and lowest in well A8 at 0.77. In reservoir P1, well A4X has the maximum NTG rating of 0.96, whereas well A5X has the minimum NTG value of 0.51.Well A1 has the highest effective porosity value of 0.29, while wells A5X and A8X have the lowest value of 0.21. The hydrocarbon saturation is greatest in well A8 at 0.90 and lowest in well A8Y at 0.70.

Figure 9 (a & b) depicts a summary graphic of the average values of the results. The H-field has often been demonstrated to have very good to good reservoir quality. Furthermore, the effective porosities are excellent and the hydrocarbon saturation is high. As a result, the field has a significant chance of producing hydrocarbons. When compared to the reservoirs, the sand facies are less laterally extensive and more irregular, resulting in a larger NTG range and more unpredictability water saturation.

The results presented in Figure 10 show that four gas-bearing units and six oil-bearing units are present in reservoirs P 0.5 and P 1. The dominant reservoir fluid type is oil. Figure. 11 shows the 3D static model for wells A5X and B1. Well A5X has both Gas-Oil-Contact (GOC) at 3384ft and Oil-Water-Contact (OWC) at 3453ft. Figure 11 depicts Well B1's only Gas Water Contact (GWC) at 3590 ft. Static reservoir simulation is used to generate the lateral and longitudinal dispersion of the inferred hydrocarbons, which is shown in Figure. 11. The calculated stock tank oil initially in place (STOOIP) and gas initially in place is shown in Table 1 for wells A5X and B1. Figure 12 shows viable prospects in the H-field for exploration.

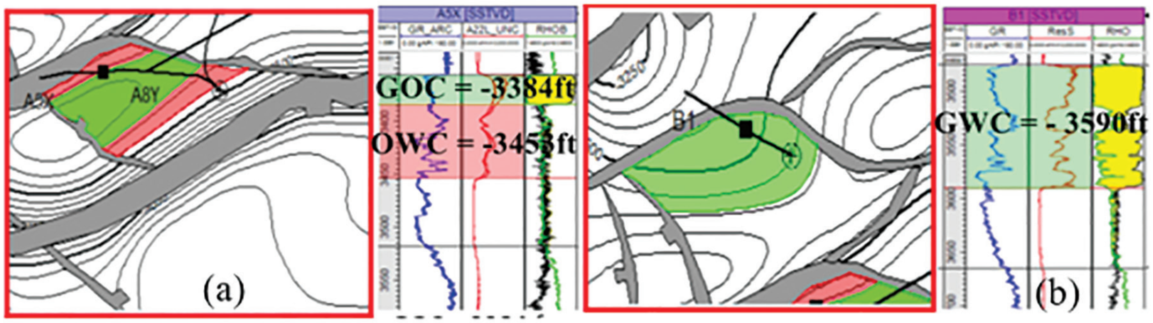

Figure 11: *Oil-gas-water contact in reservoirs P 0.5 and P 1.*

Table 1: *Estimates of mean; porosity, NTG, water saturation, and hydrocarbon volume in the two examined H-Field reservoir intervals.*

Reservoir Interval	Average Porosity (%)	Average NTG (%)	Average Water Saturation (%)	Average Pay Thickness (Gas)	Average Pay Thickness (Oil)	GIIP (BSCF)	STOIIP (MMSTB)
P 0.5	24.3	74.5	64	41.75	54.16	23.83	11.5
P 1	24.1	76	73	33.5	37.5	0.64	1.13

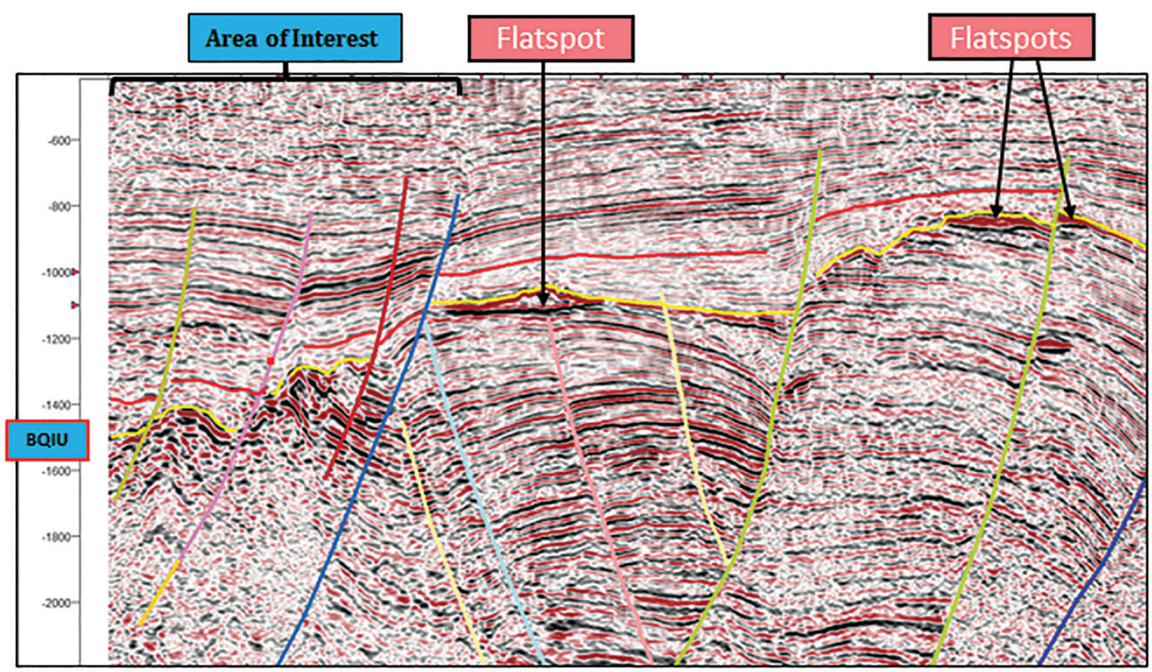

Figure 12: *Viable prospects in the H-field for exploration.*

Conclusion

This study used sequence stratigraphy and petrophysical approaches to predict prospective petroleum plays and prospects for the H-field in the Niger Delta Basin. The current 3D static reservoir simulation provides a better knowledge of the reservoir facies, structural type, and petrophysical parameters' field-wide dispersion. Because of their distinct petrophysical and sequence stratigraphic features, two large clastic reservoir sand sections were regarded as attractive hydrocarbon possibilities. Seismic interpretation and 3D structural modeling are used to evaluate NW-SE trending normal faults that affect hydrocarbon trapping in the research area. According to facies modeling, the sand-dominated reservoir facies has substantial lateral continuity. The porosity range is 22–28 percent, according to the 3D reservoir petrophysical simulation. Utilizing rock properties fluid variety data and volumetric assessment of in-place hydrocarbons, it was found that oil, gas, and water are available in the reservoirs in various proportions so the amounts are sufficient to support effective exploration and mining activities to a certain degree. The subsurface geological model given in this paper is essential for future reservoir development efforts. It could aid in the identification of future well locations. The reservoir models will be more detailed and fine-tuned depending on the prospective well data set in the future.

References

[1] Yu, X.Y., Ma, Y.Z., Psaila, D., Pointe, P.L., Gomez, E., Li, S. (2011): Reservoir characterization and modeling - A look back to see way forward. In: *Uncertainty and reservoir modeling*, Ma, Y.Z., La Pointe, P.R (eds.). AAPG Memoir, pp. 289–309.

[2] Adelu, A.O., Aderemi, A.A., Akanij, A.O., Sanuade, O.A., Kaka, S.I., Afolabi, O., Olugbemiga, S., Oke, R. (2019): Application of 3D static modeling for optimal reservoir characterization. *Journal of African Earth Sciences*, 152, pp. 184–196, DOI:10.1016/j.jafrearsci.2019.02.014.

[3] Adeoti, L., Onyekachi, N., Olatinsu, O., Fatoba, J., Bello, M. (2014): Static reservoir Modeling Using Well Log and 3-D Seismic Data in a KN Field, Offshore Niger Delta, Nigeria. *International Journal of Geosciences*, 5, pp. 93–106.

[4] Jika, H.T., Onuoha, K.M., Dim, C.I.P. (2020): Application of geostatistics in facies modeling of Reservoir-E, "Hatch Field" offshore Niger Delta Basin, Nigeria. *Journal of Petroleum Exploration and Production Technology*, 10, pp. 769–781, DOI:10.1007/s13202-019-00788-1.

[5] Okoli, E.A., Agbasi, O.E., Lashin, A.A., Sen, S. (2021): Static Reservoir Modeling of the Eocene Clastic Reservoirs in the Q-Field, Niger Delta, Nigeria. *Natural Resources Research,* 30(2), pp. 1411–1425, DOI:10.1007/s11053-020-09804-2.

[6] Adesoji, O.A., Oluseun, A.S., SanLinn, I.K., Isaac, D.B. (2018): Integration of 3D Seismic and Well Log Data for the Exploration of Kini Field, Offshore Niger Delta. *Petroleum and Coal*, 60(4), pp. 752–761.

[7] Ahmed, H., Nyeche, M., Engel, S., Nworie, E., Mooij, H. (2011): 3D reservoir simulation of X field onshore Niger Delta, Nigeria: The power of multiple iterations. In: *SPE Nigeria International Conference and Exhibition*, Abuja, Nigeria, July 30-Aug 3. SPE-150730-MS. DOI:10.2118/150730-MS.

[8] Edwin, E.V., Jose, L.P., Carlos, A.M., María, C.H. (2011): High Resolution Stratigraphic Controls on Rock Properties Distribution and Fluid Flow Pathways in Reservoir Rocks of The Upper Caballos Formation, San Francisco Field, Upper Magdalena Valley, Colombia. In: *South American Oil and Gas Congress*, *SPE Western Venezuela Section*, Maracaibo, Venezuela, Oct 18-21. SPE WVS 095.

[9] Godwill, P.A., Waburoko, J. (2016): Application of 3D Reservoir Modeling on Zao 21 Oil Block of Zilaitun Oil Field. *Journal of Petroleum Environmental and Biotechnology*, 7, p. 262, DOI:10.4172/2157-7463.1000262.

[10] Oluwadare, O.A., Osunrinde, O.T., Abe, S.J., Ojo, B.T. (2017): 3-D Geostatistical Model and Volumetric Estimation of 'Del' Field, Niger Delta. *Journal of Geology and Geophysics*, 6, p. 291, DOI:10.4172/2381-8719.1000291.

[11] Inyang, N.J., Akpabio, O.I., Agbasi, O E. (2018): Shale Volume and Permeability of the Miocene Unconsolidated Turbidite Sand of Bonga Oil Field, Niger Delta, Nigeria. *International Journal of Advanced Geoscience*, 5(1), pp. 37–45, DOI:10.14419/ijag.v5i1.7586.

[12] Olubunmi, C.A., Olawale, O.A. (2018): Structural Interpretation, Trapping Styles and Hydrocarbon Potential of Block-X, Northern Depobelt, Onshore Niger Delta. In: *AAPG Annual Convention and Exhibition*, Salt Lake City, Utah, May 20–23.

[13] Oyeyemi, K.D., Olowokere, M.T., Aizebeokhai, A.P. (2018): Hydrocarbon resource evaluation using combined petrophysical analysis and seismically derived reservoir characterization, offshore Niger Delta. *Journal of Petroleum Exploration and Production Technology*, 8, pp. 99–115, DOI:10.1007/s13202-017-0391-6.

[14] Agbasi, O.E., Igboekwe, M.U., Chukwu, G.U., Sunday, E.E. (2018): Discrimination of pore fluid and lithology of a well in X Field, Niger Delta, Nigeria. *Arabian Journal of Geosciences*, 11, p. 274, DOI:10.1007/s12517-018-3610-7.

[15] Agbasi, O.E., Inyang, N., Ibout, J. (2013): Estimation of Water Saturation in Niger Delta Nigeria Using Wire-Line logs. *Journal of Applied Physics (IOSR-JAP).* 3(4), pp. 66–71.

[16] Inyang, N.J., Agbasi, O.E., Akpabio, G.T. (2021): Integrated analysis of well logs for productivity prediction in sand-shale sequence reservoirs of the Niger Delta—a case study. *Arabian Journal of Geoscience* 14(7), p. 587, DOI:10.1007/s11053-020-09804-2.

[17] Harry, T.A., Etuk, S.E., Joseph, I.N., Okoli, E.A. (2018): Geomechanical evaluation of reservoirs in the coastal swamp, Niger delta region of Nigeria. *International Journal of Advanced Geoscience.* 6(2), pp. 165–172, DOI:10.14419/ijag.v6i2.13762.

[18] Igboekwe, M.U., Agbasi, O.E., Chukwu, G.U., Etuk, S.E. (2021): Delineation of apparent water resistivity and porosity exponent of the Miocene unconsolidated sandstone reservoir of coastal swamp depobelt, Niger Delta, Nigeria. *Journal of Sedimentary Environments.* 6(5), pp. 551–559, DOI:10.1007/s43217-021-00068-1.

[19] Ejedavwe, J., Fatumbi, A., Ladipo, K., Stone, K. (2002): Pan-Nigeria exploration well look—back (Post-Drill Well Analysis). Shell Petroleum Development Company of Nigeria Exploration Report 2002.

[20] Doust, H., Omatsola, E. (1990): Niger Delta. In: *Divergent/passive margin basins*, Edwards, J.D., Santogrossi, P.A. (eds.). AAPG Memoir, 48, pp. 239–248.

[21] Tuttle, M.L., Charpentier, R.R., Brownfield, M.E. (1999): The Niger Delta petroleum system; Niger Delta Province, Nigeria, Cameroon, and Equatorial Guinea, Africa. United States Geological Survey (USGS) Open-File Report 99-50- H, DOI:10.3133/ofr9950H.

[22] Adiela, U.P. (2018): Reservoir Modeling Using Seismic Attributes and Well Log Analysis: A Case Study of Niger Delta, Nigeria. In: *AAPG International Conference and Exhibition*, Cape Town, South Africa, Nov 4–11.

[23] Egbe, T., Ugwu, S.A., Ideozu, R.U. (2019): Reservoir Characterization of Buma Field Reservoirs, Niger Delta using Seismic and Well Log Data. *Petroleum and Chemical Industry International*, 2(4), pp. 1–11.

[24] Farouk, I.M., El-Arabi, H.S., Mohamed, S.F. (2017): Reservoir Petrophysical Modeling and Risk Analysis in Reserve Estimation; A Case Study from Qasr Field, North Western Desert, Egypt. *Journal of Applied Geology and Geophysics (IOSR-JAGG)*, 5(2), pp. 41–52.

[25] Ndip, E.A., Agyingyi, C.M., Nton, M.E., Oladunjoye, M.A. (2018): Seismic Stratigraphic and Petrophysical Characterization of Reservoirs of the Agbada Formation in the Vicinity of 'Well M', Offshore Eastern Niger Delta Basin, Nigeria. *Journal of Geology and Geophysics*, 7, pp. 1–9, DOI:10.4172/2381-8719.1000331

[26] Ismail, A., Raza, A., Gholami, R., Reza, R. (2020): Reservoir characterization for sweet spot detection using color transformation overlay scheme. *Journal of Petroleum Exploration and Production Technology,* 10, pp. 2313–2334, DOI:10.1007/s13202-020-00913-5.

[27] Kalu, C.G., Obiadi, I.I., Amaechi, P.O., Ndeze, C.K. (2020): Petrophysical Analysis and Reservoir Characterization of Emerald Field, Niger Delta Basin, Nigeria. *Asian Journal of Earth Sciences*, 13, pp. 21–36, DOI:10.3923/ajes.2020.21.36.

[28] Okoli, E.A., Agbasi, O.E., Samuel, O.O., Etuk, S.E. (2018): Crossplot analysis of rock properties from well log data for gas detection in X-field, coastal swamp depobelt, Niger Delta Basin. *Journal of Geoscience, Engineering, Environment and Technology*, 3(4), pp. 180–186, DOI:10.24273/jgeet.2018.3.4.1318.

[29] Larionov, V. (1969): *Radiometry of Boreholes*. NEDRA: Moscow, pp. 238–240.

[30] Agbasi, O.E., Igboekwe, M.U., Chukwu, G.U., Etuk, S.E. (2021): Formation evaluation of reservoirs in Eocene, Niger Delta Nigeria using modified formation factor from Pickett's plot. *Modeling Earth Systems and Environment*. 6(4), pp. 1–10, DOI:10.1007/s40808-020-01009-z.