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Prediction of Reservoir Performance of Moby Field, Niger Delta Basin using Integrated Facies and Petro Physical Analyses

Ezenwaka KC, Obiadi II, Nwaezeapu VC*, Irumhe EP, and Ede DT

Department of Geological Sciences, Nnamdi Azikiwe University, Awka, Anambra State, Nigeria

Abstract

To effectively predict reservoir performance, and make proper reservoir managements within the depleting Moby field, Niger Delta Basin of Nigeria, the effect of facies changes on reservoir quality has been studied. Well log and 3-D seismic facies analyses were used to determine the depositional facies within the study area, and have shown how the facies changes affect the petrophysical properties of the reservoirs. The facies analysis from the well log showed five subfacies environments and three facies associations. The identified subfacies include; up bar distributary channel subfacies (UD), distributary mouth bar subfacies (DM), intertidal subfacies (IT), sub tidal subfacies (ST), and Storm dominated shelf subfacies (SD). The UD and DM subfacies belong to the delta front facies association, the IT and ST subfacies are of Tidal flat facies association, while the SD subfacies is associated to the Shore face facies. Continuous high and low amplitude (D-facies), high amplitude convergent (CBH-facies), high and low amplitude convergent (CBHL-facies), and low amplitude discontinuous, shingled to chaotic (BL-facies) all make up the four identified seismic facies. The D-seismic facies correspond to the Delta front facies, CBHL-seismic facies correspond to the sub tidal subfacies, and CBH-seismic facies are of the intertidal subfacies, while the BL-seismic facies correspond to the storm dominated shelf facies. Calculation of the sand percentages for the seismic facies show that the D-seismic facies has the highest reservoir percentage, and is ranked highest than the other seismic facies identified. The paleoenvironment of the Moby field was therefore inferred to be marginal to shallow marine environments. Nine reservoirs (H1–H9) were identified from qualitative petrophysical analysis. The H1 and H2 reservoirs are deposits of the delta front facies, the H3–H6 reservoirs are deposits of the intertidal subfacies, while the H7–H9 reservoirs are deposits of the sub tidal subfacies. Quantitative Petrophysical analysis of the reservoirs shows that H1 and H2 reservoirs possess the best petrophysical properties. This is followed by that of the H7–H9 reservoirs, and lastly the H3–H6 reservoirs. The variations in petrophysical properties of the reservoirs within the study area are associated with different depositional conditions and settings.

Keywords: Optimization; ASP; Polymer flooding; Simulation; Sensitivity analysis

Introduction

Hydrocarbon has been of great economic importance to Nigeria and the world at large, and its effectual exploitation is chiefly a function of understanding the characteristic behavior of the conventional reservoirs where hydrocarbons accumulated. The earth is makeup of rocks that vary in properties, and the complexity of the earth due to its heterogeneity impedes the ability to explore its resources maximally. Therefore, the ability to understand the physical and chemical properties of the earth is vital for detailed study of the subsurface and its constituents, especially hydrocarbon.

The understanding of the depositional setting of a field is fundamentally important in the determination of reserves, and in the design of optimum reservoir management procedures. In different depositional environment, the Sands deposited are characterized by different sand body trend, textures and heterogeneity [1]. This tends to show that the physical characteristics of clastic reservoir rocks reflect the response of a complex interplay of processes operating in depositional environments. Hence, the reconstruction of depositional environments in clastic successions provide optimum framework for describing and predicting reservoir quality distribution.

Reservoir performance is usually a function of petrophysical properties of the reservoir, which in turn are strongly influenced by depositional heterogeneity at different scales, as well as diagenetic processes. However, it is necessary to determine changes in facies and how they affect the reservoir quality, for effective prediction of reservoir performance, and for proper reservoir management. This forms the thrust of this study.

Literature Review

Geologic and structural settings

The Moby field is located between latitudes 4° 22'N to 4° 31'N and longitude 6° 57'E to 7° 68'E in Central Swamp Depobelt, Niger Delta Basin (Figure 1) and covers an area extent of 338.83 km^2. The geology of the Tertiary section of the Niger Delta is divided into three formations representing prograding depositional facies distinguished mostly on the basis of sand–shale ratio [2-4].

Its stratigraphy has been elaborated by Short and Stauble, Frankl et al., [2,5] in which they recognized three lithostratigraphic units, namely;

*Corresponding author: Nwaezeapu VC, Department of Geological Sciences, Nnamdi Azikiwe University, Awka, Nigeria, Tel: +234 8067691526; E-mail: victor.nwaezeapu@gmail.com

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the continental Benin Formation, the paralic Agbada Formation, and prodelta marine Akata Formation. The Benin Formation is a continental deposit of alluvial and upper coastal plain sands consisting predominantly freshwater bearing continental sands and gravels deposited in an upper deltaic plain environment. The Agbada Formation comprises paralic siliciclastics consisting of fluviomarine sands, siltstones and shales. The sandy parts constitute the main hydrocarbon reservoir, and their grain sizes ranges from very coarse to fine. The Akata Formation is the basal unit of the Tertiary Niger Delta complex. It is of marine origin and composed of thick shale sequences (potential source rocks), turbidities sand (potential reservoirs in deep water) and minor amount of clay and silt. According to Stacher [6] the Akata Formation formed during low stands when terrestrial organic matter and clays were transported to deep sea water areas characterized by low energy conditions and oxygen deficiency.

From the Eocene to the present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development [3]. These depobelts form one of the largest regressive deltas of the world, and according to Evamy [7] each of the zones constitute a separate province in terms of time-stratigraphy, deformation style, sedimentary facies, and generation and migration of hydrocarbon.

Ekweozor and Daukora [8] presented a detailed report of the petroleum geology and stratigraphy of the Niger Delta, and showed the relationship between depositional patterns, structures and stratigraphy, and their influence on the oil generation in the Niger Delta basin.

3-D seismic studies carried out in the predominantly basin floor setting, offshore Niger Delta revealed the presence of extensive gravity flow depositional elements [9]. Hence, five key elements were observed to include:

(1) Turbidity-flow levee channel.

(2) Channel-over bank sediment waves and levees.

(3) Frontal splays and distributary channel complexes.

(4) Crevasse-splay complexes.

(5) Debris-flow channels, lobes and sheets.

The reservoir geometry of each of this depositional element is a function of the interaction between sedimentary processes, sea floor morphology, and sediment grain-size distribution [10].

Dataset and Methodology

The dataset that was used for this analysis consists of 3-D seismic volume that covers an area extent of 338.83 km^2, four wells with their different log suites, deviation data, and check shot for only one well. For an effective interpretation as regards predicting the reservoir performance of the area of study, three definite but interrelated aspects were used. They include:

(a) Well log facies analysis and associated depositional environments,

(b) Seismic facies analysis, and

(c) Reservoir properties estimations.

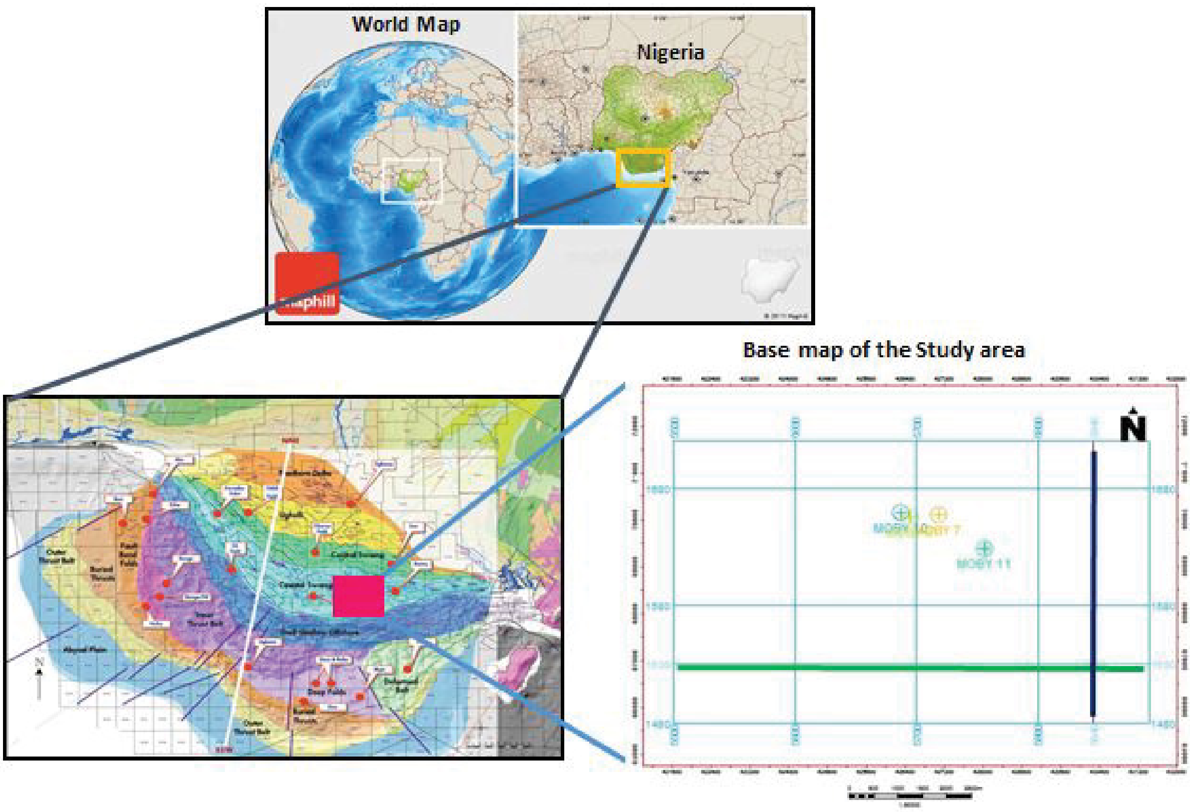

Figure 1: Location map of the study area.

Well log facies analysis and associated depositional environments

The well log facies analysis and associated depositional environments were interpreted using the gamma ray log responses to shaliness according to Cant and Rider [11,12] and the gamma ray responses and different depositional environments according to Kendall [13] as modified from the studies of Cant [12].

The individual log pattern became important because they commonly stack to form larger trends, which may have regional significance. The smooth patterns are commonly indicative of more uniform massive bedding and consistent depositional energy within the bed, while the serrated log curves result from heterogeneous interbedded laminae of silt and clay and short term fluctuations in depositional energy.

Nwaezeapu et al. presented that the electrofacies established on well logs correlate well with the sedimentary facies from core analysis, and the electrofacies established on well logs can be used to directly interpret the pale environments of the well formation [14].

Seismic facies analysis

According to Bourguin et al., Prather et al., and Colombera et al., [15-17], seismic facies analysis involves analyzing the reflection geometry, amplitude, and continuity of seismic reflections to define seismic facies that are linked to specific stratigraphic bodies which can be used to make qualitative lithology prediction away from existing well control and interpretation of environmental setting.

Seismic facies were interpreted based on seismic reflection parameters, including configuration, amplitude, frequency, continuity, and geometry of the reflections, by adopting model of Bourguin et al. [15].

Each parameter provides considerable information on the geology of the subsurface. Reflection configuration reveals the gross stratification patterns from which depositional processes, erosion and pale topography can be interpreted [18]. Continuity in reflection suggests widespread, uniformly stratified deposits. It can be grouped as high, low or variable, and is associated with continuity of strata. The reflection amplitude contains information on the velocity and density contrasts of individual interfaces and their spacing. It can be grouped into high, low, and variable amplitude reflection.

The identified seismic facies were marched with the Gamma ray log in order to observe the log responses within the different facies intervals. Calibration of facies with well control boosts resoluteness in the interpretation because seismic facies are unique, and the continuity and configuration of seismic reflectors changes in a predictable manner from one seismic facies to another [18]. A pie and bar charts of the different facies were also plotted, and the seismic facies with the highest reservoir percentages were selected.

Reservoir quality estimation

The reservoir quality estimation was done in order to identify the distribution of the reservoirs within the study area, and observe how the interpreted facies and depositional environments affect the properties of these reservoirs.

This analysis was done both qualitatively and quantitatively. The qualitative interpretation involves the assessment of reservoir properties from log pattern, while the quantitative interpretation involves the numerical estimation of the reservoir properties. The key rock properties that were studied include the lithology and volume of shale, porosity, permeability, and water saturation. These properties of conventional reservoirs were estimated with the use of the available well logs. The thickness of the reservoir was delineated with the use of Gamma Ray log, porosities were estimated with the use of Neutron and Density logs, while the water saturation was calculated using the resistivity log. Standard formation evaluation techniques as described by Abiola et al., Mitchum et al., Abdolla, Ebuka et al., and Emujakporue [19-23] were used to derive lithology and Volume of shale (Vsh), porosity, as well as water saturation.

Results, Interpretations and Discussion

Lithofacies description

The description of the lithology was done within the paralic Agbada Formation as the well logs used for this interpretation started from that section, except for the Moby 11 well (Figure 2).

The description showed the occurrence of thick layers of sand with low shale volume within interval A (2440.28–3045.01 m for Moby 11 well, and 2530.31 m–2967.61 m for Moby 10 well), an intermediate ratio between the sand and shale volume within interval B (2934.54 m–3529.85 m for Moby 11 well, 2967.61 m–3564.76 m for Moby 10 well, 2960.26 m–3535.36 m for Moby 5 well, and 2919.84 m–3491.27 m for Moby 7 well), a relatively thick volume of sand and small shales in interval C (3529.85 m–4027.78 m for Moby 11 well, 3564.76 m–3926.73 m for Moby 10 well, 3536.36–3825.67 m for Moby 5 well, and 3491.27 m–3930.40 m for Moby 7 well), and a thick volume of shale with little sands in interval D (4027.78 m–4408.12 m for Moby 11 well. 3926.76 m–4306.90 m for Moby 5 well, and 3825.67 m–4343.81 m for Moby 7 well).

The litho-description allowed for an effective interpretation of the sub–facies environments, as well as the facies associations, with which the depositional environments were inferred.

Well log facies analysis

Six distinct log patterns were identified based on the Gamma ray log motifs as described by Cant [11]. The log successions were identified within intervals in Moby 11 well and correlated across the other wells and sub environments of deposition were assigned to the different log patterns (Figure 3).

Facies I (Interval 2440.28–2693.84 m)

The approximated thickness of this subfacies is about 253.56 m. The unit consists of very thin shale and thick sand beds. On the Gamma ray log motif of Moby 11 well, the sand show a blocky serrated cylindrical shaped log motif, characteristic of deposition within an up bar distributary channel (UD) sub-facies environment (Figure 3). It is correlated between the intervals of 2530.31–2743.45 m in Moby 10. This subfacies unit was not identified in Moby 5 and 7 wells because the provided well log data (Gamma Ray) was missing for that section.

Facies II (Interval 2693.84 m - 3045.01 m)

This subfacies is approximately 351.17 m in thickness, and is correlated within intervals (2743.45–2967.61) in Moby 10 well. The unit comprises of very thick sand with minor shale beds. The sands show a coarsening upward log signature (serrated funnel shape) with a sharp top on the Gamma ray log. This is indicative of deposition within the distributary mouth bar (DM) (Figure 3) as described by Cant [11]. The

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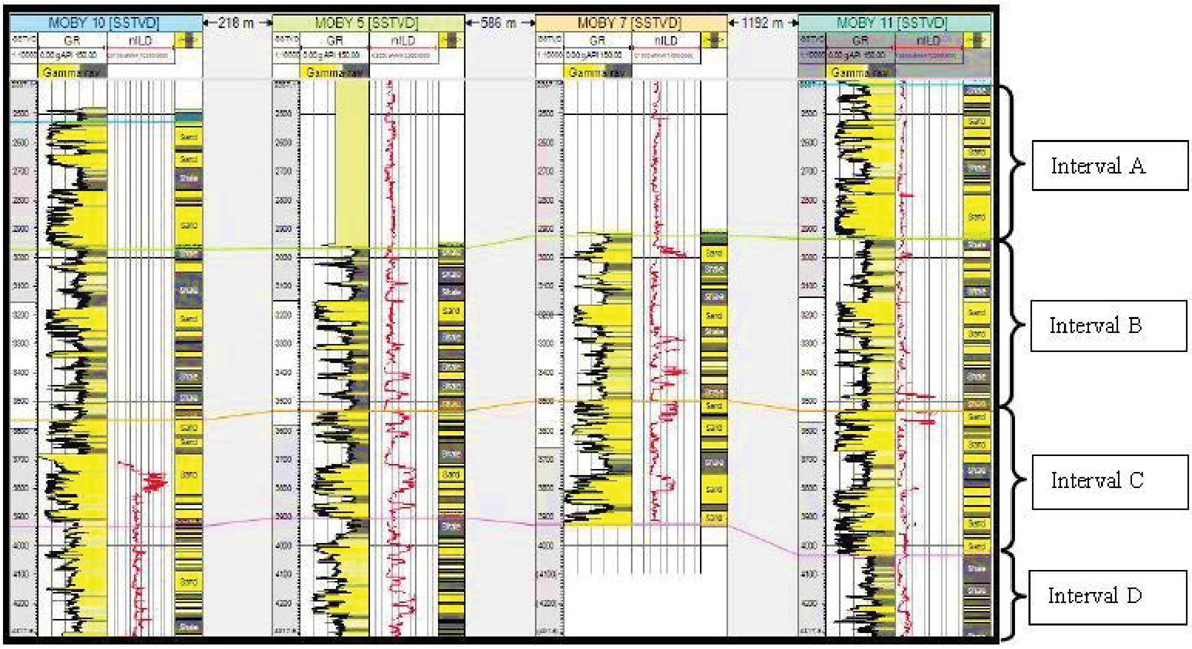

Figure 2: Lithologic description of the study area showing the different lithologies distributed vertically and laterally across the four wells.

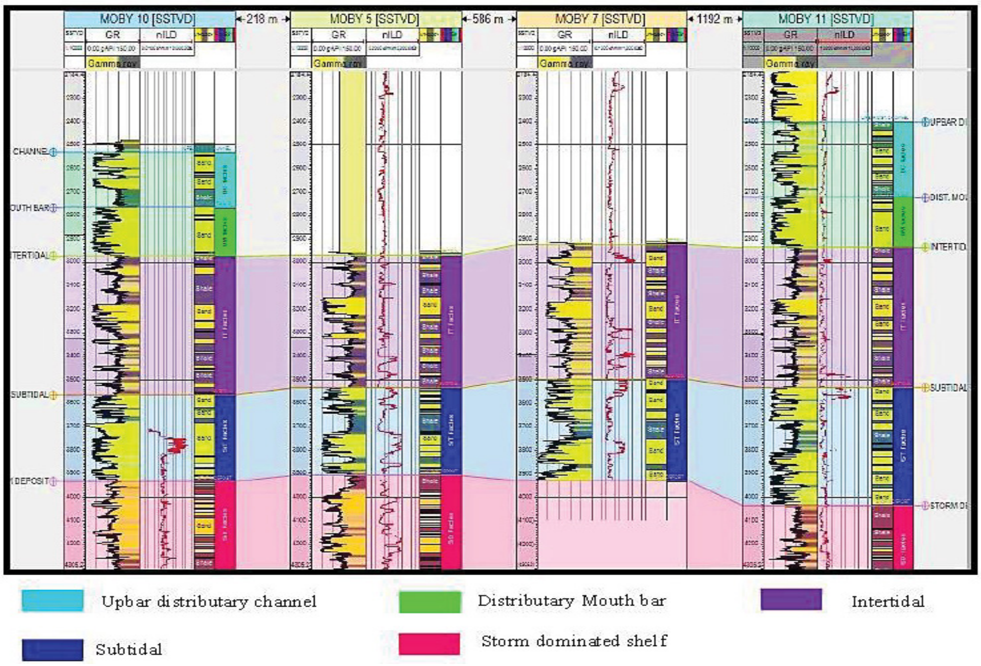

Figure 3: Subfacies units of the study area correlated across Moby 10, 7, 5, and 11.

distal portion consisting of minor shale is associated with the distal bar which receives sediments only sporadically during floods.

Facies III (Interval 2934.54–3529.85 m)

This unit is about 595.31 m thick, and occurs between intervals (2919.84–3491.27 m, 2960.26–3535.36 m, and 2967.61–3564.76 m) in Moby 7, 5 and 10 wells respectively. It comprises of heterolithic lithology made up of beds of sands and shales. The sands unit as observed in the wells exhibit fining upward with sharp base Gamma-ray log motifs and is interpreted as intertidal (IT) subfacies environment (Figure 3). The thick sand unit occurring within the upper section of this interval is inferred to be a tidal channel. The heterolitihs indicate deposition from reversing tidal current [24,25] and represents inter tidal succession of decreasing current energy [26].

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Facies IV (Interval 3529.85–4027.78 m)

This subfacies occurs within intervals (3491.27–3930.40 m, 3535.36–3825.67 m, and 3564.76–3825.67 m) in Moby 7, 5, and 11 wells respectively. It is approximately 497.93 m in thickness. It comprises of very thick sand separated by thin bands of shale. The Gamma ray log motifs as observed from the wells show that the sands in this section has a fining upwards log motif (serrated bell shape) (Figure 3). This is indicative of deposition within a sub tidal (SB) subfacies environment. The sand observed in this subfacies decreases in thickness from SE to NW (in the order: Moby 11, 7, 5, 10).

Facies V (Interval 4027.78 m–4408.12 m)

This subunit is about 380.34 m thick. It comprises of very thick shale separated by thin interbedded sands. The sands show serrated Gamma ray log motifs, suggestive of storm-dominated (SD) shelf subfacies environment (Figure 3). The interval is correlated within intervals (3825.67–4343.81 m and 3926.73–4306.90 m) in Moby 5, and 10 wells.

Facies associations

The identified subfacies were grouped into facies association which allowed for the interpretation of the depositional environments. The facies were grouped into three facies associations namely; Delta front facies, tidal flat facies, and shore face facies (Figure 4).

The deposits of the up bar distributary channel and the distributary mouth bar were interpreted as delta front facies, the intertidal and the sub tidal subfacies were interpreted as tidal flat facies, while the storm dominated shelf was inferred to be of shore face facies.

Depositional environments

The interpretation of the depositional environments is based on the electrofacies, as well as the facies associations as described from the wire line logs.

Based on the identified subfacies in the study area which include; an up bar distributary channel, distributary mouth bar, intertidal, sub tidal, and storm dominated shelf, as well as the facies associations including; a delta front, a tidal flat, and a shore face facies, the environment of depositions of the area has been inferred to be marginal marine to shallow marine environments. The subfacies, association of facies, and the inferred depositional environments are shown in Table 1 below.

Seismic facies analysis

The seismic facies analysis allowed for the identification of four distinct seismic facies, they include; the D-Facies (Continuous high and low amplitudes), Cbh-Facies (High amplitude convergent), Cbhl-Facies (High and low amplitude convergent), and Bl-Facies (Low amplitude discontinuous, shingled to chaotic).

Calibration of the seismic facies with the well logs enhanced the confidence level of the interpretation (Figure 5). The D-facies corresponded to the Delta front facies, consisting of both the up bar distributary channel, and the distributary mouth bar. The Cbh-facies corresponds to the intertidal sub facies, the Cbhl-facies is attributed to the sub tidal subfacies, while the Bl-facies corresponds to the shore face facies.

Statistical representation showing calculation of the sand percentages for the seismic facies allowed prediction of reservoir potentials suggesting that seismic facies that have higher sand percentages should conform to exploration targets (Figure 6).

The D-facies has the highest reservoir percentage occurring consistently across the penetrated wells, and has therefore been ranked highest than the other seismic facies identified. This is followed by the reservoir percentage of the Cbhl-facies, then those of the Cbh-facies, with the lowest being the Bl-facies.

Reservoir quality estimations

Nine distinct reservoirs (H1–H9) were identified from the Gamma ray log. Reservoirs H1, and H2, were found to be deposited within the delta front sub-environment. Reservoirs H3, H4, H5, and H6 occur within the intertidal subfacies environment, while reservoir H7, H8, and H9 occur within the sub tidal subfacies environment, both of which are deposits of the tidal flat environment.

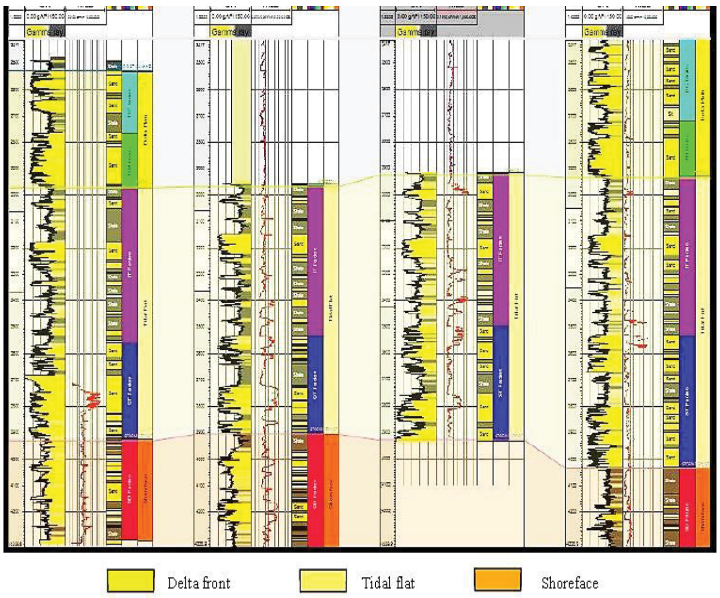

Figure 4: Well panel displaying the interpreted facies associations for the study.

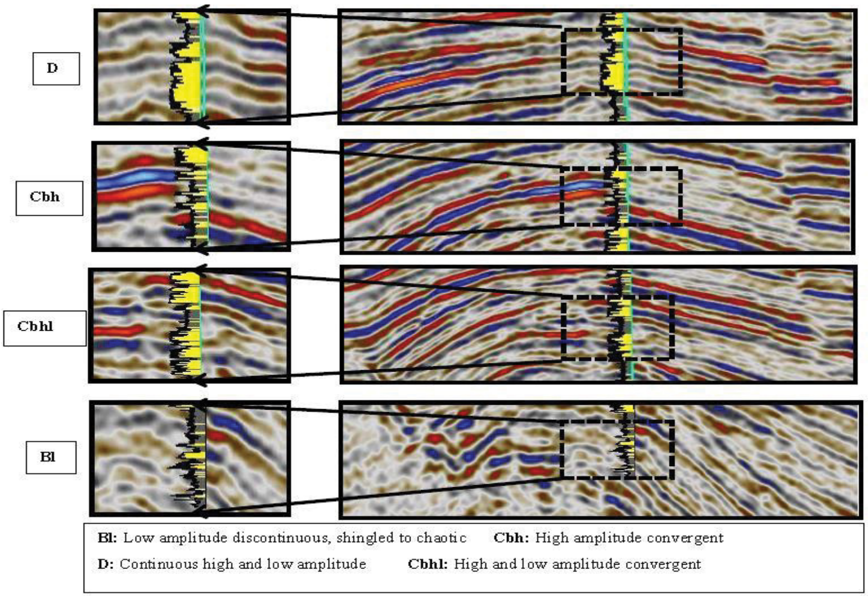

Figure 5: Seismic facies interpretation calibrated with well gamma ray log.

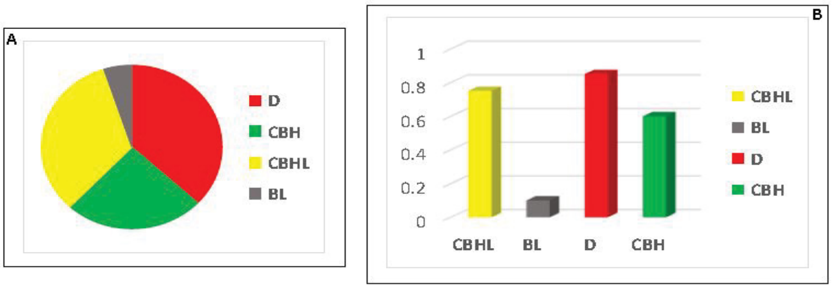

Figure 6: Seismic facies and their corresponding sand percentages.

The average reservoir properties as estimated from well logs from the study area is shown in Table 2, while the relationship between the average reservoir properties are presented in Figure 7.

Effect of facies changes on reservoir properties

In different structural units of a basin, different sedimentary facies develop. So also, different characters of lithologic rocks develop in different sedimentary facies, and variable porosity and permeability develop in different rocks. The enrichment and mechanism of hydrocarbon accumulation in reservoirs with different porosity and permeability vary in oil bearing basins. Hence, sedimentary facies and lithologic characters are important factors controlling hydrocarbon accumulation.

Sedimentary facies controlling hydrocarbon accumulation refers to reservoir having high porosity and permeability favorable for hydrocarbon to accumulate. Reservoirs formed in different sedimentary facies are significantly different in clastic composition, structure, particle size, sorting, and single-layer thickness. The identification of favorable sedimentary facies guides effort to identify the distribution of favorable exploration areas in sedimentary basins.

The distribution of reservoirs within the study area occurs in different sedimentary facies and subfacies which are associated with different depositional conditions and settings. The reservoirs occur within the delta front facies, as well as the tidal flat facies (intertidal and sub tidal sub facies), and have varying petrophysical properties.

The reservoirs present within the delta front facies precisely in the up bar distributary channel, and the distributary mouth bar exhibit the best reservoir properties. They have very high porosity and permeability values, high percentage of sand, with high Net to Gross (NTG). Reineck et al., [27] noted that the distributary mouth bar sand bodies of the fan delta front have good sorting, high maturity, good porosity, and high permeability, and in addition, the horizontal and vertical extent of the sand bodies are large, and can be overlapped. Thus, allowing them rank highest than the other reservoirs identified in terms of their reservoir properties.

This is followed in ranking by the reservoir rocks distributed within the sub tidal subfacies environments. These reservoirs also exhibit good reservoir properties, having good porosity and permeability values, as well as high NTG. According to Dalrymple, Chen et al., and Jackson et al., [28-30] tidal sandstone reservoirs contain significant intervals of hydrocarbon bearing heterolithic facies, characterized by the presence of tidally generated sedimentary structures.

The presence of these tidally generated sedimentary structures usually affects the reservoir properties of hydrocarbon reservoirs

Subfacies	Facies Associations	Inferred depositional Environments
Upbar distributary channel	Delta Front	Marginal Marine
Distributary Mouth bar		
Intertidal	Tidal Flat	
Subtidal		
Storm dominated Shelf	Shore face	Shallow Marine

Table 1: Subfacies, facies associations and inferred depositional environments of the study.

Reservoir	Facies	Average Gross (m)	Average Net (m)	Average NTG	Average Porosity	Average Permeability (md)
H1	Delta Front	151.94	136.76	0.9	0.32	7102.42
H2		205.79	198.7	0.96	0.35	9132.38
H3		37.91	29.06	0.69	0.23	451.29
H4	Intertidal	20.64	20.14	0.98	0.22	343.01
H5		20.09	13.95	0.72	0.23	273.48
H6		21.62	13.13	0.63	0.23	451.01
H7	Subtidal	134.66	109.51	0.8	0.28	1437.85
H8		106.14	98.62	0.92	0.26	5823.83
H9		48.05	43.21	0.88	0.25	1099.55

Table 2: Average petrophysical properties of the reservoirs within the study area.

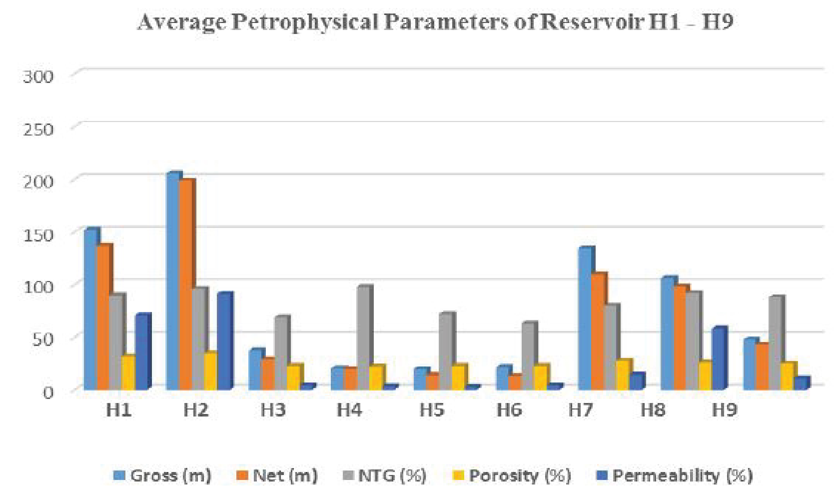

Figure 7: Relationship between average petrophysical properties of the reservoirs.

present within a tidal flat. However, the sub tidal zone encompasses the part of the tidal flat that normally lies below mean low tide level. Deposition of materials takes place mainly by lateral accretion of sandy sediments in tidal channels and point bars, and they are influenced to some extent by wave processes. This explains for the thick sands with good reservoir properties observed within the sub tidal zone.

The third in ranking are reservoirs present within the intertidal subfacies environment still in the tidal flat. As stated earlier, hydrocarbon reservoirs formed in tidally influenced environments contain significant intervals of heterolithic sandstones. They are characterized by the presence of complex millimeter to centimeter scale intercalations of sandstones and shale or mudstones. These small scale intercalations are highly variable both laterally and vertically, and commonly reflect diurnal and/or semi diurnal variations in depositional energy during the tidal cycle [26]. This is highly evident in the reservoir thickness observed in reservoirs present in this subfacies, as they are very thin and are separated by layers of shale, resulting to the non-connectivity of the reservoirs. The porosity and permeability, reservoir thickness, as well as NTG values observed within the reservoirs present in this facies are appreciably low compared to those observed in the other facies. Therefore, the facies has been ranked lowest with respect to reservoir properties.

Based on the reservoir properties as interpreted from this work, the productivity and effectiveness of the reservoirs has been ranked from those occurring within the delta front facies as highest, followed by those of the sub tidal subfacies, and then the intertidal subfacies environments.

Conclusion

Understanding the depositional settings of a field is fundamentally important in the determination of reserves and in the design of optimum reservoir management procedures. Sands deposited in different depositional environments are characterized by different sand body trend, shape, size, and heterogeneity. This tends to show that the physical characteristics of clastic reservoir rocks reflect the response of a complex interplay of processes operating in depositional environments. Hence, the reconstruction of depositional environments in clastic successions provides optimum framework for describing and predicting reservoir quality distribution.

This research has shown how the changes in depositional facies affect the petrophysical properties of the underlying reservoir rocks with respect to reservoir performance, with a view of making an effectual reservoir management. It allowed the identification of five subfacies environments and three facies associations. The identified subfacies include; up bar distributary channel subfacies (UD), distributary mouth bar subfacies (DM), intertidal subfacies (IT), sub tidal subfacies (ST), and Storm dominated shelf subfacies (SD). The UD and DM subfacies belong to the delta front facies association, the IT and ST subfacies are of Tidal flat facies association, while the SD subfacies is assigned to the shore face facies.

The seismic facies analysis further allowed and enhanced the identification of the exploration play facies of interest. Four seismic facies including; D-facies, CBH-facies, CBHL-facies, and BL-facies were identified. Calculation of the sand percentages for the seismic facies allowed prediction of reservoir potentials suggesting that seismic facies that have higher sand percentages should conform to exploration targets. The D-seismic facies corresponding to the Delta front facies when calibrated with the well logs has the highest reservoir percentage. This is followed by the CBHL-seismic facies corresponding to the sub tidal, then the CBH-seismic facies of the intertidal subfacies, and the BL-seismic facies corresponding to the shore face facies. The reservoir quality analysis had that, of the nine reservoirs (H1–H9) that were identified, H1 and H2 reservoirs belonging to the delta front facies possess the best petrophysical properties. This is followed by that of the H7–H9 reservoirs of the sub tidal subfacies, and lastly the H3–H6 reservoirs corresponding to the intertidal subfacies. The variations in petrophysical properties of the reservoirs within the study area are associated with different depositional conditions and settings. This study has successfully predicted reservoir performance of the Moby field using an integrated approach in order to make proper reservoir managements, and serves as a guide to ensure future exploration success.

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