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Sequence Stratigraphy and Petrophysical Evaluations of the Miocene Sediments in the Eastern Niger Delta Basin, Nigeria

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Abstract

Miocene sediments from nine oil wells in the Eastern Niger Delta basin were subjected to both stratigraphic sequence analysis and petrophysical evaluation, which established a good relationship among reservoir properties with various depositional sequences. Three sequence boundaries (SB 8.5Ma, SB 10.35Ma and SB 10.6Ma) and three maximum flooding surfaces (MFS 9.5Ma, MFS 10.4Ma and MFS 11.5Ma) were important stratigraphic surfaces established within the field. These surfaces cut across various depositional settings from fluvial proximal marine to shoreface environments. Reservoir sand-A was interpreted as a channel sand within the fluvial setting and showed good reservoir properties with average net-to-gross ratio of 0.9, average porosity value of 19.23% and average permeability value of 540mD. Reservoir sands-B, C and E were interpreted as shoreface sands with good to excellent reservoir properties with average net-to-gross ratio ranging from 0.8 to 0.98, average porosity values ranging from 9.2 to 23% and average permeability values ranging from 189 to 996mD. At the top of the stratigraphic sequence was a transgressive shale sequence, which probably formed an excellent seal facies that perhaps trapped the observed hydrocarbon occurrence in the area.

Key words: Sequence Stratigraphy, Petrophysical Evaluation, Depositional Environments, Reservoir Sand and Miocene Niger Delta

Introduction

Petroleum production from conventional reservoirs is on the decline globally. Exploration and Production companies are now developing complex reserves by focusing on the microscopic pore spaces of reservoirs that are filled with hydrocarbon. Thus, the need to relate the reservoir properties to high resolution sequence stratigraphic analysis to make a detailed predictions of specific intervals with optimum reservoir connectivity, distribution and stratigraphic trapping potential (Lang *et al*, 2002). Physical evaluation of reservoir properties is one of the most useful and important technique that helps define physical rock characteristics such as lithology, porosity, permeability that is used to identify productive zones, thickness and depths to hydrocarbon zones and estimate hydrocarbon reserves. (Asquith and Gibson, 1997).

Sequence stratigraphic analysis is also another successful technique in the exploration of petroleum resources. This technique has advanced through seismic stratigraphy as a methodology for stratigraphic interpretation. (Vail and Wormardt, 1991).This was applied in the Niger Delta basin, which has restated the potential for the prediction of hydrocarbon (Stacher, 1995). The application of sequence stratigraphy in the Niger Delta basin has enhanced the interpretation of stratigraphic build-ups, recognized isochronous surfaces and identify prospects and leads (Nwokocha and Oti, 2016).

The paper is aimed at establishing relationships among reservoir properties with various depositional sequences within the Miocene Niger Delta through the erection of a stratigraphic framework of genetically related chronostratigraphic surfaces of the field under study and evaluation of their reservoir petrophysical properties.

Geology of the Niger Delta Basin

The Niger Delta basin is situated at the southern part of Nigeria bordering the Atlantic ocean. It covers an area of approximately 75,000 square kilometres. The basin evolved from the separation of the African and South American continental plates.

Several Scholars such as Grant (1971), Burke (1971) and Wright (1976) proposed that the origin of the basin started after the development of the **RRR** (ridge-ridge-ridge) system. The failed arm of this triple structure is the Anambra-Benue rift valley within which the oceanic crust was inactive. The rivers depositional centres moved seawards thus making the coastal plain deposits to become progressively younger in that direction.

Short and Stauble (1967) divided the tertiary deltaic complex into three depositional lithofacies identified as the Akata Formation, Agbada Formation and Benin Formation respectively. Agbada Formation constitutes the main reservoir of hydrocarbon in the Niger Delta.

Location of the Study Area

The study area (Fig. 1) is located in OML18 and 24, which is part of the coastal swamp Depobelt of the Eastern Cenozoic Niger Delta. It is about 40KM South West of Port Harcourt, Rivers State. Its coordinates are longitudes $6^0 46^1$ - $6^0 53^1$E and latitudes $4^0 28^1$ - 4^0 32^1N. Sediment deposition started in the Early Miocene times

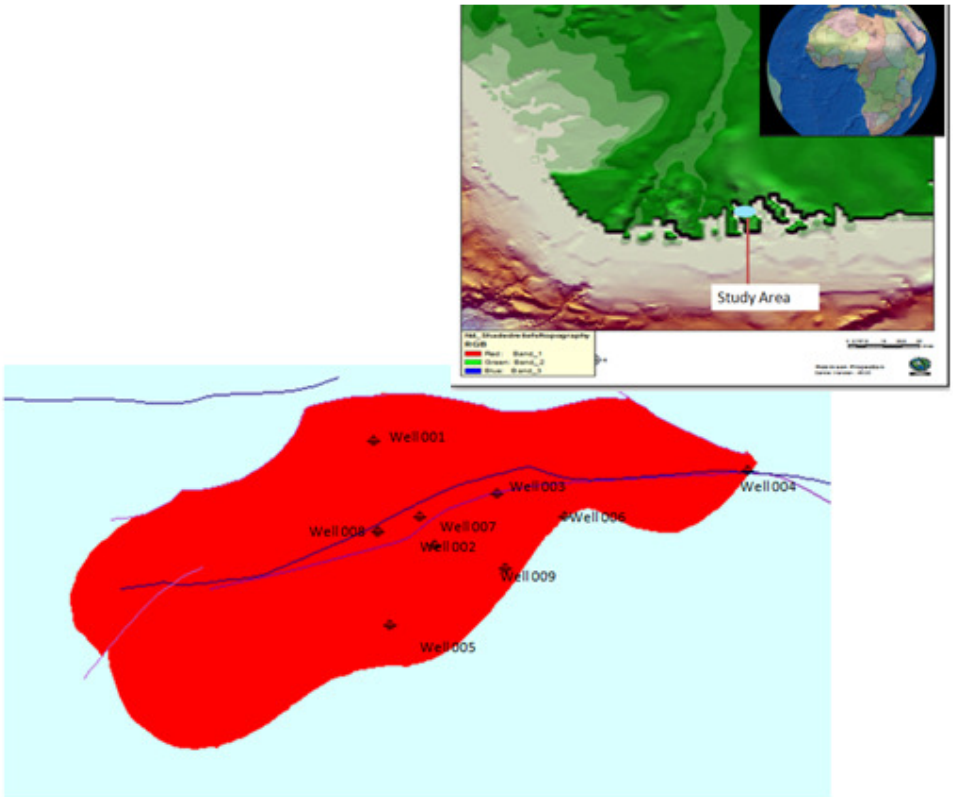

Fig. 1: Satellite Imagery of the Niger Delta basin, showing the study area and base map of the studied field showing well positions (insert is the map of Africa)

Materials and Method

Biofacies data and suite of wire line logs were used for the study. The biofacies data were used to construct the sequence stratigraphic framework of the area (Posamentier *et al.* 1988, Vail and Wormardt 1990, Van Wagoner *et al.* 1990, Mitchum and Van Wagoner 1994). A decrease in the total faunal and planktonic abundances corresponded to sequence boundaries and were interpreted to represent a fall in the relative sea level, while an increase in the total abundance of faunal and planktons, high peaks in the curve corresponded to maximum flooding surfaces and were interpreted to represent a rise in the relative sea level in the area. The highest and lowest deflections of the resistivity logs were used to confirm already established maximum flooding surfaces and sequence boundaries respectively.

Suite of wire line logs namely gamma ray, neutron, density and sonic logs were used to evaluate the reservoir petrophysical properties. The gamma ray log was used to correlate the reservoir sands, estimate the volume of shale and calculate the net-to-gross ratio as well as the porosity and permeability of the pay zones.

Results and Discussion

Sequence Stratigraphy

Three sequence boundaries (8.5Ma, 10.35Ma and 10.6Ma) and three maximum flooding surfaces (9.5Ma, 10.4Ma and 11.5Ma) were identified from the nine wells (Fig. 2) across the field, which gave rise to three systems tracts namely lowstand, transgressive and highstand systems tracts thereby constituting one complete and two incomplete sequences as can be seen in one of the deepest wells (well-05, Fig. 4).

The lowstand systems tract was interpreted at the base of the sequence, and was bounded on top by a transgressive surface. The lowstand systems tract was made up of three components; the basin floor fan, slope fan and the lowstand prograding wedge (Figs. 3 and 4) with a log response reflecting an aggradational to progradational deposits that probably formed an onlap on the continental shelf during a slow rise in the relative sea level. Based on its log motif, reservoir-A (well-05 and well-04) was interpreted as a deposit of lowstand systems tract.

The transgressive systems tract was associated with a relative rise in sea level, when the accommodation space was greater than sediment supply. It was identified based on increase in the total abundance of faunal and planktons, which was confirmed by maximum deflection of the resistivity curve within the same stratigraphic interval (Figs. 2, 3 and 4). The transgressive systems tract was bounded on top by the 10.4Ma maximum flooding surface.

The Highstand system tract occurred at the uppermost part of the sequence, which was probably formed during the latter part of the relative sea level lowstand when the rate of sediment supply outpaced the rate of rise. It exhibited an upward coarsening sequence based on the gamma ray log motifs as could be seen in reservoir-A (well-02) and reservoirs-B, C, D and E (Figs. 2, 3 and 4).

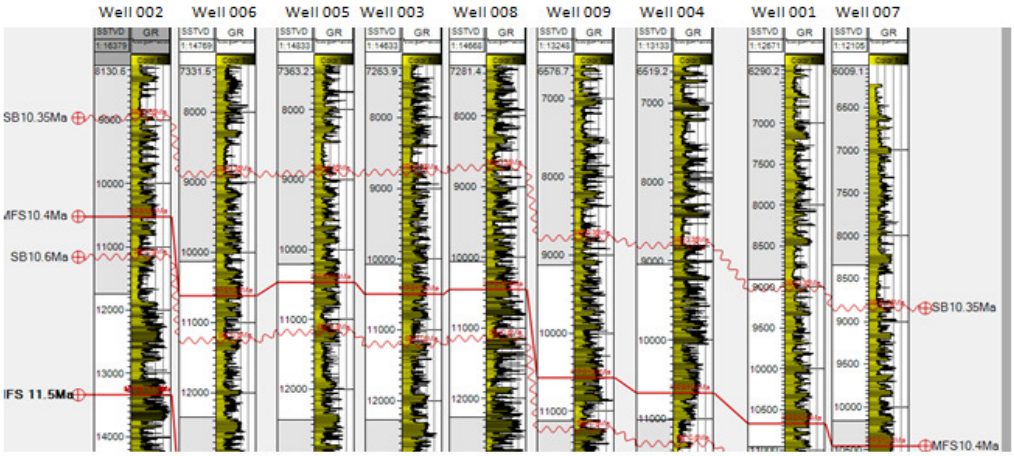

Fig. 2: Correlation Panel, showing genetic correlation of the field. The red lines indicate the key stratigraphic surfaces (Sequence Boundaries and Maximum Flooding Surfaces)

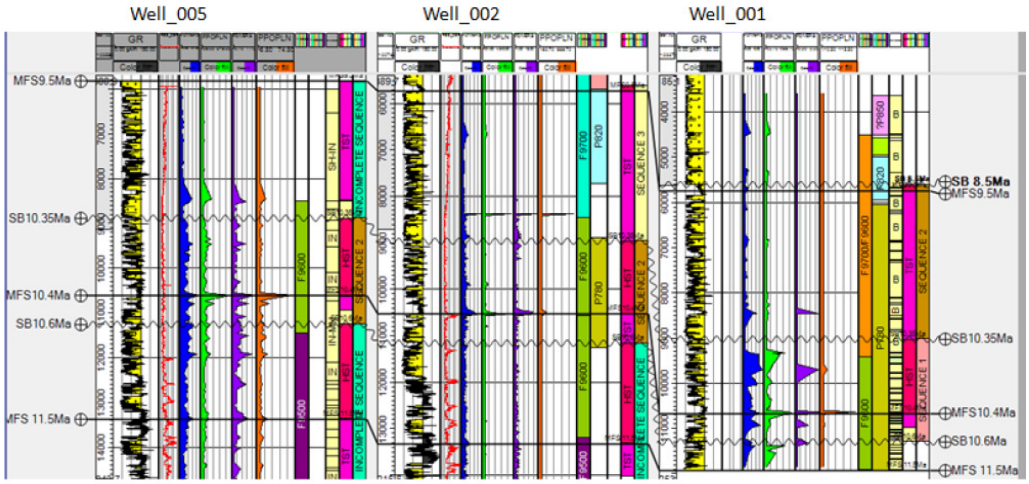

Fig. 3: Correlation Panel, showing genetic correlation of the stratigraphic surfaces and their systems tract across the field

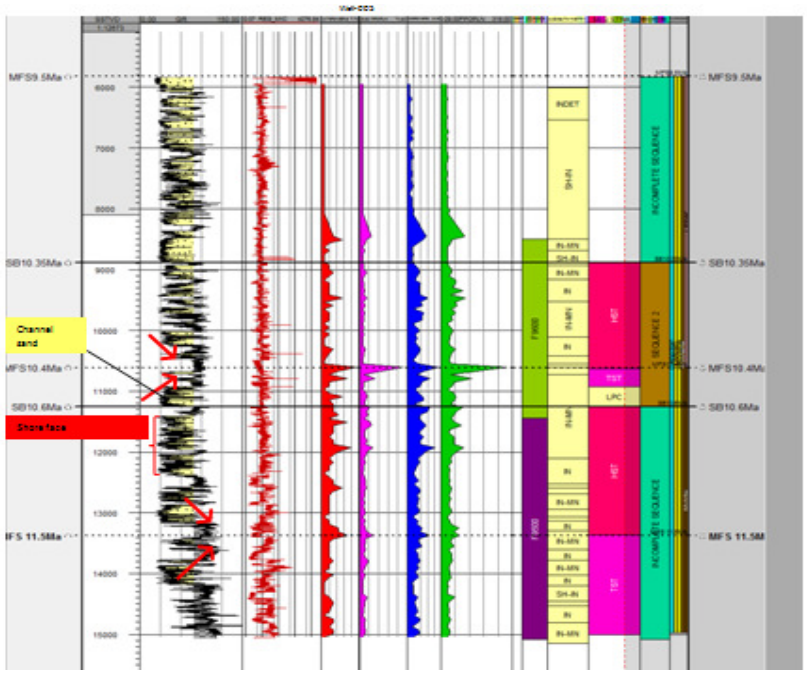

Fig. 4: Correlation Panel, showing the system tracts, channel sands within the LST and the shoreface sands within the HST

Petrophysical Evaluation

Stratigraphic Correlation of A, B, C, D and E Reservoir Sands

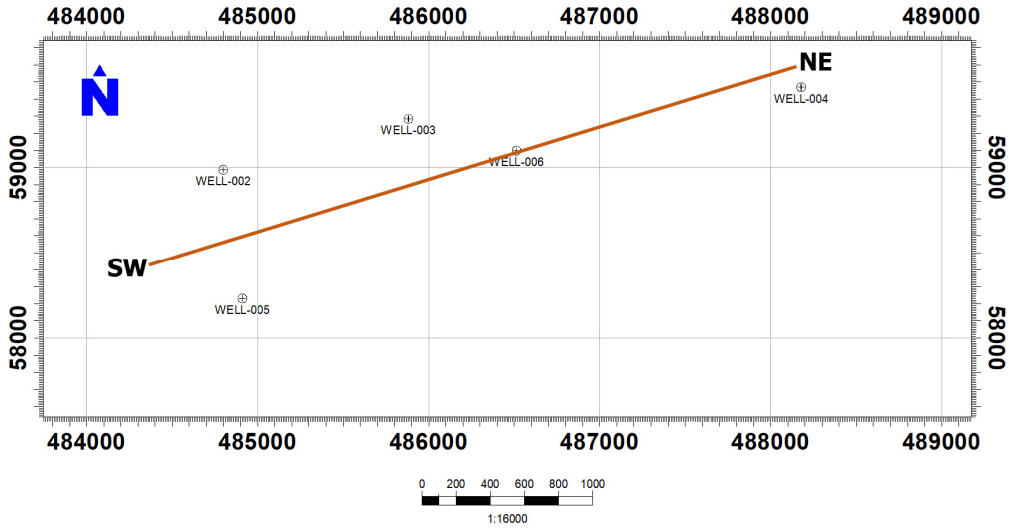

Fig. 5: Base map of the field, showing the positions of the various wells. Note the positions of **SW-NE** in figure 6

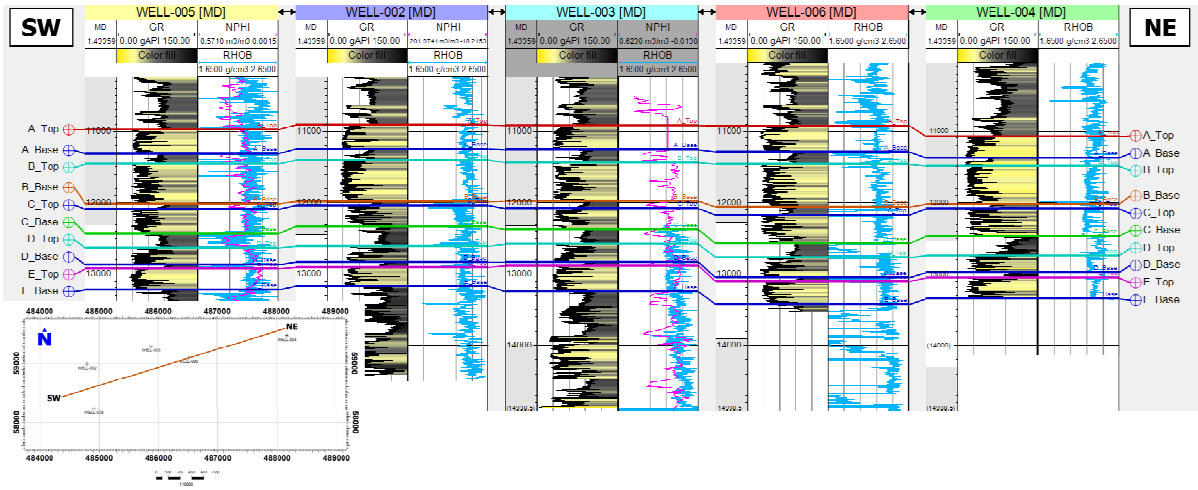

Fig. 6: Stratigraphic Correlation of the A, B, C, D, and E Reservoir Sands. Insert is a base map of the X-field, showing positions of various wells and correlation transect (**SW-NE**)

In the correlation panel, all the reservoir sands were laterally extensive cutting across the five wells and relatively developed well across the field with minor shaly sand intercalations (Fig. 6).

Sand Development and Lateral Continuity of the Reservoirs

After flattening on the top of each of the reservoir sands (**A** – **E**) (Figs. 7a-e) in order to restore their depositional conditions and possibly delineate their development and continuity in the direction of **SW-NE**, it was observed that the reservoirs-**A** and **B** developed almost equally in all the five wells with little or no shaly sand intercalation (Figs. 7a and b). However, reservoirs-**C**, **D**

and **E** display lots of shaly sand intercalations with varying thicknesses across the field (Figs. 7c, d and e).

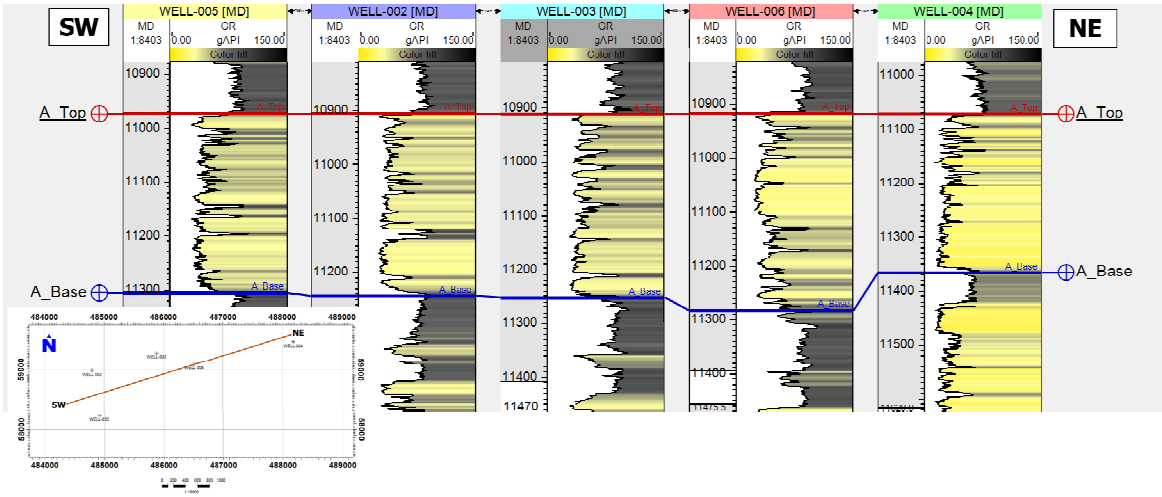

Fig. 7a: **A**-sand development and lateral continuity in the direction of **SW – NE**. Insert is a base map of the field, showing positions of various wells and correlation transect

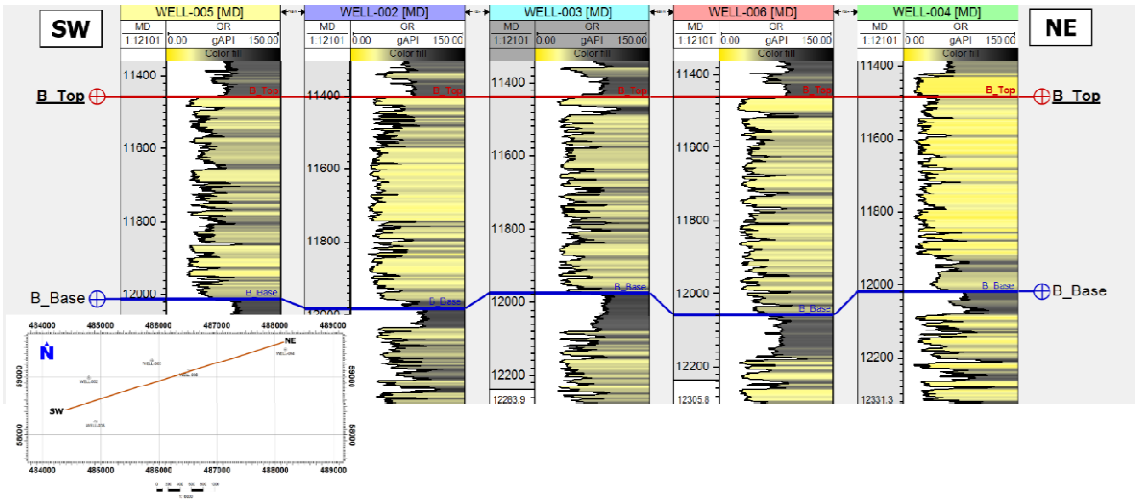

Fig. 7b: **B**-sand development and lateral continuity in the direction of **SW – NE**. Insert is a base map of the field, showing positions of various wells and correlation transect

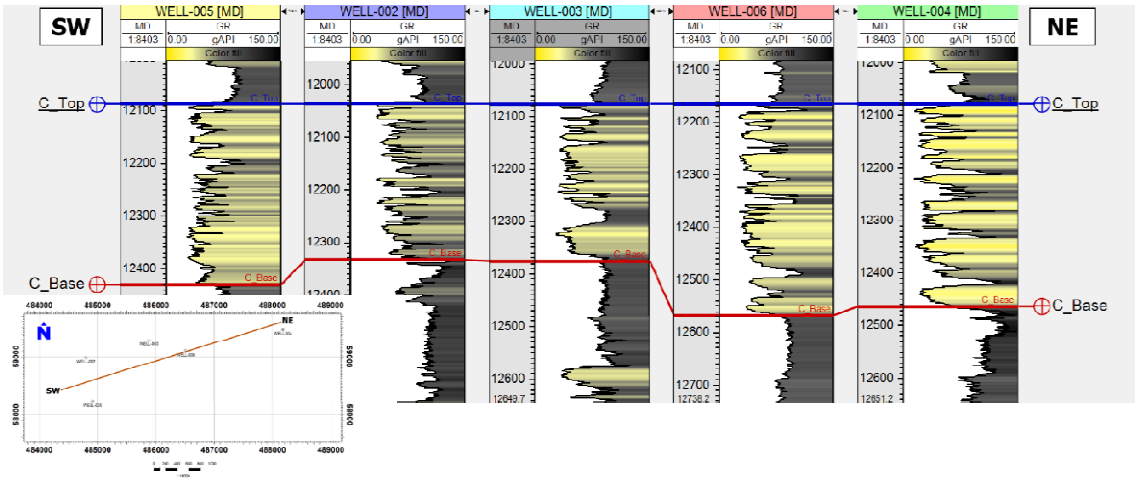

Fig. 7c: **C**-sand development and lateral continuity in the direction of **SW – NE**. Insert is a base map of the field, showing positions of various wells and correlation transect

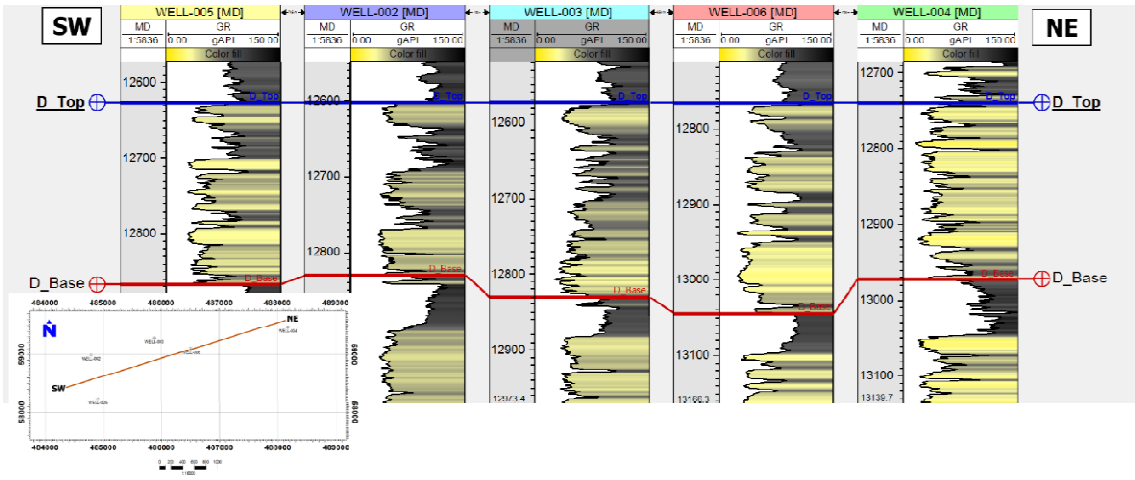

Fig. 7d: **D**-sand development and lateral continuity in the direction of **SW – NE**. Insert is a base map of the field, showing positions of various wells and correlation transect

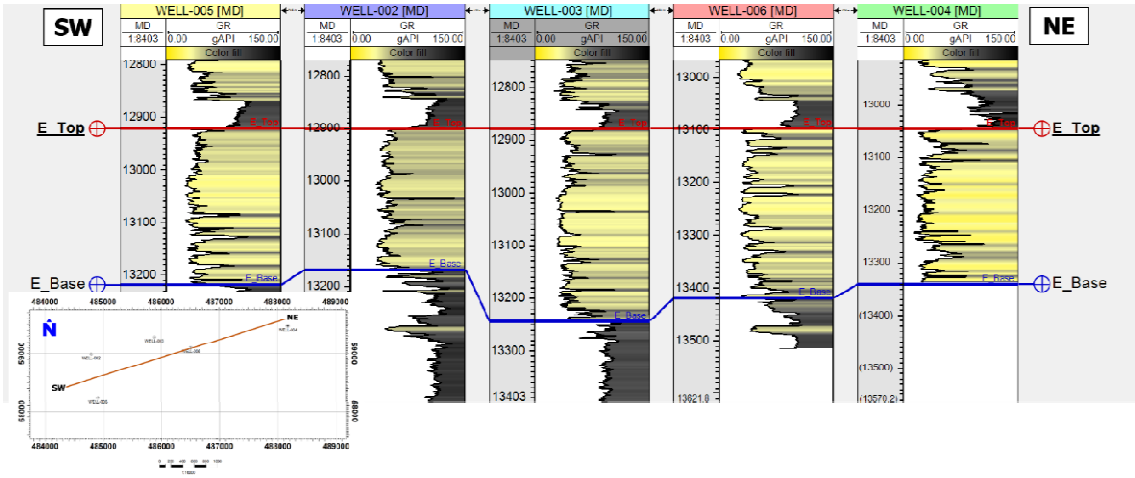

Fig. 7e: **E**-sand development and lateral continuity in the direction of **SW** – **NE**. Insert is a base map of the field, showing positions of various wells and correlation transect

The average values of the volume of shale, gross and net thickness, net-to-gross, porosity and permeability of the reservoir sands (**A** – **E**) across the field and according to the spatial distribution of the wells were tabulated as shown below (Tables 1-4).

It was quite interesting to note that **A** and **B**-sands displayed relatively high volume of shale towards the south-western and mid-sections of the field unlike the north-eastern section. However, this observation did not essentially correlate well with the porosity and permeability of the same sands in the same directions (Tables 1 and 2). Both porosity and permeability values were approximately the same for each reservoirs across the field irrespective of their net-to-gross ratios. Nevertheless, B-sand displayed higher permeability values centrally in wells 002 and 006 (Table 2).

At a deeper stratigraphic intervals, the values of the volume of shale increased much more in reservoirs-**C**, **D** and **E**. Expectedly, there was also a noticeable decrease in the values of the porosity and permeability at deeper stratigraphic intervals for these reservoir sands.

Conclusively, the quality of the reservoir sands generally depreciated with increasing depth of burial regardless of their net-to-gross ratios. However, each reservoir sand displayed variable quality across the field judging by the values of their respective porosity and permeability.

Table 1: Average Petrophysical Properties of Reservoir-A across SW-NE Direction

Petrophysical Parameters	WELL-005	WELL-002	WELL-003	WELL-006	WELL-004
Top Depth (ft)	10973	10905	10911	10917	11071
Bottom Depth (ft)	11306	11243	11252	11282	11366
Volume of Shale (%)	30	23	50	22	13
Gross Thickness (ft)	333	338	342	363	295
Net Thickness (ft)	303	316	292	341	282
Net-To-Gross (%)	91.1	93.3	85.5	93.9	95.7
Porosity (%)	19.6	23.3	20.3	22.8	18.6
Permeability (mD)	144	559	615	936	-

Table 2: Average Petrophysical Properties of Reservoir-B across SW-NE Direction

Petrophysical Parameters	WELL-005	WELL-002	WELL-003	WELL-006	WELL-004
Top Depth (ft)	11457	11402	11437	11459	11484
Bottom Depth (ft)	12011	11981	11975	12056	12018
Volume of Shale (%)	29.6	17.8	46.8	24.6	13.32
Gross Thickness (ft)	555	562	493	598	599

Net Thickness (ft)	525	544	446	573	586
Net-To-Gross (%)	94.7	96.8	90.5	95.9	97.8
Porosity (%)	19	19.4	19.9	21.6	18.6
Permeability (mD)	514	996	437	913	-

Table 3: Average Petrophysical Properties of Reservoir-C across SW-NE Direction

Petrophysical Parameters	WELL-005	WELL-002	WELL-003	WELL-006	WELL-004
Top Depth (ft)	12087	12036	12077	12165	12079
Bottom Depth (ft)	12430	12332	12375	12566	12463
Volume of Shale (%)	30.95	56.96	52.66	30.07	29.82
Gross Thickness (ft)	351	297	298	401	385
Net Thickness (ft)	320	240	245	373	355
Net-To-Gross (%)	91.2	80.8	82.3	93	92.3
Porosity (%)	19.8	9.5	19.8	19.3	18.8
Permeability (mD)	414	6.57	313	555	867

Table 4: Average Petrophysical Properties of Reservoir-D across SW-NE Direction

Petrophysical Parameters	WELL-005	WELL-002	WELL-003	WELL-006	WELL-004
Top Depth (ft)	12626	12602	12572	12765	12739
Bottom Depth (ft)	12866	12830	12829	13044	12972
Volume of Shale (%)	38.83	25.38	62.2	41.02	25.91
Gross Thickness (ft)	240	229	251	279	234
Net Thickness (ft)	201	203	188	242	208
Net-To-Gross (%)	83.8	88.9	75.2	86.8	89
Porosity (%)	18.4	21.8	17.9	17.7	19.8
Permeability (mD)	671	598	189	386	-

Table 5: Average Petrophysical Properties of Reservoir-E across SW-NE Direction

Petrophysical Parameters	WELL-005	WELL-002	WELL-003	WELL-006	WELL-004
Top Depth (ft)	12921	12901	12878	13097	13045
Bottom Depth (ft)	13218	13168	13244	13418	13340

Volume of Shale (%)	30.52	48.06	44.17	23.83	15.29
Gross Thickness (ft)	298	268	367	322	296
Net Thickness (ft)	267	219	322	298	281
Net-To-Gross (%)	90	82	87.9	92.6	95.1
Porosity (%)	15.1	9.2	17.7	17.2	17.8
Permeability (mD)	595	315	247	732	688

Depositional Environments

From the above sequence stratigraphic analysis and petrophysical evaluation, it was observed that the reservoir sand units in the highstand system tract and the lowstand system tracts exhibited good to excellent reservoir qualities as seen from their petrophysical properties in tables 1 to 5. Reservoirs-A, B, C, D and E have high net to gross values of 75 to 98% on the average, high porosity values of about 23.3% and permeability of about 996mD on the average. The different log shapes responses on the gamma ray log depicts different environment of deposition. Channel sands within the LST showed a low gamma ray response with sharp boundaries and coarsens out with no internal change in facies. It indicated a massive cylindrical/blocky shape (Fig.4) in well-005. A shore face sands within the HST was inferred based on the gradual upward decrease in the gamma ray log response. A funnel shaped, coarsening upward sequence (Fig. 4) was also noticed in well-005.

Conclusion

The study revealed that the channel and the shoreface sands are the best areas to explore for hydrocarbon as they exhibit average to excellent reservoir properties. The reservoir properties were controlled by the environment of deposition.

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