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DEPOSITIONAL ENVIRONMENT AND RESERVOIR FLOW UNIT CHARACTERIZATION OF OKOGBE FIELD, ONSHORE NIGER DELTA, NIGERIA

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ABSTRACT
Okogbe Field is an Onshore field located in the South-Eastern part of the Niger Delta. Depositional environments and flow unit characteristics of Okogbe Field reservoirs have been evaluated using wireline log data. Four (4) wells from the Okogbe Field were used in this study to delineate the stratigraphic positions of the reservoir flow zones, depositional environments of the reservoir sand bodies, their depositional trends and geometry. In addition, evaluated the reservoir petrophysical properties and characterize the reservoir flow units (storage capacity and flow capability assessment. The Stratigraphic Modified Lorenz (SML) plot (a cross plot of Cumulative Flow Capacity versus Cumulative Storage Capability from porosity and permeability data) was applied in this study. The results, show that the porosity is 22% to 34% and permeability is 1400mD to 2883mD indicating excellent reservoir quality for the field. Well F-021 has the best porosity (34%), permeability (2883.03mD) and lowest water saturation (26%) suggesting highest reservoir productivity. Twenty-four (24) flow units based on the Stratigraphic Modified Lorenz (SML) plot and gamma log motifs have been identified and indicates that the reservoirs have similar flow patterns. The dominant depositional setting of the study area is shallow marine - shoreface and beach environments. The depositional environmental model and reservoir flow unit characterization of Okogbe Field has been carried out which may serve as a control in predicting flow properties in the other unexplored project areas.

Key words: Flow Unit Characterization, Depositional Environment, Reservoir Sand Bodies Okogbe Field, Niger Delta

INTRODUCTION
The Tertiary Niger Delta Basin has developed within the Passive Margin of West Africa like other basins of the world such as the Gulf of Mexico, Santos and North Sea Basins (Ziegler and Peter, 1990; Salvador, 1991; Asmus, 1975). The Niger Delta Basin has an estimated 30 billion barrels of oil and 260 trillion cubic feet of natural gas as compared to about 937 million barrels of oil and condensate discovered in Rio Del Rey Basin of Cameroon and 45 million barrels of oil in Equatorial Guinea Basin (Reijers et al. 1972). The concept of hydraulic flow units and petrophysics, have been documented and summarized (Slatt and Hopkins, 1991; Ebanks *et al.*, 1992; Amaefule *et al.*, 1993; Kerr *et al.* 1999; Yangquan et al. 1998; Maglio-Johnson, 2000; Trondheim and Stavanger, 2003; Slatt, 2006; Taghavi *et al*,. 2007; Momta *et al.*, 2015) Flow units are classified on basis of the combination of petrophysical, geological, production data

and reservoir engineering to characterize and model heterogeneous reservoirs. In this study, Stratigraphic Modified Lorenz (SML) plot method (Gunter *et al.*, 1997; Rahimpour-Bonab *et al.*, 2014) which consists of the cross plot of the Cumulative Flow Capacity versus Cumulative Storage Capacity will be used to illustrate the concept of hydraulic behavior of deposited sand bodies within a given depositional environment. The inflection points from the Stratigraphic Modified Lorenz (SML) plot method determines the flow capacity and storage capacity that affects the reservoir quality. This graphical approach for obtaining the various flow units quantitatively is useful in obtaining petrophysical rock types, storage capacity (ϕh), flow capacity (Kh) and the reservoir process speed (K/ϕ) as parameters of the SML plot (Gunter *et al.*, 1997). The petrophysical parameters like true formation Resistivity(Rt), Net to Gross(NTG), Volume of Shale(VSH), Water Saturation(SW), Hydrocarbon Saturation(SH), porosity and permeability, were deduced from wireline logs (Gamma Ray, Resistivity, Sonic, Density and Neutron logs).

Okogbe Field is situated in Onshore Southeastern part of the Niger Delta sedimentary basin (Figure 1.0). The aim of this research is to determine the reservoir flow units and the depositional environments and of Okogbe Field, while the objectives are to infer the stratigraphic positions of the reservoir flow zones, delineate the depositional environments of the reservoir sand bodies, their depositional trends and geometry, evaluate the reservoir flow properties and characterize the reservoir flow units (storage capacity and flow capability assessment).

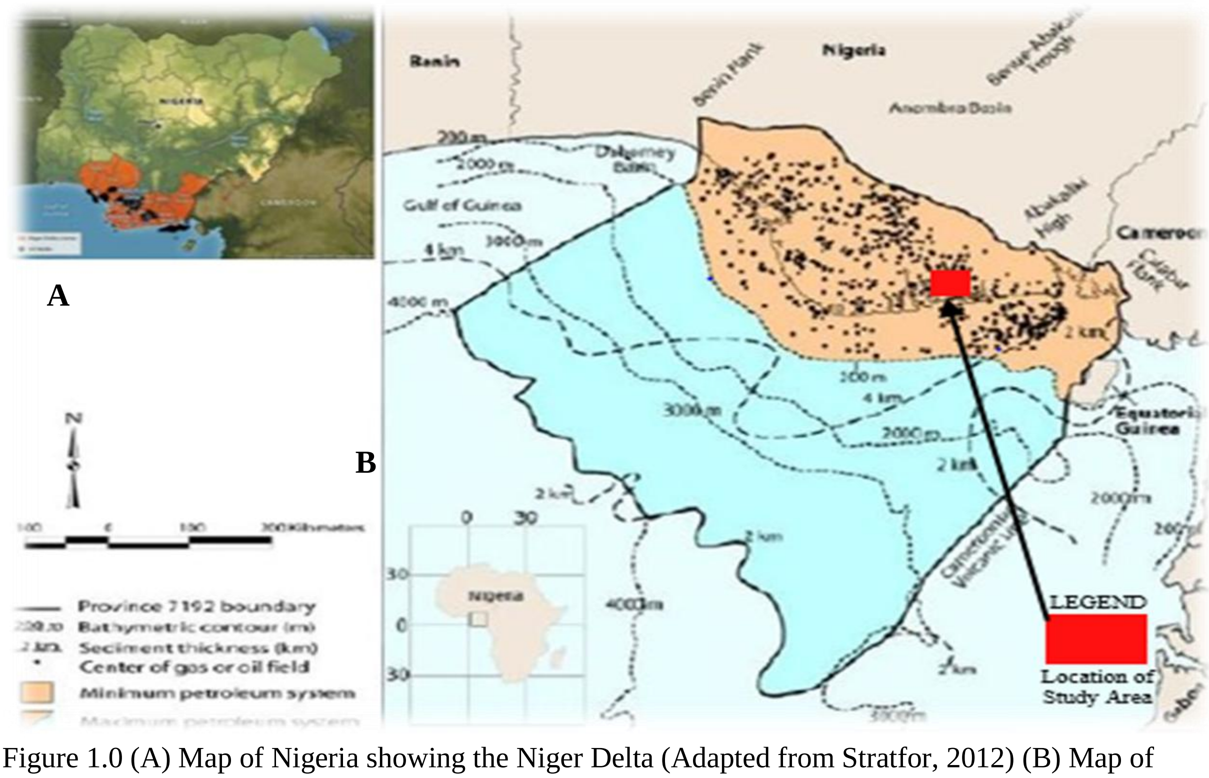

Figure 1.0 (A) Map of Nigeria showing the Niger Delta (Adapted from Stratfor, 2012) (B) Map of Niger Delta showing the maximum petroleum systems and key structural features and location of the Okogbe Field (Modified from Tuttle et al. 1999)

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Geological Setting

The Niger Delta Basin developed from the late Paleocene to early Eocene with the accumulation of continental and marine sediments. The Eocene period kick-started the growth of oil rich Niger Delta because of the positive epeirogenic movement along Benin and the Calabar flank (Doust and Omatsola, 1982). By the Mid-Eocene period, a major regression occurred that gave rise to the expansion of the Niger Delta followed by the Ameki Formation deposition in the West and Niger River in the East (Doust and Omatsola, 1990). This led to the prograding of the Delta plain southward into the oceanic crust (Short and Stauble, 1967). The shape of the Cretaceous coast line gradually changed with the growth of the Niger Delta (Reijers et al. 1997). The Niger Delta province has only one recognized petroleum system which is the Akata-Agbada petroleum system (Ekweozor and Daukoru, 1994; Kulke, 1995).

MATERIALS AND METHODS

Materials

Four (4) wells (F-003, F-007, F-013 and F-021) and wireline logs (comprising Gamma Ray, Resistivity, Sonic, Density and Neutron logs) were used to generate the petrophysical parameters used in characterizing the identified reservoirs of the study area.

Methods

The depositional environments were interpreted from the Gamma Ray log motifs using the conceptual depositional model by Kendall, (2004). The funnel, cylindrical and blocky log pattern shapes indicate good porosity and permeability values interpreted from the well logs and high reservoir potential of the wells. Maglio-Johnson, (2000) used the equations (1-4) proposed by Amaefule et al. (1993) to obtain the Cumulative Flow Capacity and the Cumulative Storage Capacity of a given reservoir (Figure 2.0). The Stratigraphic Modified Lorenz (SML) plot method uses the porosity and permeability values as determinants of flow capacity (Kh) and its corresponding storage capability (ϕh) (Equation 1 and 2).

$Kh = K1(h1 - h0), K2 (h2 - h1), \ldots, Kn (hn - hn - 1)$ ------ (1) Amaefule *et al.,* (1993)

$\Phi h = \Phi 1(h1 - h0), \Phi 2(h2 - h1), \Phi n (hn - hn - 1)$ ----- (2) Amaefule *et al*., (1993)

The equation for Cumulative Flow Capability values (Equation 3) is as follows;

$(Kh)cum = K_1(h_1 - h_0) + K_2 (h_2 - h_1) + \ldots + K_i (h_i - h_{i-1}) / \Sigma K_i (h_i - h_{i-1})$ ---- (3) Amaefule *et al.,* (1993)

The equation for Cumulative Storage Capacity values (Equation 4) is as follows;

$(\phi h)\ cum = \phi_1(h_1 - h_0) + \phi_2(h_2 - h_1) + ... + \phi K_1(h_i - h_{i-1}) / \Sigma\phi K_i (h_i - h_{i-1})$ --- (4) Amaefule *et al.,* (1993)

Given K is permeability (md)
h is sample interval thickness,
ϕ is fractional porosity

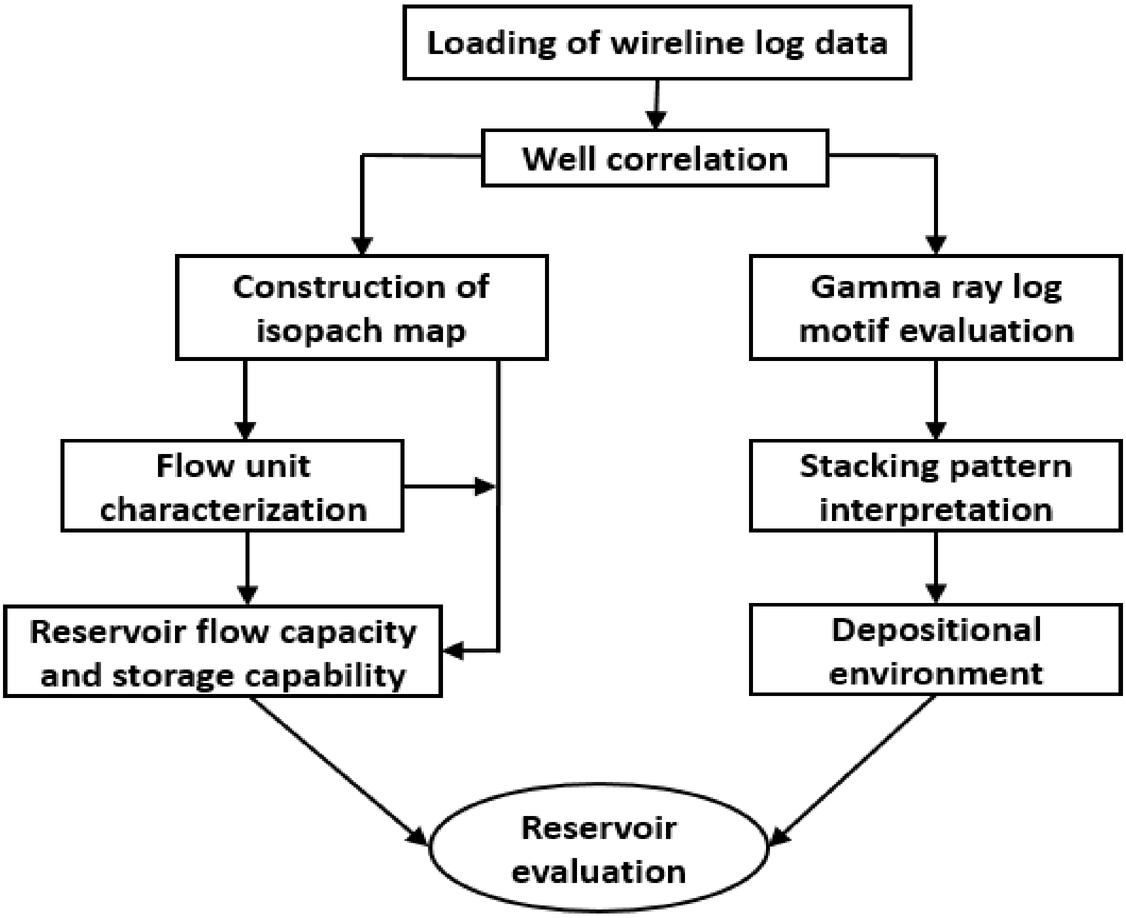

Figure 2.0 Flow chart showing the steps adopted for this work

RESULTS AND DISCUSSION

Sedimentology and Depositional Environments

The interpretation of the depositional environment based on facies and facies association give an insight of grain size trends and sedimentological association. The depositional settings for reservoirs A, B and C include supra fan lobes, channel point bar, prograding coastal plains and inner fan channel deposits with alternating stacking patterns (Figure 3 - 8). The depositional environment that exhibit these features are typically the shallow marine Shoreface and beach environment.

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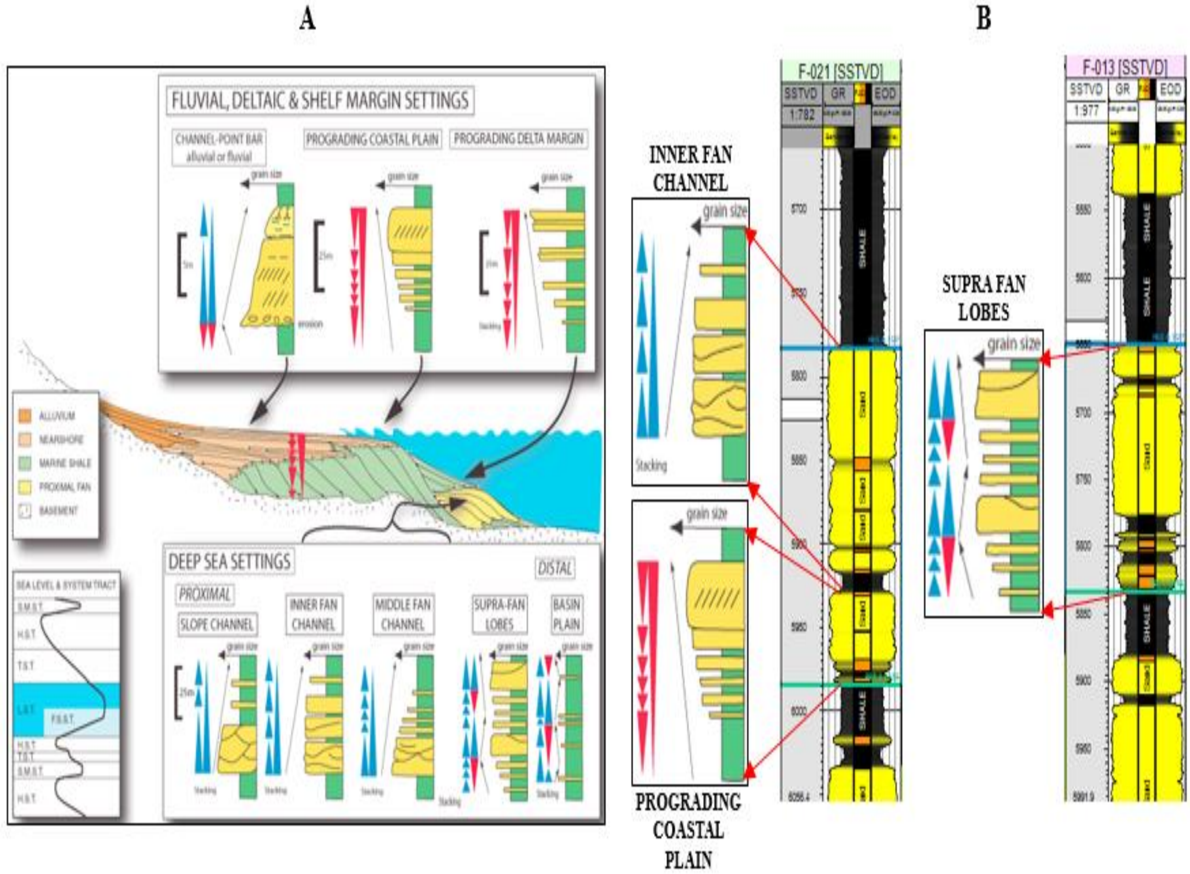

Figure 3.0 (A) Conceptual depositional model of Okogbe reservoir sands (modified after C. Kendall, 2004) (B) Stacking pattern interpretation of Wells F-021 and F-013 of reservoir A

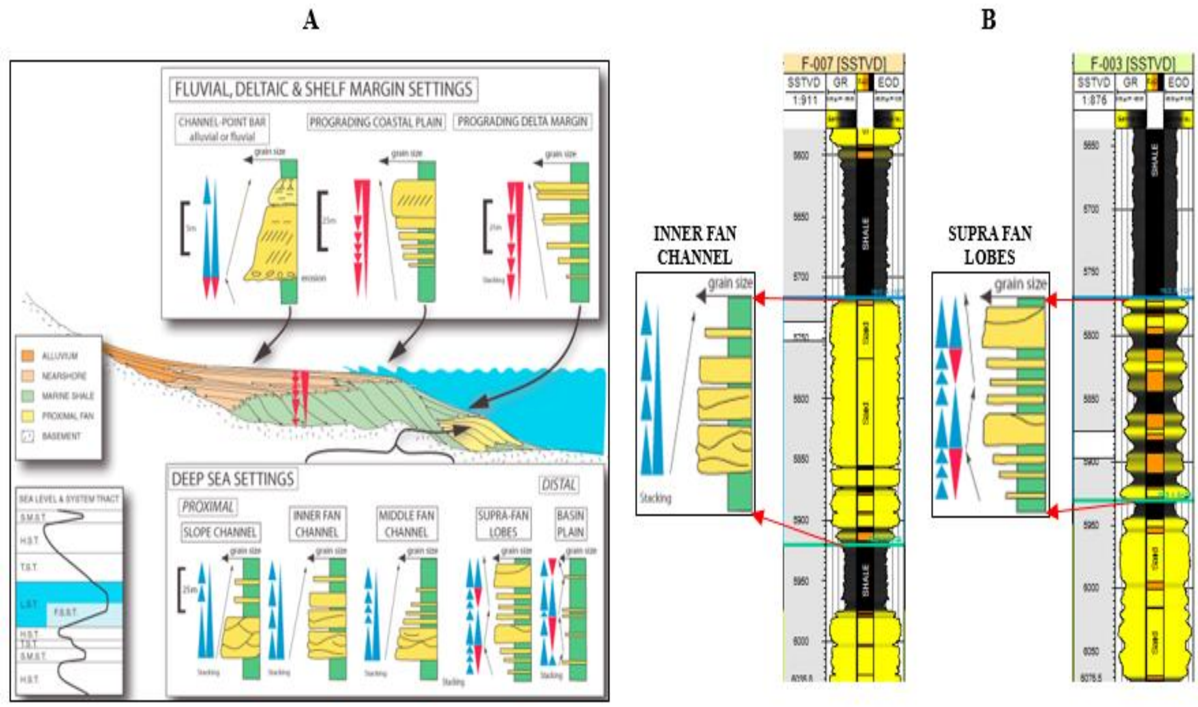

Figure 4.0 (A) Conceptual depositional model of Okogbe reservoir sands (modified after C. Kendall, 2004) (B) Stacking pattern interpretation of Wells F-007 and F-003 of reservoir A

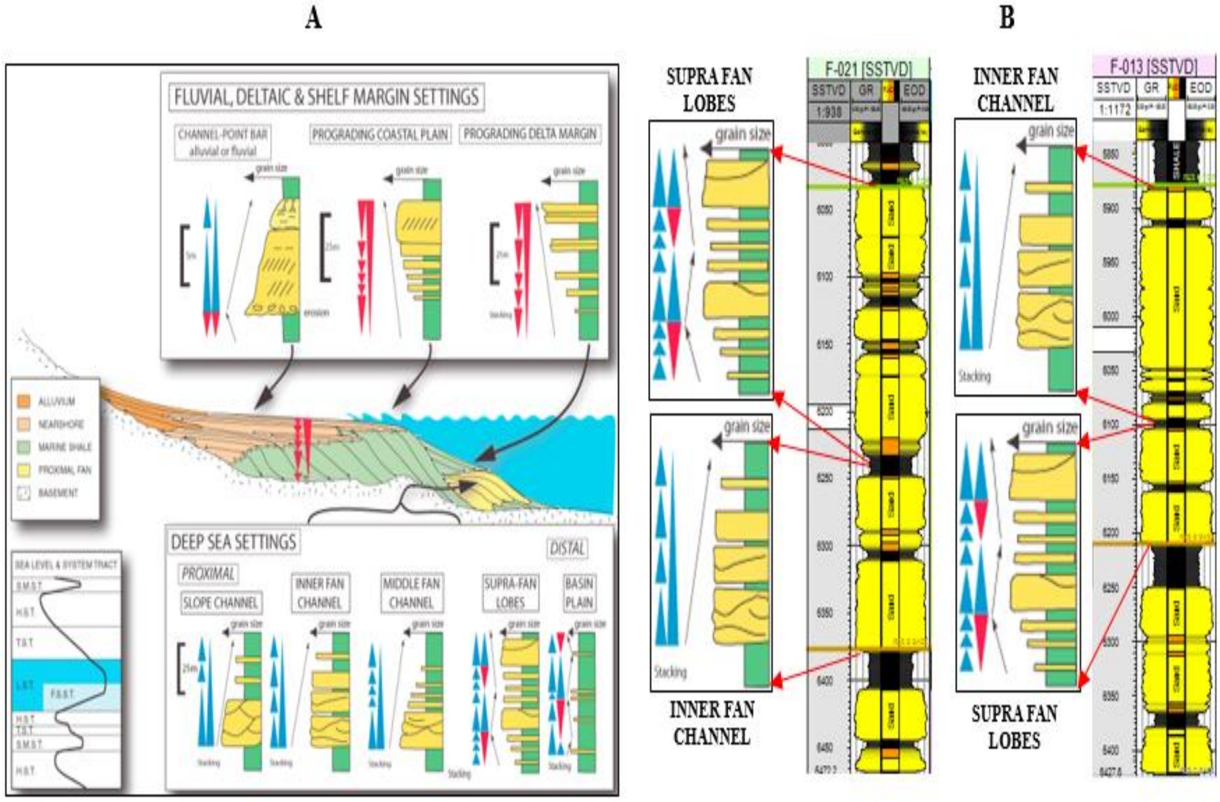

Figure 5.0 (A) Conceptual depositional model of Okogbe reservoir sands (modified after C. Kendall, 2004) (B) **S**tacking pattern interpretation of Wells F-021 and F-013 of reservoir B

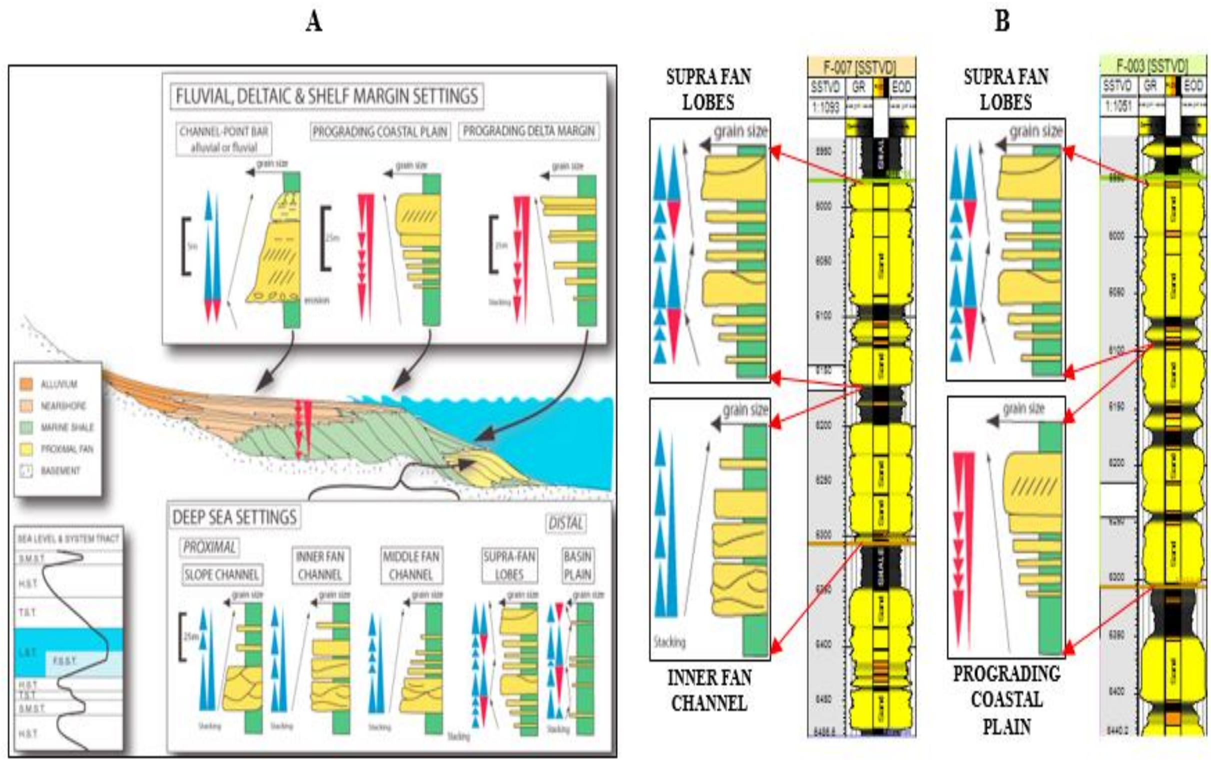

Figure 6.0 (A) Conceptual depositional model of Okogbe reservoir sands (modified after C. Kendall, 2004) (B) Sacking pattern interpretation of Wells F-007 and F-003 of reservoir B

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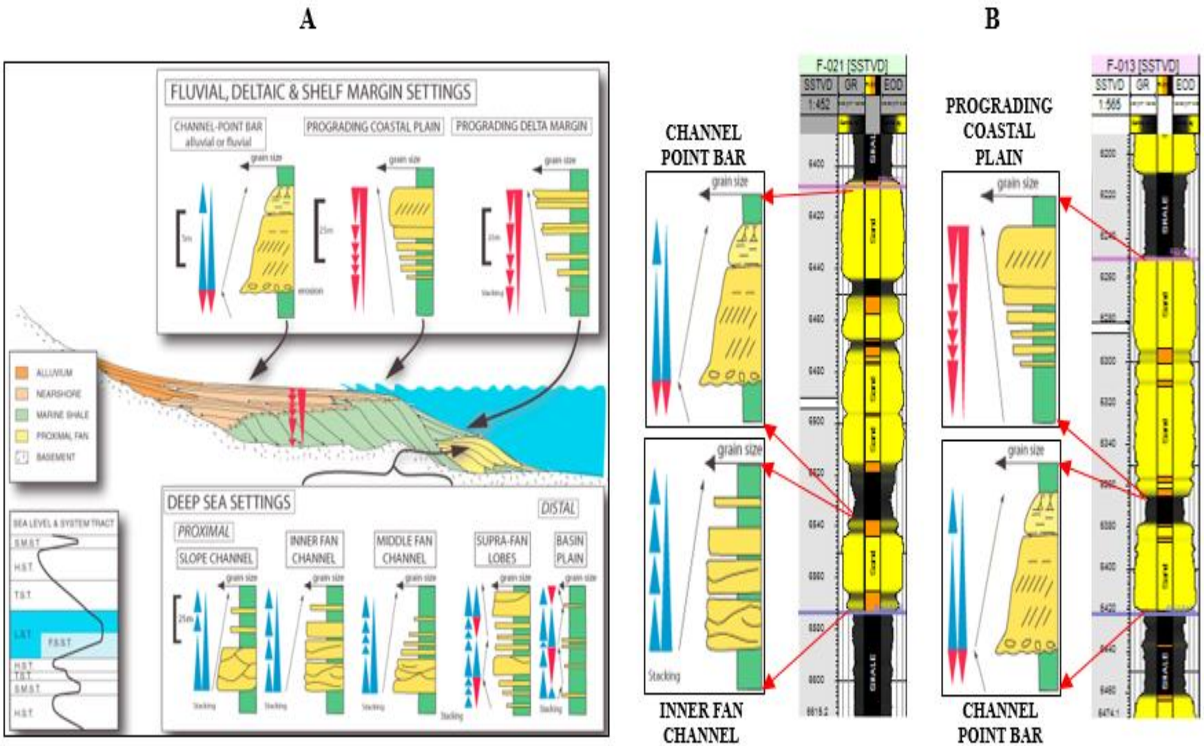

Figure 7: (A) Conceptual depositional model of Okogbe Field reservoir sands (modified after C. Kendall, 2004) (B) Stacking pattern interpretation of Wells F-021 and F-013 of reservoir C

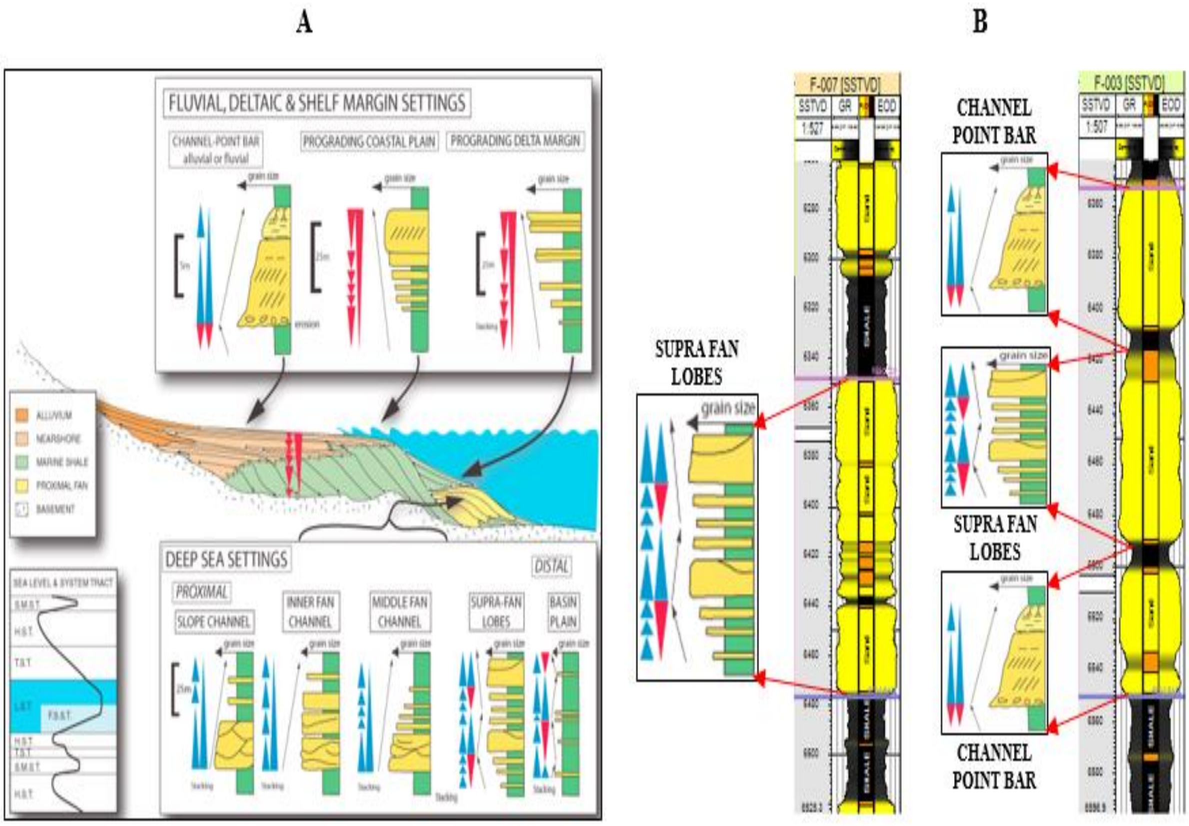

Figure 8: (A) Conceptual depositional model of Okogbe Field reservoir sands (modified after C. Kendall, 2004) (B) Stacking pattern interpretation of Wells F-007 and F-003 of reservoir C

Reservoir Quality Assessment

The results of the petrophysical evaluation of reservoirs (A, B and C) out shows the average porosity as 22% - 34% and permeability as 1.4mD - 2.8mD indicating excellent reservoir quality for the field (Tables 5 to 11). The sand bodies develop significantly towards the North-Eastern direction while the shale content increases towards the South-Western direction. The sand gets dirty across the wells to the right trend direction (Figure 2).

The increase in porosity and permeability from right to left direction across the wells indicates a change in facies laterally and reservoirs A and B is basinward next to reservoir C. Reservoirs A and B have high hydrocarbon prospect based on its excellent porosity and permeability values with low water saturation values.

Reservoir A

Reservoir A is interpreted as funnel based on the shaped Gamma Ray log motif indicating an upward coarsening sequence indicating with an increase in grain size. The range of depth is 5770 to 5930.52 ft in well F-003, 5719 - 5920 ft in well F-007, 5695.4 - 5879.2 ft in well F-013 and 5822.14 - 6023.50 ft in well F-021 (Figures 3 – 4). The range of porosity values 22 - 34% with an average value of 28% (Table 1 to 3). The permeability is between 1.4 - 2.8 mD with an average of 2mD. The average water saturation is 29% while the hydrocarbon saturation 70.8%. Based on the porosity and permeability values, the reservoir has a very good porosity and excellent permeability and low water saturation value suggesting highest reservoir productivity.

Reservoir B

Reservoir B is funnel/blocky shaped based Gamma Ray log motif with alternating stacking patterns. This reservoir is like reservoir A in terms sedimentological and reservoir properties. It has a depth range of 5948.16 - 6306.15 ft in well F-003, 5974.89 - 6306.83 ft in well F-007, 5924.77 - 6254.84 ft in well F-013 and 6072.80 - 6415.92 ft in well F-021 (Figures 5 – 6). The porosity ranges from 28 -34% with an average value of 30% (Tables 1 - 3). Its permeability is between 1.9 - 2.8mD and has an average permeability of 2.2mD. The average water saturation is 28% while the hydrocarbon saturation value is 71.6%. This reservoir has a great hydrocarbon prospect with very good petrophysical properties.

Reservoir C

Reservoir C has a bell log shaped Gamma Ray log motif indicating a fining upward stacking pattern for the wells in relation to the resistivity logs that identifies the permeable zones (Figures 7 – 9). It has a depth range of 6352.77 - 6550.15 ft in well F-003, 6347.85 - 6474.68 feet in well F-007, 6295.87 - 6468.01 ft in well F-013 and 6446.31 - 6613.16 ft in well F-021. The porosity and permeability values range from 28 - 29% and 2.0 - 2.2mD respectively. The average porosity value is 29% and average permeability value is 2.1mD. The water saturation is low with about 30% and hydrocarbon saturation of 70%.

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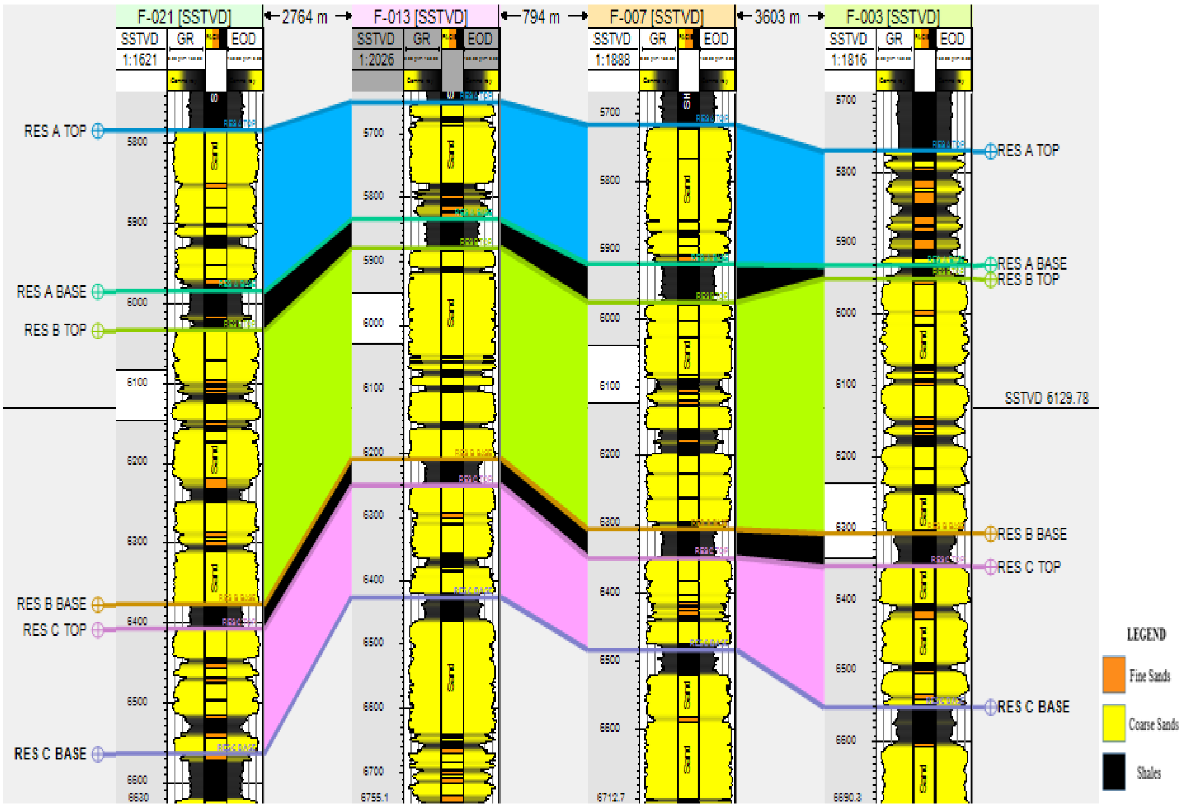

Figure 9 Wells F-021, F-013, F-007 and F-003 showing reservoirs A, B and C of the Study Area

Table 1: Result summary of Reservoir A across the wells

WELLS	F-021	F-013	F-007	F-003	RES. AVG
Porosity (%)	34.00	31.00	26.00	22.00	28.00
Water Saturation Sw (%)	26.00	28.00	24.00	39.00	29.00
Permeability (K) mD	2843.85	2346.53	1500.00	1400.74	2022.78
Average Thickness(ft)	186.67				

Table 2: Result summary of Reservoir B across the wells

WELLS	F-021	F-013	F-007	F-003	RES. AVG
Porosity (%)	34.00	29.00	28.00	28.00	30.00
Water Saturation Sw (%)	26.00	29.00	28.00	30.00	28.00
Permeability (K) mD	2883.03	2147.71	2054.00	1972.39	2264.28
Average Thickness(ft)	340.78				

Table 3: Result summary of Reservoir C across the wells

WELLS	F-021	F-013	F-007	F-003	RES. AVG
Porosity (%)	29.00	28.00	-	28.00	29.00
Water Saturation Sw (%)	29.00	31.00	-	30.00	30.00
Permeability (K) mD	2214.49	2095.45	-	2045.11	2118.35
Average Thickness(ft)	166.30				

Flow Unit Determination

Twenty-four (24) flow units were identified from the Stratigraphic Modified Lorenz (SML) plot method for reservoirs A and B only (Figure 10 – 11 and Table 4). The Stratigraphic Modified Lorenz (SML) plot method inflection points reveal the number of flow units in the reservoirs of the study area. Based on Rahimpour-Bonab's model, two (2) flow units were identified in this research which include normal and baffle flow units (Figures 4 and 5). Gunter et al. (1997), showed that the segments of each slopes are indicators of the flow performance in the reservoirs. Gentle and almost horizontal slope segments show low permeability flow units while steep or high angle gradient slopes are indicative of high permeability flow units (Rahimpour-Bonab *et al*., 2014).

Reservoir A has a total of thirteen (13) flow units of which nine (9) normal flow units with high or equal storage and flow capacities values (A3, A4, A6, A7, A8 A9, A10, A11 and A13) (Figure 4) and four (4) baffle flow units which have low flow capacity with high storage capacity (A1, A2, A5 and A12) (Figure 4 and Table 4).

Reservoir B has a total of eleven (11) flow units of which six (6) normal flow units have high or equal storage and flow capacities values (B1, B2, B5, B9, B10 and B11) (Figure 4) and five (5) baffle flow units have low flow capacity with high storage capacity (B3, B4, B6, B7 and B8) (Figure 5 and Table 4).

Reservoir C has no flow units because the porosity and permeability values were unknown across the wells; it terminates at reservoir B (Table 4).

Reservoirs A and B have more normal flow units with the highest flow and storage capabilities as compared with the baffle flow units. The normal flow units indicate that the sediments may have been deposited within the fluvial/deltaic environments as seen in the log motifs (Figures 4 and 5) which indicates good reservoir qualities. Reservoirs A, B and C have reservoir heterogeneities because of the intercalations of sands and shales which is synonymous in the case of the Niger Delta.

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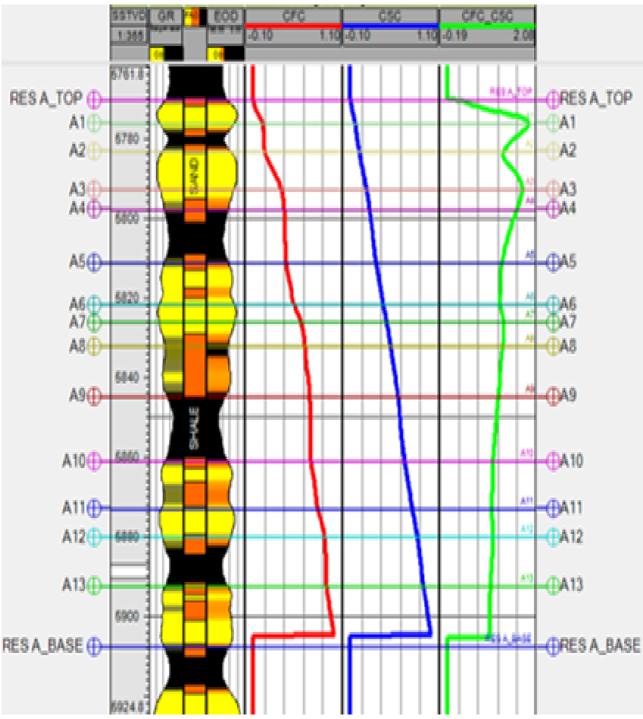
Table 4: Summary of the total flow units, Where FU: flow units

WELLS	RESERVOIR A	RESERVOIR B	RESERVOIR C
F-021	5	4	-
F-013	2	1	-
F-007	4	4	-
F-003	2	2	-
TOTAL FU	13	11	-
OVERALL TOTAL FU	24		



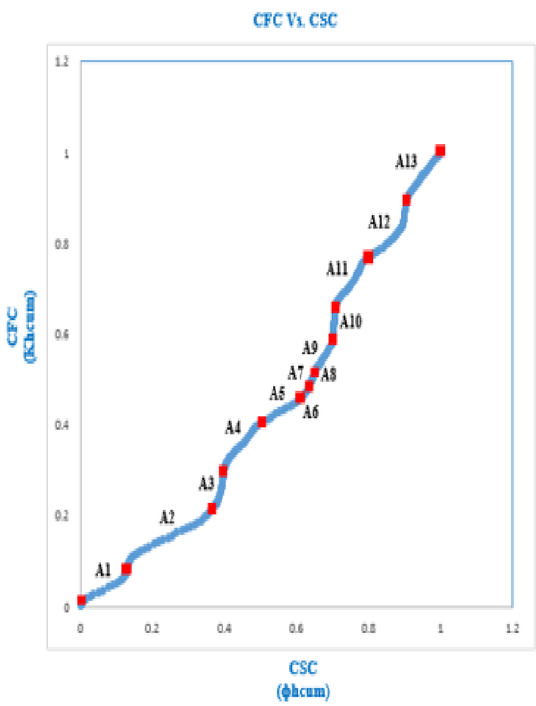


Figure 10: SML plot of Cumulative Flow Capacity(Khcum) versus Cumulative Storage Capacity (ϕhcum) for the four (4) wells, reservoir A

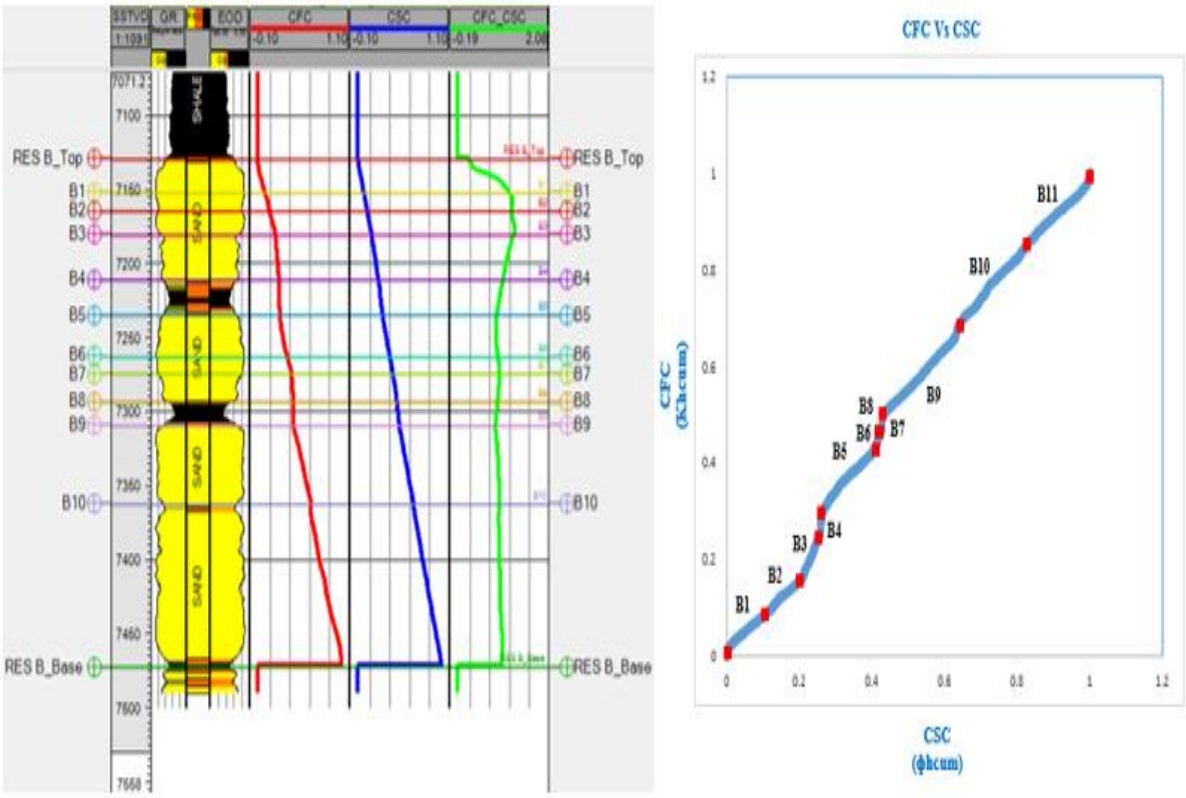


Figure 11: SML plot of Cumulative Flow Capacity(Khcum) versus Cumulative Storage Capacity (ϕhcum) for the four (4) wells, reservoir B

Table 5: Petrophysical parameters for well F-003, reservoir A

DEPT(Ft)	H	GR	SW%	NTG	Porosity %	K (mD)	KH	FRC	Hperm	CFC	CSC	CFC/CSC
5770	0.5	72.6364	.40.938	1	20.0303	1161.522	12.61407	0.423261	0.100152	0.100152	0.100152	4.226201739
5770.5	0.5	68.8447	39.1833	1	20.9273	1239.768	16.40615	0.550502	0.104636	0.204788	0.304939	1.805283388
5771	0.5	61.025	35.9936	1	22.7818	1412.414	27.30612	0.916246	0.113909	0.318697	0.623636	1.469199737
5771.5	0.5	55.175	33.9353	1	24.1636	1550.577	38.87793	1.304534	0.120818	0.439515	1.063152	1.227044669
5772	0.5	47.4932	31.5532	1	25.9879	1745.434	60.16653	2.018865	0.129939	0.569455	1.632606	1.236590674
5772.5	0.5	41.1212	29.8215	1	27.497	1917.341	84.41872	2.832639	0.137485	0.706939	2.339545	1.210764501
5773	0.5	36.0788	28.5805	1	28.6909	2060.222	108.9422	3.655514	0.143455	0.850394	3.189939	1.145950803
5773.5	0.5	33.7152	28.0356	1	29.2485	2129.029	122.2787	4.103016	0.146242	0.996636	4.186576	0.980041013
5774	0.5	31.9424	27.6405	1	29.6667	2181.501	133.1503	4.467808	0.148333	1.14497	5.331545	0.83799498
5774.5	0.5	32.2477	27.7084	1	29.5939	2172.322	131.2039	4.402497	0.14797	1.292939	6.624485	0.664579485
5775	0.5	34.9659	28.3232	1	28.9515	2092.216	115.0157	3.859309	0.144758	1.437697	8.062182	0.478692875
5775.5	0.5	37.6841	28.9722	1	28.303	2013.137	100.3985	3.368833	0.141515	1.579212	9.641394	0.349413477
5776	0.5	41.7318	29.9867	1	27.3454	1899.643	81.66582	2.740266	0.136727	1.715939	11.35733	0.241277252

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Table 6: Petrophysical parameters for well F-003, reservoir B

DEPT(Ft)	H	GR	SW %	NTG	Porosity %	K(mD)	KH	FRC	Hperm	CFC	CSC	CFC/CSC
5778.5	0.5	70.6962	40.0414	1	.20.4788	1200.217	14.40642	0.483402	0.102394	2.30103	21.76861	0.022206387
5779	0.5	75.7288	42.5204	1	19.2848	1099.101	10.04679	0.337116	0.096424	2.397454	24.16606	0.013949995
5779.5	0.5	80.0523	44.9054	1	18.2606	1017.197	7.241369	0.242981	0.091303	2.488757	26.65482	0.009115854
5780	0.5	83.8439	47.2416	1	17.3576	948.6917	5.341513	0.179232	0.086788	2.575545	29.23036	0.006131722
5780.5	0.5	82.8788	46.623	1	17.5879	965.8325	5.781094	0.193982	0.087939	2.663485	31.89385	0.006082127
5781	0.5	80.6136	45.2508	1	18.1212	1006.395	6.915967	0.232063	0.090606	2.754091	34.64794	0.006697735
5781.5	0.5	76.0538	42.7083	1	19.2000	1092.147	9.784477	0.328314	0.096	2.850091	37.49803	0.008755513
5782	0.5	71.1689	40.2798	1	20.3576	1189.674	13.90229	0.466486	0.101788	2.951879	40.44991	0.011532437
5782.5	0.5	66.1167	38.0377	1	21.5576	1296.801	19.60329	0.657781	0.107788	3.059666	43.50957	0.015118077
5783	0.5	60.8477	35.9554	1	22.8061	1414.768	27.48094	0.922113	0.11403	3.173697	46.68327	0.019752531
5783.5	0.5	54.5053	0.337407	1	24.303	1564.966	40.24317	1.350345	0.121515	3.295212	49.97848	0.027018518

Table 7: Petrophysical parameters for well F-007, reservoir A

DEPT(FT)	H	GR	SW %	NTG	Porosity %	K(mD)	KH	FRC	Hperm	CFC	CSC	CFC/CSC
5796.5	0.5	62.6598	36.6865	1	22.3515	1371.051	24.35412	0.817193	0.111758	6.822818	184.8347	0.004421211
5797	0.5	64.1962	37.2933	1	21.9879	1336.71	22.07142	0.740598	0.109939	6.932757	191.7674	0.00386196
5797.5	0.5	65.7424	37.9204	1	21.6242	1302.933	19.96988	0.670082	0.108121	7.040879	198.8083	0.003370491
5798	0.5	68.0765	38.9241	1	21.0667	1252.235	17.07277	0.572871	0.105333	7.146212	205.9545	0.002781539
5798.5	0.5	70.1742	39.8645	1	20.5697	1208.164	14.79439	0.49642	0.102848	7.24906	213.2036	0.002328386
5799	0.5	72.075	40.753	1	20.1212	1169.296	12.96147	0.434917	0.100606	7.349666	220.5533	0.001971938
5799.5	0.5	73.9758	41.6949	1	19.6667	1130.777	11.30094	0.379199	0.098333	7.448	228.0013	0.001663143
5800	0.5	75.8765	42.6679	1	19.2182	1093.634	9.840191	0.330184	0.096091	7.544091	235.5454	0.001401785
5800.5	0.5	76.4576	42.9797	1	19.0788	1082.264	9.419637	0.316072	0.095394	7.639485	243.1848	0.001299721
5801	0.5	78.1121	43.8858	1	18.6848	1050.579	8.311258	0.278881	0.093424	7.732909	250.9177	0.001111445
5801.5	0.5	80.4561	45.2357	1	18.1273	1006.864	6.929874	0.232529	0.090636	7.823545	258.7413	0.000898694

Table 8: Petrophysical parameters for well F-007, reservoir B

DEPT(ft)	H	GR	SW %	NTG	Porosity %	K(mD)	KH	FRC	Hperm	CFC	CSC	CFC/CSC
5803	0.5	82.5833	46.5268	1	17.6242	968.56	5.853193	0.196402	0.088121	8.090515	282.7478	0.000694618
5803.5	0.5	82.8197	46.6874	1	17.5636	964.0182	5.733468	0.192384	0.087818	8.178333	290.9262	0.000661282
5804	0.5	84.878	48.0128	1	17.0788	928.244	4.846986	0.162639	0.085394	8.263727	299.1899	0.000543597
5804.5	0.5	86.4932	49.1285	1	16.6909	900.3467	4.222898	0.141698	0.083455	8.347182	307.5371	0.00046075
5805	0.5	87.2121	49.6331	1	16.5212	888.343	3.971753	0.133271	0.082606	8.429788	315.9669	0.000421787
5805.5	0.5	88.6599	50.6931	1	16.1758	864.2852	3.498787	0.1174	0.080879	8.510666	324.4775	0.000361814
5806	0.5	87.7242	50.00	1	16.40	879.8434	3.800082	0.12751	0.082	8.592666	333.0702	0.000382833
5806.5	0.5	85.7545	48.6166	1	16.8667	912.908	4.496815	0.150889	0.084333	8.677	341.7472	0.000441522
5807	0.5	85.3508	48.356	1	16.9576	919.4578	4.644227	0.155835	0.084788	8.761788	350.509	0.000444597
5807.5	0.5	83.578	47.1757	1	17.3818	950.4857	5.386439	0.18074	0.086909	8.848697	359.3577	0.000502953
5808	0.5	82.1992	46.3197	1	17.703	974.4885	6.011965	0.201729	0.088515	8.937212	368.2949	0.000547738
5808.5	0.5	79.9833	44.9801	1	18.2303	1014.842	7.169573	0.240572	0.091152	9.028363	377.3233	0.000637576

Table 9: Petrophysical parameters for well F-013, reservoir A

DEPT(Ft)	H	GR	SW %	NTG	Porosity %	K (mD)	KH	FRC	Hperm	CFC	CSC	CFC/CSC
7129	0.5	63.6447	40.8391	1	20.0788	1165.664	12.79836	0.144249	0.100394	0.100394	0.100394	1.436830461
7129.5	0.5	61.2614	39.724	1	20.6424	1214.548	15.11101	0.170315	0.103212	0.203606	0.304	0.560245931
7130	0.5	58.3068	38.4266	1	21.3394	1276.868	18.44263	0.207865	0.106697	0.310303	0.614303	0.338375381
7130.5	0.5	57.1152	37.9204	1	21.6242	1302.933	19.96988	0.225078	0.108121	0.418424	1.032727	0.217945733
7131	0.5	55.825	37.3963	1	21.9273	1331.042	21.70893	0.244679	0.109636	0.528061	1.560788	0.156766504
7131.5	0.5	54.7023	36.947	1	22.1939	1356.101	23.34195	0.263085	0.11097	0.63903	2.199818	0.119593901
7132	0.5	54.6432	36.9269	1	22.2061	1357.246	23.41847	0.263947	0.11103	0.750061	2.949879	0.089477306
7132.5	0.5	54.5644	36.8966	1	22.2242	1358.968	23.53382	0.265247	0.111121	0.861182	3.81106	0.069599348
7133	0.5	54.2197	36.7663	1	22.303	1366.439	24.03881	0.270939	0.111515	0.972697	4.783757	0.056637271
7133.5	0.5	52.9098	36.2637	1	22.6121	1396.007	26.10824	0.294263	0.113061	1.085758	5.869515	0.050134183
7134	0.5	51.4424	35.7086	1	22.9636	1430.129	28.64005	0.322799	0.114818	1.200576	7.070091	0.045656999
7134.5	0.5	49.5811	35.0427	1	23.40	1473.219	32.06453	0.361396	0.117	1.317576	8.387666	0.043086604
7135	0.5	47.2864	34.2445	1	23.9455	1528.222	36.81871	0.41498	0.119727	1.437303	9.824969	0.042237286
7135.5	0.5	44.8045	33.4239	1	24.5333	1588.922	42.58631	0.479986	0.122667	1.55997	11.38494	0.042159735

Table 10: Petrophysical parameters for well F-013, reservoir B

DEPT(Ft)	H	GR	SW %	NTG	Porosity %	K(mD)	KH	FRC	Hperm	CFC	CSC	CFC/CSC
7142	0.5	22.9606	27.6122	1	29.697	2185.333	133.9684	1.509945	0.148485	3.400697	44.23058	0.034138031
7142.5	0.5	22.7735	27.5729	1	29.7394	2190.703	135.1208	1.522933	0.148697	3.549394	47.77997	0.031873884
7143	0.5	22.7735	27.5729	1	29.7394	2190.703	135.1208	1.522933	0.148697	3.698091	51.47806	0.029584122
7143.5	0.5	23.0295	27.6292	1	29.6788	2183.033	133.4771	1.504407	0.148394	3.846485	55.32455	0.0271924
7144	0.5	22.9705	27.6179	1	29.6909	2184.566	133.8046	1.508098	0.148455	3.994939	59.31949	0.025423319
7144.5	0.5	22.9114	27.6066	1	29.703	2186.1	134.1328	1.511797	0.148515	4.143455	63.46294	0.023821727
7145	0.5	22.8523	27.5897	1	29.7212	2188.401	134.6261	1.517357	0.148606	4.292061	67.755	0.022394759
7145.5	0.5	22.7932	27.5785	1	29.7333	2189.936	134.9558	1.521073	0.148667	4.440727	72.19573	0.021068746
7146	0.5	22.7735	27.5785	1	29.7333	2189.936	134.9558	1.521073	0.148667	4.589394	76.78512	0.019809481

Table 11: Petrophysical parameters for well F-021, reservoir A

DEPT(Ft)	H	GR	SW%	NTG	Porosity %	K(mD)	KH	FRC	Hperm	CFC	CSC	CFC/CSC
7148	0.5	22.1235	27.4386	1	29.8849	2209.176	139.1351	1.568178	0.149424	5.186333	96.63464	0.016227911
7148.5	0.5	22.1038	27.4331	1	29.8909	2209.946	139.3043	1.570085	0.149455	5.335788	101.9704	0.015397455
7149	0.5	22.3402	27.4832	1	29.8364	2203.007	137.786	1.552972	0.149182	5.48497	107.4554	0.014452248
7149.5	0.5	22.2909	27.4777	1	29.8424	2203.779	137.9542	1.554868	0.149212	5.634182	113.0896	0.013748994
7150	0.5	22.2318	27.4609	1	29.8606	2206.09	138.4592	1.56056	0.149303	5.783485	118.8731	0.013127951
7150.5	0.5	22.0053	27.4164	1	29.9091	2212.262	139.8134	1.575823	0.149545	5.93303	124.8061	0.012626172
7151	0.5	21.1977	27.2398	1	30.103	2237.051	145.342	1.638135	0.150515	6.083546	130.8896	0.012515392
7151.5	0.5	21.2174	27.2453	1	30.097	2236.274	145.1667	1.636159	0.150485	6.23403	137.1237	0.011931994
7152	0.5	21.2568	27.2562	1	30.0848	2234.72	144.8161	1.632208	0.150424	6.384455	143.5081	0.01137363
7152.5	0.5	20.597	27.1142	1	30.2424	2254.967	149.4271	1.684178	0.151212	6.535667	150.0438	0.011224579
7153	0.5	19.9864	26.9845	1	30.3879	2273.749	153.7913	1.733367	0.151939	6.687606	156.7314	0.011059473

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Table 11: Petrophysical parameters for well F-021, reservoir B

DEPT(Ft)	H	GR	SW %	NTG	Porosity %	K(mD)	KH	FRC	Hperm	CFC	CSC	CFC/CSC
7158	0.5	26.9295	28.5383	1	28.7333	2065.411	109.9123	1.23881	0.143667	8.169182	231.8337	0.00534353
7158.5	0.5	27.2644	28.6168	1	28.6545	2055.78	108.1162	1.218566	0.143273	8.312454	240.1461	0.005074271
7159	0.5	27.7765	28.7383	1	28.5333	2041.017	105.4012	1.187966	0.142667	8.455121	248.6012	0.0047786
7159.5	0.5	27.9636	28.7872	1	28.4848	2035.129	104.331	1.175904	0.142424	8.597545	257.1988	0.004571965
7160	0.5	28.0326	28.8056	1	28.4667	2032.923	103.9321	1.171408	0.142333	8.739879	265.9387	0.004404806
7160.5	0.5	30.0712	29.3047	1	27.9818	1974.633	93.7532	1.056683	0.139909	8.879788	274.8185	0.003845022
7161	0.5	31.45	29.6515	1	27.6545	1935.85	87.36324	0.984662	0.138273	9.018061	283.8365	0.003469118
7161.5	0.5	32.0311	29.7952	1	27.5212	1920.182	84.86636	0.95652	0.137606	9.155667	292.9922	0.003264661
7162	0.5	32.228	29.8478	1	27.4727	1914.503	83.97311	0.946452	0.137364	9.29303	302.2852	0.003130992
7162.5	0.5	32.1492	29.828	1	27.4909	1916.632	84.30728	0.950219	0.137455	9.430485	311.7157	0.003048351
7163	0.5	31.9129	29.769	1	27.5455	1923.026	85.31596	0.961588	0.137727	9.568212	321.2839	0.002992953
7163.5	0.5	31.6076	29.6906	1	27.6182	1931.571	86.67639	0.976921	0.138091	9.706303	330.9902	0.00295151
7164	0.5	31.3417	29.6256	1	27.6788	1938.708	87.82384	0.989854	0.138394	9.844697	340.8349	0.002904203
7164.5	0.5	30.9576	29.5286	1	27.7697	1949.443	89.5687	1.00952	0.138848	9.983545	350.8185	0.002877613
7165	0.5	29.9136	29.273	1	28.0121	1978.246	94.36404	1.063568	0.140061	10.12361	360.9421	0.002946644
7165.5	0.5	28.4856	28.9226	1	28.3515	2018.989	101.435	1.143264	0.141758	10.26536	371.2074	0.003079853

Depositional environments interpreted influenced the reservoir flow properties of the Okogbe Field. The qualitative evaluation of the well logs identified three (3) hydrocarbon bearing reservoirs A, B and C which are predominantly sandstones. The major petrophysical parameters (i.e. porosity, permeability, water saturation, net to gross) were determined quantitatively. The identified twenty-four (24) flow units based on the Stratigraphic Modified Lorenz (SML) plot show that each of the reservoirs have similar flow patterns. The petrophysical parameters of reservoir A has better reservoir productivity in zones A1 - A3 while A4 - A8 has good reservoir productivity. Reservoir B has better reservoir productivity in zones B1 - B3 while B4 - B8 has good reservoir productivity. Reservoirs A, B and C have very good quality flow units towards the top of each of the wells and poor-quality flow units towards the base of each of the wells. The normal flow units indicated high storage and flow capacities which are dominant in the reservoirs as compared to the baffle flow units. This suggests that the dominant depositional setting of the study area which is the shallow marine shoreface and its reservoir properties primarily control the reservoir flow pattern in the reservoirs.

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