Depositional Environments and Reservoir Quality Assessment of the "AKJOM Field," Niger Delta

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Abstract

The two sand bodies C and D studied in the Akjom field, at eastern portion of the portion of the Niger Delta Basin were deposited in shallow marine environments. Sand C was deposited in Fluvial, shoreface and tidal environments. Fluvial environments occur towards the western portion of the field caping a shoreface environment which occur throughout the field at the bottom. The D sand was deposited in shoreface and tidal environment (shallow marine environment). Predominantly shoreface environment was capped with minor tidal channel eastwards. Tidal environment occurs at the eastern edge of the field capping shoreface environment. The axis of deposition of the sands is northwest to southeast, the Isopach map and the major antithetic fault within the field show this. The facies and the reservoir quality models, show a good correlation – area with good sand development have better porosity and permeability while area with poor sand development have lower reservoir quality. The average effective porosity of between 14.2 to 25.3 % and permeability of between 206.3 to 1027.4 milidarcy, show that the sands has moderate to good reservoir quality. The effective porosity and permeability variation among the thirteen wells used suggest possible changes in depositional processes such as change from laminar to turbulent flow and change in sediment source leading to variation in sorting and thus variation in porosity. The study therefore reveals that a reservoir need be studied in each well for its quality in order to have accurate field development and reserve update.

Keywords: Depositional Environment, Reservoir Quality Assessment, Akjom Field, Niger Delta

1.0 Introduction

Production success in the Niger Delta where the field is a part depend on adequate knowledge of the depositional environment. Depositional environment is the determinant of reservoir textural properties like grain size, sorting, structures on which the reservoir quality of porosity and permeability depends. Depositional environment also controls the geometry, lithologic sequences and biostratigraphic character of sedimentary unit. This study reveals the environment of deposition of the C and D sands of the coastal swamp major depositional period inside the Niger Delta Basin. The reservoir quality was assessed and correlation was made between the reservoir quality value and the facies which was environmentally determined.

Every environment has its own combination of depositional processes that determine variation in textural properties and hence reservoir qualities (Nichol 2009). Each process produces unique features such as grain size distribution pattern in a vertical section, sedimentary structures; which help to identify the process from a sedimentary deposit. Combination of such identified processes help to define environments of deposition.

Models of features of various of environments where sediments are deposited have been generated.

The objectives of this study are to interpret the depositional environment of the C and D sands through comparison of observed features produced by depositional processes with those of model generated for various environment. The reservoir quality was determined and compared with the facies variation.

1.2 Geology of the Niger Delta: A review (Area)

The coastal swamp major depositional period is one of the depobelt in the Niger Delta sedimentary Basin. Depobelts represent major depositional periods that displayed the geology of the Tertairy Niger Delta Basin. Niger Delta geology comprise of three formations : the Benin formation , Agbada formation and Akata Formation which are superimposed on each other with the Akata formation occurring at the bottom the Benin formation occurring at the top while the paralic Agbada formation is sandwiched between them. One distinguished feature of the geology of eastern portion of the Basin is the presence of the Afam Clay member in the Benin formation (figure 1) which is not seen in the western part. The study area occurs in the eastern portion of the Basin. Two of the three formations generally known in the Niger Delta basin: Benin, Agbada, were seen in the study area. The base of the Benin Formation ranges from 7485ft (2281.42m) to 7943ft (2421m) within the 13 wells used for this study. The Benin Formation was identified with the sand / shale ratio which is conspicuously higher than that of the Agbada below. The gamma ray signature which reflects grain size distribution, also help to identify the Benin Formation (sharp Base, funnel shapes predominates within it). This reflect braided and meandering channels of upper delta plain environment. Little clay shown in the area occupied by the Benin formation within the 13 wells, reflects flood plains and abandoned oxbow lakes. No significant fault penetrates the Benin formation as seen from the seismic section, confirming the cessation of gravity tectonic in the Agbada formation prior to the deposition of coastal plain Benin deposit. The Agbada Formation occurs from below the base ranges identified for the Benin Formation: 7485ft (2281.42m) to 7943ft (2421m) to the maximum drilled depth in each well. Thick shale sequences, different reservoir facies, such as distributary channels, shoreface, mouth bars, Tidal channels occurs in the Agbada Formation. The shales mark the onset of new depositional cycles with some transgressive sands in some of them, (Weber,1971).

NIGER DELTA

SUBSURFACE			SURFACE OUTCROPS		
YOUNGEST KNOWN AGE		OLDEST KNOWN AGE	YOUNGEST KNOWN AGE		OLDEST KNOWN AGE
RECENT	BENIN FORMATION Afam Shale Member	OLIGOCENE	PLIO/ PLEISTOCENE	BENIN FORMATION	MIOCENE ?
RECENT	AGBADA FORMATION	EOCENE	MIOCENE	OGWASHI-ASABA FORMATION	OLIGOCENE
			EOCENE	AMEKI FORMATION	EOCENE
RECENT	AKATA FORMATION	EOCENE	L. EOCENE	IMO SHALE FORMATION	PALEOCENE
EQUIVALENTS NOT KNOWN			PALEOCENE	NSUKKA FM	MAESTRICHTIAN
			MAESTRICHTIAN	AJALI FORMATION	MAESTRICHTIAN
			CAMPANIAN	MAMU FORMATION	CAMPANIAN
			CAMP./MAEST.	NKPORO SHALE	SANTONIAN
			CONIACIAN/ SANTONIAN	AWGU SHALE	TURONIAN
			TURONIAN	EZE AKU SHALE	TURONIAN
			ALBIAN	ASU RIVER GROUP	ALBIAN

Figure 1: Table of formations, Niger delta area, Nigeria (Adapted from Short and Stauble).

2.0 Materials and Methods

Thirteen well logs were used after quality check for the study. Lithologic types were determined from the application of log response principles. Gamma ray, density, Neutron, Sonic, Resistivity principles of operation was used to determine the lithologic types. Log response variation- trend, showing shape especially in gamma ray was interpreted and compared with models designed for various enviroment of deposition. From this, and the relative position of the sand to other facies - shale, the depositional environment of the sands were interpreted. The facies model was generated using petrel software.The reservior quality (porosity) of the sands were determined from density log using the relationship between the matrix density, formation fluid density and measured (bulk) formation density. The permeability was generated using the Tixer equation. A comparision was made between the lithofacies model and the reservoir quality model to examine probable cause of variation in reservoir quality.

3.0 Results and Discussion

3.1 Depositional Environment features of sand C.

A. Gradational base, funnel shape and bell shape

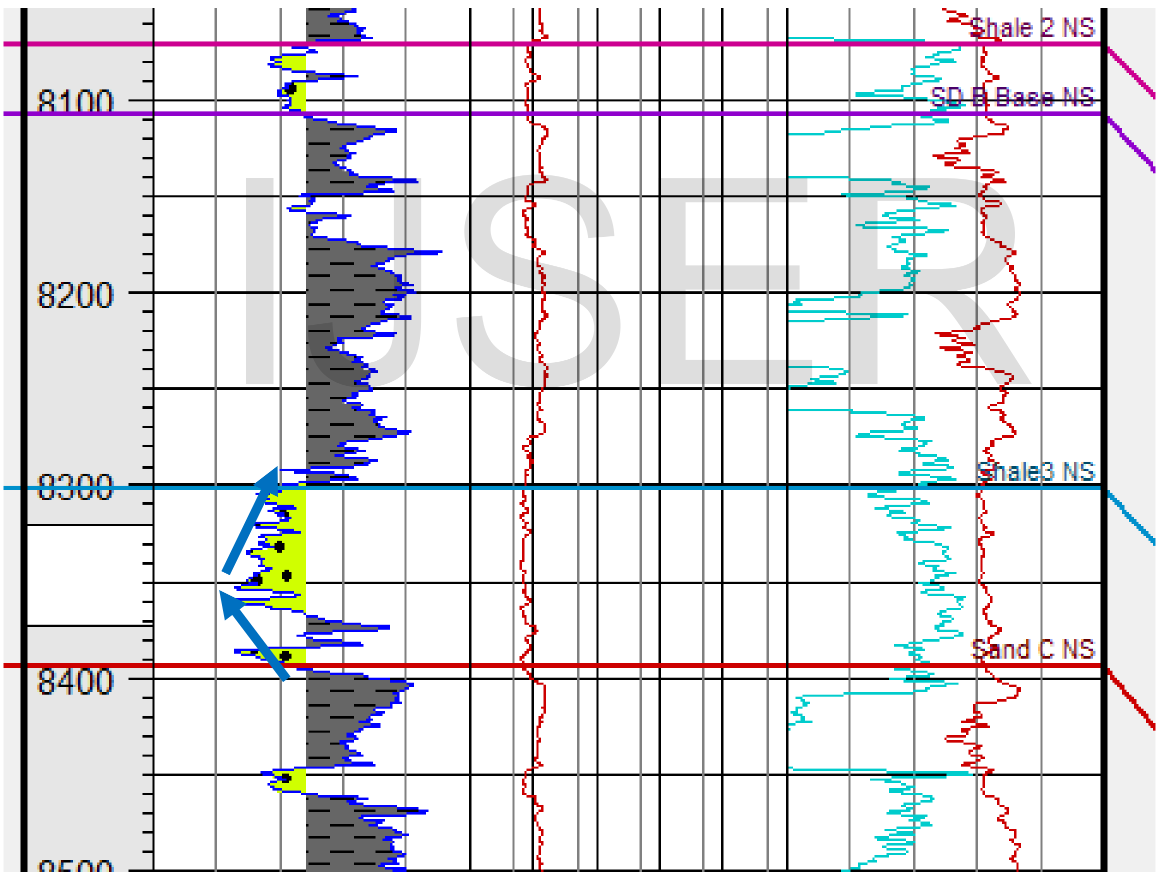

Fig 2 a : Gradational base, funnel shape, followed by bell shape of sand C reflecting an initial upward increase in grain size followed by an upward decrease in grain size.

B. Relative position of sand C to other facies

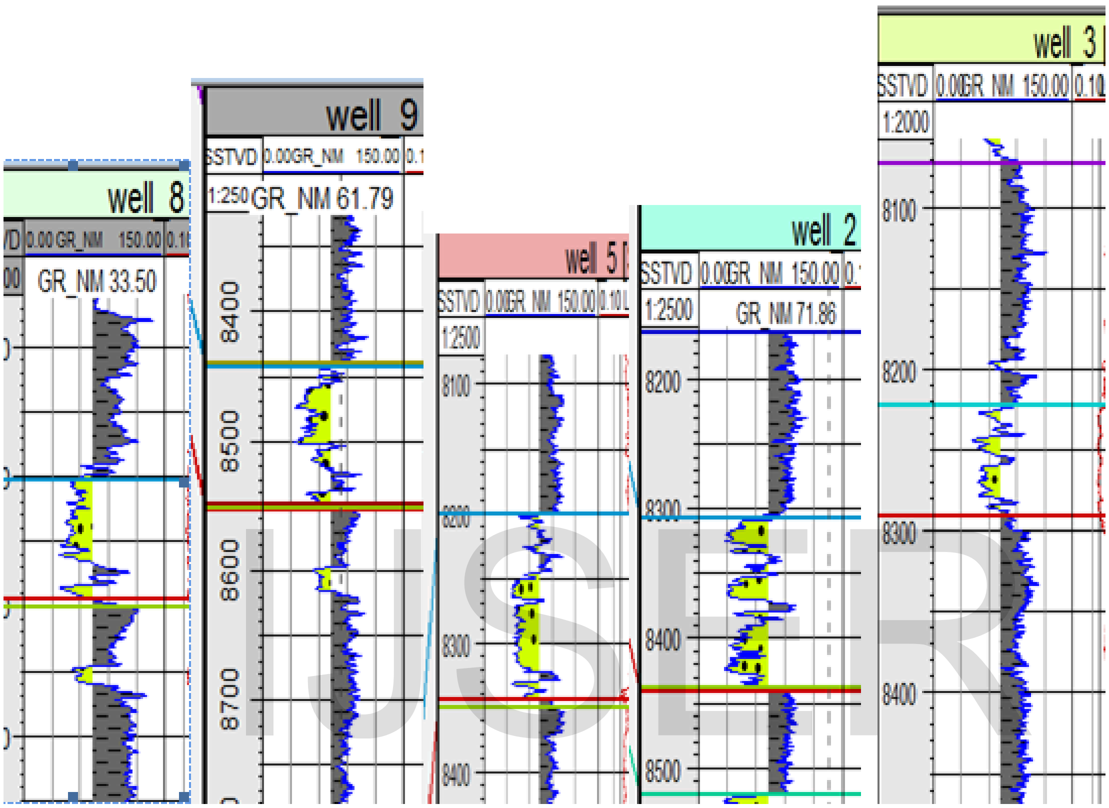

Fig 2 b: Relative position of sand C to other facies, (sandwiched between marine clay/shale), help define its environment of deposition.

C. Isopach map showing thickness variation within the field.

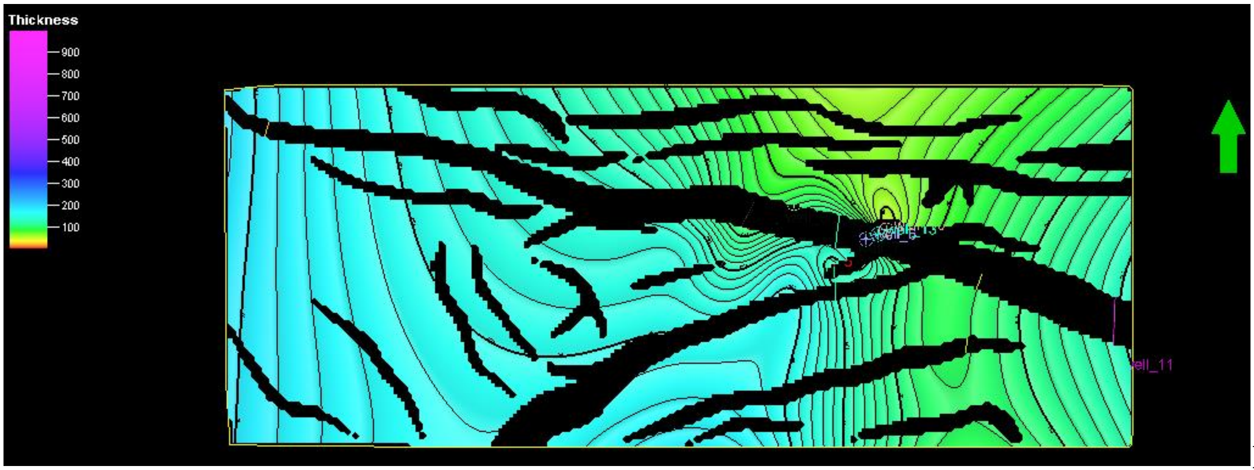

Fig 2

c: Sand C thickness (thickens towards the west), Note also the initial thinning towards the south and later thinning towards the north.

D. Facies models

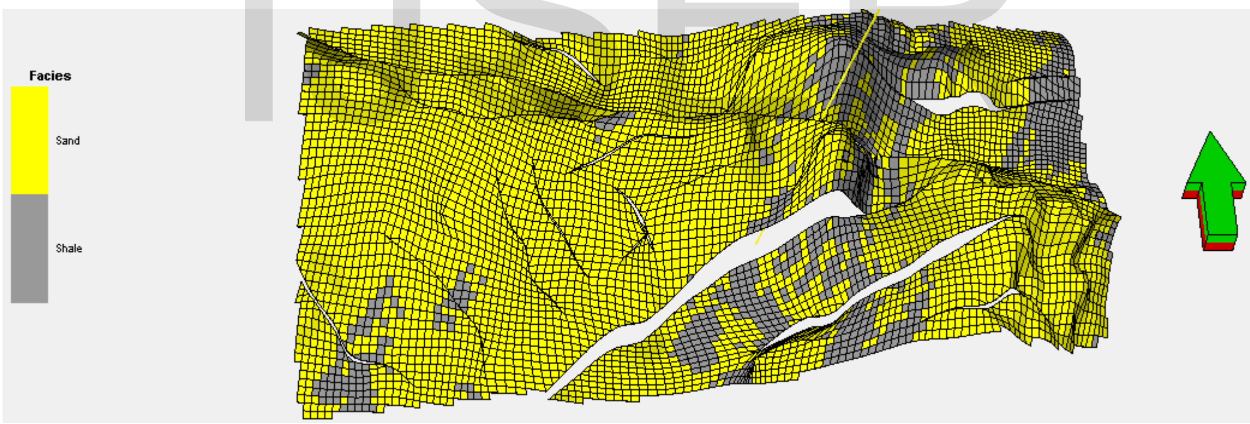

Fig 3a: Sand C facies model at the top (8313ft/ 2533.8m) showing more sands than shale

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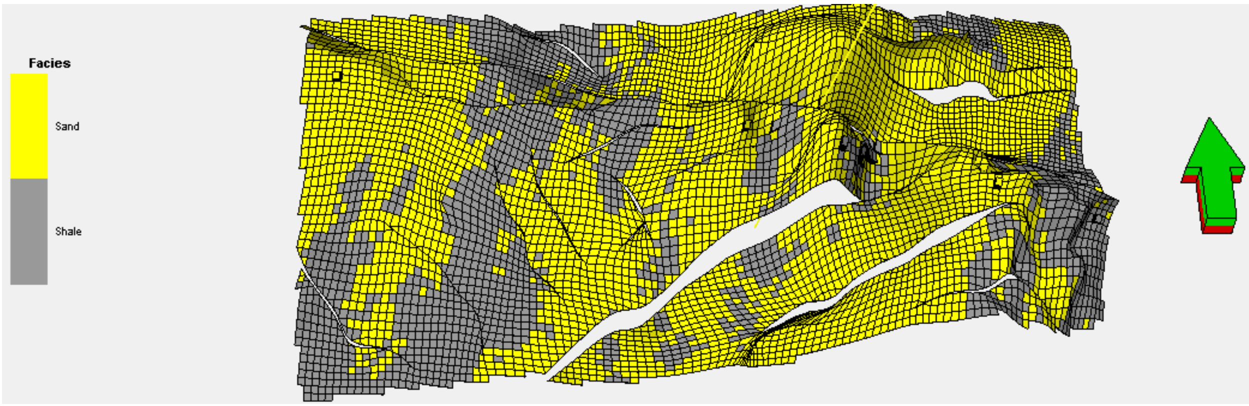

Fig 3b: Sand C facies model at middle (8361ft / 2548.43m); showing decrease in sand and increase in shale

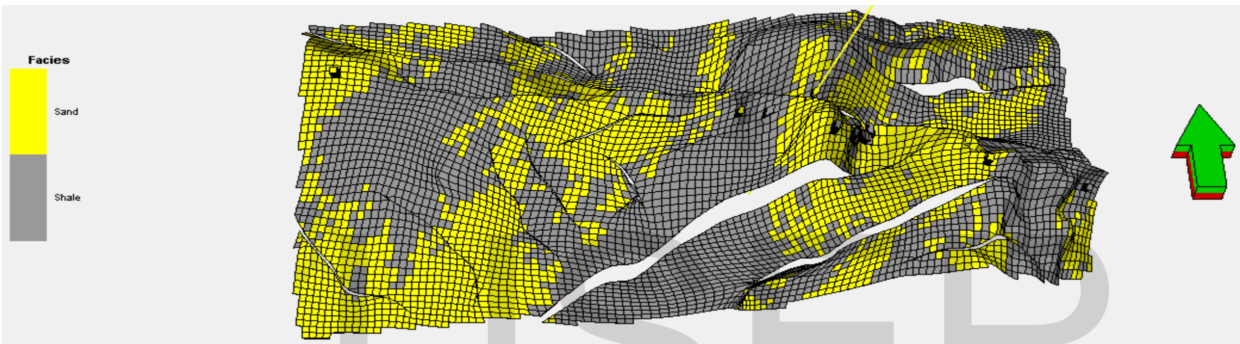

Fig 3c: Sand C facies model at bottom (8412ft /2563.9m); showing increase volume of shale and decrease in sand

E. Log shape signature

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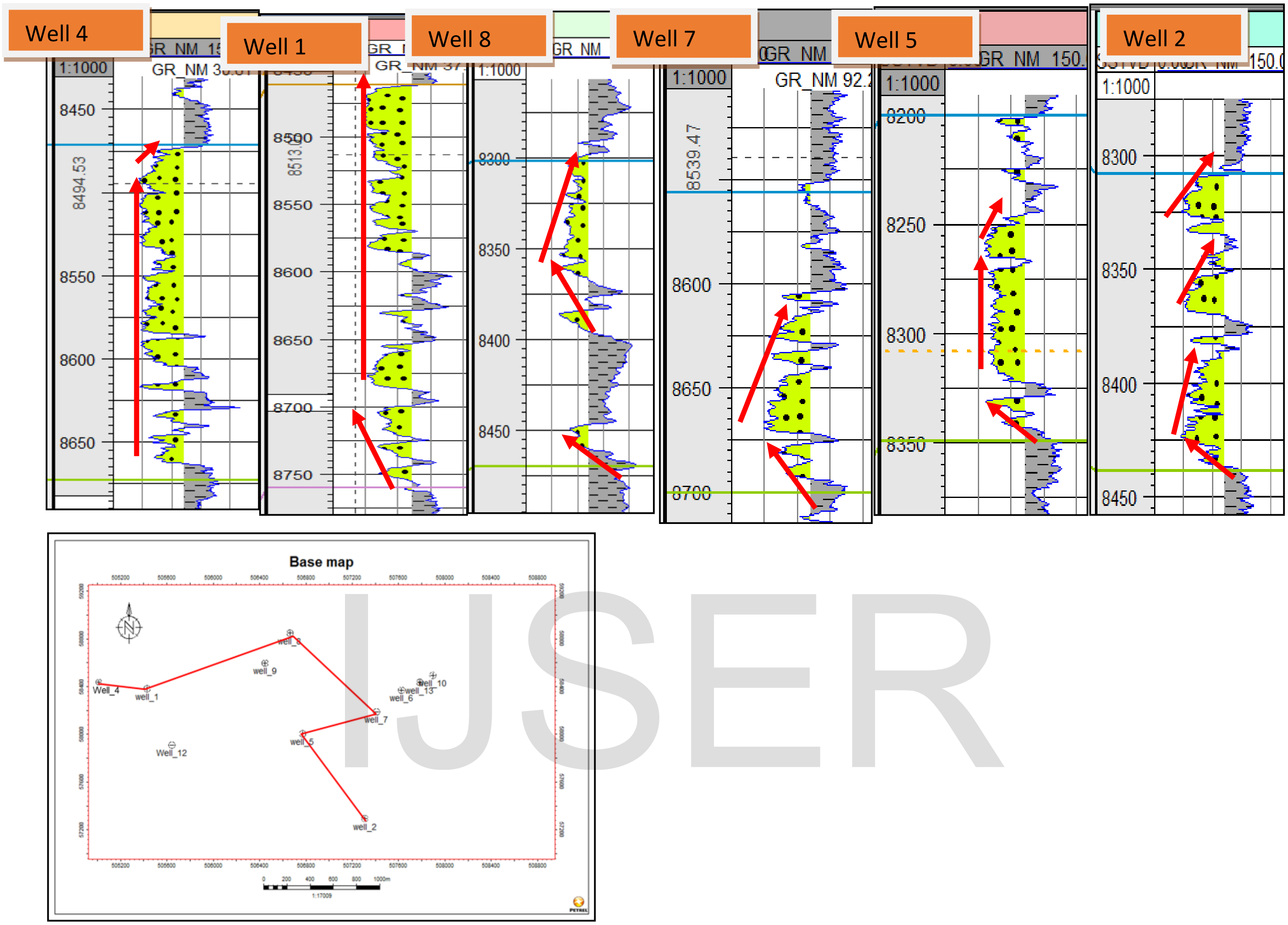

Figure 4a: Gradational base, funnel shape capped by bell shape signifying shoreface capped with fluvial deposit.

. According to Weber 1971, one of the major criteria for identifying the depositional environment of sand bodies in the Niger Delta is their grain size distribution, this was reflected by the gamma ray log shape and trend.

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From the above features: nature of upper contacts and lower contacts, relative position of sand C to other facies, isopach map, better sand development in the upper section of the facies model, log shape trend (funnel capped with bell shape); the sand was interpreted to be from shallow marine environment: a shoreface capped with fluvial facies to the west and tidal facies to the east. The tidal channel to the east was inferred based on the serrated nature of the bell shape to the east

Depositional processes Features of Sand D

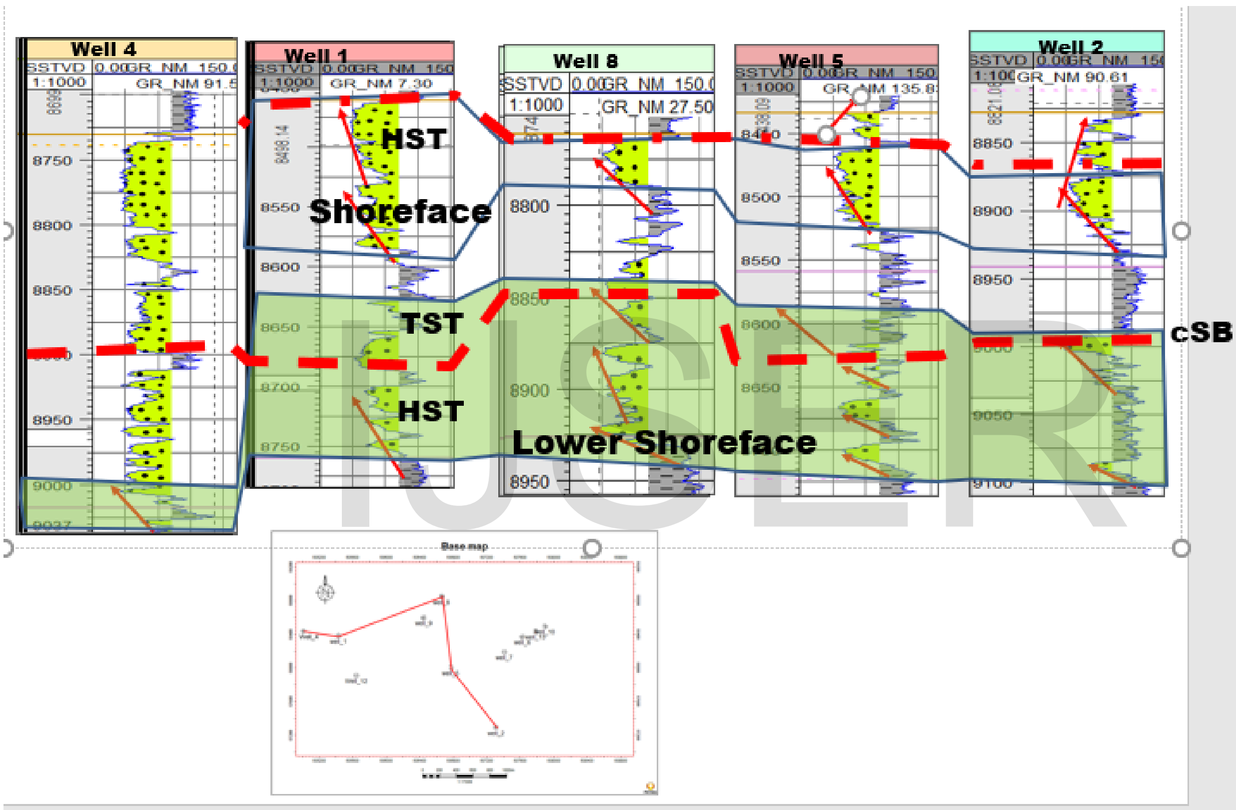

Figure 5: grain size variation of sand D with nature of upper / lower contacts produced by depositional processes.

From the log signature in the wells, facies D is seen to be made predominantly of sand with laminations of shales, have a gradational base, repeated funnel shape, which implies repeated upward increase in grain size, overall upward decrease in clay / shale content.

The dominant of sand suggest deposition from bedload transport with minor alternation from suspension fall out. The suspension load falls out may be related to tidal influence which generate temporary increase water depth thereby lowering the energy of transportation and thus deposition of suspension materials. Funnel shape refers to upward increase in grain size with corresponding decrease in clay content which represent an increase in depositional energy over time - a progradation sedimentation. The repetitive nature of the funnel shape suggests dominants of progradation with minor transgression which may be related to local change in base level, or change in sediment supplied. These features are produced by shoreline processes such as transportation, deposition from bedload with minor suspension deposition and little tidal current effects generating the minor bell shape especially toward the eastern portion.

3.2 Depositional Environment features of sand D.

The following features were used to infer the depositional environment of sand D:

A Multiple funnel shape with gradational base

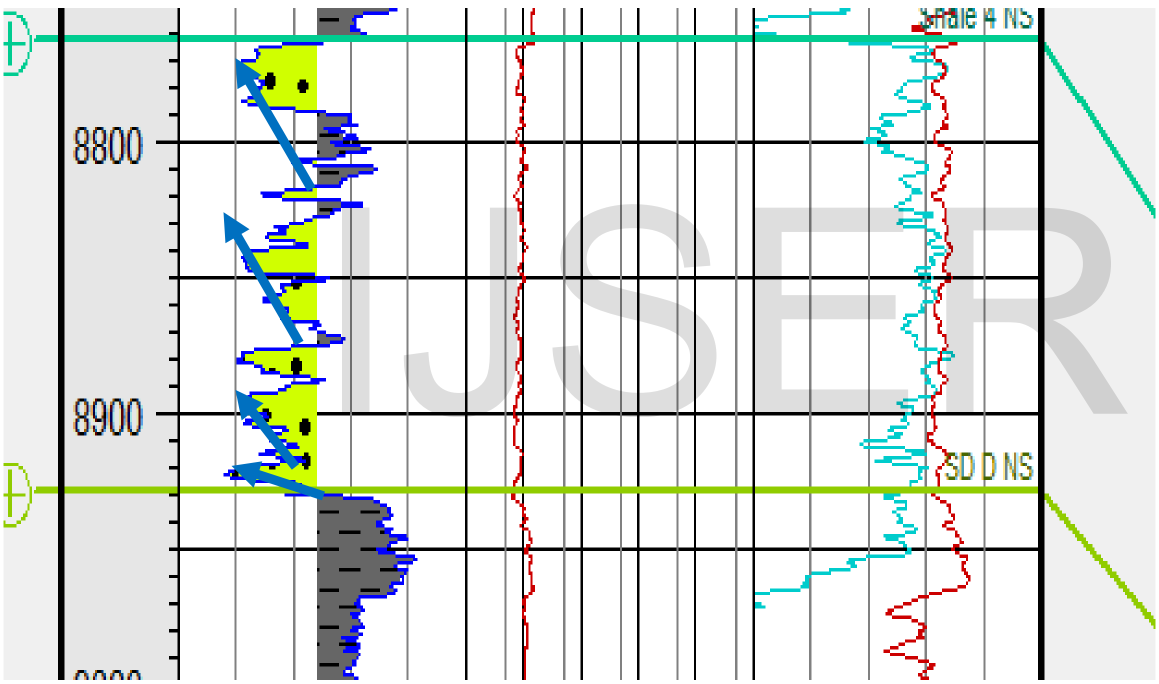

Fig 6 : Multiple funnel shape of sand D with gradational base reflecting repetitive up ward increase in grain size.

B Position of the sand in relation to other lithologies (facies)

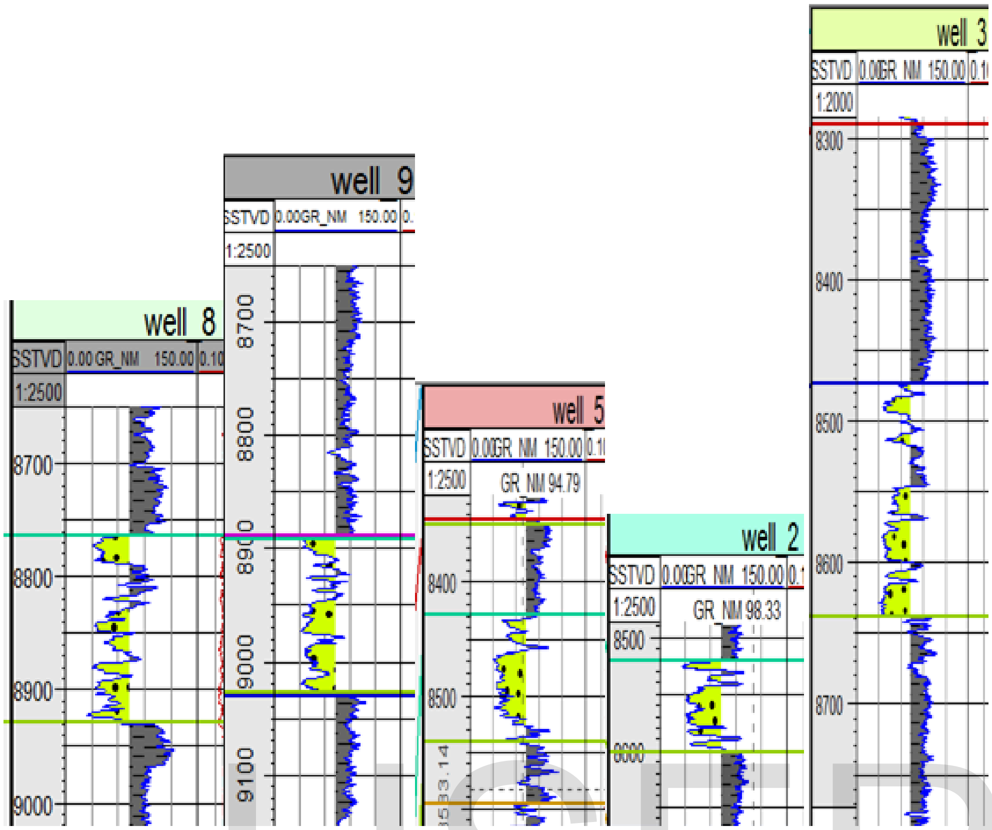

Fig 7: Position of sand D to other facies (lying between marine shale)

C. Thickness of the sand within the field

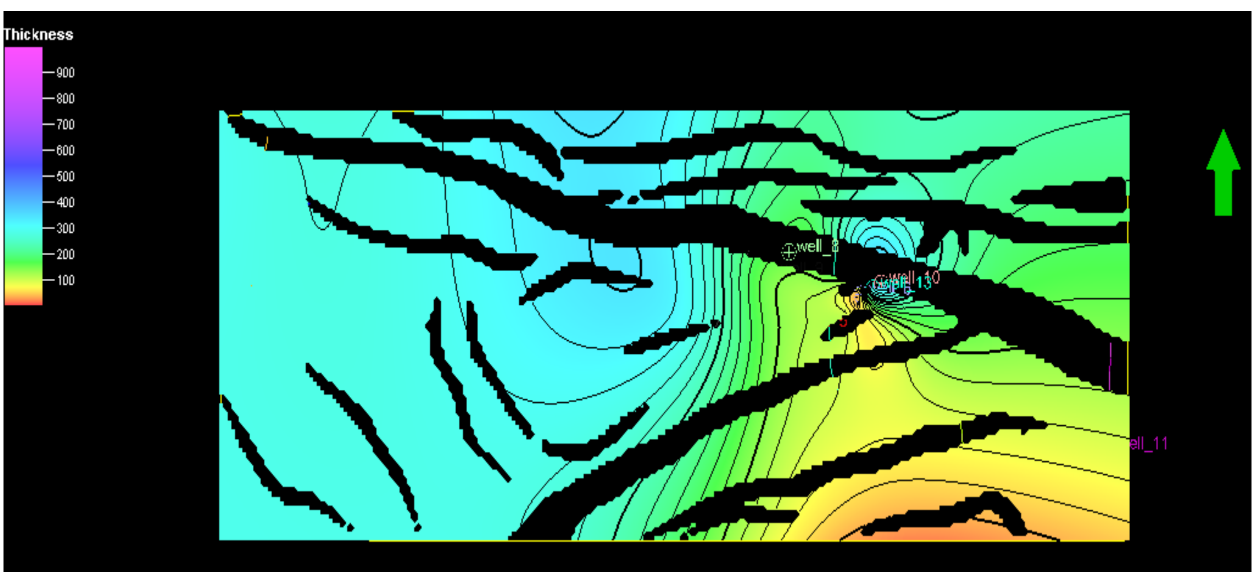

Fig 8: Sand D thickness, increase towards the west, and thins towards the southeast. This reflects a typical shoreline progradation of deposition, shoreface and shallow marine environments deposits thins towards the down current direction.

D Lithofacies Models

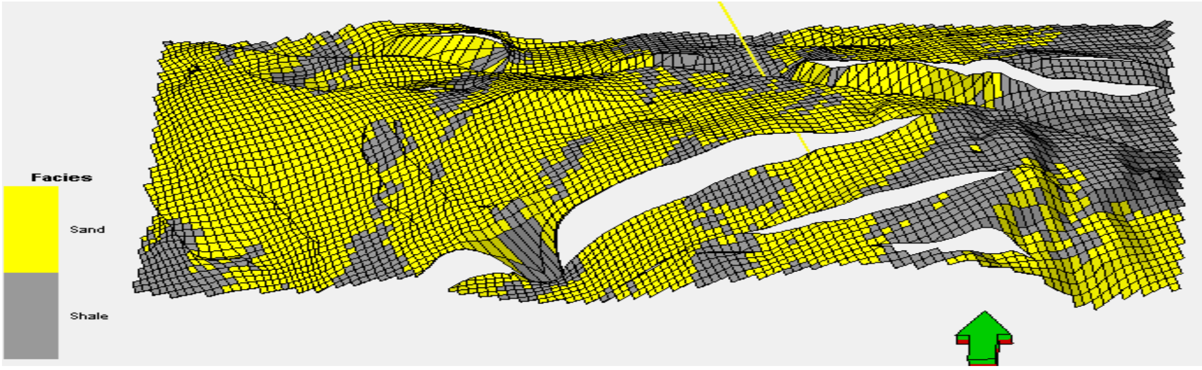

Fig 9 : Sand D facies model at 8785.7ft / 2677.8m showing higher sand percentage than shale

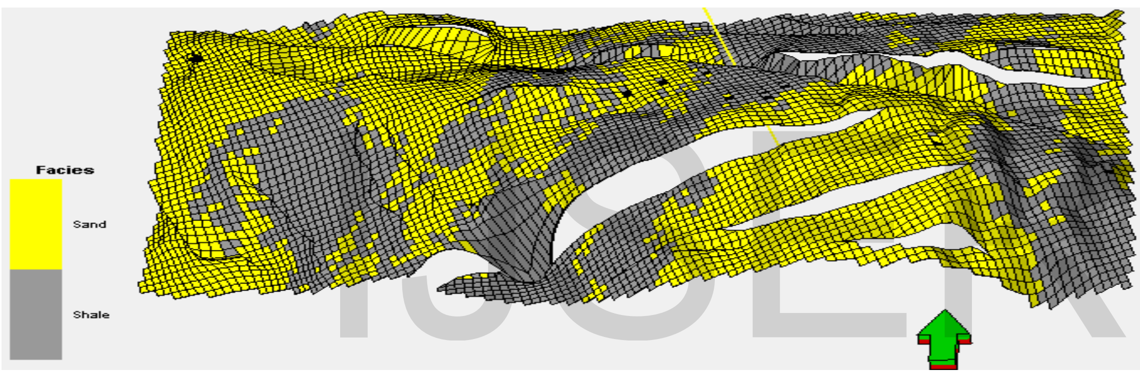

Fig 10: Sand D facies model at 8826.6ft/ 2690.3m showing reduction in sand percentage and increase in percentage of shale.

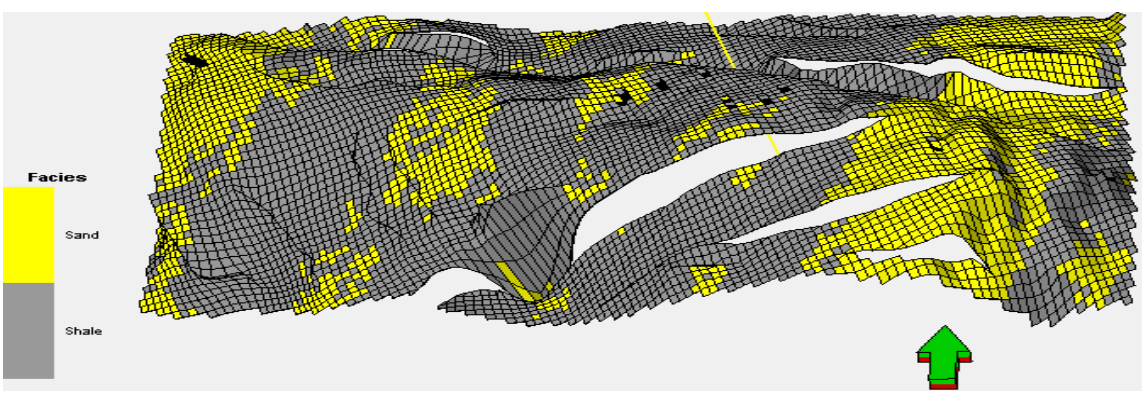

Fig 11 : Sand D facies model at 8887.8ft/2709.0m showing increase in percentage of shale with more reduction in sand percentage.

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From the above features, sand D was identified as a shallow marine environment deposits – an upper shoreface environment with minor tidal influence towards the eastern part.

3.3 Reservoir Quality.

The porosity and permeability of the sands is shown below:

Table 1: Porosity and Permeability of sand C

SAND C			
Well Name and Depth (ft / m)	Average Total Porosity (%)	Average Effective Porosity (%)	Average Permeability (milidarcy)
Southward direction			
Well 8 (8298.86 / 2529.49)	32.8	22.7	349.4 North

Well 9 (8439.2 / 2572.26)	30.2	17.9	265.5
Well 5 (8201 / 2499.66)	25	21.3	731.9
Well 2(8308.7 / 2532.49)	26.3	19.5	508
Well 11(8201.5 / 2499.8)	26.7	14.2	239.9 South
Westward direction			
Well 4 (8473 / 2582.57)	24.4	23.06	1027.4 West
Well 1(8231 / 2508.8)	31.9	25.3	825
SAND C cont'd			
Well Name and Depth (ft / m)	Average Total Porosity (%)	Average Effective Porosity (%)	Average Permeability (milidarcy)

Well 12 (8409.5 /2563.2	28.16	15.13	223.7
Well 7 (8604.3 /2622.59	26.4	16.4	172.0
Well 6 (8466.4 /2715.76	29.4	15.1	392.6
Well 13 (8438.2 /2571.96	29.4	20.5	344.2
Well 10 (8391.4 /2557.69	31.16	18.8	206.2 East

The base map of the field showing the wells position is shown below:

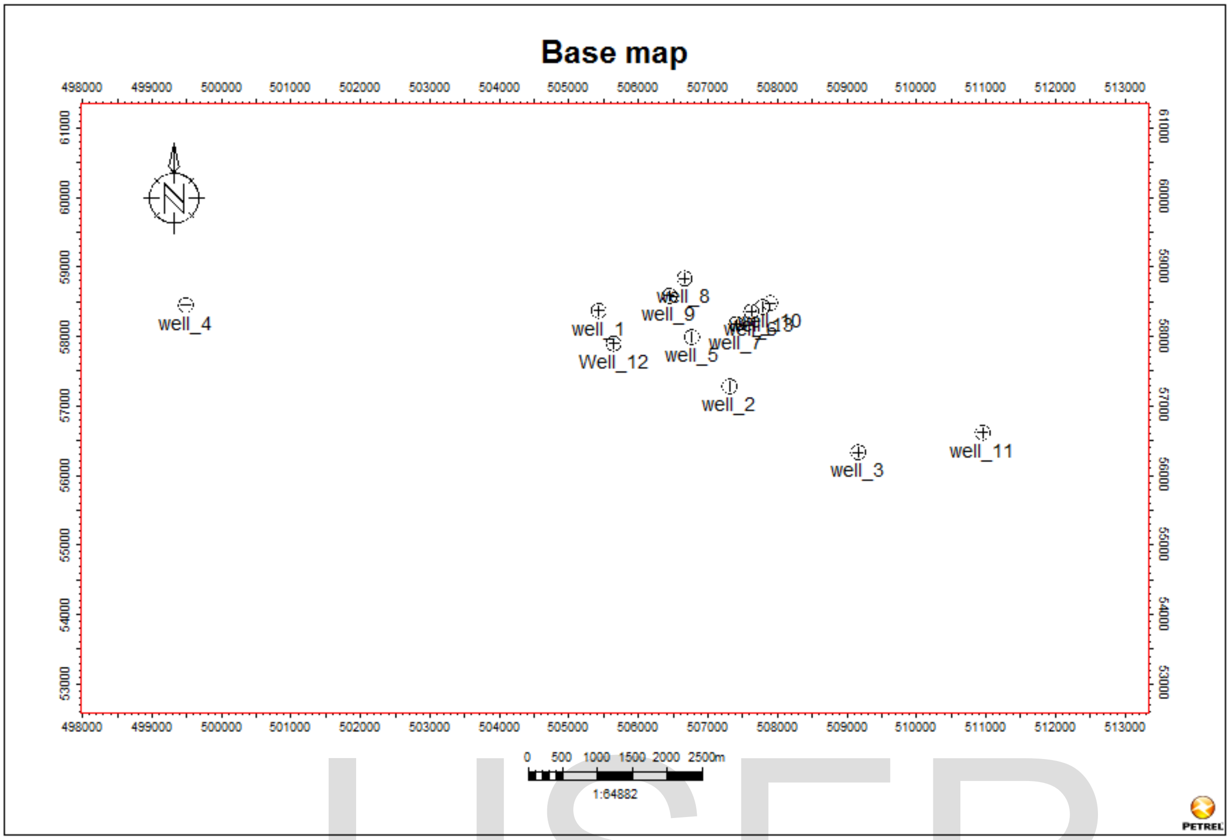


Figure 12: Base of the field study area, showing location of the wells.

From figure 12 and table 1, the average reservoir quality of sand C was seen to decrease southwards, reflecting decrease in grain size and thus depositional energy in this direction. Although the change in reservoir quality from well 8 to 9 is more rapid, this might not be unrelated to the deeper depth of the sand at well 9 position or probable increase in diagenetic processes in the region. Again in well 11, which occur most southerly, the reservoir quality show lesser reduction than expected when compared with other wells, this may be attributed to probable early porosity preservation processes which occur at shallow depth such as chlorite and clay mineral coating of grains which inhibit later diagenetic processes such as quartz overgrouth (Odigi, 2011). The average reservoir quality variation from the western path of the field, which is the direction of the depositional axis of the sand, shows an uneven variation. The effective porosity which already removed the unconnected pore spaces of clay minerals found in shale, shows that diagenetic processes of compaction and cementation might have affected the reservoir to various decrees and at different scale. It also suggests that depositional processes might have varied in strength and sediments properties might have changed during the deposition of the sand. Since the depositional axis is from northwest to southeast,the reservoir quality is expected to be highest in the position of well 4 (figure 12) because of the higher energy of deposition there and least in position of well 10 or 11due to the expected lower energy of deposition there, but this was not so as the reservoir quality was highest in the position of well 1 which although also closer to well 4 and least in the position of wells 6 and 12. This could be attributed to effect of uneven sorting of the reservoir, or supply of sediments with different textural properties such as roundness and angularity or diagenetic processes which altered the reservoir quality in these wells positions since shale effect have been removed. The relative increase in the reservoir quality in the position of wells 10 and 13 might be attributed to better sorting of the reservoir in that area due to change from turbulent to laminar flow, or porosity enhancing diagenetic processes such as pressure dissolution or local absence of elements needed for the precipitation of cements in pore spaces which would have reduced porosity in that area (Odigi 2011).

Table 2: Sand D reservoir quality

Well Name and Depth (ft / m)	Average Total Porosity (%)	Average Effective Porosity (%)	Average Permeability (milidarcy)	
Southward Direction				
Well 8 (8763.86 / 2671.2)	28.2	18.8	299.8	North
Well 9 (8888.3 / 2709.15)	26.06	18.35	240.3	
Well 5 (8432.9 / 2570.34)	26.7	19.2	328.1	
Well 2 (8833.2 / 2692.34)	26.2	21.4	688	South
Westward Direction				
Well 4(8728 / 2660.29)	25.5	21.85	525.3	West
Well 1(8461 / 2578.9)	19.56	17.54	216.4	
Well 12 (8877.5 /2705.86	25.6	17.84	235.5	

ISSN 2229-5518

Well 7 (8798.3 /2681.7	25.8	20.4	586.4	
Well 6 (8910/2715.76	23.8	18.72	473.1	
Well 13 (8802.2 /2682.9	25.8	17.6	227.2	
Well 10 (8837.18 /2693.57	27.8	15.35	121.4	East

From table 2 and figure 12 above, the average reservoir quality of the sand was seen to increase from the north to south. This may be related to increase in wave current / tidal activity which approaches from the south enhancing the sorting of the reservoir and thus its quality. It may also be related to lack of serious diagenetic cementation processes affecting the reservoir or homogenous composition and good fabric which preserve the original porosity and permeability. Looking at the reservoir from the western to the eastern direction - approximate depositional axis, there is a general decrease though not uniform, but in the position of well 7; there was a marked increase from 17.84% in well 12 to 20.4% in well 7 position. This show that the reservoir quality tends to follow the depositional axis but deviate in the position of well 7 probably due to porosity preservation processes of diagenesis such as dissolution of liable grains and leaching or probable overpressure around the region. The petrophysical log of the sand is shown in figure 13. It confirms the environment of deposition to be of shoreface where depositional mechanism allows for an upward increase in reservoir quality.

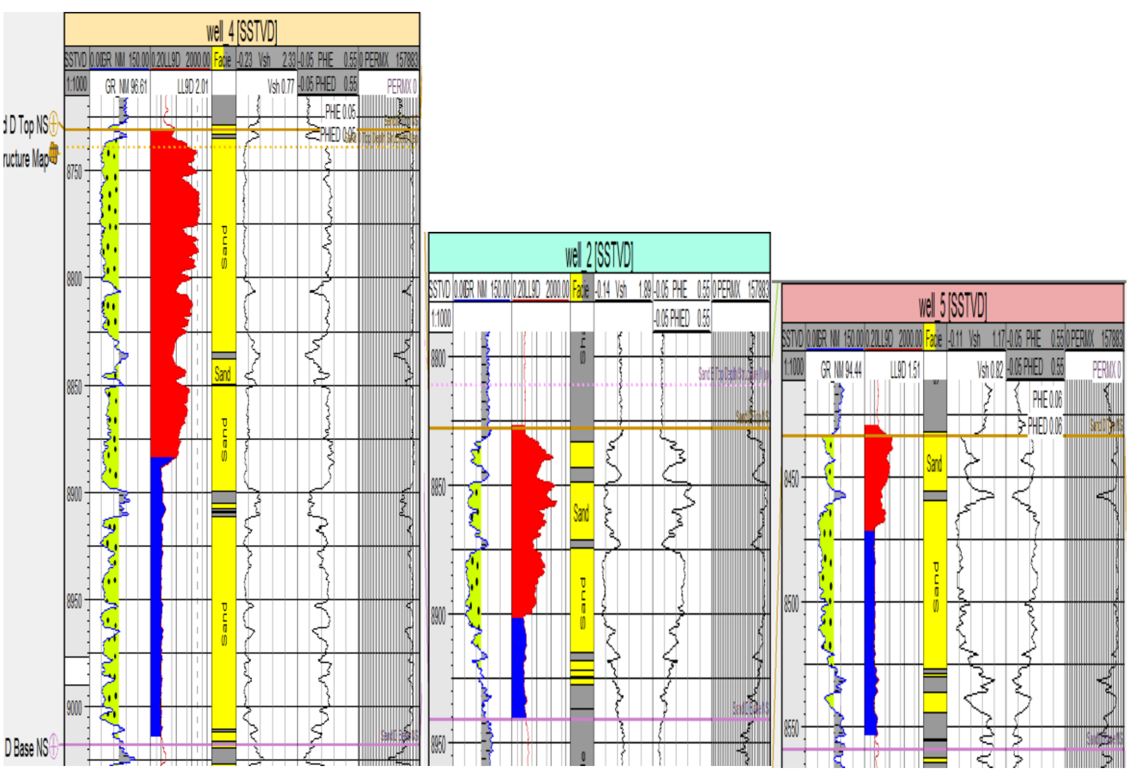
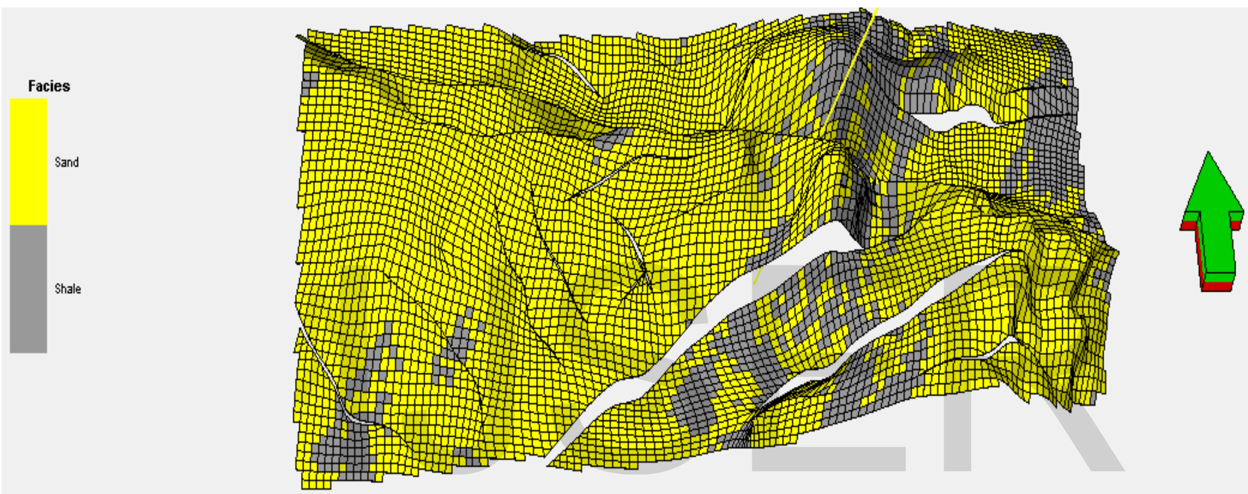


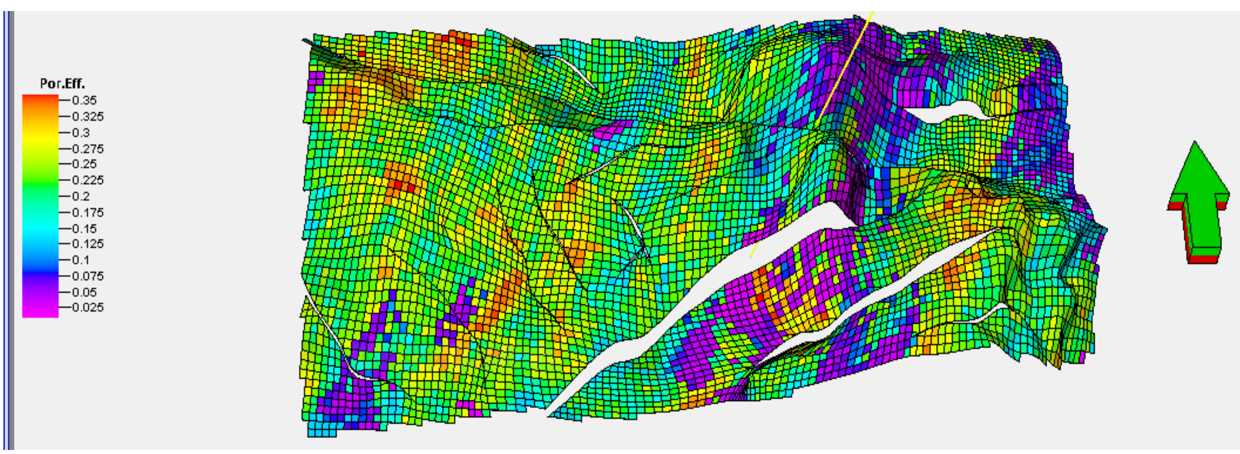
Figure 13: petrophysical log of sand D showing variation in reservoir quality

DISCUSSION

4.0 Relationship between Facies model and Reservoir Quality Model.

The facies model of the sands and their corresponding reservoir qualities at different depths are shown below:





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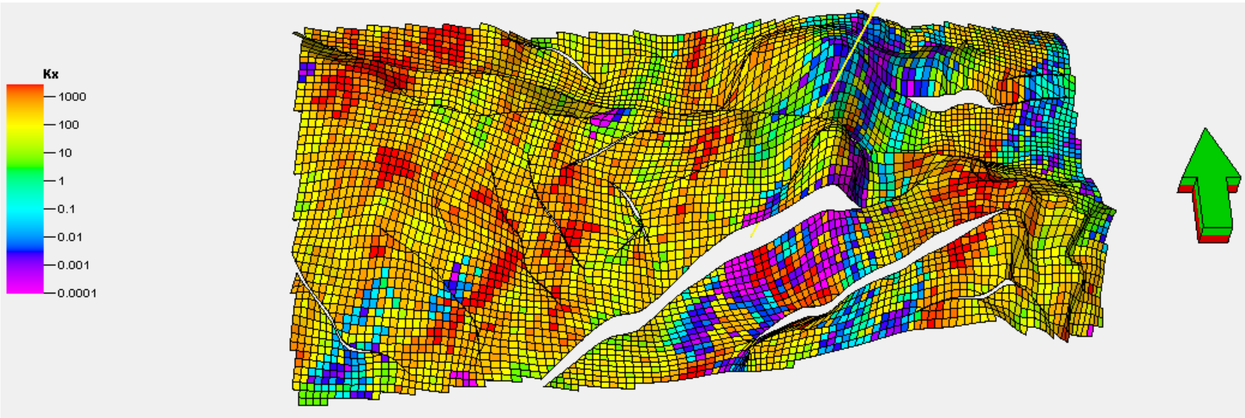
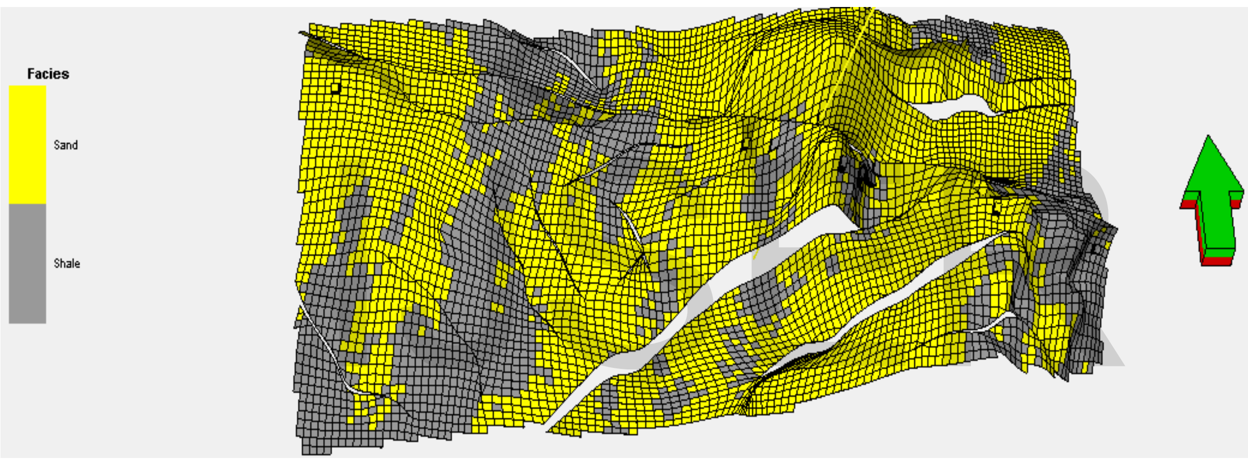
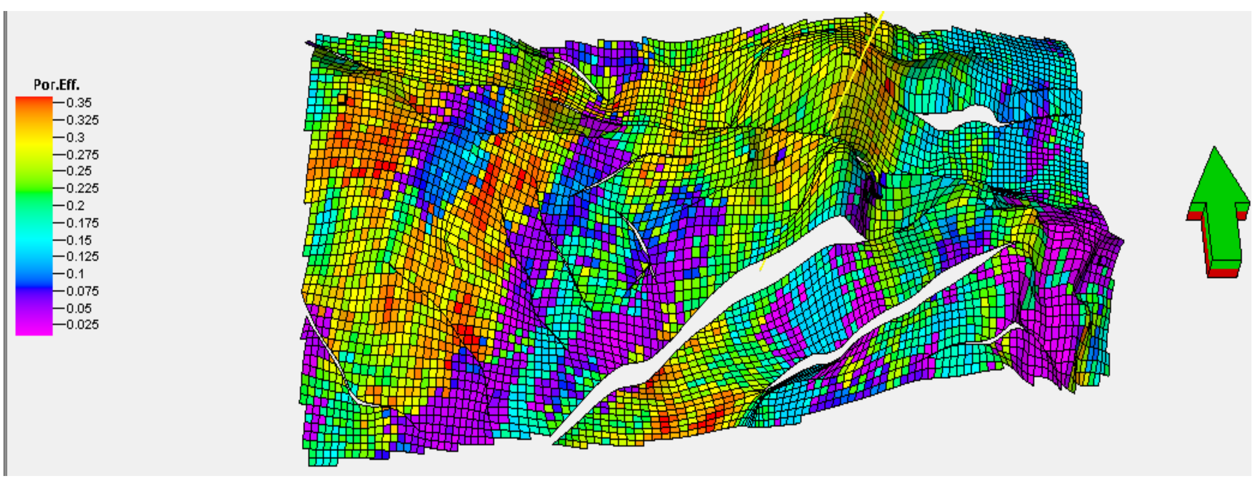


Fig 14a : Sand C Facies, effective porosity and permeability values and distribution at the top(8313ft / 2533.8m) within the field showing correlation between lithology and reservoir quality.





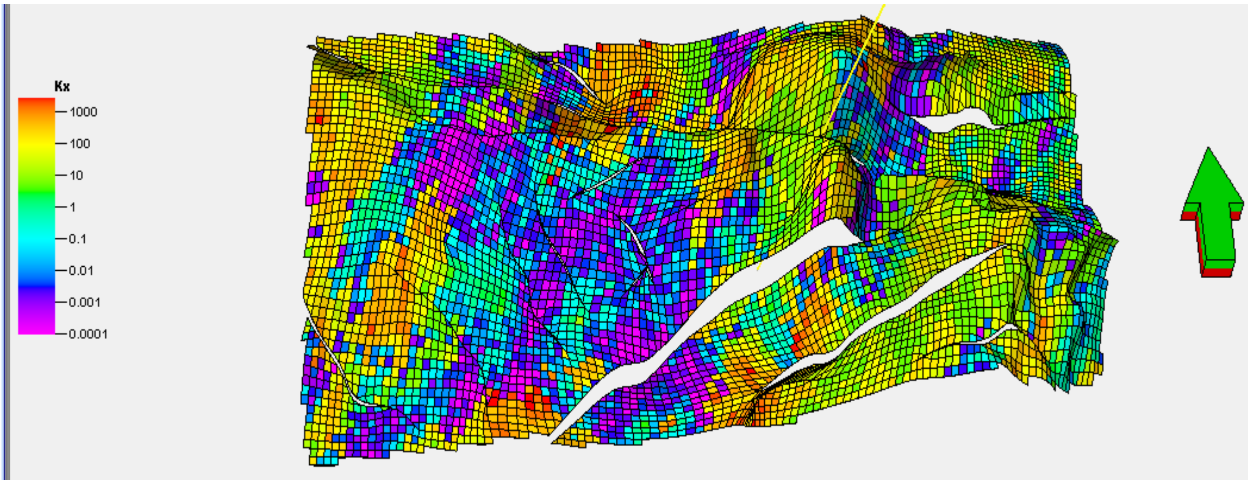
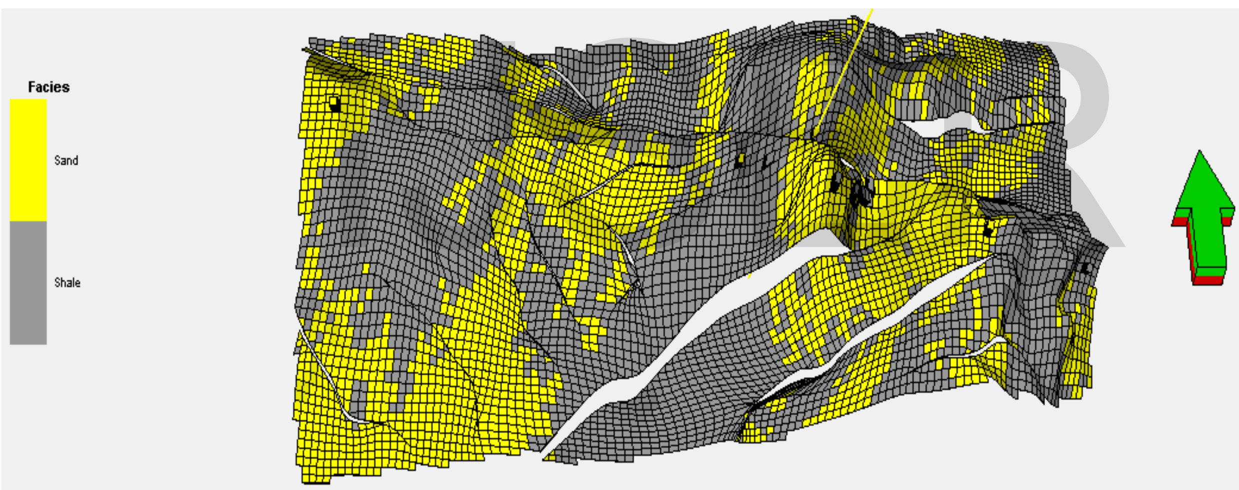
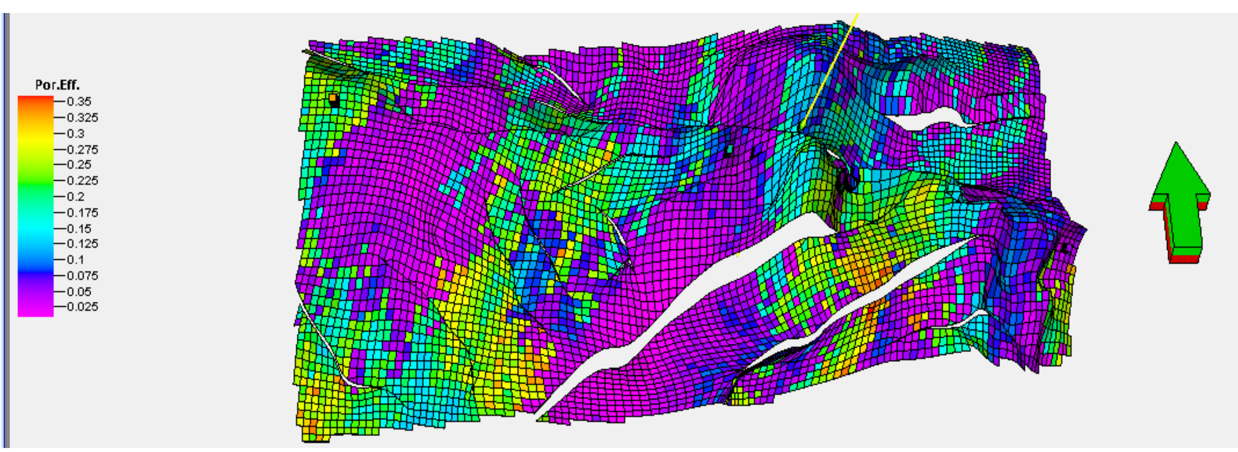


Fig 14 b: Sand C Facies, effective porosity and permeability values at middle (8361ft /2548.43m); showing a gradual reduction in value with scattered values of good porosity and permeability.





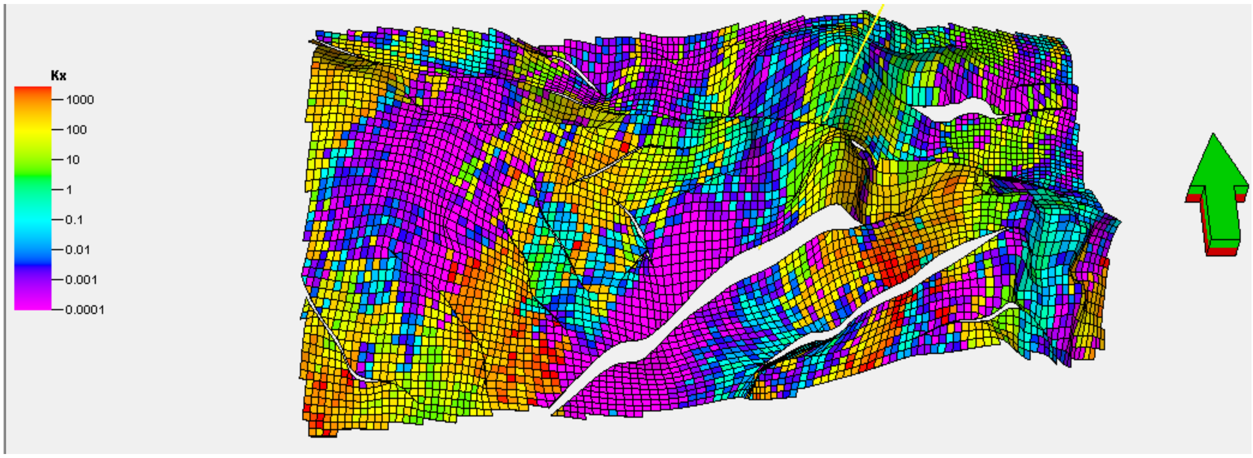


Fig 14 c: Sand C Facies, effective porosity and permeability distribution at bottom (8412ft / 2563.9m);, showing remarkable decrease in values with only isolated good values.

From the facies, effective porosity and permeability models of sand C, figure 14a to 14c, it can be seen that the reservoir quality increases upwards and decreases downwards following the facies (lithofacies) pattern. This temporal distribution of the facies and quality confirm the reservoir to be of shallow marine environment where progradation is taking place allowing coarser sediments with good reservoir quality to overlies finer sediments with poor reservoir quality deposited in low energy areas. The facies models of sand C with its corresponding reservoir qualities models (porosity and permeability), show that its reservoir quality was controlled by depositional fabric: area with good sand development have good reservoir quality. The depositional processes in a shallow marine shoreface / mouth bar environment, allow the porosity and thus permeability to increase upward within the reservoir due to increasing grain size upwards. This is seen from the porosity and permeability model of sand C which are better developed in the upper section than the lower part, see also the petrophysical log, figure 15.

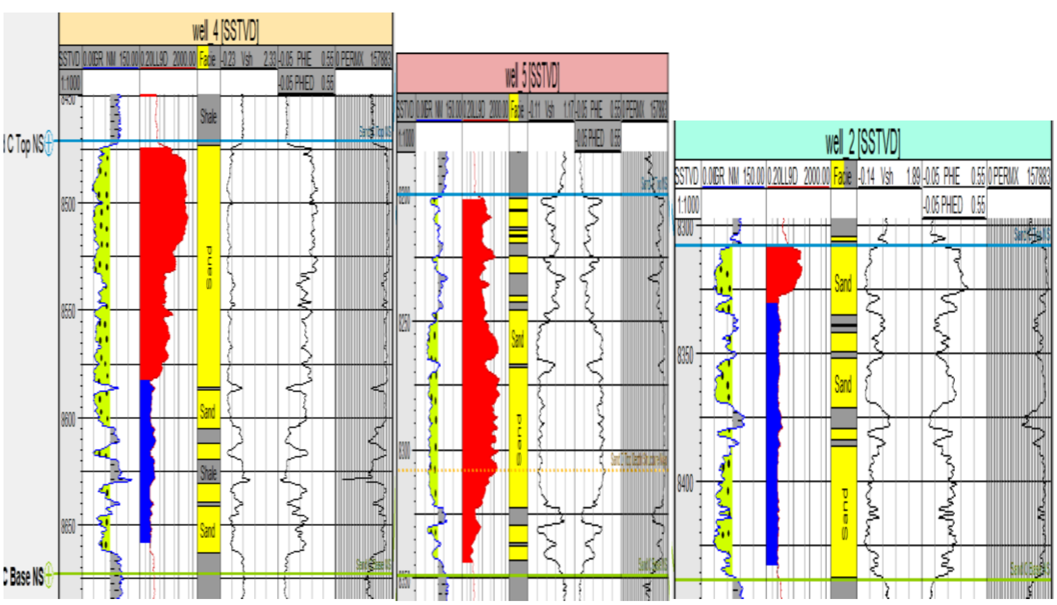


Figure 15: petrophysical log of sand C showing variation in reservoir quality

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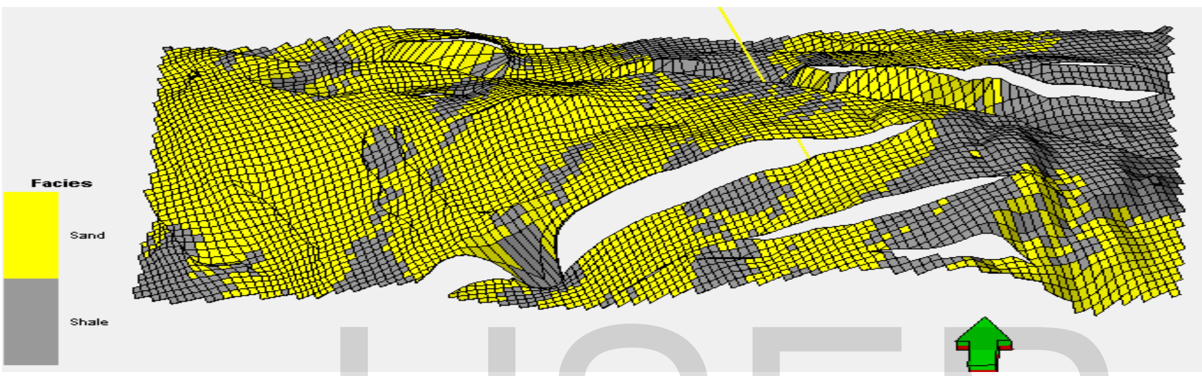

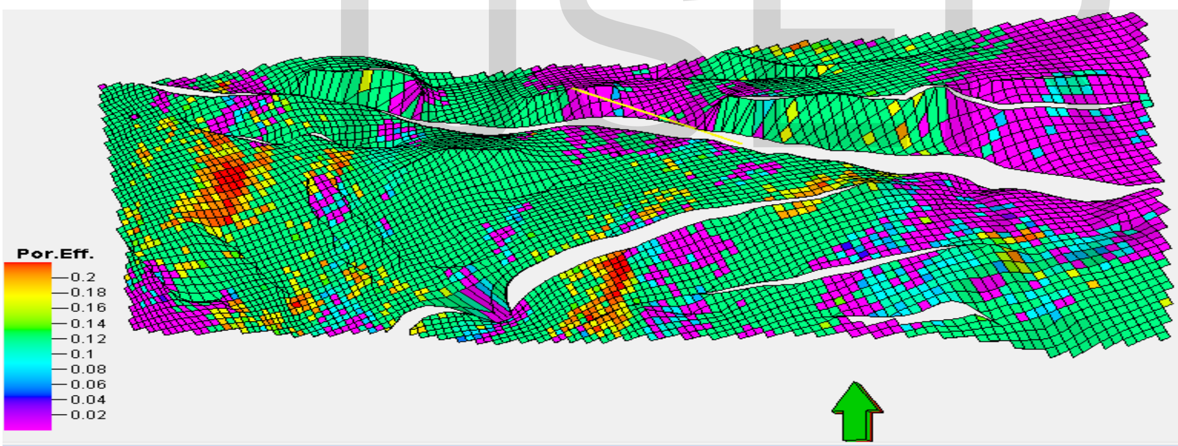

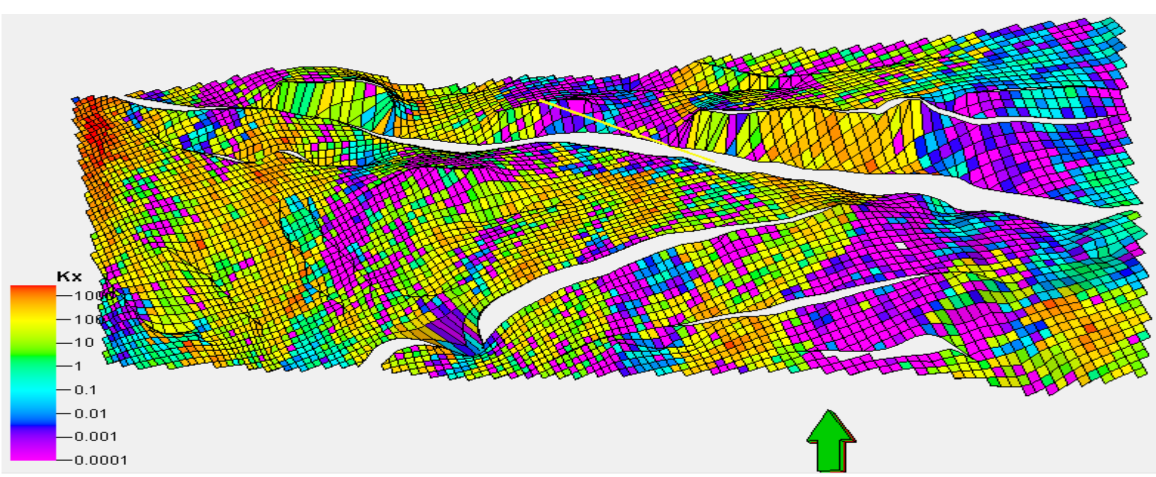

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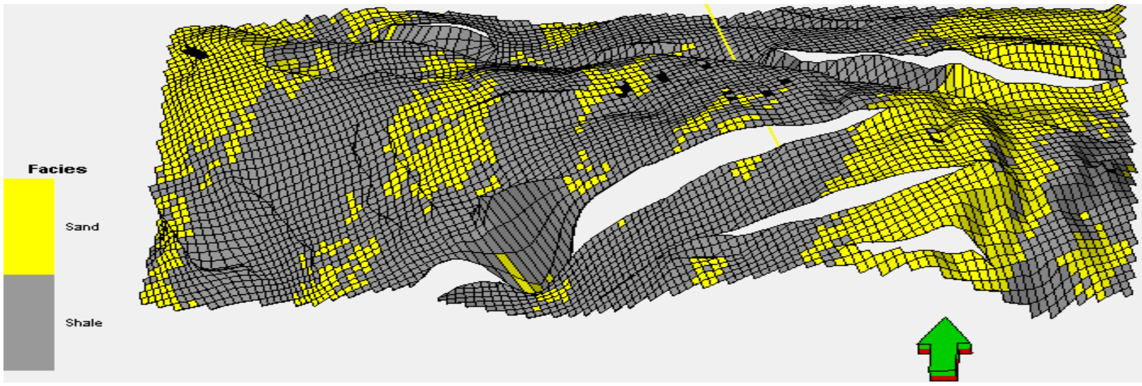
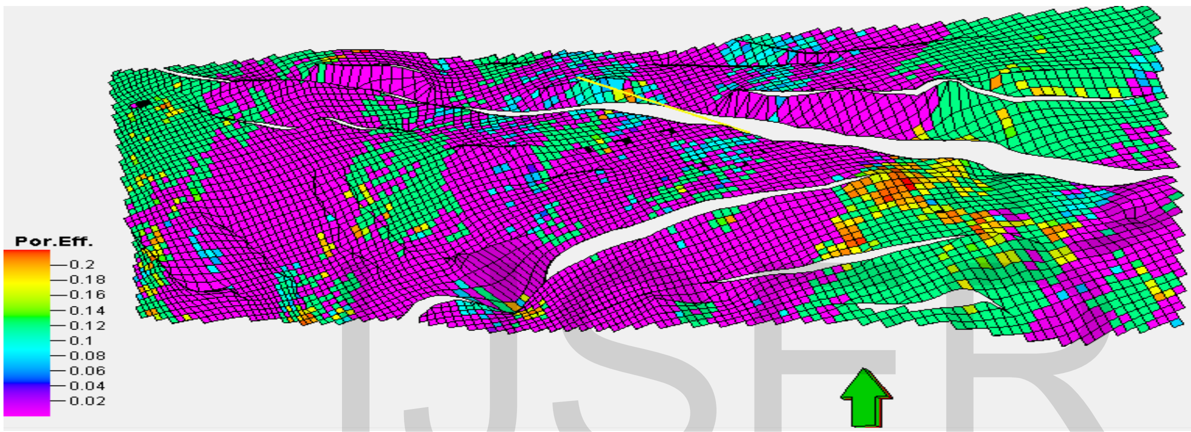
Fig 16 a: Sand D Facies, effective porosity and permeability at top (8785.7ft / 2677.88m) showing good reservoir quality in areas with good sand development.





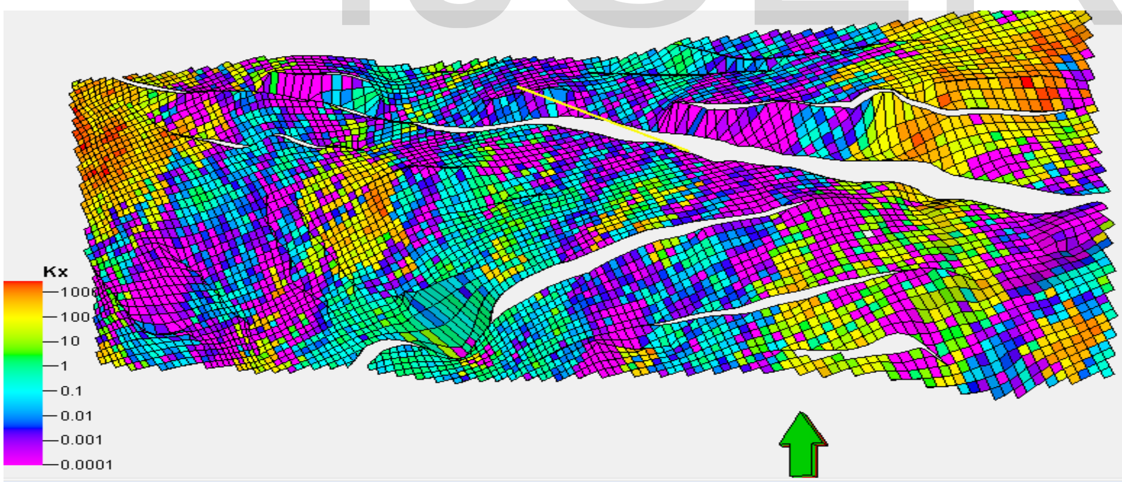


Fig 16 b: Sand D Facies, effective porosity permeability at bottom (8887.8ft /2709.0m) showing great reduction in value corresponding with lithofacies

The facies models of sand D with its corresponding reservoir qualities models (porosity and permeability), show that the reservoir quality was controlled by depositional fabric: area with good sand development have good reservoir quality. At the top of sand D, figure 16a the facies model show a good correlation with the reservoir quality model: areas with good sand development have good porosity and permeability. where both the facies and the reservoir qualities are well developed from the north west to the south east, the few isolated poor textural and thus poor reservoir qualities sediments (silt and clay), may reflect localized change in sediment supply, reduction in slope of the depositional surface, reduction in the quantities of water transporting the sediment and bed roughness (Boggs,2006), all of which reduce transport velocity thereby causing deposition of fines. The reverse is also true for the lower part of the reservoir, figures 16b where there are isolated good textural and reservoir qualities development in areas where fines, are expected to produce poor reservoir qualities. Such good textural development might result from localized catastrophic events such as shock or storm induced turbidity current that flow into the fine sediment.

5.0 Conclusions

The sand C of the Akjom field, Niger Delta Basin was deposited in the shoreline to shallow marine environment: shoreface overlain with fluvial channel to the west and tidal channel to east.

The sand D was deposited in a shoreface environment with tidal effect generating minor tidal channel toward the Eastern portion..

The depositional axis of the sands is from northwest to southeast judging from the Isopach

The highest porosity values occur in area with fluvial and shoreface environments suggesting the combined effects of higher grain size of the channel with wave effect on the shoreface creating betting sorting. Higher grain size and good sorting will produce better porosity and permeability.

Their reservoir qualities increase upward following the facies pattern suggesting that reservoir quality was controlled primary by depositional processes and thus environment of deposition.

The reservoir quality varies aerially and temporally suggesting probable variation in depositional processes such as change from turbulent to laminar flows, change in composition and textural properties of deposited sediment or varying degree of diagenetic processes.

This study thus suggest that reservoir quality is mainly controlled by processes in depositional environment and for accurate field development and reserve update, a reservoir must be studied in all the wells the penetrates it.

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