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Sequence Stratigraphy and Petrophysical Analysis of 'Aje' Field, Offshore Niger Delta

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Abstract A detailed sequence stratigraphic and petrophysical analysis was performed on six (6) wells in the "AJE" field, Niger Delta. The purpose is to re-evaluate the petrophysical properties, determine the depositional environment of reservoirs as well as the sequence stratigraphic attributes of hydrocarbon bearing section of six wells in AJE Field in the Niger delta. Four (4) sand reservoirs were identified across the field. Biofacies and shape of well logs signatures; funnel, cylindrical or blocky shapes were used to infer the depositional environment. Based on biostratigraphic data, two maximum flooding surfaces dated 9.5Ma and 7.4Ma and three type 1 sequence boundaries dated 10.36Ma, 8.5Ma and 5.7Ma were recognized. Petrophysical parameters estimated for all the reservoirs in the six wells shows that: porosity estimation varies between (8–31) %, volume of shale is between (5–24) %, hydrocarbon saturation is between (81-99) % and water saturation varies between 0.3 and 15%. All the reservoirs have a good hydrocarbon saturation, low water content, good porosity and permeability value. Most reservoirs were completely saturated with gas. The encountered facies within the wells comprises of deltaic distributary channels, shoreface sands, barrier bars, restricted mudstones, fluvial channels and turbiditic complexes. The most excellent reservoirs were turbidites and channel complexes of the lowstand system tract.

Keywords Biofacies data, Lowstand System Tracks, Petrophysics, Shoreface sands, Niger delta

Introduction

The advent of renewable energy and slump in demand due to pandemic has made it imperative to develop a strategy to reduce exploration and production cost and increase the profitability of oil and gas companies. As a result, proper planning, delineation and development of reservoirs become very necessary and challenging as the demand for maximum possible turnover and return on investment is increasingly more in a high cost industry with increasing competition and technological advancement. Offshore Niger Delta, exploration targets are usually turbiditic channel complexes and stratigraphic traps. The difficulty in finding these reservoirs and the cost of producing them has necessitated detailed understanding of these reservoirs using the principle of sequence stratigraphy.

Sequence stratigraphic techniques involve the careful evaluation of the interaction between eustacy, subsidence, and sediment supply as equally important controls on changes in accommodation space, which in turn controls depositional geometries and successions [1]. Since the origination of stratigraphic concept by Vail *et al.* [2] and various advances in the use of the concept [1-4] it has proven to be one unique technique for generating exploration prospects and predicting reservoir and seal qualities in both stratigraphic and structural traps. Depositional processes and environment are best studied using the principles of stratigraphy and well log analysis. The general purpose of well log analysis is to convert the raw log data into estimated quantities of oil, gas and water in a formation [5].

Sequence stratigraphy has been applied in several sedimentary basins of the world leading to the discovery and recovery of more hydrocarbon reserves. In the north central Gulf of Mexico, this technique improved reservoir development and management strategies, provided insights into basin fill history, and contributed to the ongoing exploration successes in the basin [6]. The sequence stratigraphic concept was gradually introduced in the Niger Delta Basin studies, when Durand [7], Stacher [8], and Reijers [9] first applied it in refining the process for prediction of hydrocarbon habitats.

Several authors have shown that sequence stratigraphic surfaces such as sequence boundaries and maximum flooding surfaces (MFS) can be identified from fossil abundance and diversity using biofacies data. The advantages of calcareous nannofossils in the recognition of Marine Flooding Surfaces in the Niger Delta most especially in the Late Miocene to Late Pliocene time was discussed by Ogunjobi [10]. He recognized four delta wide flooding surfaces based on the Discoaster quinqueramus, Ceratholithus species and Gephyrocapsa species and Sphenolithus species. This was confirmed by Oyebamiji [11] who also observed the influx of Sphenolithus abies in the Late Miocene of the Niger delta. Fadiya [12] employed seismic and well-log data in the sequence stratigraphic study of five wells in the North western Niger Delta. He established a strong correlation between hydrocarbon occurrences and the lowstand systems tracts. The most prolific sequence tract is the lowstand system tract due to the presence of basin floor fan, levee channel complexes and prograding wedges which are excellent reservoirs.

More recent works includes Omoboriowo *et al* [13] which showed that most reservoir sand lies within marginal marine environment with porosity and permeability ranging from good to excellent and Ola & Alabere [14] that revealed the trapping mechanism to be mainly fault assisted anticlinal closure and transitional-to-deltaic depositional environment for the sand facies in the Niger delta.

The objective of this research includes determination of the depositional environment and the System tracts of hydrocarbon bearing sand facies and calculation of the petrophysical properties of reservoirs in AJE field in the Niger delta petroleum province. The principal aim is to understand the depositional environment of reservoir facies and how this affects the distribution of petrophysical properties.

Location and Geology of the study area

The field is located offshore Niger Delta in the southern part of Nigeria. Field base map showing well distributing in the field is seen in figure 1. The Niger Delta Basin is situated at the North Eastern margin of the Gulf of Guinea on the West coast of Africa and it covers an area of about 75,000km^2 and is at least 11km deep in its deepest parts [15-16]. The Niger Delta province consists of three litho-stratigraphic units all of which are stronglydiachronous [17-19]. These units from the oldest to the youngest include the Akata Formation which is made up of dark gray shales and silts with rare streaks of sand of probable turbidite flow origin and is estimated to be 7000m thick in the central part of this clastic wedge [17]. This formation composed of marine shales and form the main source rocks for petroleum. The Agbada Formation which occurs throughout the Niger Delta clastic wedge and has a maximum thickness of more than 3,000m [17]. This formation is the hydrocarbon-prospective sequence in the Niger delta, where the sand serves as reservoirs and shale as the source rock [17]. The Benin Formation which comprises the top part of the Niger Delta clastic wedge, from the Benin-Onitsha area in the north to beyond the present coastline [18]. These three major lithostratigraphic units defined in the subsurface of Niger Delta reflect a gross upward-coarsening clastic wedge. The sedimentary wedge in Niger Delta has been laid down in five depobelts with the oldest lying furthest inland and the youngest located offshore [17]. These depobelts includes: Northern Delta, Greater Ughelli, Central Swamp, Coastal Swamp, and Offshore depobelts. Each depobelt is a separate unit that corresponds to a break in regional dip of the delta and is bounded landward by growth faults and seaward by large counter-regional faults or growth fault of the next seaward depobelt [17, 20]. The Coastal Swamp Depobelt is characterized by structural complexity due to internal tectonics on the modern continental slope, associated with growth faults, rollover anticlines, collapsed crests, and back-to-back features [20, 21].

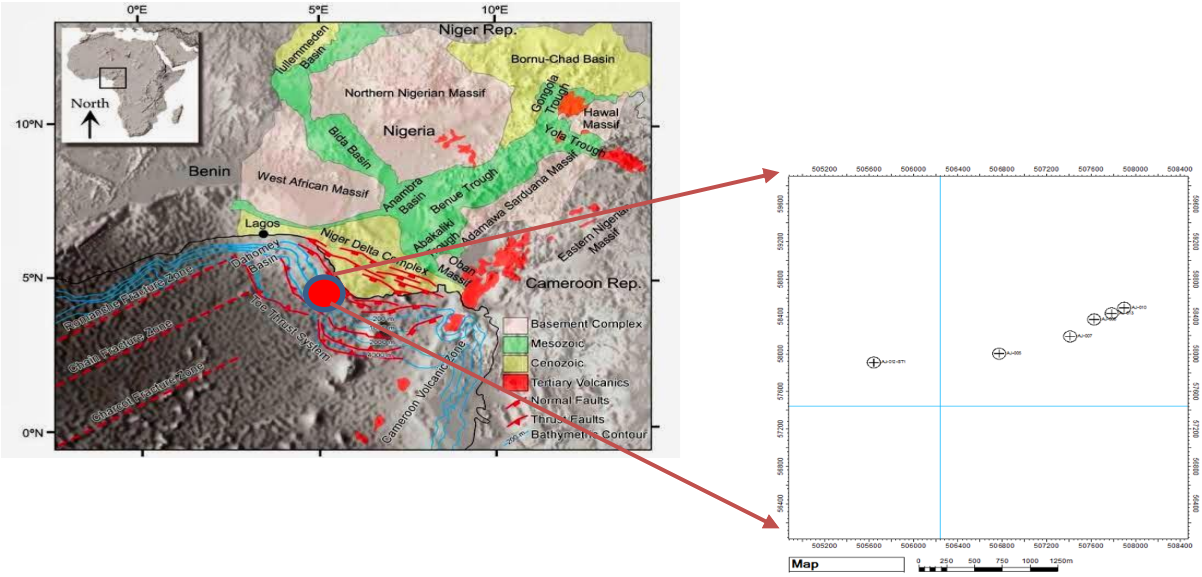

Figure 1: Map showing location of 'AJE' Field in Niger Delta

Materials and Methodology

The dataset used in this study includes well header, well log data (caliper log, gamma ray log, resistivity log, density log, neutron and sonic log) from four wells, deviation data and biofacies data. Schlumberger petrel software 2015 was used for this research. The well log data were Quality Checked (QC), validated and edited as appropriate to reduce error. The analysis of AJE field was carried out qualitatively and quantitatively. The qualitative interpretation includes the lithologic identification, establishing stratigraphic relationship as well as lateral lithologic distribution through formation correlation of well log signatures from wells in the AJE field. Quantitative interpretation on the other hand, includes the determination of formation thickness, Net to Gross (NTG), net oil /gas pay, effective porosity, formation permeability, hydrocarbon saturation, water saturation, shale volume, Bulk Volume Water (BVW).

Lithological interpretation which involves delineating sand and shaly intervals by first setting a cut-off range of 0-60API for sand, 61-80 API for sandy shale and 81-150 API for shale. The sand bodies were identified by the deflection to the left of the gamma ray log due to the low concentration of radioactive minerals while deflection to the right signifies shale which is as a result of presence of radioactive minerals. This is then followed by identification of hydrocarbon bearing reservoirs using resistivity log. Hydrocarbon bearing sands usually have high values of resistivity while water-bearing reservoirs have relative low resistivity values. Neutron-density logs were then used to determine fluid type and separate oil saturated sands from water saturated sands.

The environment of deposition of the sandstone facies were also inferred from comparing log signature trends which could be cylindrical/blocky, funnel and bell shapes with standard defined by schlumberger [22] and Rider [23] as seen in Figures 2 & 3. Blocky or Cylinderical shape indicates massive or thickly bedded sand which is lithologically uniform with very little shale intercalation [22]. It indicates constant energy level and is characteristics of deposition in tidal channel, barrier bar and fluvial channel. It also indicates an aggradational stacking pattern [23]. Funnel shape implies a coarsening upward sequence implying deposition during sea level regression. It indicates upward increasing energy level. It indicates beach sands, barrier bar sands characteristics of shoreline deposits and deltaic environment. It also indicates a progradational stacking pattern [23]. Bell shape implies a fining upward sequence implying deposition during sea level trangression. It represents waning current sequences and indicates alluvial point bars, tidal flat, deep sea channel, and deltaic distributary channel. It also indicates a retrogradational stacking pattern [23].

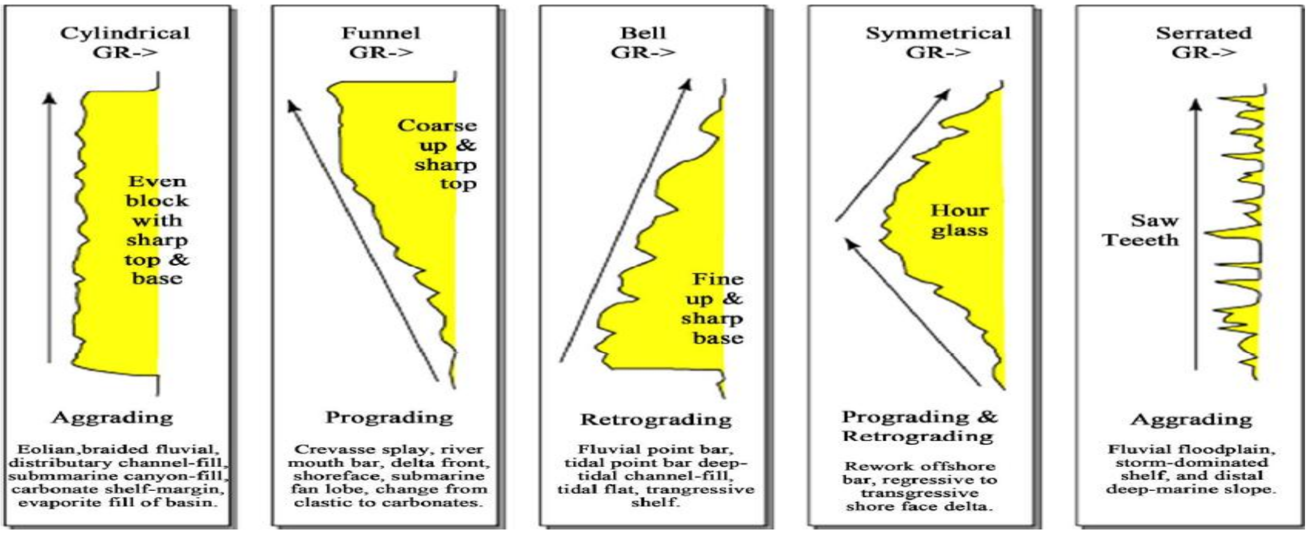

Figure 2: Well log response character for different environment [22]

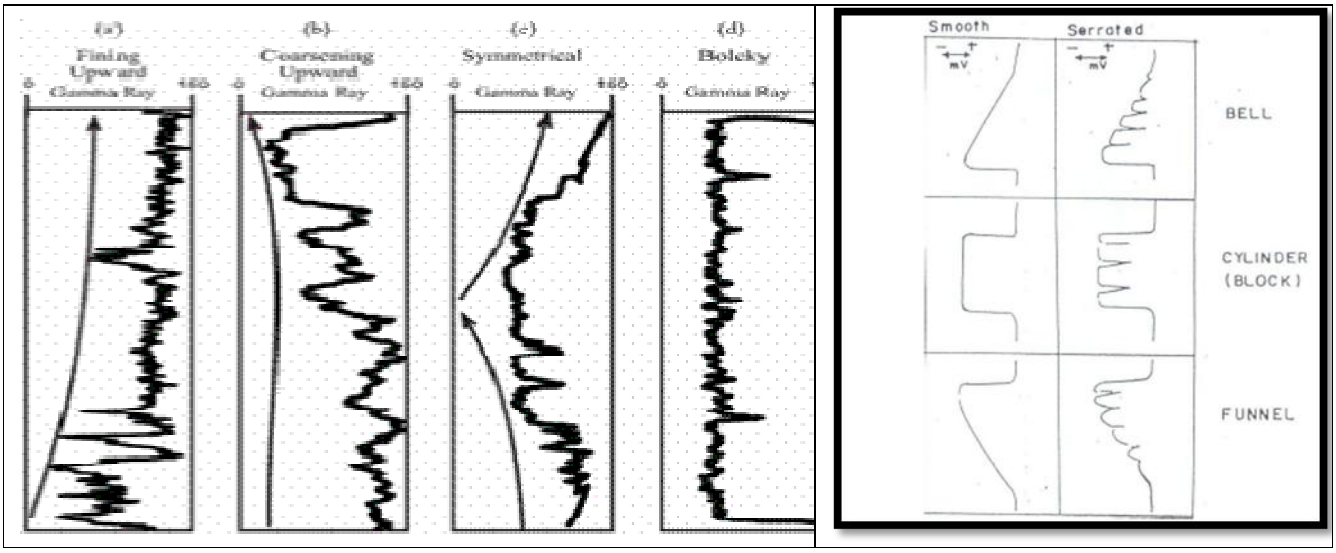

Figure 3: Log shape classification and representative gamma ray log patterns (a) Fining upward (b) Coarsening upward (c) symmetrical and (d) Blocky log pattern (From Rider [23])

Stratigraphic analysis of "AJE" field was carried out based on the information gotten from the bio-facies data. The system tract (i.e., HST, LST, and TST) were identified in the biofacies data based on their depositional settings, with their respective depth values. Two major surfaces were also identified on the biofacies data. They include; the maximum flooding surfaces (MFS) and the sequence boundary (SB). The maximum flooding surface corresponding to where there is abundance of fauna deposition while the sequence boundary corresponds to where there is low fauna deposition. To date the key sequence stratigraphic surfaces, the wireline log of the well was first constrained based on the biostratigraphic data of the well. This permitted comparison with the SPDC Niger delta chronostratigraphic Chart.

Quantitative interpretation involves detailed petrophysical analysis on identified reservoir intervals on the field. The shale volume (Vsh) was estimated from the gamma ray log, sonic log or from Neutron-density crossplots. For this study, we first determined the gamma ray index (eq. 1) then evaluated the volume of shale Vsh in porous reservoirs using the Dresser Atlas formula (eq. 2).

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \text{……. eq. 1}$$

$$V_{sh} = 0.083\ [2^{(3.7 \times I_{gr})} - 1] \text{ ….. eq. 2}$$

Formation porosity was determined using the bulk density log. The bulk density porosity (eq. 3), for example, is the overall gross or weight average density of a unit of the formation and it can be taken as total porosity for a monomineralic reservoir.

$$\emptyset_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \text{……. eq. 3}$$

Where ρ_{ma}= matrix (or grain) density, ρ_{fl}= fluid density and ρ_b= log derived bulk density which accounts for both the fluid and the grain density. The average rock density in clastic reservoir (sandstones) is 2.65 gcm^{-3}.

Accurate formation porosity known as the effective porosity (Φe) is essential to obtaining credible information for reservoir characterization, especially to ensure correct reservoir volume estimate. Effective porosity accounts for the proportion of pore volumes occupied by shale grains within the shaly sandy formation. It is computed from the porosity and volume of shale (V_{sh}) as seen in eq. 4.

$$\theta_e = \theta * (1 - V_{sh}) \text{….. eq. 4}$$

To effectively understand hydrocarbon reserves in the field and their distribution, water and hydrocarbon saturation needs to be estimated. This requires the use and computation of the elements of the Archie's equation. To start with, we compute the formation factor which relates the resistivity of brine saturated rock sample (Ro) to the brine resistivity (eq. 5).

$$F = \frac{a}{\theta^m} \text{ ….. eq. 5}$$

Where a = Tortuosity factor and m is the cementation factor. The water saturation which is the fraction of the formation occupied by water is computed using equation 6. Hydrocarbon saturation is then estimated from the water saturation using equation 7.

$$S_w = \left(F \times \frac{R_w}{R_t}\right)^{1/n} \text{ ……. eq. 6}$$

$$S_h = 1 - S_w \text{ …. Eq. 7}$$

Bulk volume water which is the product of a formation's water saturation (Sw) and its porosity is given in equation 8. Then the movable oil saturation (eq. 9) which is the fraction of oil that is moved during the invasion process and is given by:

$$BVW = S_w * \phi \quad \text{… eq. 8}$$

$$MOS = Sxo - Sw \text{ …. eq. 9}$$

A typical formation is usually divided into three parts. The zone of invasion, the intermediate zone and the zone of saturation. The invaded zone is where the mud filtrate enters into the formation and this usually has consequences for skin and some other reservoir properties. Microspherically focused log (MSFL) is usually used to compute the resistivity of the mud filtrate in the invaded zone. The saturation of the mud filtrate (Sxo) is then computed using archie's equation (eq. 10).

$$Sxo = \sqrt{\frac{FxRmf}{Rxo}} \quad \text{… eq. 10}$$

The residual hydrocarbon is the amount of hydrocarbon left in the flushed zone. It's the difference between the flushed zone water saturation and unity (eq. 11). Then the movable hydrocarbon index was then calculated using equation 12. Where MHI > 1 implies that hydrocarbon was not moved during invasion and MHI < 0.7 implies that hydrocarbon was moved during invasion.

$$Shr = 1 - Sxo \text{ …. eq. 11}$$

$$MHI = S_w / S_{xo} \text{ …. eq. 12}$$

The irreducible water saturation is then calculated using equation 13 as a prerequisite to estimating the permeability using Timur (1968) equation (eq. 14).

$$Swirr = \sqrt{\frac{F}{2000}} \text{ …eq. 13}$$

$$K = \sqrt{\frac{250 * \theta}{Swirr}} \quad \text{… eq. 14}$$

The fraction or the percentage of bulk reservoir volume that is occupied by hydrocarbon known as the hydrocarbon pore volume (HCPV) is computed using equation 15.

$HCPV = \theta \times S_h$ …. eq. 15

Result and Discussion

Correlation and Hydrocarbon Occurrences.

The well correlation of AJE field was carried out along the strike direction. Six wells namely: AJE-010, AJE-013, AJE-006, AJE-007, AJE-005 and AJE 012STI were correlated along the strike direction. It was observed from the correlation panel that the sand packages are thinning towards the (NE-SW) direction (Fig. 4 & 5). Using the gamma ray and other log motifs, thirteen (13) sand packages were identified across the field out of which four (named A, B, C and D) are hydrocarbon bearing .Generally, it was observed that most of the wells within this field are completely saturated with gas. Based on the wireline log motifs and classification of Rider [23] the sand bodies penetrated by the wells comprises of deltaic distributary channels, barrier bars, restricted mudstones, fluvial channels and turbiditic complexes.

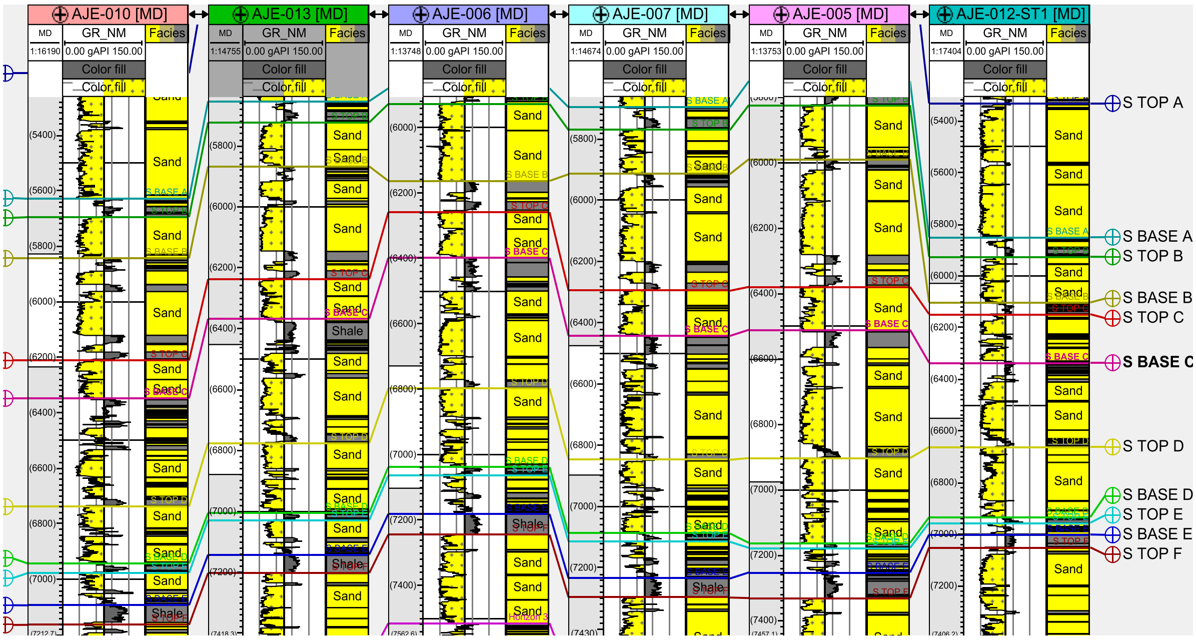

Figure 4: Well sand correlation along the NE-SW (strike) direction

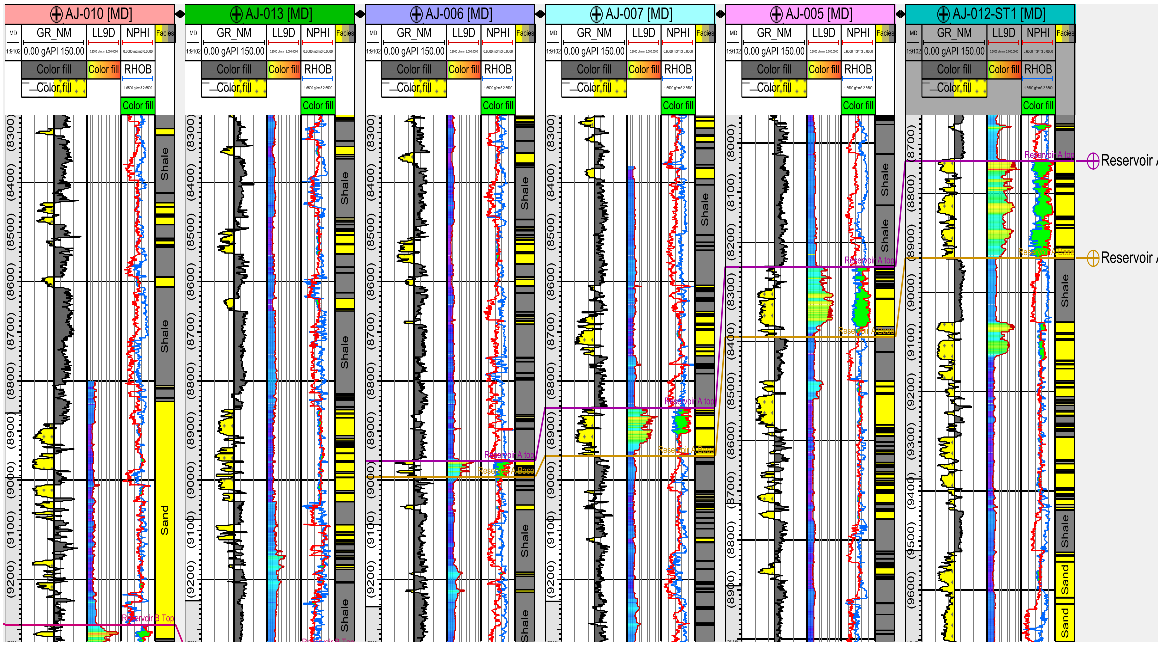

Figure 5: Lithostratigraphic correlation of sand bearing hydrocarbon across the wells in NE-SW direction

Sequence Stratigraphic Significant Surfaces

Two (2) complete depositional sequences (SEQ1, SEQ2) and the accompanying systems tracts were interpreted (Table 1) and mapped in the 'AJE Field' based on biostratigraphic data of the reference well (AJE 12-ST1) and the spatial distribution of the recognized constrained surfaces (MFSs and SBs). All MFS and Sequence boundaries (SB) mapped are seen in Figures 7 & 8.

The first maximum flooding surface designated as MFS1 occurred within P780 and F9600 zone and is characterized by uvigerina 8 shale markerat 9740ft. It is dated 9.5Ma using the SPDC Niger Delta chronostratigraphic chart. The MFS 2 is identified at depth 8178ft and dated 7.4Ma. The 7.4Ma is characterized by unnamed shale marker and defined within the P780 and F9600 biozones. Conversely, sequence boundary (SB) was also identified in the studied well (Fig. 6). The oldest sequence boundary (SB1) identified at 11351ft which was dated 10.36Ma. SB2 was identified at 9254ft dated 8.5Ma while SB3 was identified at 7588 and dated 5.7Ma.

Table 1: Key stratigraphic surfaces recognized from log data in the wells

Key Surfaces	Wells with Depth to Top of Recognized Surfaces					
	AJ 010 (ft)	**AJ 013 (ft)**	**AJ 006 (ft)**	**AJ 007 (ft)**	**AJ 005 (ft)**	**AJ 012SRI (ft)**
SB 3	7781	7812	7852	8042	7745	7570
MFS 2	8455	8498	8502	8692	8284	8202
TS 2	8603	8628	8597	8887	8478	8734
SB 2	8987	9053	8987	9128	8755	9248
MFS 1	9164	9142	9117	9206	9206	9756
TS 1	9223	9200	9229	9295	9477	10394
SB 1	9970	9986	9891	9939	9861	11327

Sequence Stratigraphic Surfaces and Hydrocarbon Trapping

Sequence 1 is the oldest depositional sequence, ranging from a depth of 9215ft to 11351ft with an average thickness of 2136ft. It is dated 10.36Ma SB and is capped by the 8.5Ma SB. This sequence shows predominantly fluvial processes depicting an overall progradational parasequence stacking pattern. Sand A is the LST and it formed thick sand deposits with shale intercalations and is interpreted as basin floor fans. The TST consists of thick shale units with thin sand sediments serving as a seal to the oil saturated sand in the underlying systems tracts (TST). The log motif shows a fining upward retrogradational pattern to the maximum flooding surfaces. The highstand systems tracts lies on the top of the TST with a funnel shaped, coarsening upward prograding parasequence sets.

The sequence 2 (8.5Ma - 5.7Ma) has a thickness of about 1683ft with a depth range of 7582ft to 9265ft. Reservoir sand B, C and D are found within this sequence. The lowstand systems tract of this sequence formed with a prograding fan complex characterized by a general trend of coarsening upward; shore face sand bodies that prograded into marine shale. A thick transgressive systems tract overlies the trangressive surface with a characteristic retrogradational stacking.

Petrophysical Parameters

The petrophysical parameters were evaluated for the hydrocarbon bearing reservoirs designated as sands A, B, C. D. Tables 2and 3shows the computed petrophysical parameters for the reservoir sands in the six wells with reservoir A not penetrated by well AJE 010 and AJE 013.

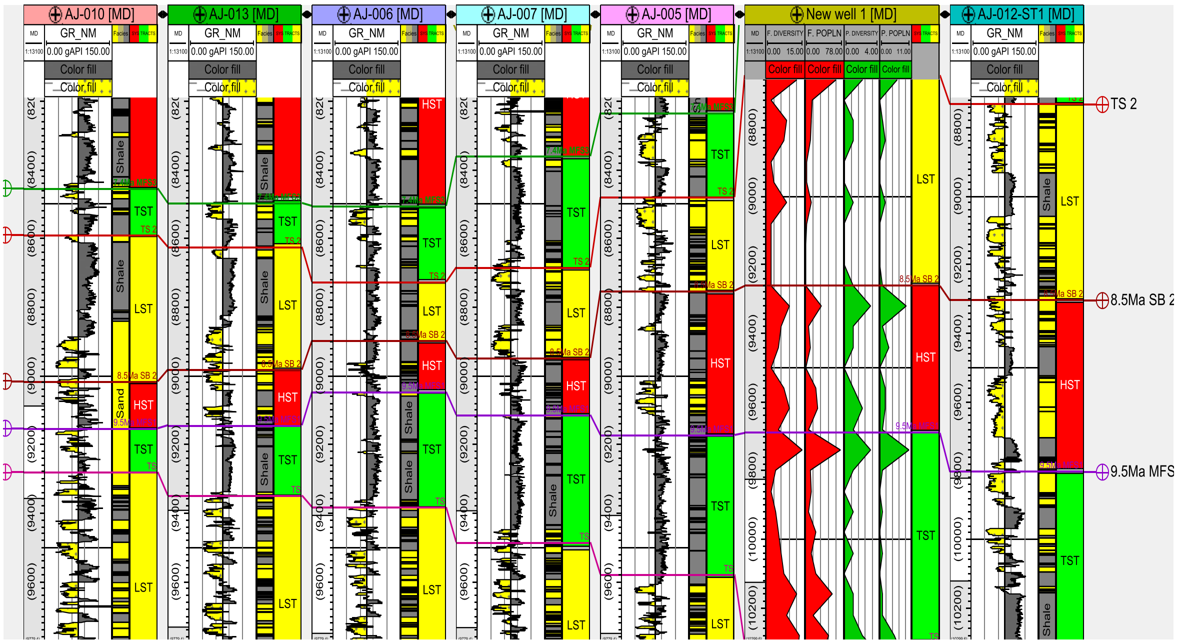

Figure 6: System Tracts and Parasequence Sets Identification across the Wells

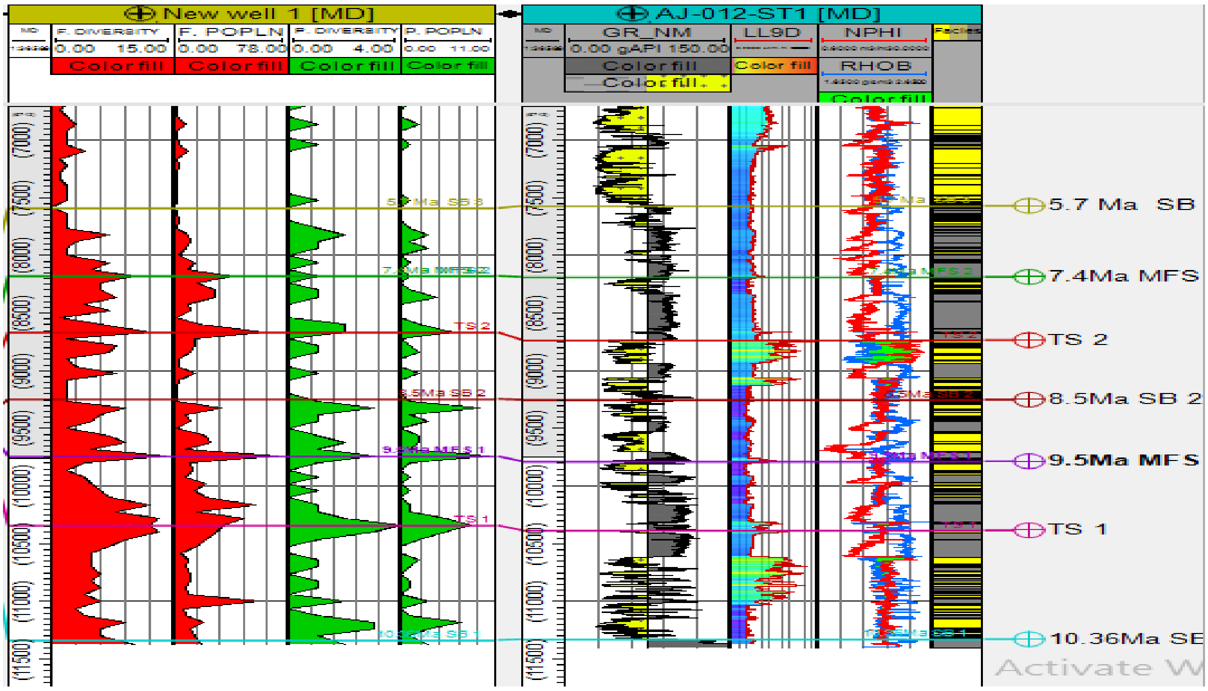

Figure 7: Stratigraphic analysis of AJE 012STR

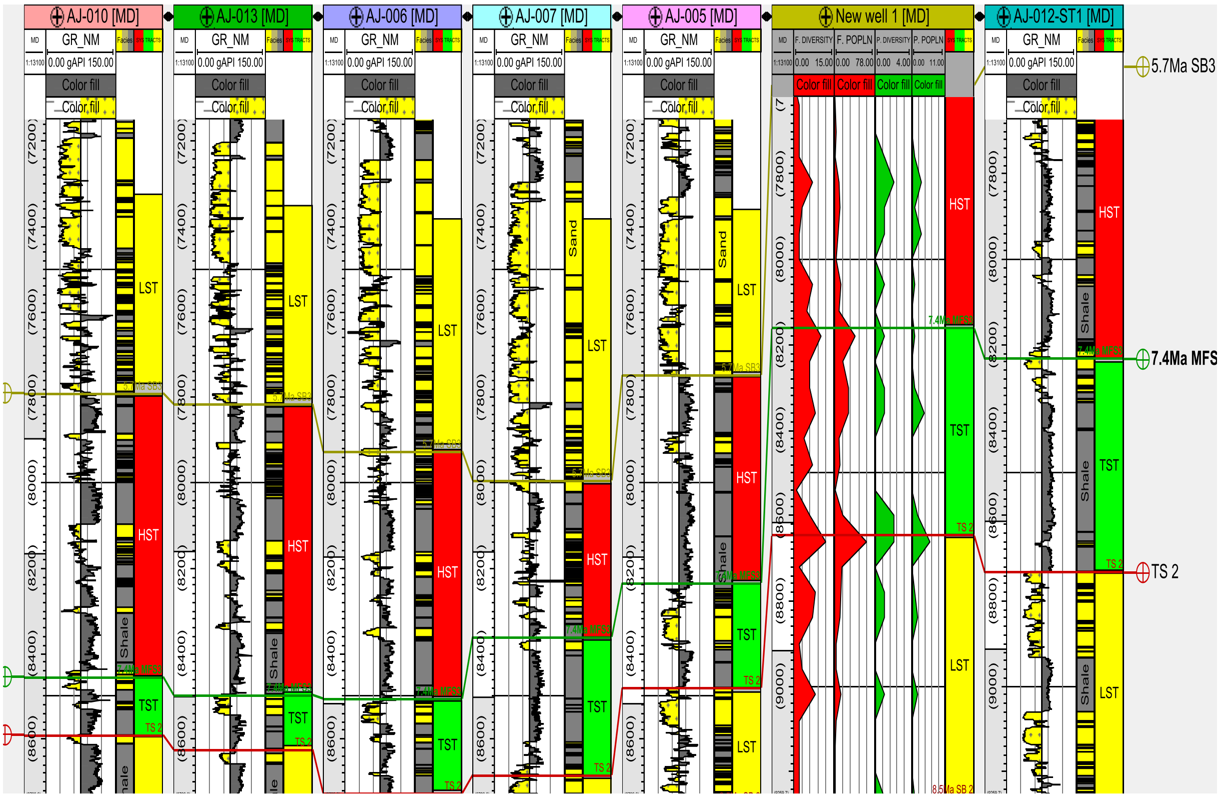

Figure 8: System tracts and parasequence sets identification across the Wells

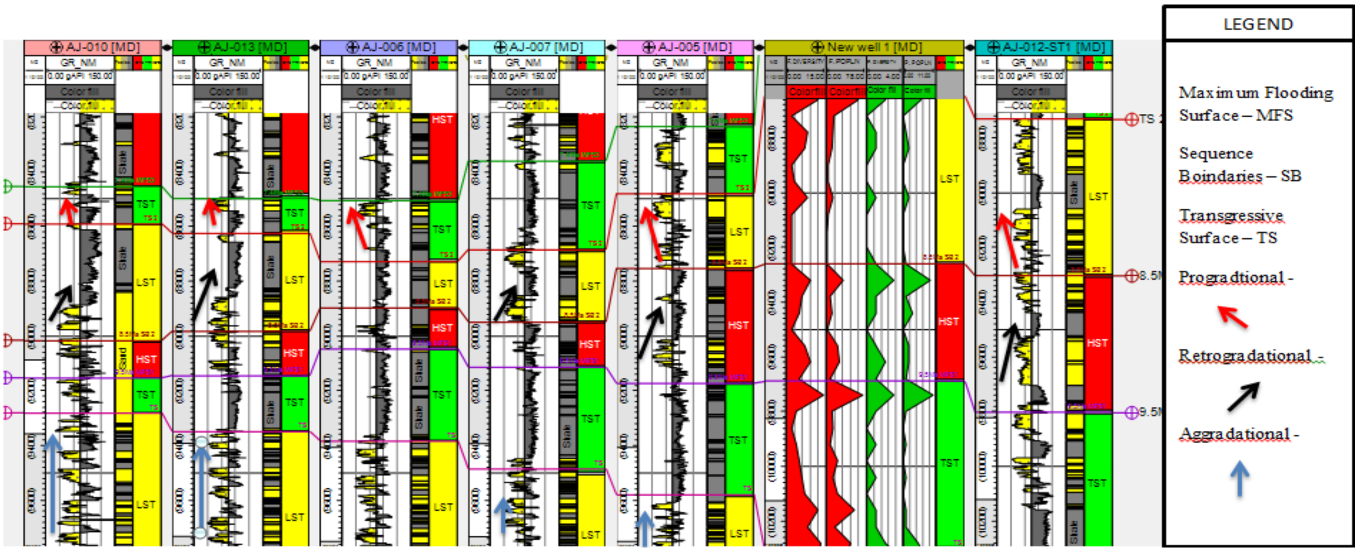

Figure 9: Stratigraphic Surfaces and parasequence sets identification across the Wells

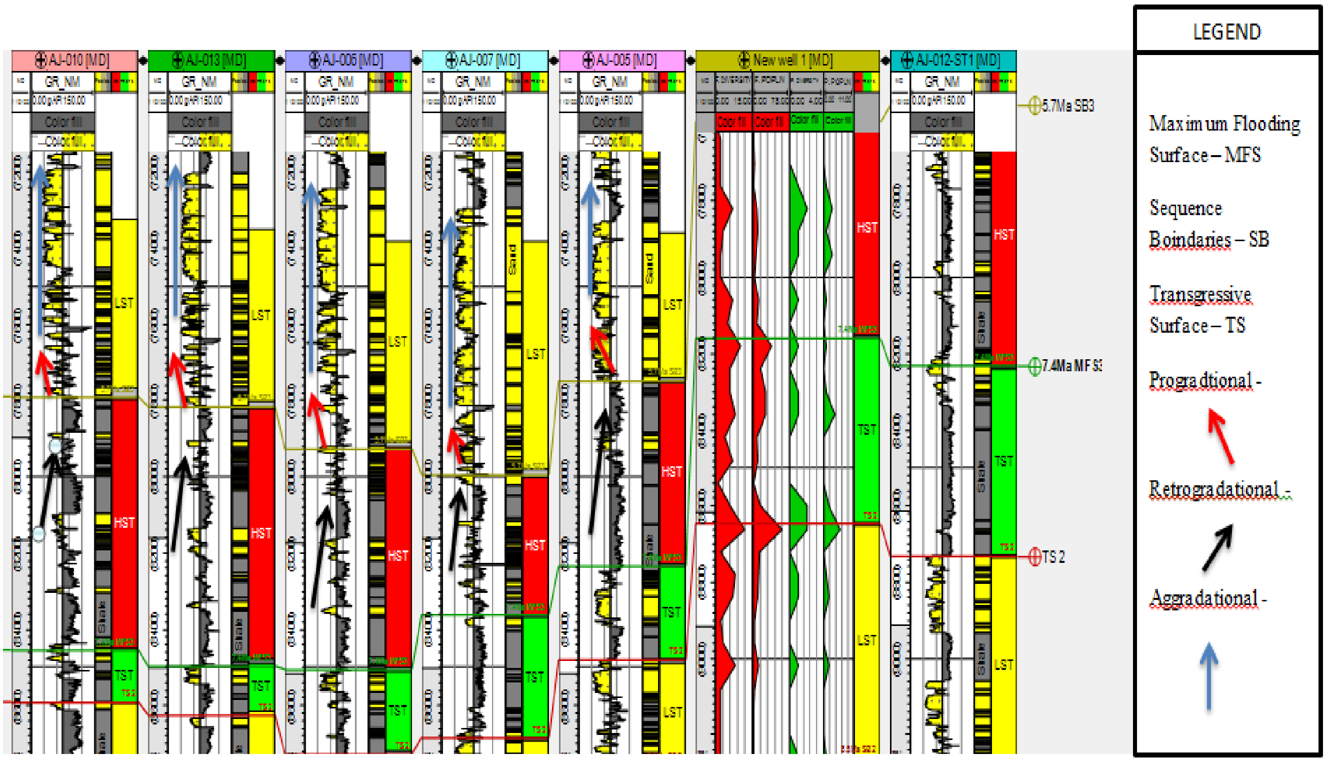

Figure 10: Stratigraphic surfaces and parasequence sets identification across the Wells

From the petrophysical parameters determined, it was discovered that hydrocarbon accumulation was mainly found in the lowstand systems tract of sequence 1 and 2 and transgressive systems tract of sequence 2. The potential reservoirs delineated in the "AJE Field" were mainly channel sands and shoreface sands of LSTs and HSTs, respectively. The shale of the TST in most cases, serve as a seal or source rock to the reservoirs since it is characterized by a very thick shale and thin sands. This reservoir A is not laterally continuous in the field. It thin out in SW direction across the wells. It has a varying thickness across the wells and it stores hydrocarbon across the four wells. The reservoir is characterized by an average net to gross thickness of 86%, average volume of shale (Vsh) of 12%, average effective porosity (θ_{eff}) of 26.5%, average hydrocarbon saturation (S_h) of 98%, average absolute permeability (K) of 2916.75md, average hydrocarbon pore volume (HCPV) of 25.6% and movable hydrocarbon index (MHI) of 1.6%. All the petrophysical parameters show that across the wells, the reservoir has good volume of shale, good effective porosity, excellent permeability and high hydrocarbon saturation. Tables2&3 presents result of petrophysical analysis in the wells.

Reservoir B and C are laterally continuous in the field and do not thin out in any direction across the wells. They have a fairly constant thickness across the wells and they store hydrocarbon across the six wells. Reservoir B is characterized by an average net to gross thickness of 86.2%, average volume of shale (Vsh) of 13.6%, average effective porosity of (θ_{eff}) of 23.6%, average hydrocarbon saturation(S_h) of 81.0%, average absolute permeability (K) of 3421.9md, average hydrocarbon pore volume (HCPV) of 23.6% and movable hydrocarbon index (MHI). Reservoir C is characterized by an average net to gross thickness of 85.6%, average volume of shale (Vsh) of 14.3%, average effective porosity (θ_{eff})of 21.1%, average hydrocarbon saturation (S_h) of 90%, average absolute permeability (K) of 2038.6md, average hydrocarbon pore volume (HCPV) of 20.0% and movable hydrocarbon index (MHI) of 8.6%. Reservoir D is laterally continuous in the field and is characterized by an average net to gross thickness of 90.4%, average volume of shale (Vsh) of 9.6%, average effective porosity (θ_{eff})of 19.0%, average hydrocarbon saturation (Sh) of 87%, average absolute permeability (K) of 1851.5md, average hydrocarbon pore volume (HCPV) of 23.6% and movable hydrocarbon index (MHI) of 6.5%. Petrophysical parameters show that reservoir C, B & D has high volume of shale, good effective porosity, excellent permeability and high hydrocarbon saturation.

Table 2: Petrophysical parameters of the reservoir sand in well 012ST1

Reservoirs	Gross (ft)	Net (ft)	N/G (%)	F	θ_{eff}	V_{sh} (%)	S_h (%)	S_{wirr} (%)	BVW	MHI	HCPV (%)	K (md)
A	193	190	94.2	11.28	31.9	5.8	99.8	7.3	0	0.01	25.6	755
B	86	78	93.8	18.48	26.9	6.2	98.2	8.8	0.3	0.03	26.4	4449.2
C	138	110	91.2	37.53	21.9	8.8	93.9	12	1.3	0.1	20.5	2176.8
D	119	87	90.1	55.75	19.6	9.9	87	14.2	2.5	0.11	17	1067.6

Table 3: Average petrophysical parameters

Reservoirs	Gross (ft)	Net (ft)	N/G (%)	$\theta_{eff}(\%)$	$S_h(\%)$	HCPV (%)	K (md)
A	106	98	86	26.5	98	25.6	2916.7
B	91	66	86.2	23.6	81	23.6	3421.9
C	111	88	85.6	21.1	90	20	2038
D	91	78	90.4	19	87	23.6	1851.7

Conclusion

Two (2) sequences were identified from the sequence stratigraphic analysis corresponding to three maximum flooding surfaces obtained. All sequences are type 1 sequence containing two or three of the system tracts. The transgressive systems tract (TST) was made of retrograding shale and sand units. The highstand system tract was made of prograding sands with decreasing shale volume upwards.

Four (4) sand reservoirs were identified across the well. Reservoir A is not laterally continuous in the field as it thin out in SW direction across the wells. All the petrophysical parameters show that reservoir A has good volume of shale, good effective porosity, excellent permeability and high hydrocarbon saturation. The reservoir B and C are laterally continuous in the field, have a fairly constant thickness across the wells and they store hydrocarbon across the six wells. From the petrophysical parameters determined, it was discovered that hydrocarbon accumulation was mainly found in the lowstand systems tract of sequence 1 and 2 and transgressive systems tract of sequence 2. Average petrophysical parameters estimated for all reservoirs in the six wells shows porosity ranges between (8–31) %, volume of shale between (5–24) %, hydrocarbon saturation between (81-99) % and water saturation varies between (0.3–15) %. All the reservoirs have a good hydrocarbon saturation, low water content, good porosity and permeability value. Most reservoirs were completely saturated with gas. The encountered facies within the wells comprises of deltaic distributary channels, shoreface sands, barrier bars, restricted mudstones, fluvial channels and turbiditic complexes. The most excellent reservoirs were turbidites and channel complexes of the lowstand system tract.

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