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Integrated Sequence Stratigraphic Analysis of Ogbo Field, Niger-Delta Basin: Insights from Seismic, Biostratigraphy and Well Log Data

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Abstract
Ogbo field, one of the prolific hydrocarbon field in Niger Delta basin has been studied holistically using integrated geological and geophysical approach. The study integrates well log, seismic and biostratigraphic data to reconstruct and re-evaluate a comprehensive sequence stratigraphic framework within the field. In this study, two major lithologies were identified which are shale colour coded with black and sandstone color coded with yellow. Well logs were correlated with siesmic data in other to generate synthetic traces. Also, five depositional sequence boundries (SEQ.1, SEQ.2, SEQ.3, SEQ.4 and SEQ.5) were identified with maximum flooding surface demarcating each sequence which also was grouped into parasequences of highstand system tracts, transgressive system tracts and lowstand system tracts. The bounded sequences revealed a prograding, retrograding and aggrading character. The sand unit was characterized by TST while HST dominate shale zone. Also, the structural interpretation of seismic data shows the presence of fault which indicate hydrocarbon trap in flat spot, dim spot stands out and bright spot which is the AM prospect. The sequence stratigraphy of Ogbo field demonstrates that it's still a producing well but drilling activities should focus on the bright spot within the faults for commercial exploitation of hydrocarbon in the field.

Keywords: Sequence Stratigraphy, Seismic Interpretation, Well Log Data, Niger-Delta

Introduction

Sequence stratigraphy, a recent field in stratigraphy has been defined in many ways as; the study of rock relationships within a time-stratigraphic framework of repetitive, genetically related strata bounded by surfaces of erosion or non-deposition, or their correlative conformities (Posamentier, 1988; Van Wagoner, 1990) [28, 40]. Galloway (1989) [14] defined it as analysis of repetitive genetically related depositional units bounded in part by surfaces of non-deposition, whereas according to Catuneanu (2006) [4], it is the analysis of the sedimentary response to changes in base level and the depositional trends that emerge from the interplay of accommodation and sedimentation.

Sequence stratigraphy is a stratigraphic approach that allows the identification of packages of strata that were deposited during similar conditions of accommodation change in relation to sediment supply and the key stratigraphic surface that bound them (Davies, 20019) [8]. Sequence stratigraphy supports the contention that the sedimentary record of earth's crust is the product of uniform and common physical processes that interact with sediments as they accumulate (Catuneanu, 2011). Thus, it is a very useful tool in developing a correlation framework within a sedimentary basin (Embrey, 2009) on both local and regional scale. Sequence stratigraphic techniques permit the integration of a range of desperate geologic data set (e.g seismic, well logs, outcrop, biostratigraphy, geochemical e.t.c) (Catuneau, 2006; Catuuneau, 2009; Davies, 2019 [8]). Thus, it is an effective tool in evaluating reservoirs system continuity and trend of deposition as well as in the prediction of reservoir system source (Van wagoner *et al*, 1990) [40]. The concept of sequence stratigraphy has been successfully applied to petroleum exploration in the world.

Niger Delta Basin is the seventh most prolific petroleum province in the world with average oil production of about 1.8 Million barrels per day (Doust and Omatsola, 1990). Nwajide (2022) described it as one of the major hydrocarbon provinces of the world, with ultimate recovery presently estimated at close to 40 million barrels, with gas estimation of over 40 trillion cubic feet reserves. Tuttle *et al*. (1999) gave a gas estimate of over 93 trillion cubic feet. Niger Delta has been defined as the Cenozoic gross off flap clastic succession that form part of the western African geosyncline which spread out into the cooling and subsiding oceanic crust generated as African and south American Lithospheric plates separated (Whiteman,1982; Wright, 1985; Nwajide, 2013). For a better understanding of the offshore sedimentary basin of Niger Delta, the application of sequence stratigraphy will help to enhance the geographic control and correlation of world pattern of sea level changes (Payton, 1977). This method facilitates the identification of major progradational sedimentary sequences which offer the main potential for hydrocarbon generation and accumulation. High resolution biostratigraphic data will be integrated with well logs and seismic data in this research to unravel the internal stratal architecture of ogbo field, Niger Delta Basin. Niger Delta porous and permeable sediments have the enabling condition for generation of hydrocarbon with its complex structures like faults, and diaprism, which makes it an enabling environment for hydrocarbon to be trapped and generated, be it primary generation or secondary recovery of hydrocarbon which migrates into these traps (Mitchium, 1997). Thus, sequence stratigraphy is required in other to delineate these structural complications and enhance the production and secondary recovery of hydrocarbon in the field.

Niger delta is characterized by complex depositional environments such as fluvial, deltaic and marine which can complicate the identification of boundaries and system tracts. The Basin is also known for its structural complications especially growth fault and diaprism which affect the stratigraphy of the basin, creating structural traps that challenge the correlation of seismic and well log. High frequency parasequences which are composed of laterally and vertically continuous shale and sandstones that have laterally and vertically variable reservoir quality and continuity can have major effect on reservoir performance. Stratigraphic causes of poor recovery through improved understanding of internal stratal architecture can lead to new well recompletion and enhance exploitation in such fields. Hence, Ogbo field which is no longer producing commercially viable petroleum need sequence stratigraphic investigation to enhance its hydrocarbon recovery. In addressing these problems, a high-resolution geophysical data, advanced modeling techniques and integrated approach that combine seismic, well logs and biostratigraphy approach is required to refine stratigraphic interpretation.

Geology of the study area

The Niger Delta Basin is characterized by a complex and extensive lithostratigraphy that reflects its geological history, including the deposition of sediments from various sources over millions of years. The lithostratigraphy of the Niger Delta Basin typically comprises several key lithostratigraphic units or formations, each with its own distinctive lithological characteristics. The stratigraphic sequence comprises of three broads subsurface lithostratigraphic units namely (from the oldest);

1. A basal marine shale unit -The Akata Formation (Paleocene) is typically the basal lithostratigraphic unit in the lithostratigraphy of the Niger Delta. It consists of predominantly shale and mudstone and serves as the primary source rock for hydrocarbons.
2. A crustal marine sequence of alternating sand and shales – (the Agbada Formation) (Eocene). This formation overlies the Akata Formation and consists of a diverse range of lithologies. It includes sandstones, shales, siltstones, and conglomerates. Within the Agbada Formation, reservoir-quality sandstones are often found, making it a critical unit for hydrocarbon exploration
3. A continental shallow marine sand sequence The Benin Formation (Oligocene). This Formation is typically the uppermost unit in the Niger Delta lithostratigraphy. It is primarily composed of unconsolidated and poorly sorted sands. The Benin Formation often forms the uppermost cap rock for hydrocarbon reservoirs in the underlying Agbada Formation.

The Akata Formation

The Akata Formation is Paleocene in age. It primarily consists of shale and mudstone deposits. It is characterized by organic-rich, fine-grained sediments (Doust, & Omatsola, (1990). The formation is believed to have been deposited in a deep marine environment during periods of sea-level rise and in anoxic condition (Reijers, 1997). It represents a transition from deltaic and shallow marine conditions to deeper offshore settings. The Akata Formation is rich in organic material, making it a source rock for hydrocarbons in the Niger Delta. This formation is estimated to be up to 7,000 meters thick. The thickness of the Akata Formation can vary across different parts of the Niger Delta Basin.

The Agbada Formation

The Agbada Formation is characterized by a diverse range of lithologies, including sandstones, shales, siltstones, and conglomerates. Sandstone intervals are particularly important as hydrocarbon reservoirs. Sandstone beds within the Agbada Formation often exhibit good reservoir properties, making them highly sought after for hydrocarbon exploration and production. The thickness of the Agbada Formation can vary significantly across different parts of the Niger Delta Basin. (Reijers.1997) The Agbada Formation is of great significance to the petroleum industry, as it contains reservoir-quality sandstones that host substantial hydrocarbon reserves in the Niger Delta. It is estimated to be 13,000 feet thick (Doust and Omatsola, 1989).

The Benin Formation

The Benin Formation consists of unconsolidated and poorly sorted sands. It is predominantly composed of sandstones with some interbedded shales and siltstones. The Benin Formation is often recognized as the uppermost cap rock for hydrocarbon reservoirs in the underlying Agbada Formation. The Benin Formation plays a critical role in hydrocarbon exploration, particularly as a cap rock, and is an essential part of the lithostratigraphy in the Niger Delta. It is estimated to be up to 2,000 meters thick (Short and Stauble, 1967) [36].

These subsurface lithostratigraphic units are complemented with their outcropping surface equivalents which includes; The facies of the Ameki Group conformably overlie the Imo Formation and contains three stratigraphic components: the Ameki Formation, the Nanka Formation and the Nsugbe Formation (Fig 1), which pinch out in both westwards and eastwards (Nwajide, 1980, 2013). The Imo Formation is the mappable equivalents of the Akata Formation and the Ameki Group and Ogwashi Formation are the mappable equivalents of the Agbada Formation of the subsurface stratigraphic units of the Niger delta (Short and Stauble, 1967) [36] (Fig 1). The Imo Formation is the oldest stratigraphic unit in the outcropping part of the Niger Delta Basin (Short and Stauble, 1967 [36]; Petters, 1991) and is composed of blue-grey shales with sand lenses, marl and fossiliferous limestones (Reyment 1965; Short and Stauble, 1967; Nwajide, 2013) [33, 36, 23]. The Ameki Formation is estimated to range from 1200 – 1500 m thick, and comprises mainly of sands, minor silt with thin shelly limestone and calcareous clay intercalations (Reyment, 1965; Nwajide, 2013) [33, 23]. The Nanka Formation is estimated at 305 m thickness, is mainly sands and minor calcareous clay/mud with heterolith (Nwajide, 1980, 2013; Ekwenye *et al*., 2014). The Nsugbe Formation is predominantly sands with some conglomerate bands, estimated to be about 100 m thick (Nwajide, 2013) [23]. The Ogwashi Formation comprises alternating coarse sands, silts, and clays with thin to thick lignite seams (Kogbe, 1976; Nwajide, 2013 [23]).

The Benin Formation: The Benin Formation which is the youngest stratigraphic unit of the Niger Delta Basin (Short and Stauble, 1967) [36]. The Benin Formation exists in both outcrops and the subsurface (Fig 2) and occupies an extensive area of southern Nigeria (Reyment, 1965; Short and Stauble, 1967; Nwajide, 2013) [33, 36, 23]. The stratigraphic succession of the Niger Delta is presented as Fig 2.

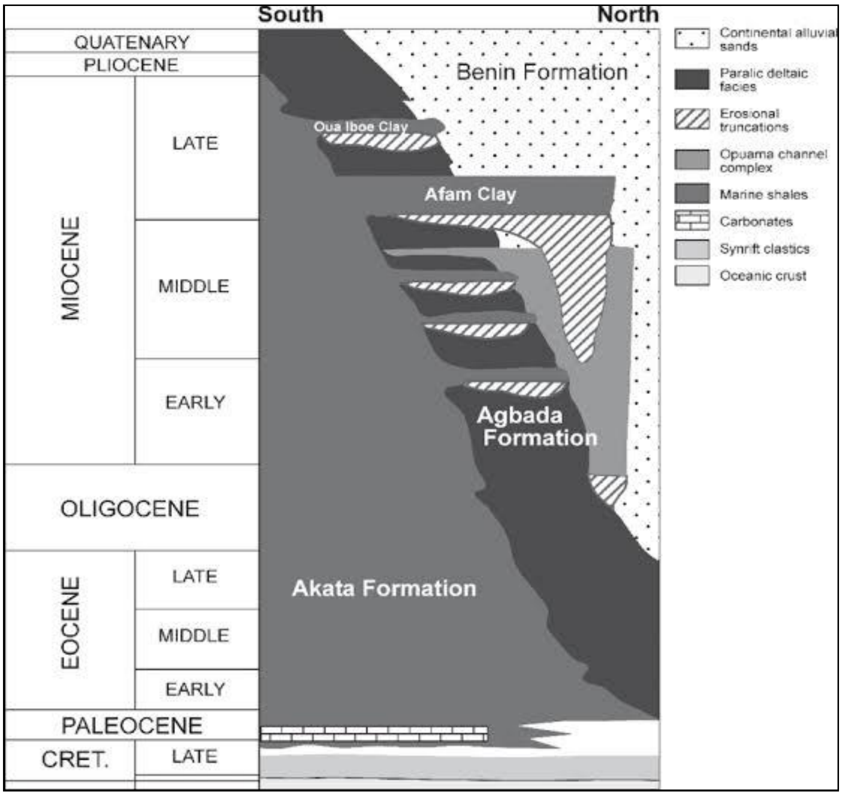


Fig 1: The regional Stratigraphic column of the Niger Delta Basin shows the three major units in the Delta (Akata, Agbada, and Benin formations) (Doust and Omatsola 1990)

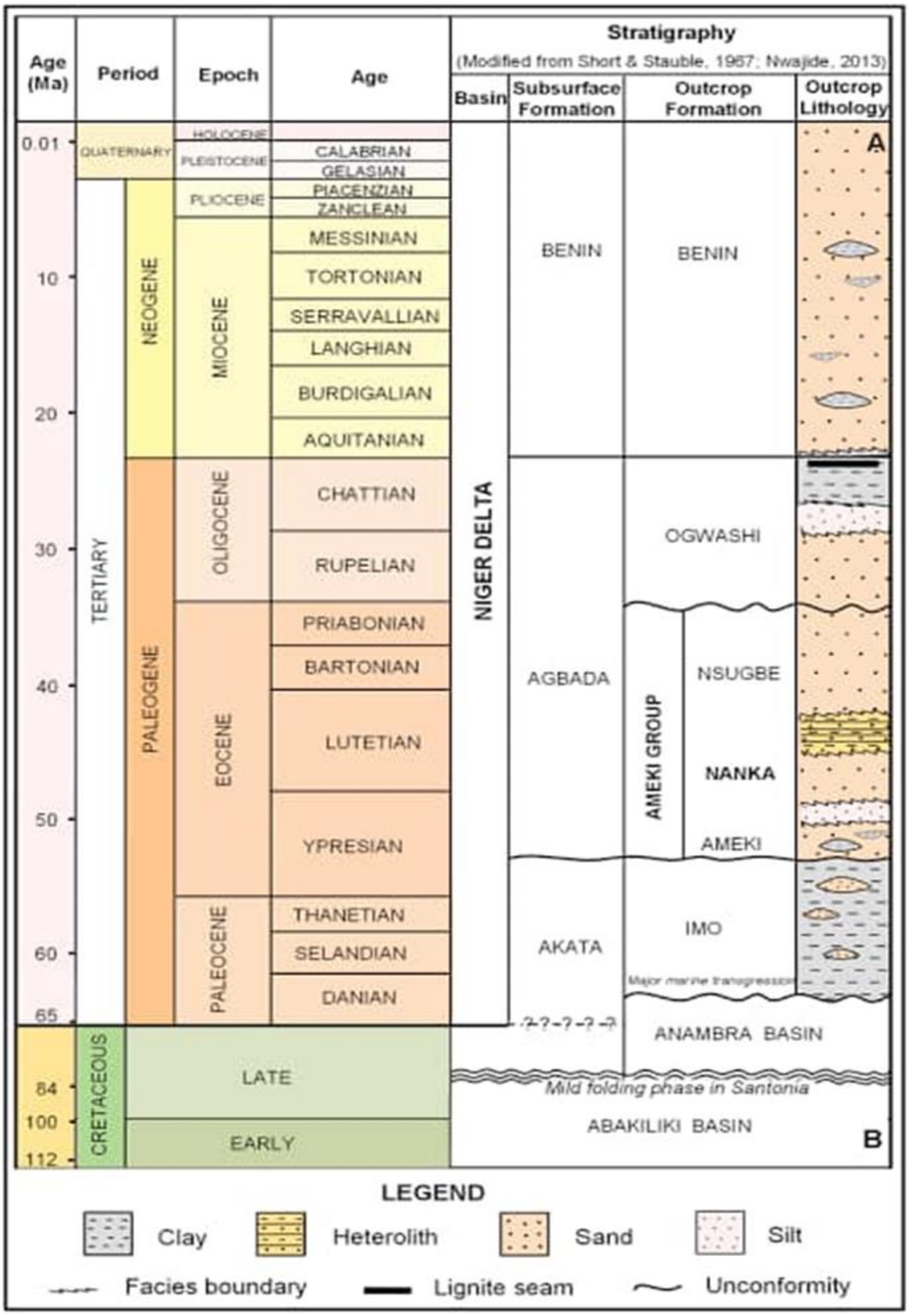


Fig 2: Stratigraphic Succession of Niger Delta Basin (redrawn and modified from Short and Stauble, 1967 [36]; Nwajide, 2005)

Materials and Method

Materials/ Data Set

The data set for this study was made available by Shell Petroleum Development Company (SPDC), Port Harcourt, Nigeria. The data consists of a 3-D seismic reflection volume (Fig 4), fifteen wells with full log suites, check shot data for eleven wells and biostratigraphic data for one well (Table 1). The biostratigraphic data is shown in Table 2.

3D Seismic Data

The seismic data used for this study is a post-stack, time migrated seismic reflection volume stored in SEG-Y format. The 3-D seismic displayed as zero phase, SEG reverse polarity where a peak represents increasing acoustic impedance coloured red (positive amplitude) and a trough represents decreasing acoustic impedance coloured blue (negative amplitude). The bin spacing of the data is 25.00m (inline) by 25.00m (cross-line), a sample rate of 2milliseconds, and a record length of 5500 milliseconds Two-Way-Time (TWT). The inline (dip section) has a total of 751 lines while the cross-line (strike section) has a total of 306 lines. The reflection quality of the data is good (Fig 3).

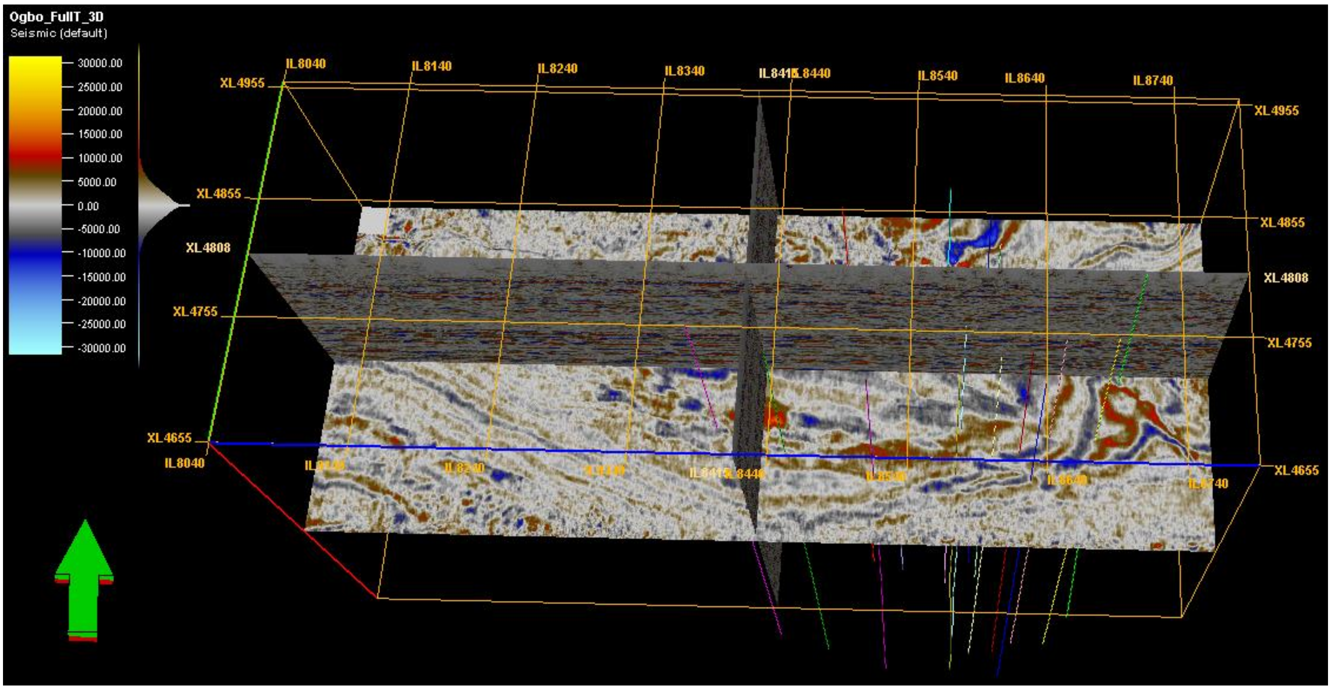


Fig 3: 3-D display of the seismic volume and the locations of the well data used in this study

Well data

Fifteen (15) wells were used in this study to integrate seismic and well-log data. The well data that were used in this study include full well-log suites (including gamma ray, resistivity, sonic, density and neutron), check shots data for five wells, and biostratigraphic data for two wells (Table 1). Biostratigraphic data includes the foraminiferal and palynological zones extracted from side-wall samples and ditch-cuttings which were depth calibrated with corresponding well logs. The population and diversity peaks of the benthic and planktonic foraminifera were used for age calibration and paleobathymetric interpretation (Table 2).

Table 1: Display of well data showing available log suites for the wells

Well Name	Surface X	Surface Y	MD (FT)	Elevation (ft)	GR (API)	ILD (Ohm-m)	DT (µs/ft)	RHOB (g/cm3)	NPHI (ft/ft)	Checkshot	Biostrat
Ogbo-1	434726.49	98143.24	11400.00	47.90	Y	Y	Y	Y	Y	Y	Y
Ogbo-3	433451.38	98840.47	12060.00	43.64	Y	Y	Y	Y	Y	Y	N
Ogbo-6	434949.60	96804.05	11910.00	46.59	Y	Y	N	N	Y	Y	N
Ogbo-7	435573.15	98522.97	11970.00	44.95	Y	Y	N	N	Y	N	N
Ogbo-10	435609.32	96209.51	12000.00	36.16	Y	Y	N	N	Y	Y	N
Ogbo-12	436805.81	96636.02	12000.00	33.79	Y	Y	Y	N	N	Y	N
Ogbo-15	433147.54	95720.77	11950.00	38.29	Y	Y	Y	Y	N	Y	N
Ogbo-19	435396.36	99170.46	12100.00	41.00	Y	Y	Y	Y	N	Y	N
Ogbo-24	431257.40	96216.07	11880.00	36.91	Y	Y	Y	Y	Y	Y	N
Ogbo-25	434848.55	95806.92	12050.00	40.04	Y	Y	Y	N	Y	N	N
Ogbo-30	436413.26	95704.25	12310.00	36.68	Y	Y	N	N	N	Y	N
Ogbo-31	434608.46	99740.05	8344.00	39.80	Y	Y	N	N	N	Y	N
Ogbo-33	438293.95	97960.32	12490.00	36.81	Y	Y	N	Y	Y	N	N
Ogbo-34	437765.51	96618.36	12143.00	36.42	Y	Y	Y	Y	N	N	N
Ogbo-35	432567.79	99257.82	12284.00	35.86	Y	Y	Y	Y	Y	Y	N

Y = available, N = not available.
GR (Gamma Ray log), DT (Sonic log), LLD & LLS (Resistivity logs), NPHI (Neutron log), RHOB (Density log).

Table 2: The biostratigraphic zonation for Ogbo-1 well

Well Name	Top Depth (ft)	Base Depth (ft)	Zone Type	Zone Code	Quality	Remarks
Ogbo-1	0	450				No Data
Ogbo-1	0	6070				No Data
Ogbo-1	500	5400				Barren
Ogbo-1	5600	7200	F	F9500/F9600		
Ogbo-1	6080	6100	P	P770	2	occurrence of 440
Ogbo-1	6179	7800	P	P750	1	t.r.320
Ogbo-1	10000	10000	F	F9540	1	Bol.25 Uvigerina 5

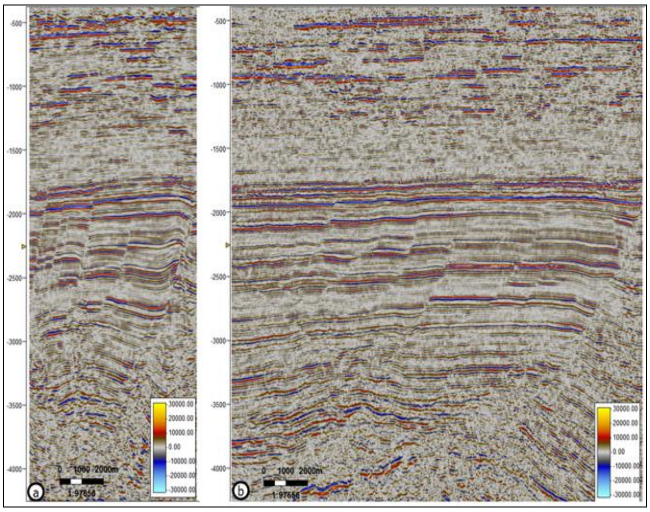


Fig 4: The quality of seismic data on (a)inline 8415 and (b)crossline 4808

Methodology

The sequence stratigraphy of the Ogbo Field, in Greater Ugheli Depobelt, Niger Delta Basin, Nigeria was interpreted using 3-D seismic data and well logs. Interpretation of the well logs and seismic data were done using Schlumberger's Petrel "seismic-to-simulation" interpretation software. The packages that were used included all available tools for seismic and well data interpretation.

Well Log Conditioning (Normalization)

Well logs are result of physical measurements of the earth properties taken within the confined space of a borehole. Sometimes, the measurements are subject to borehole irregularities and lapses of time between drilling and logging of the hole and this need to be corrected to have a quality data for efficient geological interpretation. The well log editing was carried out using LOG MATH in E-LOG program where various editing mechanism such as median filtering, depth shift splice, and block were applied to the well logs prior to data analysis. The idea is to obtain consistent and accurate logs from well to well.

The dispersion and median filtering corrections were applied to account for differences in frequencies between logging tools, surface seismic reflection data which minimize errors arising from wellbore washouts, casing points, mud filtrate invasion, gaps, missing data or insufficient log suites. The median Filtering corrections on the logs were carried out by simply creating or overwriting a log from an existing log by applying a median filter with a user defined operator length of n. It smoothens the logs and removes the high frequency noise.

However, in splice corrections, I created or overwrite a log by copying one existing log to another existing log. Therefore, before splicing, few precautions were undertaken and these include but not limited to environmental corrections, editing and compatibility of the units of the wellbeing spliced. It is also important to avoid auto splicing routines and use of generic log names common to spliced logs. In this study, we created a model that illustrates how we could overwrite a log by copying one existing log to another existing log.

Well-log Interpretation

Data used for the interpretation comprise gamma ray logs with counts measured on the horizontal scale from 0 to 150 calibrated in standard American Petroleum Institute (API). A baseline of 65 API was chosen to discriminate between sands and shales. The gamma ray facies cut off that will be applied in this study include 0 - 65 API representing sandstone facies, 65 – 75 API representing siltstone facies and >75 API representing shale facies. The approach adopted for the sequence stratigraphic analysis include the identification of important key stratigraphic surfaces was based on the integration of well logs, biostratigraphic (Foraminifera and Palynological) data and the Chronostratigraphic chart of the Niger Delta Basin updated by Shell Petroleum Development Company (SPDC). The stratigraphic surfaces comprising Maximum Flooding Surfaces (MFS) and Sequence Boundaries (SB) identified were used to subdivide the stratigraphic architecture of the field into 3rd Order Sequences using the Galloway (1989) [14] genetic sequence model (Fig 5). The stratigraphic surfaces were dated using the Niger Delta Basin Chronostratigraphic Chart. The stratigraphic surfaces were identified based on several criteria comprising the peak of fossil population and diversity, the pattern of stratal contact with the identified stratigraphic surfaces and their depositional stacking patterns (Fig 6). The individual interpretations for each well were correlated across all available wells to reveal the lateral variations of the lithologies, stratigraphic packages and depositional environments.

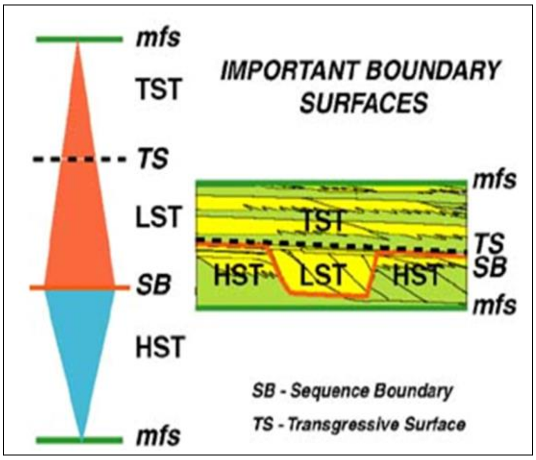


Fig 5: Illustration of the Galloway (1989) [14] genetic sequence model used in interpreting the stratigraphic sequence of the Ogbo 1 Field (Modified from Kendall, 2004). MFS = Maximum Flooding Surface, TST = Transgressive System Tract, HST = Highstand System Tract, LST = Lowstand System Tract

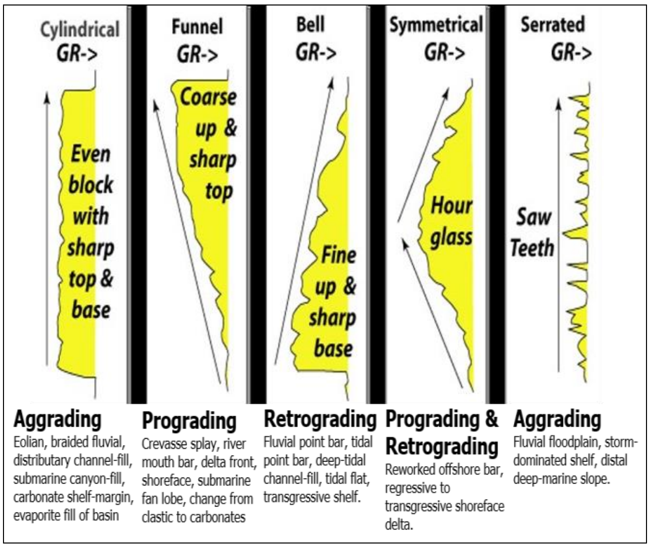


Fig 6: General gamma ray response to parasequence stacking patterns (Rider, 1990).

Well to Seismic Calibration

The starting point of geological interpretation begins with the correlation of the normalized well logs to seismic data so as to make vertical scale of the well log acoustic impedance match the vertical scale of the seismic data for spatial correlation It is also the first stage of the pre-interpretation process which involves lithologic description, picking top and base of sand-bodies, fluid discrimination and then linking these properties from one well to another based on similarity in trends. In between these two lithologies in the subsurface, the gamma ray log is often used. Correlation of reservoir sands was achieved using the top and base of reservoir sands picked. The correlation process was possible based on similarity in the behavior of the gamma ray log the Niger Delta; the predominant lithologies are sands and shales. In order to discriminate shapes. Also, the thickness of the shale bodies overlying and underlying the sand body is considered during Correlation. After defining the lithologies, the resistivity log was used for discriminating the type of fluid occurring within the pores in the rocks.

Geophysically, it is achieved by convolving the reflectivity and extracted wavelet at well location to generate the synthetic trace. However, two major processes such as check shot corrections and wavelet estimations were undertaken to obtain a good well to seismic tie in the study. Check shot corrections, was carried out using sonic and initial two-way travel time for the first sample that provides the highest correlation coefficient between the synthetic and observed trace. The idea was to adjusts the sonic log velocities or the log time depth curve to match the time depth relationship obtained from seismic data to ensure suitability and accuracy in well to seismic tie and creation of synthetic seismogram. This was done by applying a drift curve which measures the difference between the time depth curve and the checkshot. The check shot correction result shows the adjusted sonic log velocities or the log time depth curve that match the time depth relationship obtained from seismic data for suitability and accuracy in well to seismic tie and creation of synthetic seismogram (Fig 7).The applied drift curve (blue curve) measures the difference between the time depth curve and the checkshot. The red curve, indicates input depth / time curve while dark curve indicates output sonic log. The end result ensures that wells were placed at their appropriate depths and time position.

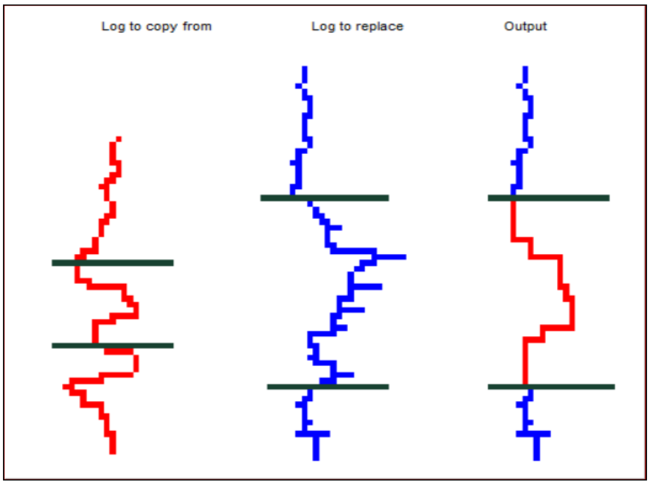


Fig 7: The model shows results of splice correction operation on well logs

Wavelet Estimation

Having placed the sonic wells in their appropriate depths and time position through checkshot corrections, we estimated the filter that best fit the well log reflection coefficients to the input seismic data at the well locations. This process is known as wavelet estimation. The wavelet extraction process was undertaken on both well logs (well log based-wavelet) and seismic data (statistical wavelet) to ensure that their wavelet has zero phase and same amplitude spectrum (Fig 8a-b). The statistical wavelet was obtained from the seismic data while the well log wavelet was deduced from the well log data.

Wavelet has amplitude and phase spectra; therefore, in the case of statistical extraction (seismic), we assumed zero/constant phase wavelet instead of minimum phase. The zero phase/ constant phase reduces the length of the wavelet and increases the vertical resolution of seismic data. These extracted wavelets represent the average of the wavelets at the individual well and seismic control points. This gives approximate values of the zero amplitude and phase spectra of the source wavelet, unlike that extracted from seismic through autocorrelation which give only amplitude spectrum without phase information. Furthermore, we convert the vertical scale of the well log synthetic trace to match the seismic trace for spatial correlation. This conversion was carried out using sonic and initial two-way travel time for the first sample that provides the highest correlation coefficient between the synthetic and observed trace. Each peak from the synthetic trace was correlated to each peak from real seismic trace.

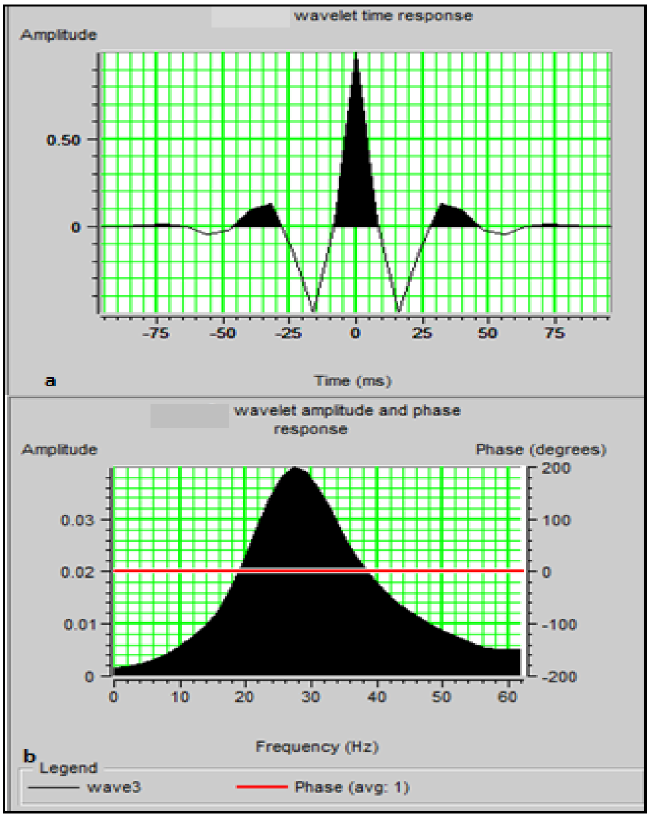


Fig 8: (a) The wavelet time response (b) The wavelet amplitude and phase response

Seismic-to-well tie

A synthetic seismogram is a modeled seismic trace derived from sonic and density logs. The synthetic seismogram allows well data recorded in units of depth to be compared to seismic data recorded in units of time. Synthetic Seismogram and seismic-to-well ties were generated for well Ogbo-1 using sonic and density logs and time-depth relationship (TDR) from the checkshot data. Deterministic wavelet method was extracted from the seismic data and was used to convolve the reflection coefficients to generate the synthetics.

Seismic Interpretation

The structural and stratigraphic mapping were carried out using the 3-D seismic volume. Interpretation of the seismic data involves fault and horizon mapping across the seismic volume. Faults interpretation was carried out on every 10th inline due to the good quality of the seismic data. The variance (edge) volume attribute used to validate the faults was interpreted by displaying the faults on a time-slice. Identified key stratigraphic surfaces were mapped using manual tracking mode on the peak event at every 10th inline and crossline.

Results and Discussion

Data Enhancement

Fig. 9 and 10 show the corrected and uncorrected median frequency spike data respectively. Fig 9 shows a sharp peak in frequency distribution and ununiform distribution of values such as radioactive values and this was denoted by thick signals. The spike was due to measurement noise, instrumental noise, thin shale beds and radioactive mineral deposits. Fig 10 shows the corrected median frequency spike which was done by filtering, smoothing, statistic adjustment and normalization to remove errors and also provide a more accurate representation of subsurface properties. The filtering and smoothing reduces the sudden and unrealistic spikes, the adjusting of data remove the outliers that causes unnatural peaks while normalization scales the resistivity values to a standard range to ensure consistency of the data. The corrected median frequency in Fig 10 have a lighter signals and smooth curve which shows that the spikes due to noise are removed and the peaks are now more accurate.

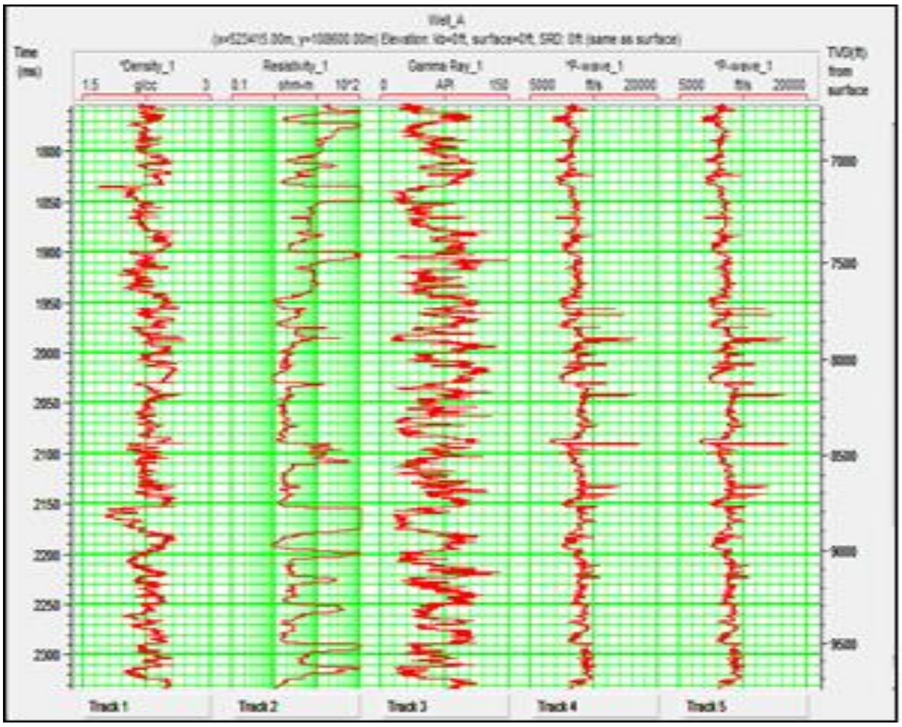


Fig 9: The Ogbo with high frequency spikes (uncorrected logs)

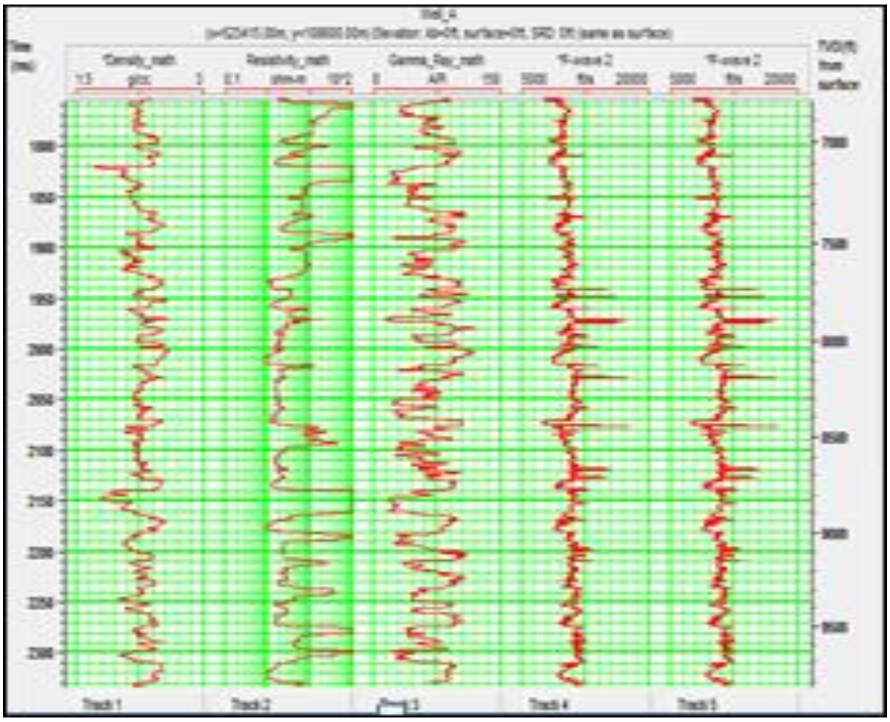


Fig 10: The Median corrected Ogbo with despiked frequency

The log to copy from was Resistivity log while log designated for repalcement was gamma ray log. The blue curve is the splice from the resistivity log while the interwined red and green curves are the overlay of the splice to gamma ray logs. This is necessary for well to seismic calibration.

In Fig 8, there were small variations in the static corrections in seismic, but still contribute to slight time-shifts above the reservoir interval. The results show maximum cross correlation value of 0.432 with time-shift of -14ms indicating velocity pull-up and thus, poor repeatability. This was corrected to zero time shifts with a maximum cross correlation coefficient of 0.7602. The large time-shifts were also observed along the edges of the survey which was associated with low correlation coefficient of 0.3051 in the low fold edge regions. The low correlation coefficient corresponding to large time-shifts which indicates low repeatability, and was corrected to zero time shifts with a normalized wavelet time response. The decrease in large window time-shifts from zero to -14ms was associated with the presence of random variations in amplitude events. The reliability of the time-shifts was measured by the strength of the correlation coefficients, and a comparison of the calculated correlation time-shifts and horizon-based time-shifts. With the times sheet correction of the seismic data, we manually stretch or squeeze the log in order to improve time correlation between the target logs and seismic trace until a good correlation or tie between the well logs and the seismic data was obtained by considering the alignment of the events on the well synthetic trace and the field acquired seismic trace.

Reservoir Identification

The reservoir identification was carried out using geological and petrophysical methods. Different horizons were marked based on the well tops recognized from petrophysical analysis of well logs (Fig 11). The horizon tops and bases were identified using gamma-ray and resistivity logs which were also linked with other six wells. Two major lithologies identified are shale color coded with black and sandstone color coded with yellow. The results further revealed that each of the identified horizons (sand unit) spreads over the field with varying thicknesses. However, some horizons occurring at greater depth than their adjacent unit which is possibly an evidence of faulting. The sand layers were observed to decrease with depth along with a corresponding increase in shale layers at the base. The resistivity logs which reveals the presence of hydrocarbons were used to identify the hydrocarbon bearing sands. Furthermore, nine major sand bodies (1,2,3,4,5,6,7, 8 and 9) were identified and correlated across all the eight wells in the field. Three bigger reservoir sands were selected for the purpose of this study.

Fig 12 presents the varying Lithologies, parasequence, systems tract and sequence analysis of the study area.

The results revealed five major sequence boundaries (SEO.1, SEO.2, SEO.3, SEO.4, and SEO.5), with each sequence showing distinctive maximum flooding surface (MFS). The key bounding surfaces identified in the study area are the MFS and SB with their corresponding depths. The Niger Delta Chronostratigraphic chart aided in this identification and is also used in dating the key surfaces. The MFSs are categorized by dense and widespread mudstone components identified by high gamma-ray value and lowest resistivity readings. The biostratigraphic interpretation was focused on the identification of major faunal abundance and diversity peaks, which coincide with maximum flooding surfaces, while faunal abundance and diversity minima correspond to sequence boundaries. The recognized sequence boundaries were considered by significant sand unit and low gamma ray value (Fig 11). It is the interval separating the overlying shallow microfacies from underlying deep-water facies with minimal biofacies abundance and diversity. The bounded sequences revealed a retrograding, aggrading and prograding character. The interpreted hydrocarbon bearing reservoirs occur within the sands of the transgressive system tract. while high stand system tracts dominate in the shale zones.

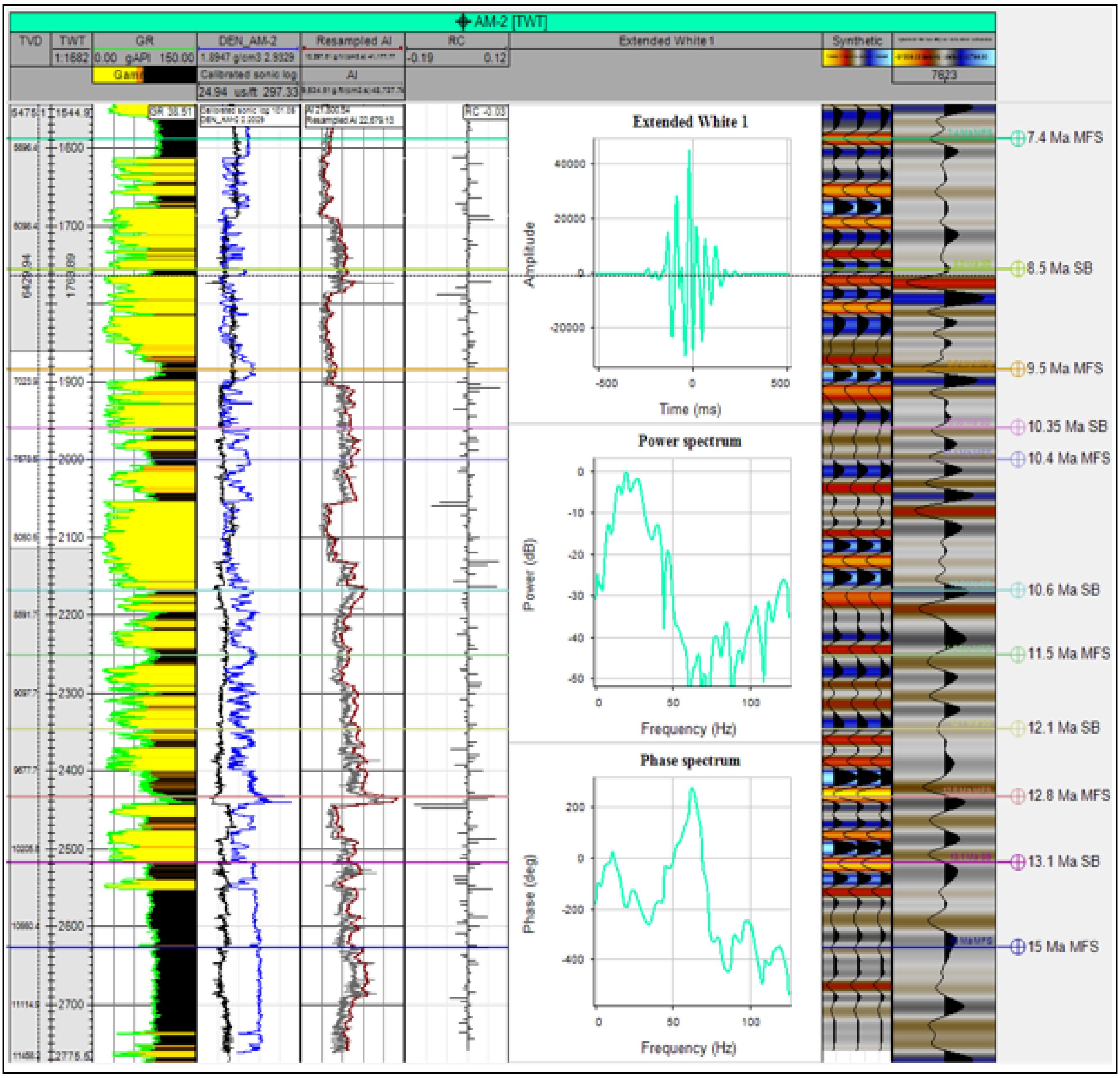


Fig 11: Well-to-seismic tie for horizon mapping across the entire seismic volume. Synthetic seismogram generation model using density and sonic log

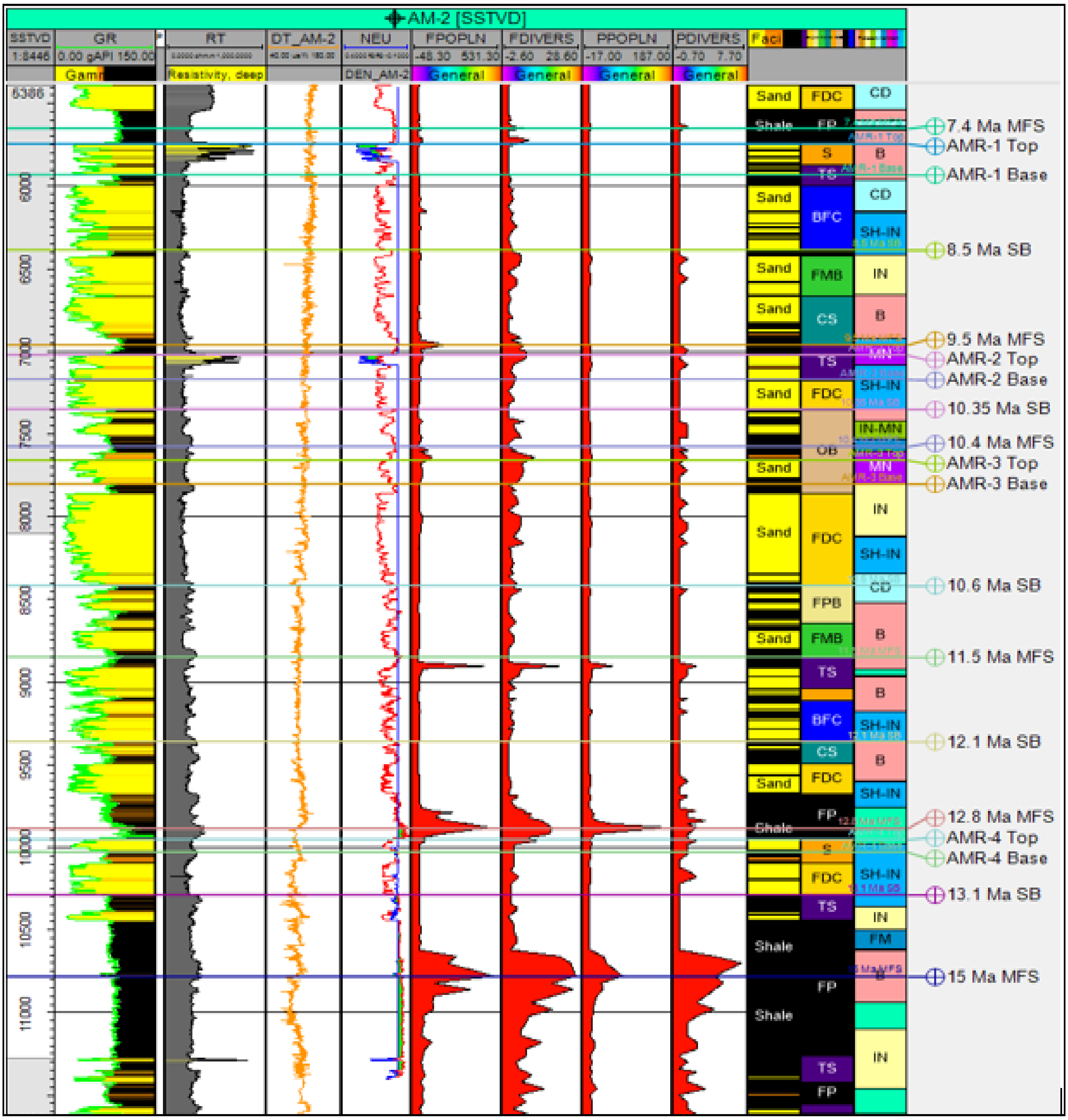


Fig 12: Presents Lithofacies and Well-Log Sequence Stratigraphic Analysis

Stratigraphic Analysis and Correlation

Five depositional sequences were identified across the correlated wells which were further divided into para-sequences and their associated systems tracts, namely Highstand systems tract (HST), Lowstand system tracts and Transgressive systems tract (TST). TST often assume a position of middle systems tract in an ideal depositional sequence which develops as a result of an increase in the rate of sea-level rise. In this system tract, retrogradational Parasequence dominates and this occurs at depth intervals: 11379ff – 10860ft, 10000ft – 9500ft, 8850-8000ft, 8500ft-70500ft.

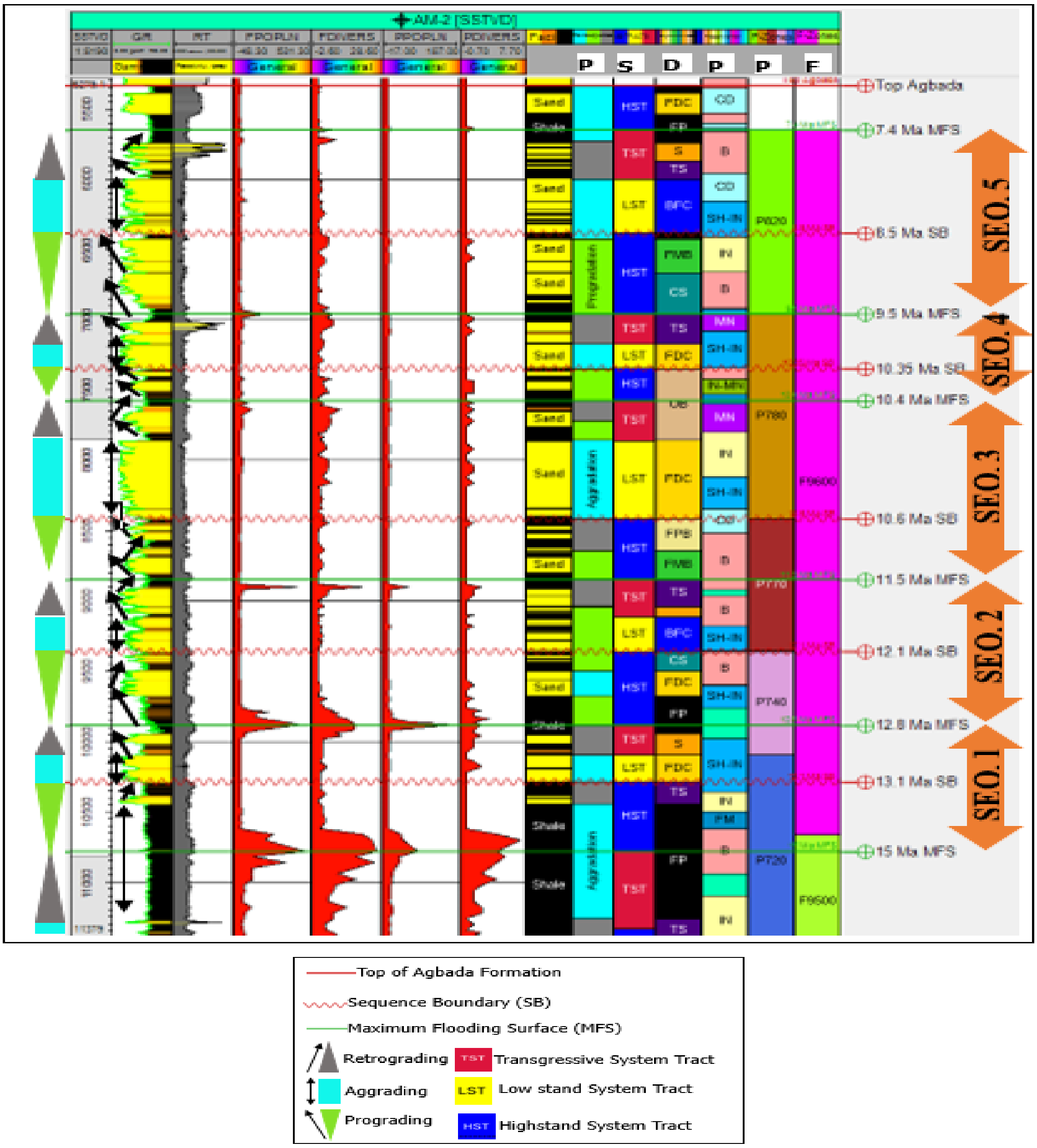


Fig 13: Lithology, Parasequence, systems tract and sequence analysis of Ogbo

On the other hand, the highstand systems tract (HST) represents the uppermost unit of a depositional sequence according to Mitchum *et al.*, 1993. It is characterized by early gradational to later progradational Para sequence sets. In the studied well, HST occurs at the depth intervals of 10750ft-10250ft, 9750ft-9250ft, 8750ft-8250ft, 7750ft-7250ft and 5780ft-5250ft. The highstand and transgressive systems tracts recognized in the studied well suggest that the wells are updipping wells. Each systems tract was deposited at a predictable position in an interpreted base level cycle caused by eustacy and has recognizable signature on well logs. The Lowstand systems tract (LST) which also occurs at the interval of 1025ft-1050ft, 9250ft-9050ft, 8250ft-8050ft, 7250ft-7050ft and 6250ft-6000ft includes deposits that accumulate after the onset of relative sea level rise which lies directly on the upper surface of the falling stage systems tract and is capped by the transgressive surface formed when the sediments onlap onto the shelf margin. The Five depositional sequences (SQ1-SQ5) were demarcated with six maximum flooding surfaces and five sequence boundaries. The depositional sequence 1 starts at the depth interval of 11379ff-10250ft with total thickness of 1129ft. The interval is bounded by SB 15ma and SB 13.1ma which falls within the 3rd order cycle based on the identification of the unit boundaries. Here, the interval of the transgressive systems track shows a retrogrational parasequence pattern consisting dominantly of pelagic shale with some transgressive sand sediments and terminate at maximum abundance and diversity of foraminiferal assemblages called the maximum flooding surface (MFS) at depth of 10750ft dated 15ma. The overlying HST interval consist of shale unit at the base and progressively into a progradational stacking pattern with sand increasing upwards to terminate at the base of cylindrical log shape marking the sequence boundary at 10750ft ft. dated 13.1 Ma. Fig 15 showed the detailed behavior of the sediments and their potential depositional environments. In depositional Sequence 2, the interval falls between SB 13.1 and SB 12.1 Ma which is of the 3rd order cycle based on the identification of the unit boundaries. The depositional sequence showed three distinct system tracts with low stand system tract at the base.

GR Log Shape and Facies	Description	Interpreted Depositional Environment	Paleobathymetry
	Retrograding: bell shape, finning upward sequence with serrated pattern.	Transgressive shelf (TS)	Shallow Neritic - Bathyal
	Prograding: funnel shape, coarsening upward sequences with serrated pattern	Crevasse splay and shoreface (CS & S)	Inner Neritic
	Aggrading: blocky shape, abrupt top and base sequences	Fluvial distributary channel (FDC)	Shallow Inner Neritic
	Prograding & Retrograding: symmetrical shape, coarsening upward changing to finning upward sequence	Offshore bar (OB)	Middle Neritic - Bathyal
	Retrograding: bell shape, finning upward sequence with clean pattern.	Fluvial point bar (FPB)	Coastal Deltaic
	Aggrading: blocky shape, abrupt top and base sequences with serrated pattern with sand/shale intercalation	Braided fluvial channel (BFC)	Coastal Deltaic – Shallow Inner Neritic
	Aggrading: serrated shape	Fluvial floodplain (FP)	Fluvio Marine - Bathyal
	Prograding: funnel shape, coarsening upward sequences with clean pattern	Fluvial mouth bar (FMB)	Inner Neritic - Bathyal

Fig 14: Detailed chart showing behavior of the sediments and their potential depositional environments

With a starting depth interval of 10250ft and the end depth interval of 1050ft. This was followed by the overlying TST interval (1050ft-9900Ft) a middle system track of both type 1 and type 2 sequences which consists of the deposits accumulated from the onset of coastal transgression until the time of maximum transgression of the coast, just prior to renewed regression. The sequence terminates at the 12.8ma MFS which formed the base of the overlying HST interval (9900ft). The HST consist of sand and shale intercalations with sand increasing upwards to terminate at base of cylindrical log shape marking the sequence boundary at the depth interval of 9500ft dated 12.1ma.
Similarly, in depositional Sequence 3 (9300ft-8400ft), the deposition episode starts at the depth of 9300ft and ends at 8400ft with total thickness of about 400ft. like depositional Sequence 2, the results showed three distinct system tracts with low stand system tract at the base (9400ft-9300) followed by the overlying TST interval (9050ft-8800ft) which terminates at 11.5ma MFS. The interval of the transgressive systems track starts with a progradational stacking pattern that finally shows a retrogrational parasequence pattern consisting dominantly of pelagic shale. This was also capped by High Stand System tract (HST) (8800ft-8300Ft) that terminate at depth interval of 8300Ft that dated 10.6ma at sequence boundary. Generally, the HST occur during the late stage of base level rise especially when the rate of sea level rise drops below the sedimentation rate. As shown in the depositional sequences so far, they bounded by maximum flooding surface at the base and composite surface at the top. In depositional Sequence 4, the sequence episode of deposition starts at depth of 7300ft and terminates at depth interval of 6400ft. The interval falls between SB 10.35ma and SB 8.1ma which is of the 3rd order cycle based on the identification of the unit boundaries. After the interval of Low Stand system tract at the base, the interval of the transgressive systems track starts witha progradational stacking pattern that terminate at the maximum flooding surface of 9.5ma. This was capped with High Stand System Tract (HST) interval that terminate at 8.5ma SB with a progradational stacking pattern consist of sand and shale intercalations with sand increasing upwards.
In the depositional sequence 5, the sediment deposit episode at depth interval of 8400ft and terminate at 5270ft. This interval falls between 8.5ma SB and undefined point with low stand system tract at the base. This is the youngest depositional sequence. The interval of the transgressive systems track is capped by the maximum flooding surface at 5600 ft. dated 7.5 Ma. The overlying HST interval (5600ft. - 5270 ft.) is capped by the top of Agbada.
However, to have more regional view, we present a regional correlation of the stratigraphic sequence along depositional dip and petroleum system elements distribution across the study area along depositional dip. In stratigraphic correlation, the results establish the age of sedimentary strata in different geographical areas in the study area by analyzing their stratigraphic relationship. In this, we create a chronological profile of an entire geologic time period by piecing together information from widely separated rock outcrops which continually exhibit the tempo spatial facies variations within third-order depositional sequences.

Depositional Environments
The faunal distribution deposits found in the shale sediments is as a result of maximum flooding surfaces which suggested the paleoenvironment of deposition to be a marine environment characterized by deep water sedimentation due to gravitational flows and high deposition of turbidity currents. However, in the other hand, the sand sediments bounded by sequence boundaries indicate a deltaic environment of deposition which is as a result of depositional process of fluvial and distributary channels (Fig 14).

Age of the Sequence
Using the Niger Delta Basin chronostratigraphic chart, the interpreted sequences range in age from Middle Miocene to Late Miocene (15 Ma - 7.4 Ma).

Petroleum System Elements
The petroleum system elements distribution across the study area along depositional dip, will determine the regions that have the right conditions to produce hydrocarbon. The results present the schematic cross section showing the source rocks (shale) that generate hydrocarbons as indicated in grey color with 50% abundance, the reservoir (sand) that stores the hydrocarbon as indicated in yellow color with 50% abundance, growth faults and rollover anticlines which serves as traps and shows the geometric arrangement of reservoir. The Shale seal rocks that allow hydrocarbon to accumulate and primary and secondary migration through faults and fractures. The prospect of finding an accumulation of natural gas or oil in an area depends on satisfactory coefficient of the above factors in the subsurface. Regionally, the correlated wells revealed that the identified reservoir tops correspond nearly to the crests of original seismic.

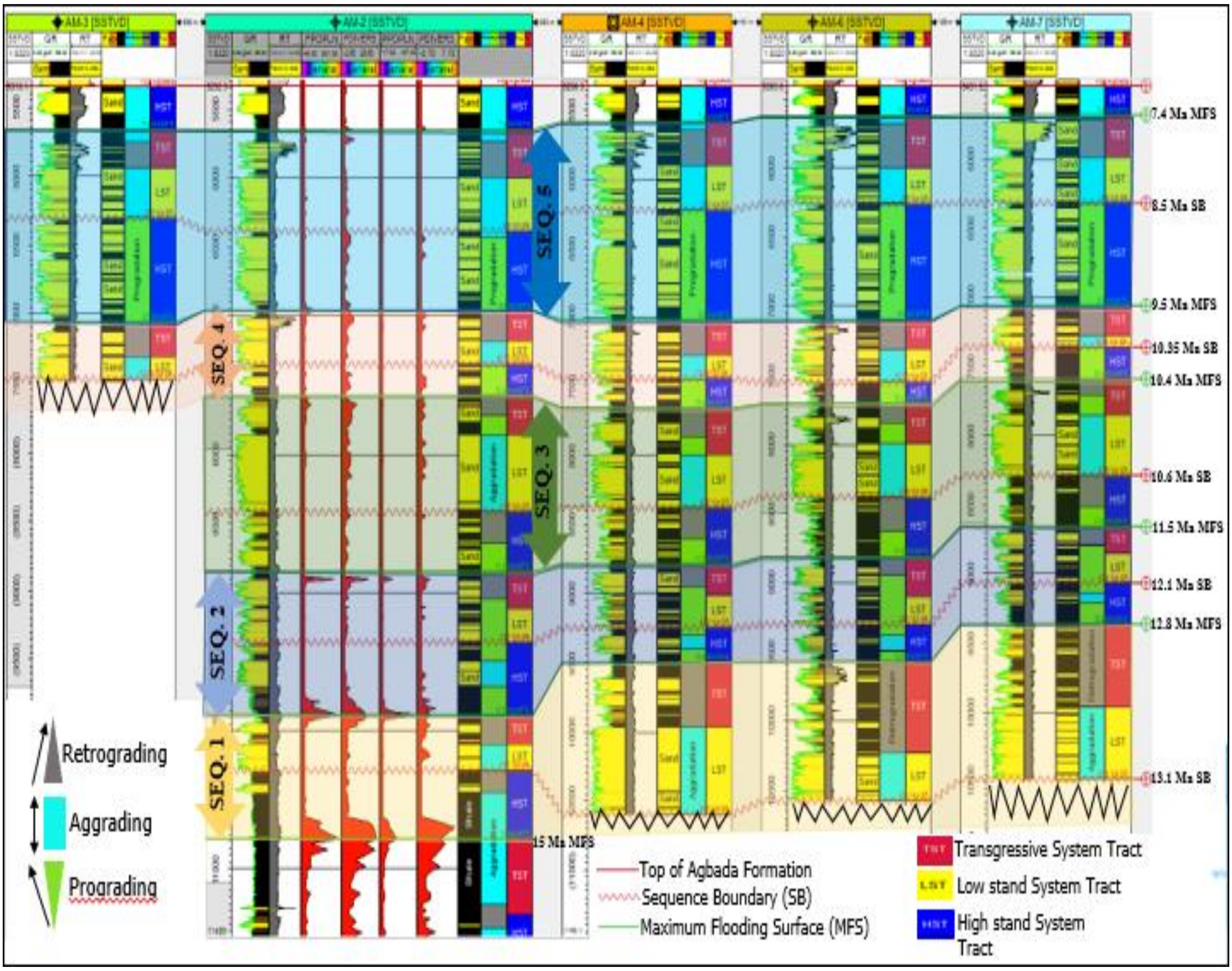


Fig 15: Regional correlation of the stratigraphic sequence along depositional dip

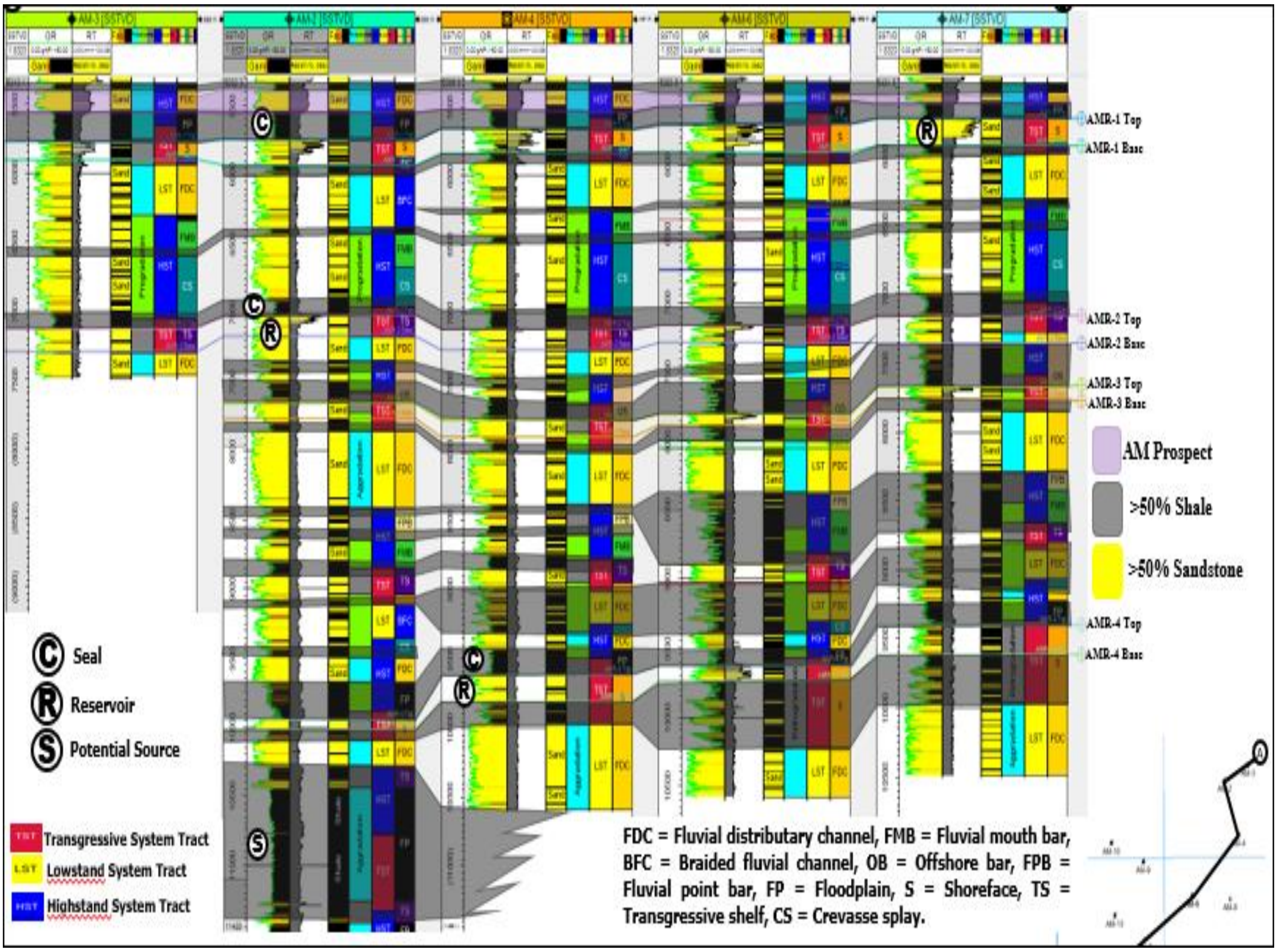


Fig 16: Petroleum system elements distribution across the study area along depositional dip

Structural Analysis

The 3-D seismic interpretation of the study area involved fault picking and correlation, which was done to establish the regional structural framework of the field. The result of the structural interpretation of the seismic data is shown in Fig. 18a-b, Fig. 18a revealed the uninterpreted seismic section at inline 7900 where presence of direct hydrocarbon indicators including flat spot, bright spots and dim spots stand out. Here, the seismic reflection terminations are indicative of faults. Similarly, in the results showed the interpreted seismic section at the same inline 7900. This was quality-controlled using the combination of seismic time slices, coherency cube generated from the seismic volume and variance cube from Petrel. The results showed horizon mapping of the bright spots named AM Prospect across the entire 3D seismic volume. As shown in Fig. 18b, two reservoirs were mapped which are indicated by light green and yellow across the seismic time window and these horizons represent the top of reservoirs in the area. Over twenty-five normal faults were mapped across the seismic volume. Three major faults divided the field into four exploration blocks indicated as block A, B, C and D. The faults were identified based on the break in reflection events which could act as a migration pathway for hydrocarbon. The structural patterns vary across the seismic dipping downward from north along the AM prospect line. Fig 19 presents the seismic density displays of the interpreted 3D grid of AM Prospect horizon. Here, the result shows seismic data by assigning different shading densities to different amplitude values that create a composite display of blue-white and red which are indicative of polarity or impedance. Fig. 20a presents time slice 1300ms showing localized high amplitudes. The localized high amplitude is a visualization of seismic data that show trends in amplitude. The high seismic amplitude anomaly can be caused gas saturation or thickness of the reservoir. In Fig. 20b-c, we present the structural control for AM-Prospect at inline 7960 and crossline

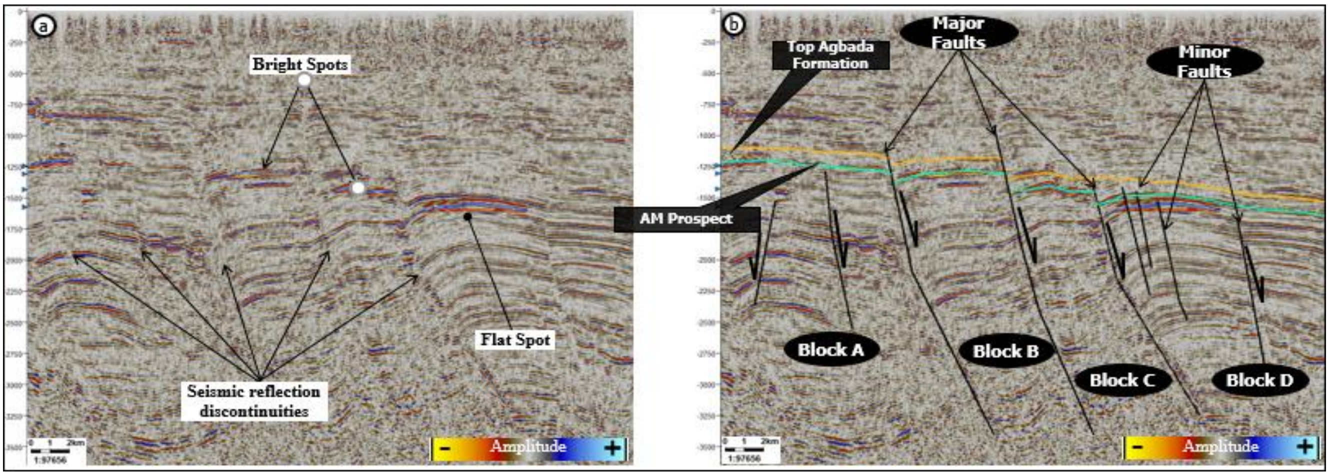


Fig 17: (a) Revealed the uninterpreted seismic section at inline 7900. (b) Revealed the interpreted seismic section at the same inline

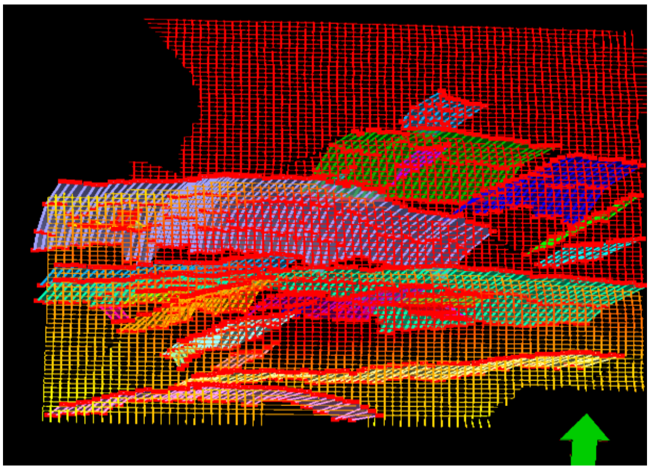
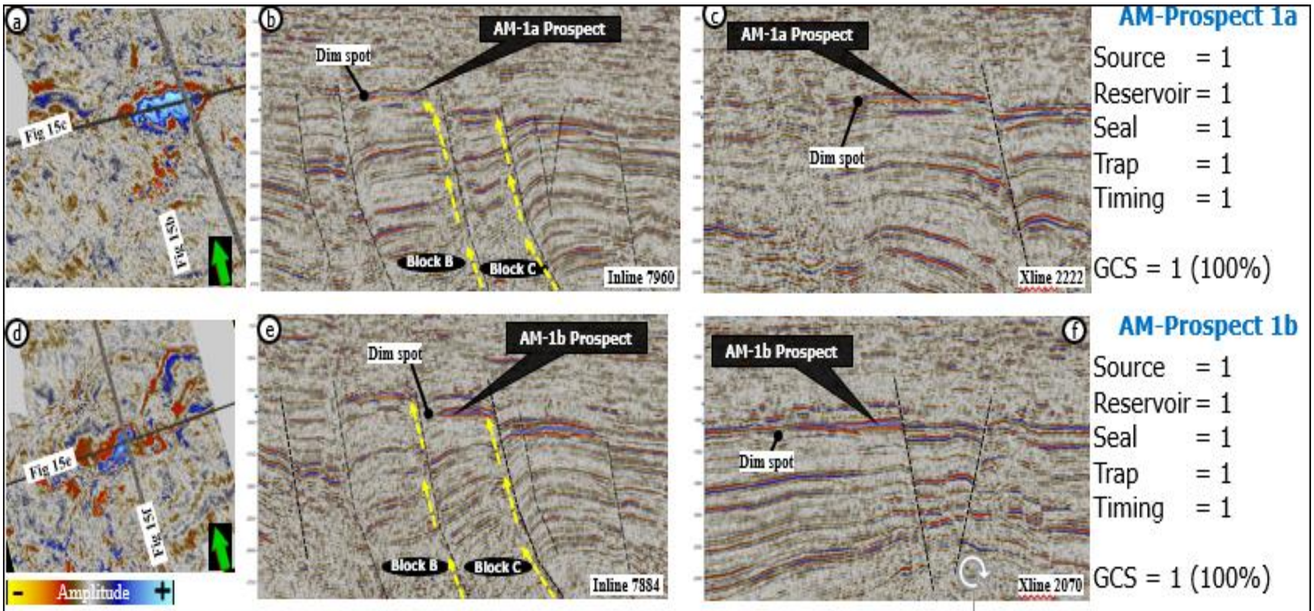


Fig 18: Shows seismic density display of the interpreted 3D grid of AM Prospect horizon



Reservoir Unit	Fluid Type	Tg (ft)	Tn (ft)	Vsh (%)	N/G (%)	ϕ (%)	K (mD)	Sw (%)	Sh (%)	Bo (rb/stb)	Area (acre)	STOIIP (MMSTB)
AM-Prospect 1a	Oil	118	118	0	100	26	715	26	74	1.29	2380.8	325.1
AM-Prospect 1b	Oil	118	118	0	100	26	715	26	74	1.29	2692	367.6

Estimation of Geologic Chance of Success (GCS) was done by accessing the presence of key petroleum system elements and assigning confidence values to them.

Fig 19: (a) Time slice 1300 ms showing localized high amplitudes. (b) and (c) shows the structural control for AM-Prospect 1a at inline 7960 and crossline 2222 respectively. AM-Prospect 1a is an anticlinal trap within block B. Dim spots were observed away from the bounding faults. (d) Time slice 1424 ms showing localized high amplitudes. (e) and (f) shows the structural control for AM-Prospect 1b at inline 7884 and crossline 2070 respectively

The AM-Prospect (1a) is an anticlinal trap within block B. in anticlinal traps, the earth movement fold the horizontal rock layer into an arch shape. Here, the dim spots were observed away from the bounding faults which were interpreted as hydrocarbon saturated zones. Fig.26d showed time slice 1424ms showing similar localised high amplitude while Fig. 20e-f present the structural control for AM-prospect 1b at inline 7884 and crossline 2070 respectively. The amplitude anomalies were identified based on their response to the seismic attributes which are indicative of the presence of hydrocarbon accumulation. As shown, the AM prospect 1b is a tow way fault- assisted trap with block C. Dim spots were observed away from the bounding faults. Hydrocarbon migration is up-dip through the major faults. The localized higher amplitude zones suggest the presence of hydrocarbon charged reservoir. Amplitude variations within the amplitude maps suggest variability in the lithology. Fig 20 shows variance (edge) attribute time slice at 1853ms showing interpreted faults and the subdivision of the blocks in plain view. This reveal the faults within the interval of interest. The Variance (edge) attribute was selected due to its relatively high accuracy in revealing faults and fractures, including those that are below seismic resolution known as sub-seismic faults. Variance (edge) attribute time slices were generated at various times and used as a guide to interpreting the faults throughout the entire seismic volume along seismic inline which clearly shows zones of stratigraphic discontinuities (Fig 20) The results indicate stratigraphic discontinuities and the presence of faults as shown in the fault blocks. The results show very strong localized high RMS amplitudes and sweetness values confined within faults in fault block A, B and C which suggest the presence of hydrocarbon confined within structural closures. The interpretation of accumulation was further strengthened by the presence of direct hydrocarbon indicators such as dim spots, flat spot and localized bright amplitudes corresponding to sand deposits. This was also reflected in AM prospect time surface map (Fig 21) and Depth Map.

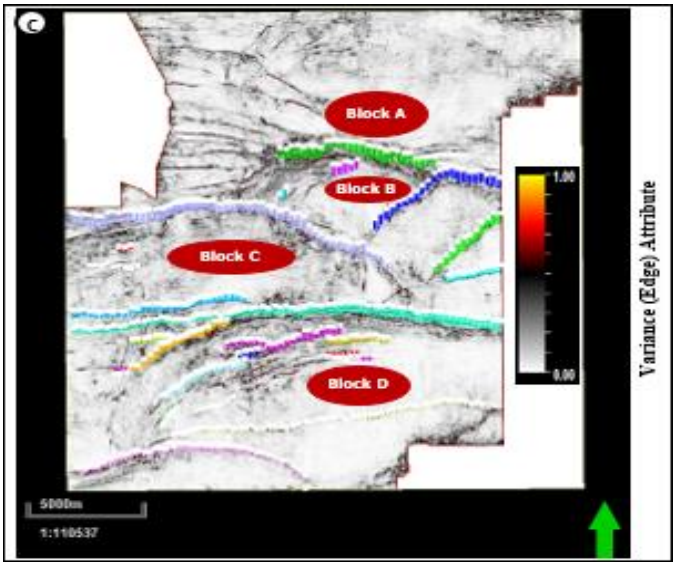


Fig 20: Variance (edge) attribute time slice at 1853ms showing interpreted faults and the subdivision of the blocks in plain view

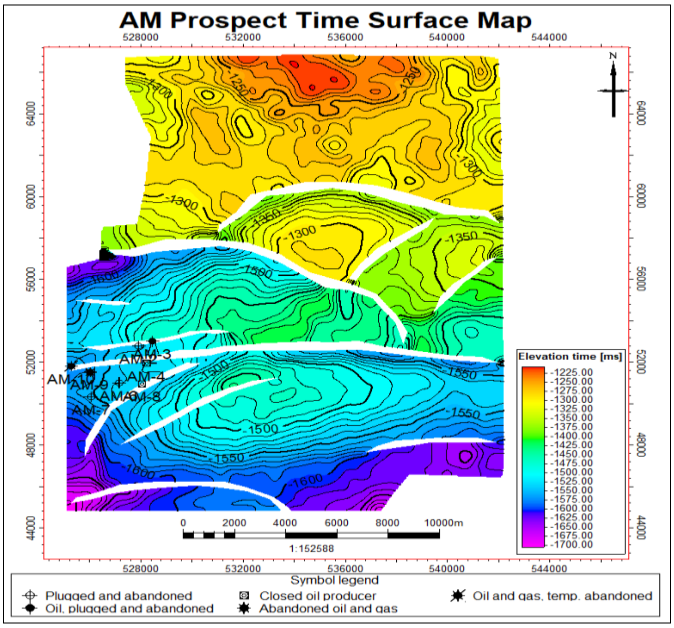


Fig 21: AM prospect time surface map

In time structural map, we mapped horizons and also generate fault polygons that was used to generate time structural maps for the reservoir of interest. The contoured map has contour interval of 50 ms and the values range from 1300 (orange/yellow) to 1500 ms (purple/blue). Points of equal time are identified by same colour. In Fig 21, areas with very high times are seen to the southern part of the field. However, in the case of the deep reservoir regions of extremely high times appear in the north eastern and western parts of the field. A time map is usually compressed in its deeper parts and stretched out in its shallow areas because of the general increase in velocity with depth. The time structure maps were then converted into depth maps as shown in Fig 22 which revealed the four major fault blocks. The time and depth structural maps of the horizons showed great similarities. However, on the depth map three closures that were fault assisted were identified and were labeled as block A, B and C. These closures were identified on the structurally high areas. These were used as leads that were further subjected to attribute analysis for prospect identification. For instance, Structural highs are observed at the North western and central part of the field. This area forms a good trapping system, thereby increasing retentive capacity for hydrocarbons. The hydrocarbon trapping system in the central part (specifically in Block B) of the field where the wells are located is a faulted rollover anticline. The low faults throw in the area is responsible for outstanding retentive volume of hydrocarbons. Structural lows are seen in the south and spreading to the western and south-eastern region of the south. There areas leave no indications of hydrocarbon prospects. Furthermore, RMS Amplitude attribute was further extracted from the depth structure maps and displayed as flattened maps for each of the interpreted horizons (Fig 23). Using the color codes, high RMS value indicated in yellow color codes is an indication of the localized hydrocarbon prospects.

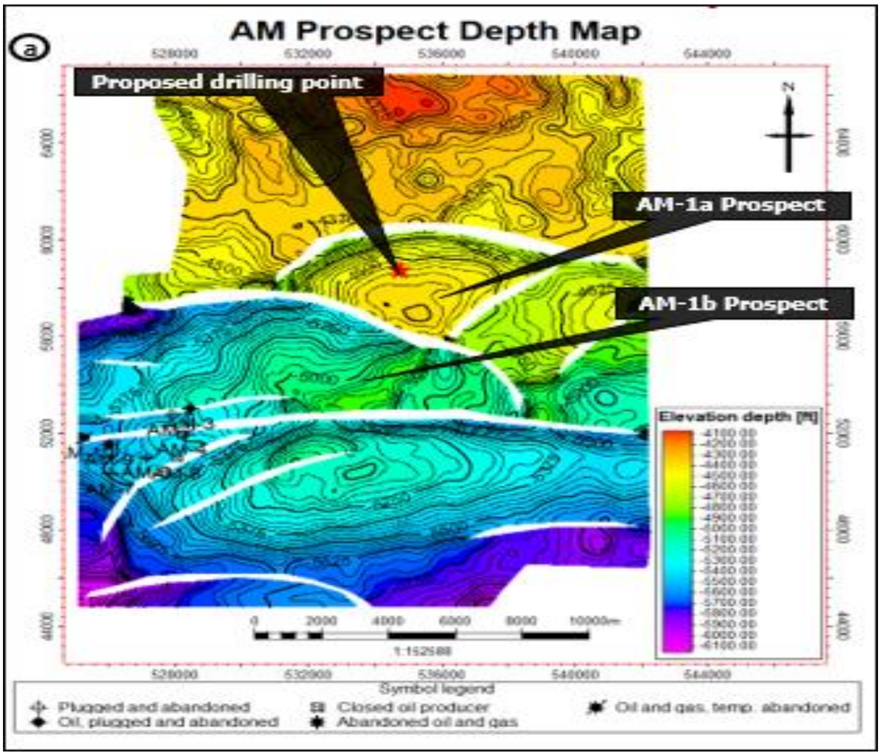


Fig 22a: AM prospect depth map

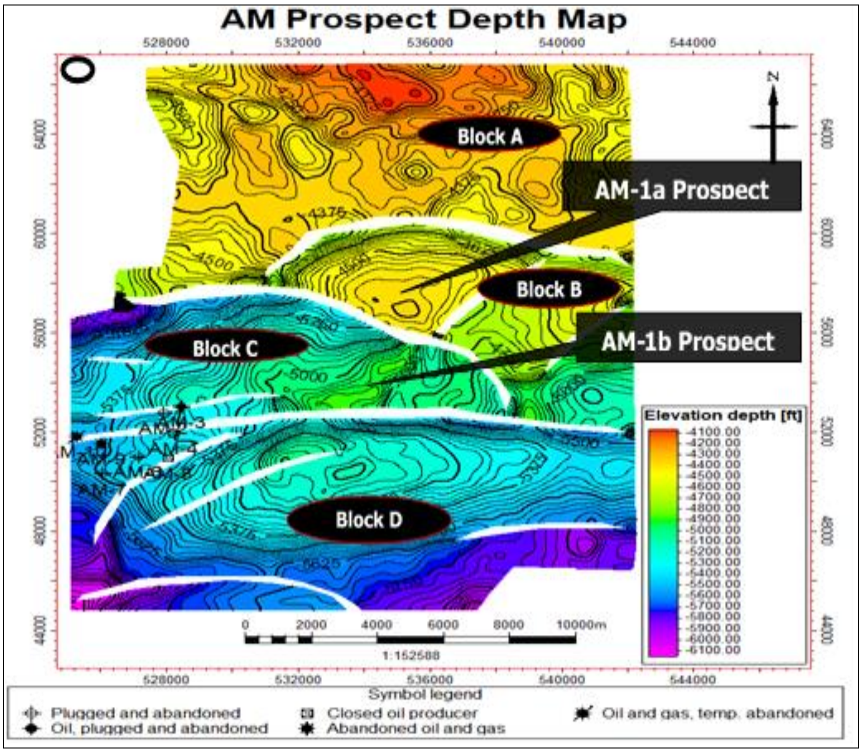


Fig 22b: AM prospect depth map

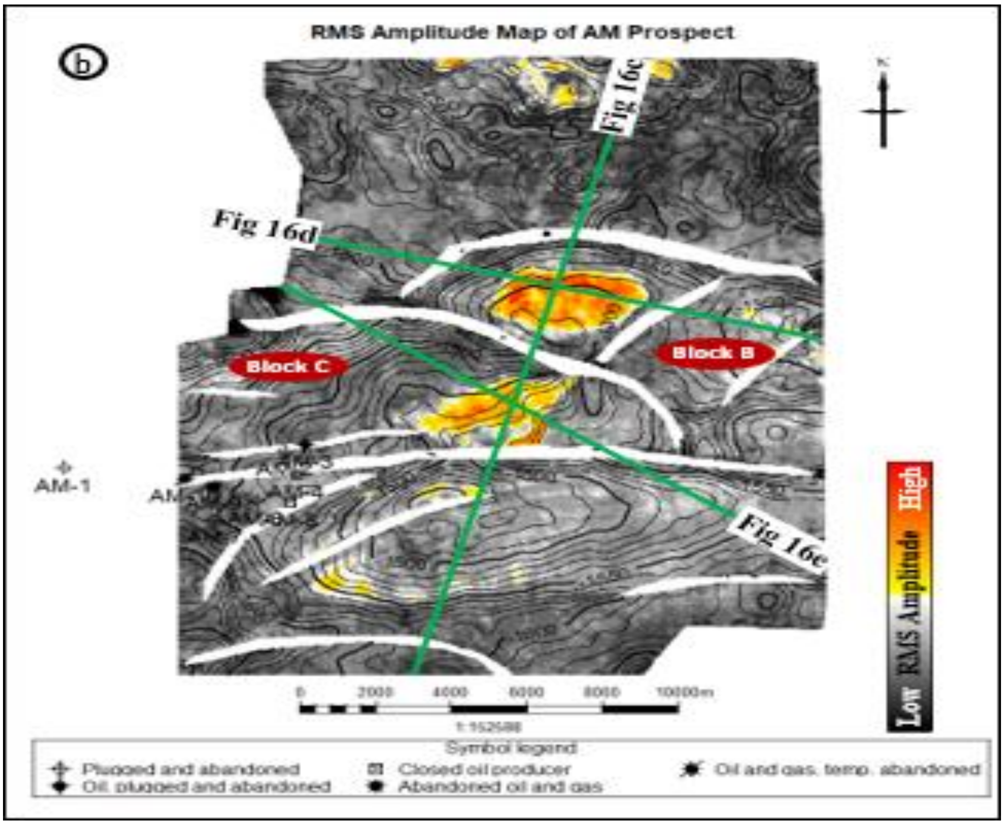


Fig 23: The root mean square amplitude map of AM prospect

Conclusion

This work provides a comprehensive framework for understanding reservoir distribution, hydrocarbon migration pathway and trapping mechanism using this combined approach. Ogbo field is influenced by relative sea-level changes, sediment supply and structural deformation which was interpreted in this work. The result of the structural interpretation of the seismic data revealed the uninterpreted seismic section at inline 7900 where presence of direct hydrocarbon indicators including flat spot, bright spots and dim spots stand out. Here, the seismic reflection terminations are indicative of faults. Similarly, in the results showed the interpreted seismic section at the same inline 7900. This was quality-controlled using the combination of seismic time slices, coherency cube generated from the seismic volume and variance cube from Petrel. The results showed horizon mapping of the bright spots named AM Prospect across the entire 3D seismic volume. Two reservoirs were mapped which are indicated by light green and yellow across the seismic time window and these horizons represent the top of reservoirs in the area. Over twenty-five normal faults were mapped across the seismic volume. Three major faults divided the field into four exploration blocks indicated as block A, B, C and D. The faults were identified based on the break in reflection events which could act as a migration pathway for hydrocarbon. The AM-Prospect (1a) is an anticlinal trap within block B. in anticlinal traps, the earth movement fold the horizontal rock layer into an arch shape. Here, the dim spots were observed away from the bounding faults which were interpreted as hydrocarbon saturated zones. Dim spots were also observed away from the bounding faults. Hydrocarbon migration is up-dip through the major faults. The localized higher amplitude zones suggest the presence of hydrocarbon charged reservoir while Amplitude variations within the amplitude maps suggest variability in the lithology. The variance (edge) attribute time slice at 1853ms showing interpreted faults and the subdivision of the blocks in plain view. Variance (edge) attribute time slices were used as a guide to interpreting the faults throughout the entire seismic volume along seismic inline which clearly shows zones of stratigraphic discontinuities. The biostratigraphic result shows the faunal distribution in Ogbo field and with Niger Delta chronostratigraphic chart, the age of the field was identified to be Miocene in age.

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