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# Direct Hydrocarbon Indicator Pitfall and Sand Development in Deepwater Environment-A Case Study of 'Oyo-Dw' Field Niger Delta, Nigeria

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**Abstract:** The high cost of deepwater developments and the limited reach from offshore platforms requires operators to have a good understanding of the sand development in delineating reservoir using Direct Hydrocarbon Indicator. A well "OYO"-10 was drilled with all reservoir levels predicted using Amplitude as Direct Hydrocarbon Indicator analysis draped on structural maps. The result came out with poor sand development in the well drilled and reservoirs appeared wet in contrast to the expectation of a prolific well. This study shows the complexity of Deepwater using "OYO" wells as a case study of why sand development needed to be investigated before interpreting Direct hydrocarbon indicators in deepwater environment. A 3D seismic dataset and geological data from OML 121 in Deepwater environment of Niger Delta was analyzed to assess and quantify the architectural elements that influence the compartmentalization of delineated reservoir units. The key aim of this study was to undertake a seismic-scale qualitative and quantitative analysis of the sand development of suspected reservoir units within the study area in Deepwater environment of Niger Delta using methodologies that can be applied to other continental margins worldwide. This study involved calibration of seismic-to-well tie, determination of spatial distribution patterns of submarine channels; establishment of hydrocarbon control; identification of various channel reservoir units and trapping mechanism over the prospect area. RMS Amplitude extraction was done which reveals that there are amplitude highs from the meandering X2 channel turbidities reservoirs while variance attribute identified major and micro channels within the study area.

**Keywords:** Niger Delta Deepwater, Seismic Attributes, SegY, Well Logs, Well Correlation, RMS Amplitude

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## 1. Introduction

In deepwater exploration a crucial, and arguably the most critical single issue, is whether oil has been generated, and if it has, what can be determined, before making costly decisions, regarding the quality, maturity, and the age of the source succession [9]. The sedimentary system of the deepwater environment till now is one of the least explored although the potential is huge [13]. As unexplored resources continually reside in deepwater which is difficult, further discovery and development gradually becomes costly, risky, and complex [2]. Deepwater sedimentation is an important factor in current oil and gas exploration. However, the study of its reservoir architecture models is lagged that of fluvial, alluvial, and deltaic deposits. [15] During the past decade, global exploration in deepwater setting has significantly increased, deepwater remains an immature frontier. Only about 25% of the discovered deepwater resources are developed and less than 5% have been produced. Most exploration activity has been concentrated within only three areas of the globe, with most of the discovered resources in the Gulf of Mexico, Brazil, and West Africa [11].

The main goal of hydrocarbon exploration is to recognize and define both structural and stratigraphic features that are commonly associated with hydrocarbon generation, deposition, migration, and entrapment [10]. With the choice of deepwater acreage continuing to attract large signature bonuses and with wells in some cases costing more than \$US50 million, a reliable means of exploring in deepwater is required. Whilst trap geometry details and reservoir horizons can be predicted from seismic with increasing degrees of confidence, no fail proof method exists for remotely predicting the composition of reservoir fluids and gases. Interpretation of seismic manually could be cumbersome and time consuming, therefore, to extract significant information and features from

the seismic data set, seismic attributes are employed to improve the accurate geological interpretation of the target horizons [3].

DHI is an anomalous type of seismic amplitude that may occur due to the presence of hydrocarbons. They occur due to change in pore fluids, which cause a change in the bulk rock's elastic properties. Seismic amplitude attributes may signify reservoir property variation to a certain extent, so seismic amplitude attributes are usually applied to qualitatively evaluate reservoir development [12]. Even though the DHI anomalies help interpreters make smarter decisions on prospect evaluation, DHI may also misguide exploration in several ways. It is well known that seismic amplitude anomalies can be caused by factors other than commercial hydrocarbons [8]. Some of such geologic conditions are: Low-saturation gas, clean blocky wet sand, low-velocity shale or marl and low-porosity gas sands can be interpreted as high-porosity oil sand.

DHI is an anomalous type of seismic amplitude that may occur due to the presence of hydrocarbons. They occur due to change in pore fluids, which cause a change in the bulk rock's elastic properties. DHI is used in hydrocarbon exploration wells, mainly to reduce the geologic risks. [16]

Examples of DHI are:

Bright Spots which are referred to as spots with a local increase of amplitude associated with hydrocarbon accumulations, Dim Spot which are caused by highly consolidated sands with much greater acoustic impedance than the overlying shale, Flat Spot that represents a hydrocarbon contact seismic response where it is apparently flat, Phase Change which is also known as polarity reversal and occurs when the overlying reservoir has a lower velocity of the reservoir rock. This can occur when a partially consolidated sand becomes wet and gas chimney that occurs when a defectively sealed hydrocarbon

nbuildupleaksgasfromadeeperlevelintothesubsurface, whichis usuallyalongafaultplane. BrightSpotTechnologyisamethodused to detectoilandgasaccumulatedintrapsbasedonrealamplitude, whichbecameanimportantorindispensablemeansinoil-gasexplorationwithgoodresultsinpracticalapplication[1]. The useofdirecthydrocarbonindicatorstopredictstructural, lithological, orcombinedtrapsisalsoanecessarythatcanbeusedtosolveexplorationproblem[18].

“OYO”10wasdrilledonthe fieldasanexploratorywellwithinthetheNorthwestblockofthefield, allreservoirlevelswerepredictedusingDirectHydrocarbonIndicatoranalysisdrapedonstructuralmaps. Electricloggingandmudloggingdataindicatedhydrocarbonlevelsafterdrilling, however, formationfluidsamplingsuggestthereservoirsarewetwithtracesofliquidhydrocarbondespitehighgasreadingswithgoodgaschromatographanalysis.

SeismicDirectHydrocarbonIndicators(DHI)amplitudeanom

alyhasbeenusedasatooltodiscovercommercialhydrocarbonaccumulationin“OYO”fielduntilthesedays. TheDHIanomaliesuchas: brightspot, flatspot, polarityreversal, anddimspotarecommonlyobservableinfield.

ThisDHIinadequacyphenomenaindicatethatthereareother aspectsneedto beaddressedwhenprospectingforhydrocarboninthefield“OYO”field. ThisstudyresultssuggestedthatDHIfeaturesarenotnecessarilyrelatedtoeconomichydrocarbonaccumulation. In1970, theseismicamplitudeforthefirsttimewasusedasatooltodirectly predictthehydrocarbonaccumulation. Itwasfoundthathydrocarbontraps couldbeassociatedwithbright-spotamplitudeanomalies. Theseamplitudeanomalies, laterknownasDirectHydrocarbonIndicators(DHI)weresuccessfullyusedinhydrocarbonexplorations. Nevertheless, somedrilledbrightspots showeddryholesinnumerouscases. [17]

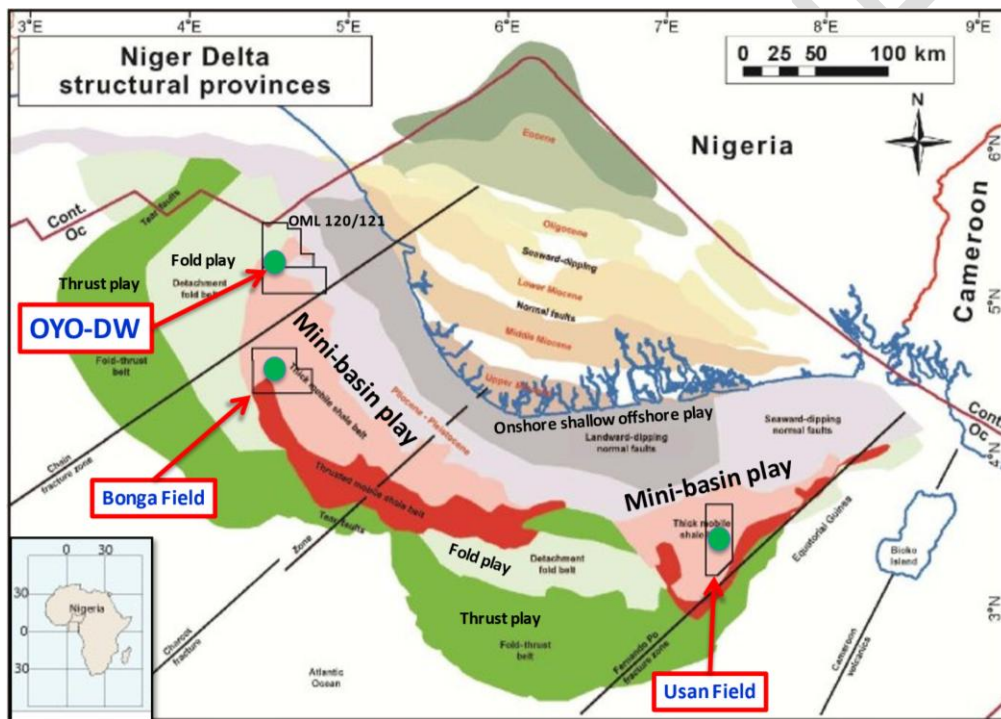


Figure 1. Deepwater Niger Delta Structural Provinces and Play Type Courtesy Weiner and Al 2010.

### Regional Setting/Geological Context:

The Niger Delta of Nigeria is located on the central West African coast within the Gulf of Guinea and is bounded to the west by Benin and to the east by Cameroon. The islands of São Tomé & Príncipe lie to the south. The Niger Delta deep offshore area may be arbitrarily subdivided into western and eastern components by a line running along the main distributaries of the Niger River and extending in a southerly-western direction into the Atlantic basin. The Niger Delta Basin is ranked as one of the most prolific deltaic systems in the world with respect to hydrocarbon accumulations or reserves [7].

The Niger Delta deep offshore basin can be divided into several hydrocarbon play segments of differing habitat styles. The study area is situated in the western part of the offshore Niger Delta, within the boundary of collapsed crest and shale diapir play segments. Diapirs and normal faults are the result of gravity tectonic processes driven by sediment loading occurring during progradation of the huge

Niger Delta sedimentary succession onto marine mobile and under-compacted shales during late Cretaceous–Paleogene (mobile shales).

The intermediate diapirs and faulting zone are contained within the inner extensional province on the continental shelf, characterized by both basinward dipping, regional and counter-regional growth faults, and the external domain at the lower slope; a detachment fold zone passing basinward to a fold and thrust belt.

The Tertiary reservoir of the Niger Delta offshore are turbidites deposited within the shale-prone Akata formation, and they are of Miocene to Pliocene in age. Turbidite reservoirs are recharged by hydrocarbon expelled mainly by early Tertiary mobile shales.

## 2. Location of the Study Area

The Oyo Field is located offshore Niger Delta in OML 120 approximately 75 km from the Nigerian coast at an average water depth of

about 350m. The Oil Mining License (OML) 120 is bounded in the north by Agip's OML 125, west by Esso's OML 133, south by OML 121 and on the east by Cavendish's OML 110 and Chevron's OML 89. OML-120 is an eight-sided elongated block with a total area of 910.05 km<sup>2</sup>. Water depths range from 200m to 900m, increasing from the NE towards the SW corner.

The field was discovered with Oyo-1, the first well drilled in the field in 1995 and followed by Oyo-2,-

3 & 4 drilled between 2006 and 2007. Oyo-2 and 3 found oil/gas in the Oyo West area, while Oyo-4 appraised the Oyo central discovery. Oyo-5 and 6 were drilled as producers into T1 A reservoir in Oyo Central and Oyo West respectively during 2008 and 2009. Oyo Far East is yet to be tested. Also the deeper Miocene prospects in OML 120 remain largely untested. This OML is within the Niger Delta depositional system, the deep water play types drilled were quite different than anything known on the Nigerian shelf onshore.

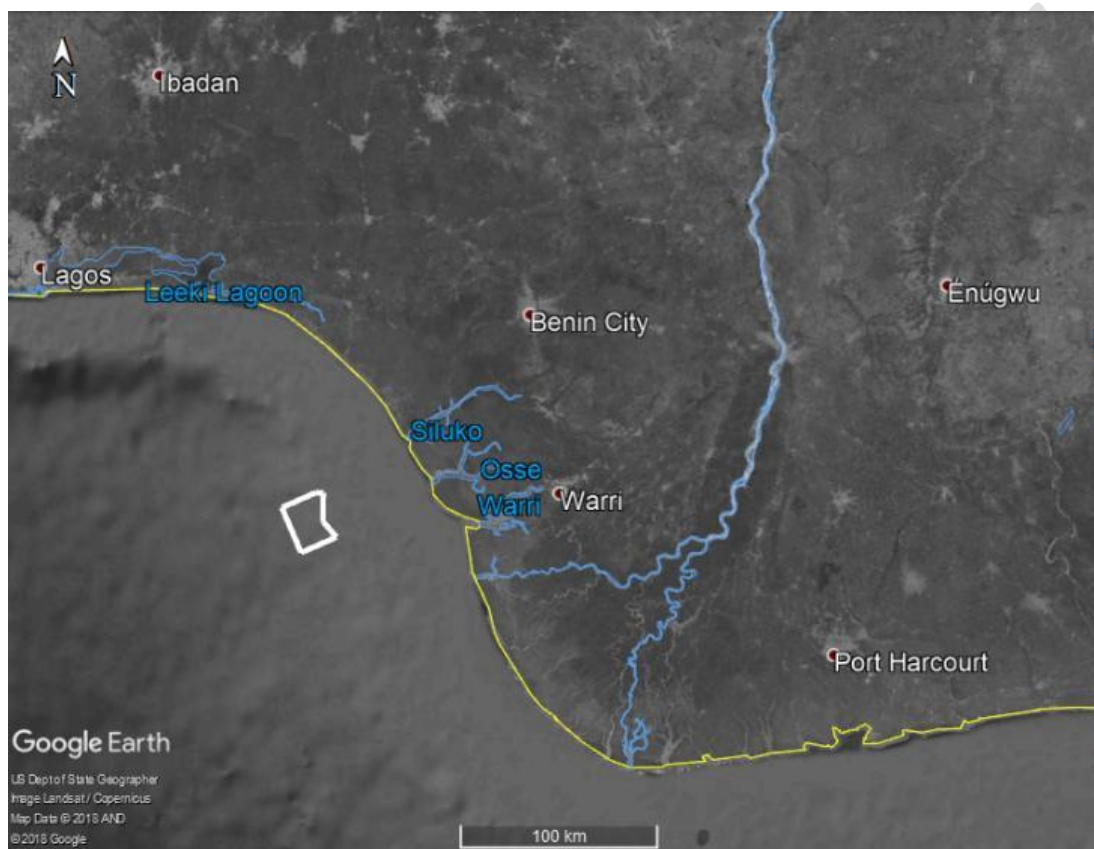


Figure 2. Map of Niger Delta Showing the study area.

### 3. Materials and Methodology

Available data include, 3D seismic data, checkshot for the wells, deviation surveys, well logs in LAS file format and biostratigraphy data. Petrel interpretation software was used for this work.

Intra-reservoir shaly intervals have also been proven to be effective reservoir rocks. Trap formation in the area is mainly due to diapir uplift in combination with stratigraphic components. (Figure 3) Turbidite deposits onlaps synsedimentary growing diapirs and drapes the same when sedimentation can compensate topographic relief, with

annular lobes systems continuing the down-dip flank of the diapir. Major sediment thickness is recorded within inter-diapir depocenters, indicating ponding effect within this portion of the slope. Genesis of major clastic sediment fairways, by which turbidite sediments are distributed throughout the continental slope to the basin plain, are likely linked to recurrent collapses of the shelf margin. Shelf margin disequilibrium and collapse phenomena are triggered by phases of rapid progradation occurring during the falling limb of relative sea level change.

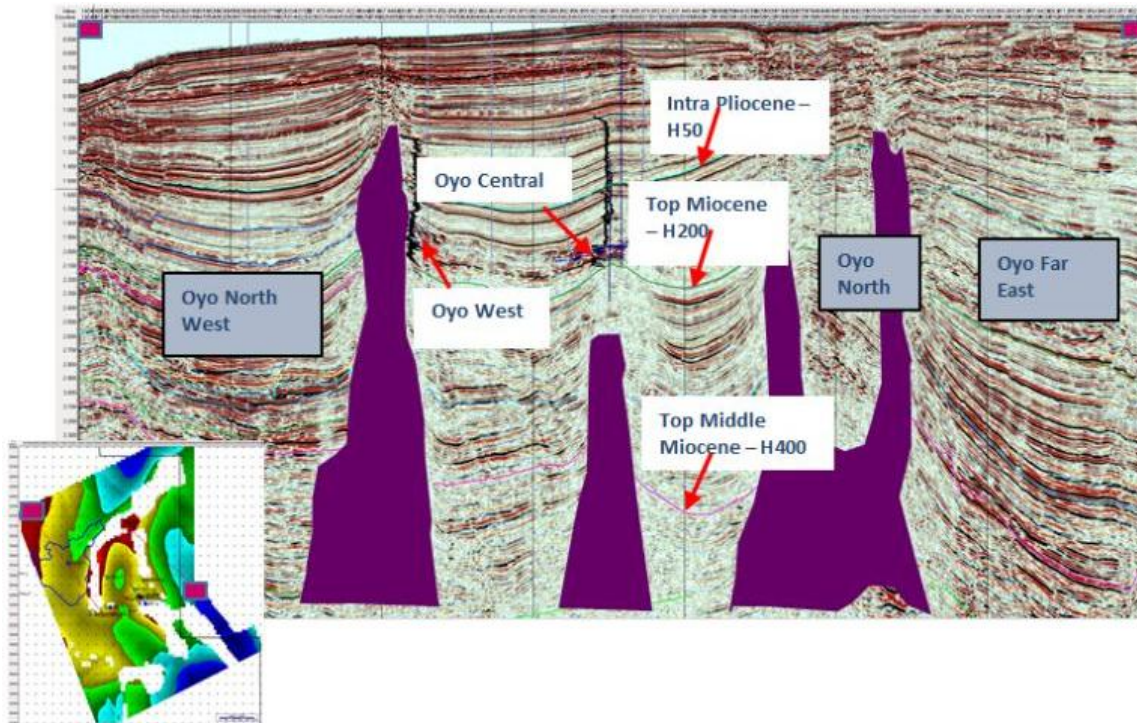


Figure3. Arbitrary Lineshowing OyoNW, Oyo field & prospects with Shale Diapir Intrusions.

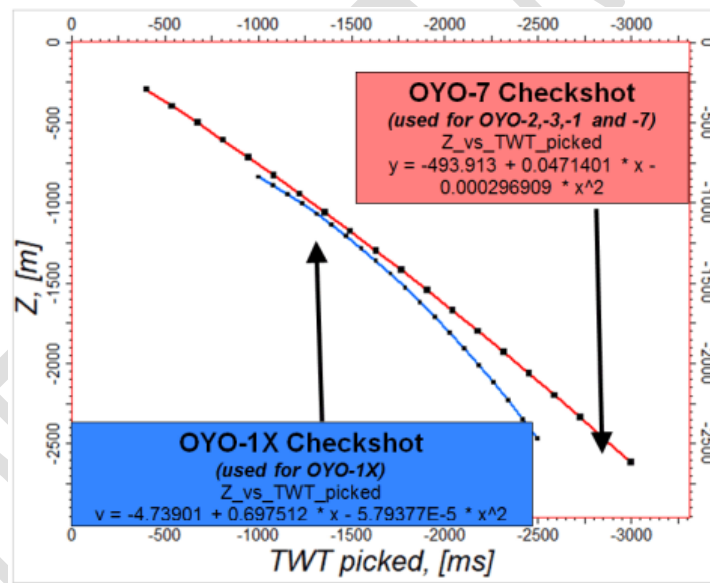


Figure4. Plot of Checkshot versus Depth plot OYO7 and IX.

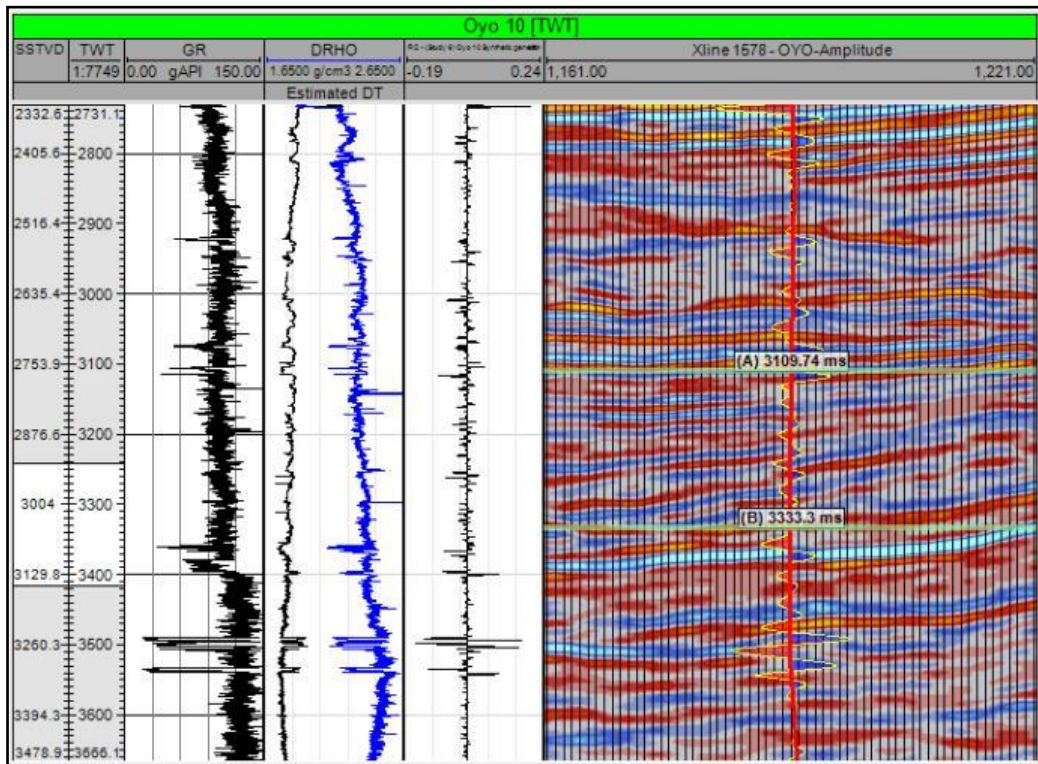


Figure 5. Synthetic Seismogram Generation.

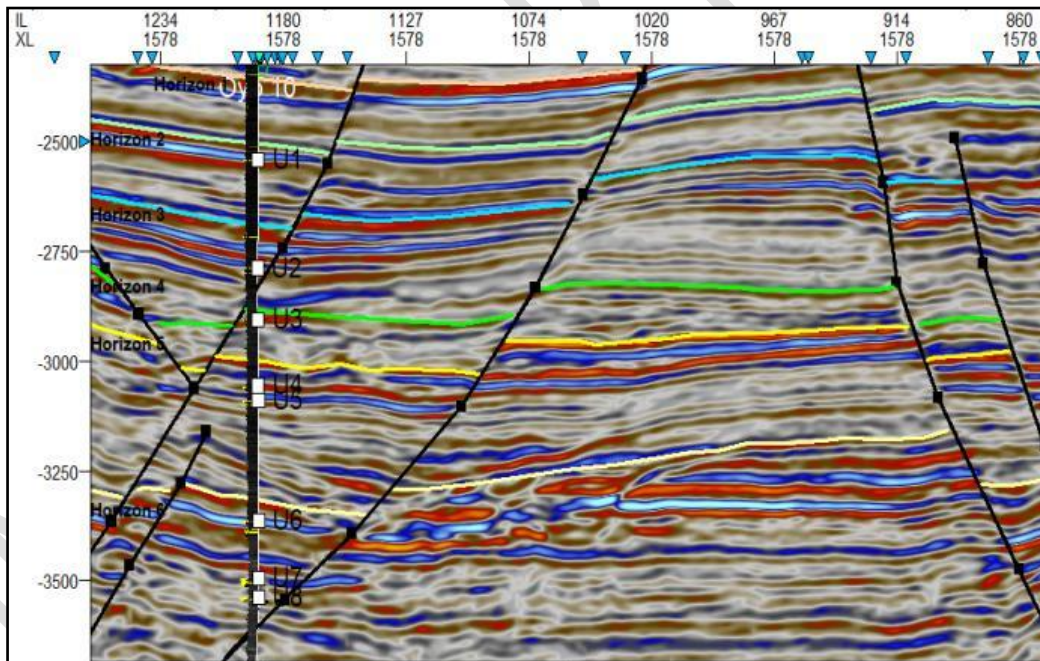


Figure 6. Welltop to seismic match.

Objective of well to seismic tie is to correlate the geological information in the well log data with the seismic information. The well to seismic tie focused on the targeted interval and synthetic seismogram used as the correlation tool to tie geological information to accurate depth [14]

Checkshot surveys are used to correct the velocities obtained by the integration of the sonic interval transit times. The adjusted sonic

was then used for translation of surface seismic time to depth and in the calculation of formation acoustic impedance necessary for the generation of a synthetic seismogram and eventually seismic to well tie was done. The checkshot generally follows the same trend indicating that there are no significant lateral variations in seismic velocities across the field even if depth of acquisition in Well 10 was shallower than that of the offset well 7.

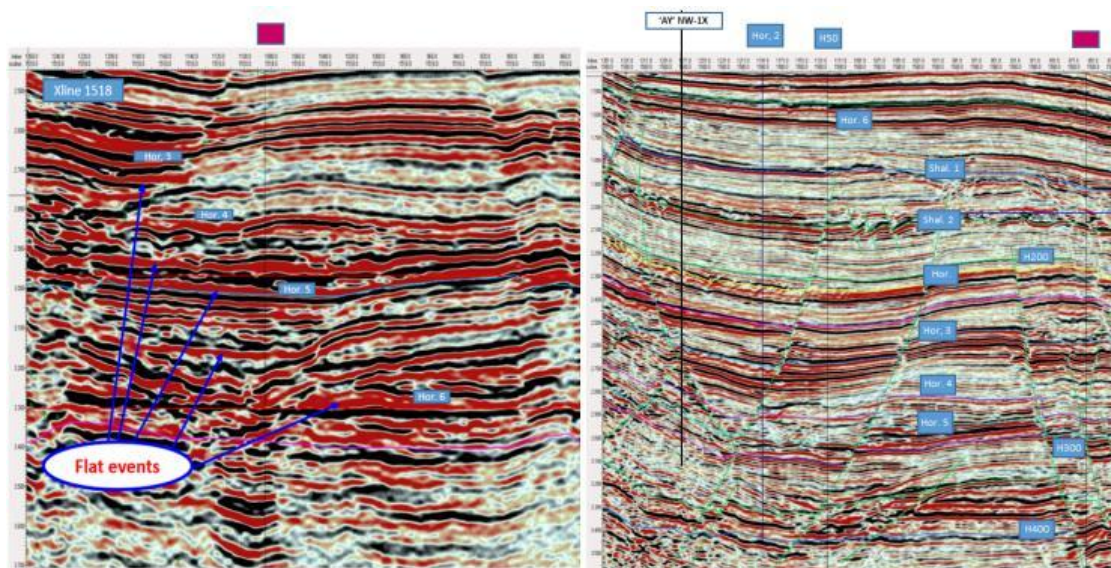


Figure 7. Seismic section with flat events (DHI) observed at all levels.

Although most reflections mark unconformities and/or timesurfaces, fluid contacts within porous permeable rocks provide acoustic impedance contrast that cut across the bedding. These are responsible for flatspots, one of the most important hydrocarbon accumulation indicators. Acoustic impedance contrasts can be caused by

emical or phase changes. Flatspots were visible on these seismic sections (Figure 7) however, the results after drilling proved that the flatspots could be due to some reasons other than hydrocarbon accumulation.

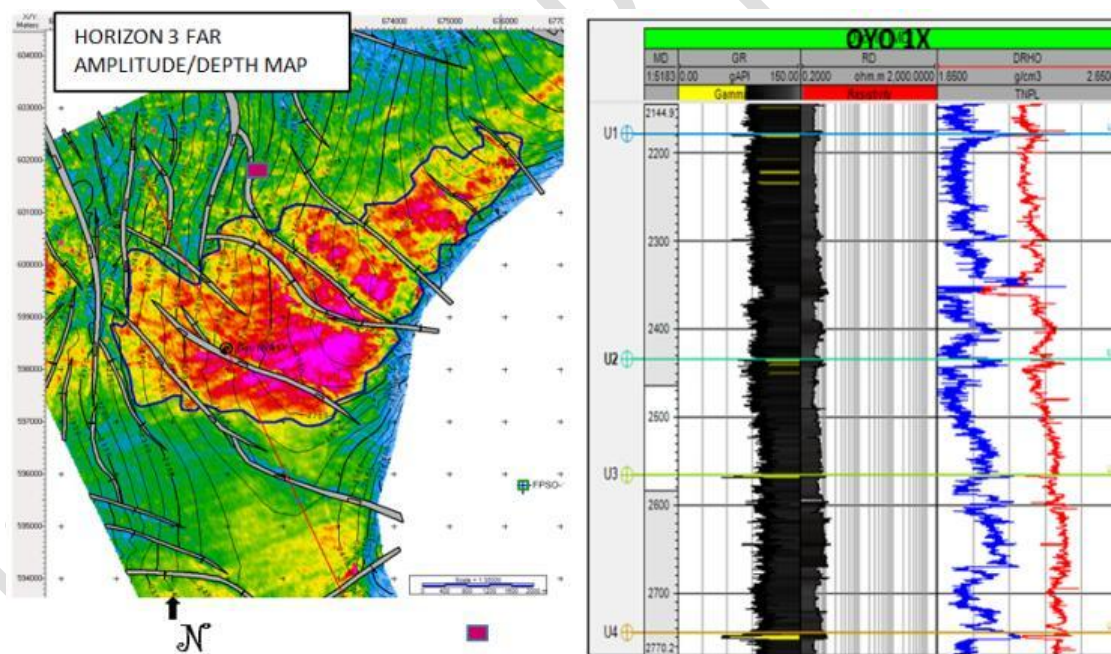


Figure 8. Interpreted horizon 3 amplitude extraction with the result of well log with poors and development.

Hydrocarbon accumulations are sometimes revealed directly on true-amplitude seismic sections by localized zones of anomalous strong reflections known as bright spots. These high amplitude reflection events are attributable to the large reflection at the top and bottom of gas zones within hydrocarbon reservoir. In contrast as shown in figure the sand development came out poor after drilling despite high amplitude observed on the horizons.

## 4. Results and Discussions

Two major reservoir units were observed in the study area; these are named as X2-Channel compartment which is the central portion of the field and the North West block. The X2-Channel compartment is characterized by meandering channels which are turbidite reservoirs. All oil and gas producer wells were observed to be located in this compartment: wells 1, 2, 3, and 7 are located within the X2-

Channel reservoirs whereas Well 1X was located on the floodplain at the Northwest part of the block. (Figure 9)

### CHRONOSTRATIGRAPHIC CORRELATION

WELLS		COMPARTMENTS
OYO-10	structure	Floodplain (outside channel axis)
OYO-2 & 3	Stratigraphy	Channel-B
OYO-1 & 7	Stratigraphy	Channel-A

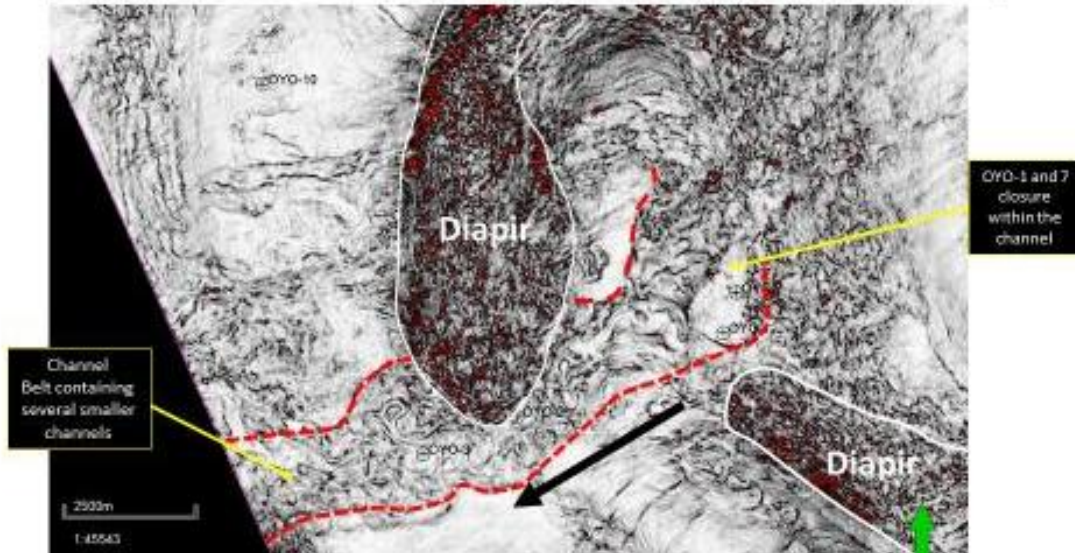


Figure 9. X2 Channel showing producing wells within the channels OYO 10 located on the Floodplain.

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# U-1 STRUCTURE MAP: OYO-COMPARTMENTS & PROSPECTS

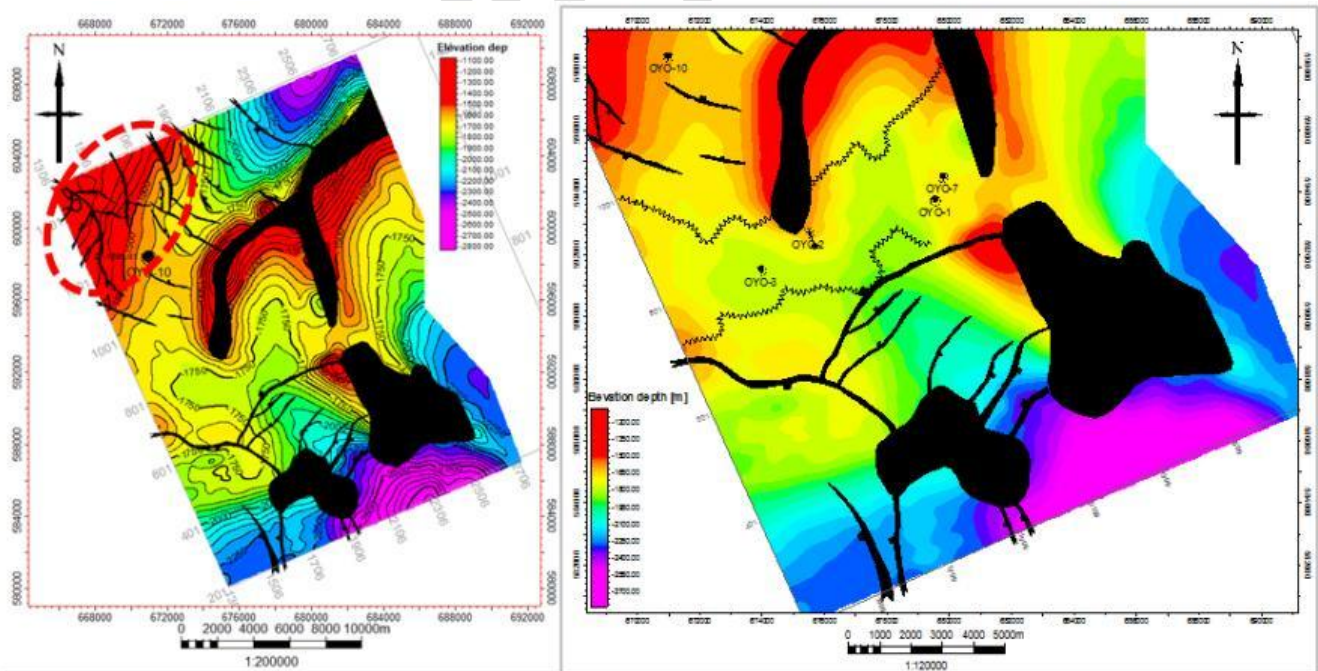
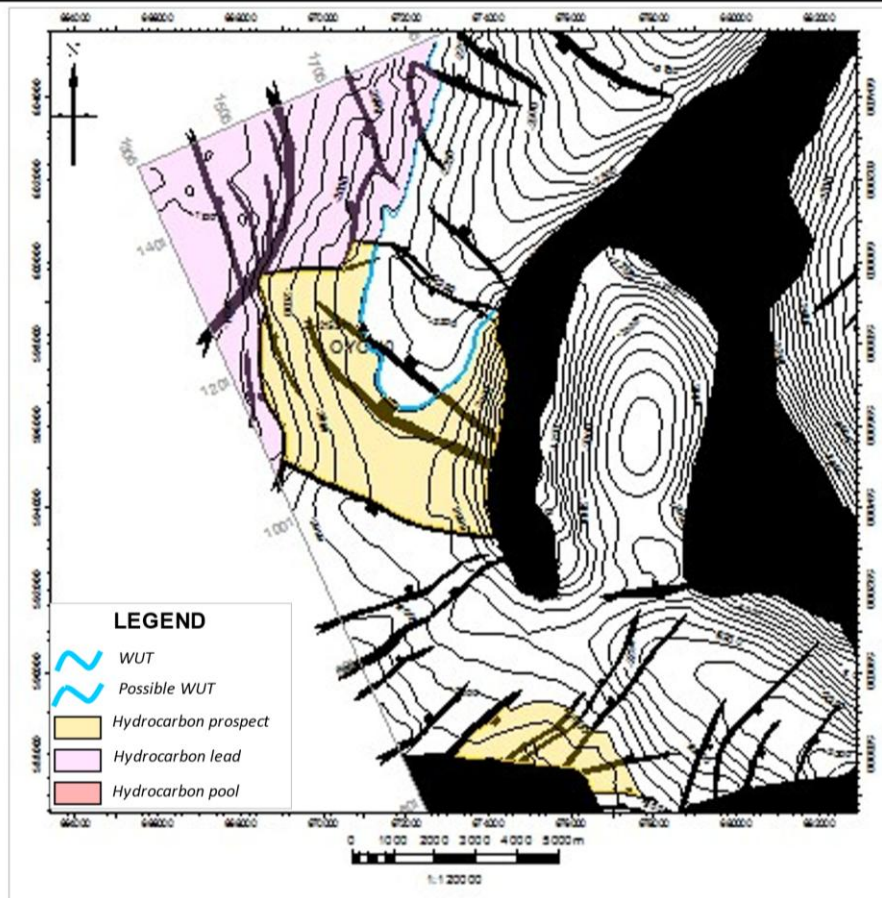


Figure 11. X2 Channel Trap Mechanism.

## 6. Amplitude Analysis

Seismic attribute analysis is significant in interpretation for oil and gas exploration and exploitation for both stratigraphic and structural interpretation [4]. These attributes are derived

from seismic data to better understand the physical properties of sedimentary strata [4]

RMS amplitude extracted that covers X2 channel reservoir units which encountered wells 1, 2, 3 and 7 as well as the location of well 10 was done using -60/+60ms and -30/+30ms. The amplitude extraction was done to cover the entire re-

servoir in the study area. The result of this shows better sand development within the X2 Channel reservoir which is conspicuously absent on well location area (Figure 12). In general, better sand development is observed within the X2 channel which is turbidite reservoir sand progressively reduced towards the southern part of the study basin but very visible in the North West area where Well 10 was located.

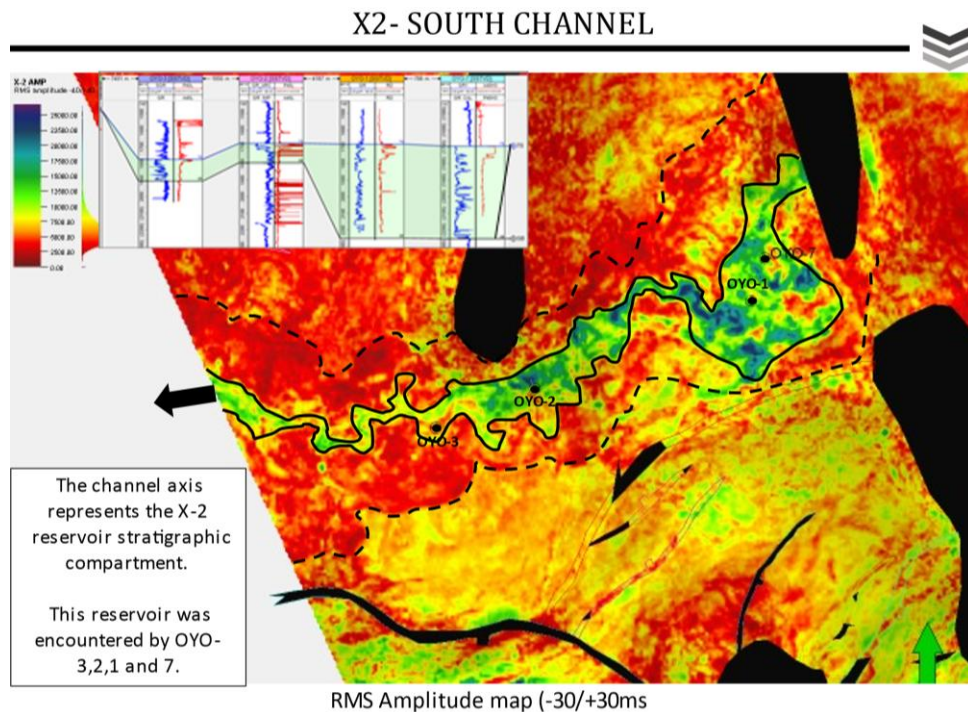


Figure 12. RMS Amplitude map showing X2 sand development (-30/+30ms).

## 7. Conclusions

The study shows that are both structural and stratigraphic traps within the study area. The major oil producers in the study area (X2 channel) are mainly turbidite reservoirs with good sand development.

It was observed from RMS amplitude extraction that this sand reveals the true amplitude which is because of the hydrocarbon content of the reservoirs. The initial amplitude anomaly observed on well 10 could have been caused by factors other than commercial hydrocarbons like low-velocity shales in the sand development in the area is poor according to Mike Forrest.

## 8. Recommendations

More studies should be carried out to establish if there are other hydrocarbon bearings and other than the turbidite channel reservoir in the area.

In deep water environment, sand development studies should be carried out first before amplitude extraction analysis to ensure that the amplitude observed corresponds to the reservoirs sand. The geology of the area is a -vis environment of depositions should be well studied to aid the interpretation for hydrocarbon accumulation.

Even though the DHI anomalies help interpreters make smarter decisions on prospect evaluation, DHI may also misguide exploration in several ways as observed in this study therefore, it is very important to have a systematic and consistent work process to interpret

and risk seismic amplitude anomalies and there should be multiple positive anomaly characteristics to have a high probability of geological success.

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