

Structural Interpretation, Trapping Styles and Hydrocarbon Potential of Block-X, Northern Depobelt, Onshore Niger Delta

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ABSTRACT

Detailed structural interpretation was carried out on the three fields within Block-X with the aim of better understanding the structural evolution, trapping styles and the influence of the fault system on the facies distribution within the Block. Well correlation was carried out on six wells to map potential reservoir intervals, which in turn were tied with seismic for horizon and structural interpretation. Structures interpreted include listric growth faults, roll-overs, synthetic and antithetic faults. The faults showed a dominant NW-SE trend, and the variance attribute also validated the interpreted fault trend. Impact of a mobile clay substratum was more noticeable around 'FLO' and 'A' Fields around the Upper Eocene to Lower Oligocene strata of the Agbada Formation. Four-way closures dominate 'OGEY' Field, the traps on 'FLO' Field are fault assisted while 'A' Field at best have some good leads which given some more control on the seismic acreage and possibility of good prospects. The facies model showed minor shale content localised at the western part of the Block with good reservoirs and some silty sand making up the remaining Block. The fault system of the Block was not observed to have any significant effect on the facies and property distribution. The fluid contact model revealed communication across the fields and the reservoir is not compartmentalised. This integrated approach in determining the hydrocarbon potential of Block – X, Northern Depobelt of Niger Delta reduces the effect of under estimation and over estimation of hydrocarbon –in – place volume, thus assisting in well planning and input into running Petroleum economics.

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Introduction

The key to obtaining structural information in a highly petroliferous basin such as Niger Delta requires an integrated approach involving the use of wireline log, seismic expressions and biostratigraphic data. This allows for high resolution study that allows correlating specific reservoir sands and accurate reservoir model especially at reservoir scale. In order to maximize the benefit from the integrated approach, an understanding of the tectonic influences and depositional systems that occurred within the area of the seismic survey to be investigated is important so as to generate structural maps. This allows for insight into the types of structures, faulting and stratigraphic geometries that may exist and the subsequent interpretation consistent with regional tectonic forces and basin infilling.

Objectives

The objectives of the study include: Establish rock packages deposited at a particular time period for proper understanding of relative sequence of deposition and the time domain.

Determine the local geology from the subsurface images by mapping faults and other structural features to examine elements of the hydrocarbon systems. Retrieve valuable information from electrical logs, including rock type, porosity and presence of oil, gas or water for possible volume quantification / reserve calculation. Establish a quick pixel model for possible facies and rock property distribution on the hydrocarbon bearing sand for possible development purposes.

Location of the Study Area

The study area is located in the Northern Delta Depobelt of the Niger Delta (Figure 1). The study area, for proprietary reasons, is named Block X and consists of three Fields-OGEY, FLO and A Fields with six representative wells namely: FLO-1, OGEY-1, OGEY-05, OGEY-06, OGEY-08 and A_05 (Figure 2).

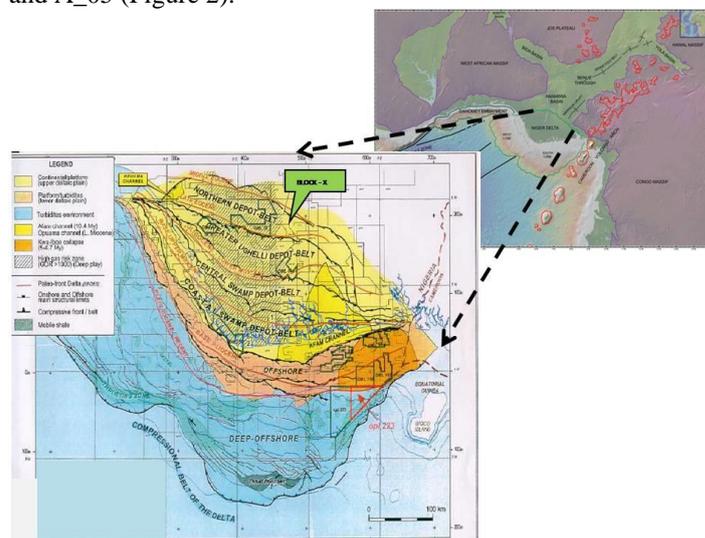


Fig 1: Regional setting of Nigeria Basin and Niger Delta Depobelts (modified after ¹).

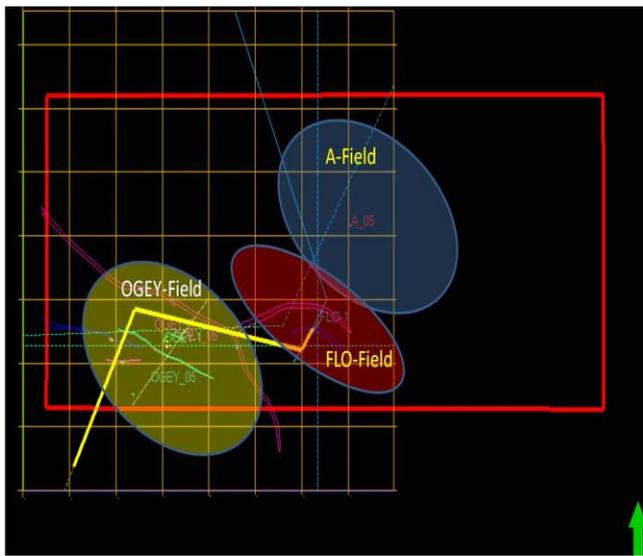


Figure 2: Base map of Block X showing the positions of the Fields and Wells

Geology of the Study area

The geology of Niger Delta basin has been widely studied mostly by oil and gas exploration and production companies and academia because of its economic importance as a petroliferous province. According to [2] and [3], the Niger Delta consist of a regressive sequence of deltaic and marine clastics defined by three major lithofacies at the base of the marine shale, made up of Akata Formation, followed by paralic sequence of Agbada Formation using lithological characteristics and other sedimentary features and grouped them into five major lithofacies formation and the topmost non-marine alluvial continental sands of the Benin Formation and submarine parts of the modern delta. The lithofacies are grouped into sandstone heteroliths and mudstones. [3] recognized 6 Depobelts in the Niger delta, which are distinguished primarily by their age and regional bounding faults. They are the northern delta (late Eocene – early Miocene), greater Ughelli (Oligocene – early Miocene), central swamp I (early – middle Miocene), central swamp II (middle Miocene), coastal swamp I and II (middle Miocene) and Offshore mega structure (late Miocene). [4] established an integrated framework of the Niger delta slope by applying the concept of sequence stratigraphy on the newly acquired seismic data set of the Niger delta coupled with biostratigraphic data from 26 key wells.

Methodology

The approach employed in this study involved wireline log interpretation of six (6) wells which include well correlation and identifying variations in lithology, well log analysis to determine rock properties (net – gross, porosity and fluid content). Seismic interpretation was carried out which involves structural mapping, establishing seismic to well tie for onward horizon mapping and generating both time and depth structure map using convergent interpolation algorithm on the Petrel platform. Variance attribute, a volume attribute, was run on the seismic volume and time slices were studied to validate the trend of the interpreted faults.

Standard Petrel workflow for producing static models (Fig. 3) was followed to generate the facies and property models of the hydrocarbon-bearing reservoir by reviewing of lithofacies and petrophysical data available from well logs and seismic data. Pixel-based modeling was done using Stochastic Indicator simulation algorithm for the facies and Stochastic Gaussian simulation algorithm for the property models

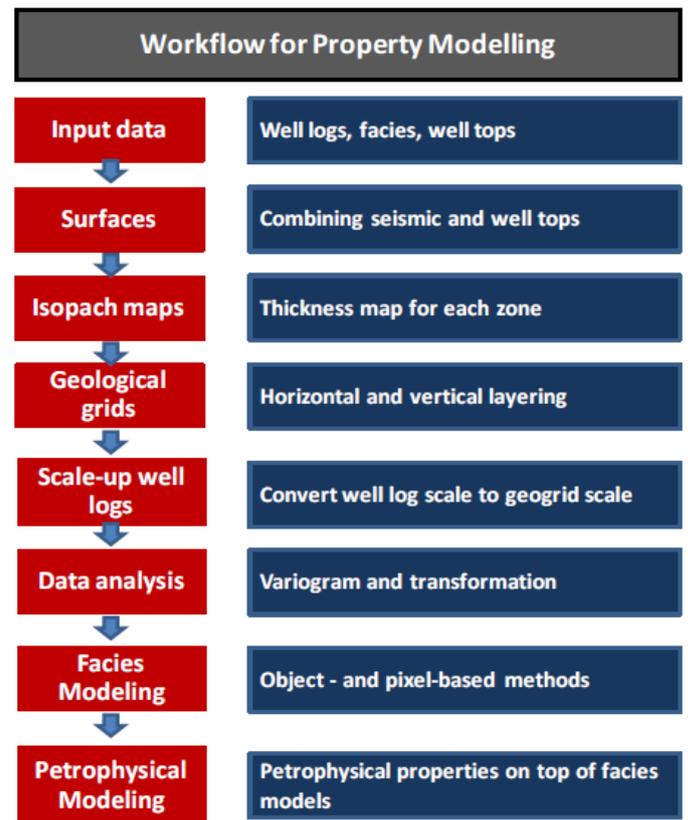


Figure 3: Workflow for static modeling.

Results and Discussion

Wireline interpretation

Well correlation

The quality-assured and quality-checked logs were correlated to establish potential reservoir intervals in the block as well as the continuity of the sand bodies. The biostratigraphic data available were analysed and posted on the logs, some of which fall within shales, and corresponding shales were used to delineate different reservoir sand bodies (Tops and Bases of the sand). Log motifs of corresponding wells were correlated. Lithologic variation, sand body's development and hydrocarbon bearing sands were identified. Fig. 4 shows the result of the well log correlation across Block-X.

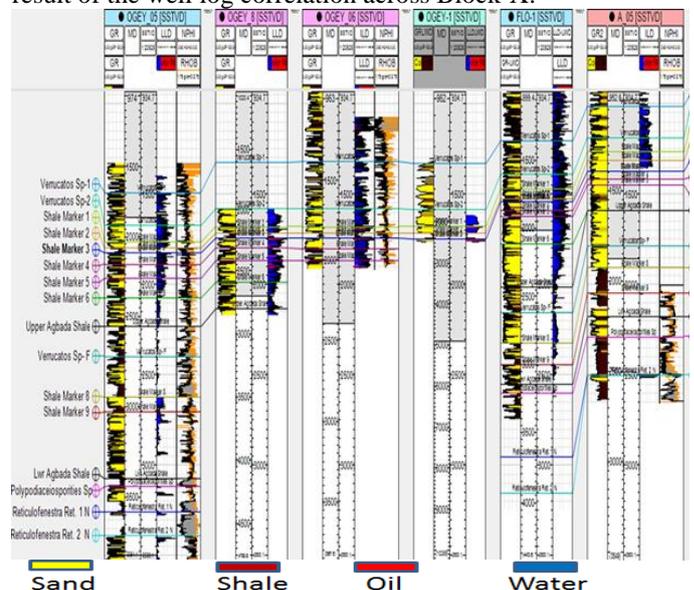


Figure 4: Well Correlation of all the available wells in Block-X.

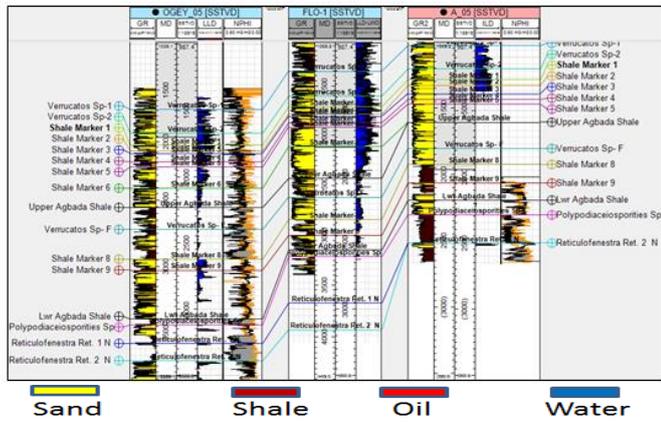


Figure 5: Well Correlation of deepest wells in each field in Block-X.

Key strata surfaces in biofacies, well logs and on seismic were used to determine correlatable surfaces. However, at the reservoir scale, beds with distinct features were correlated with high degree of confidence between wells and supporting seismic events on such markers.

The hydrocarbon reservoir interval for OGEY-1 & OGEY-6 lies within the Basal Benin formation (Transition Benin) deposited in continental to transition environment of Early Miocene age as also confirmed from the biostrat analysis done on OGEY-1. The hydrocarbon interval here falls within 1680 – 1770m TVDSS, quite a shallow well as shown in Fig. 4. The hydrocarbon reservoir interval of OGEY-1 and OGEY-6 lies within the basal Benin Formation (Transition Benin) deposited in continental to transition environment of early Miocene age as confirmed from the biostratigraphy result done on OGEY-1. The hydrocarbon interval here falls within 1680 – 1770m SSTVD, quite a shallow well as shown in figure 6. The reservoir sands are blocky to slightly serrated, Net – To – Gross (NTG) range from 80 – 95% sandstone and approximately 20m thick. The logs typically reveal shoreface to channel sand.

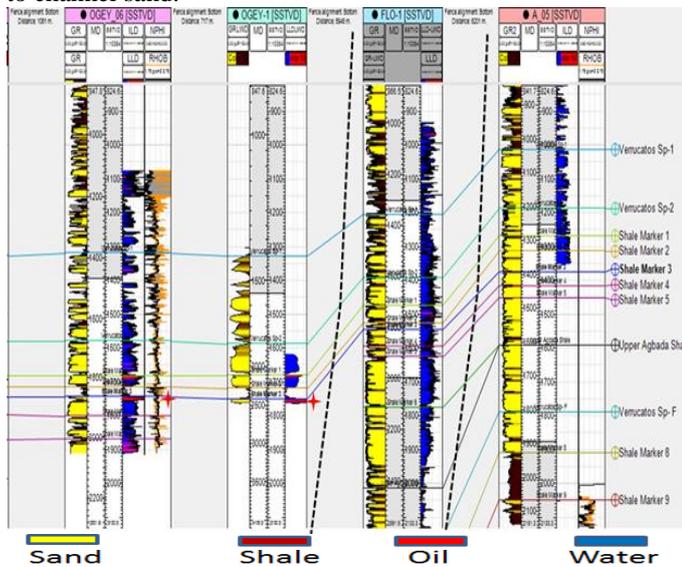


Figure 5: Well Correlation of deepest wells in each field in Block-X.

Seismic interpretation

Structural interpretation

Faults were interpreted within the seismic volume. The faults were picked on the dip lines and names were assigned to each of the interpreted faults.

Within Block-X are growth faults, roll over, listric faults, synthetic and antithetic faults (Fig. 7). The interpreted fault patterns were supported with variance attribute as seen in (Fig. 8).

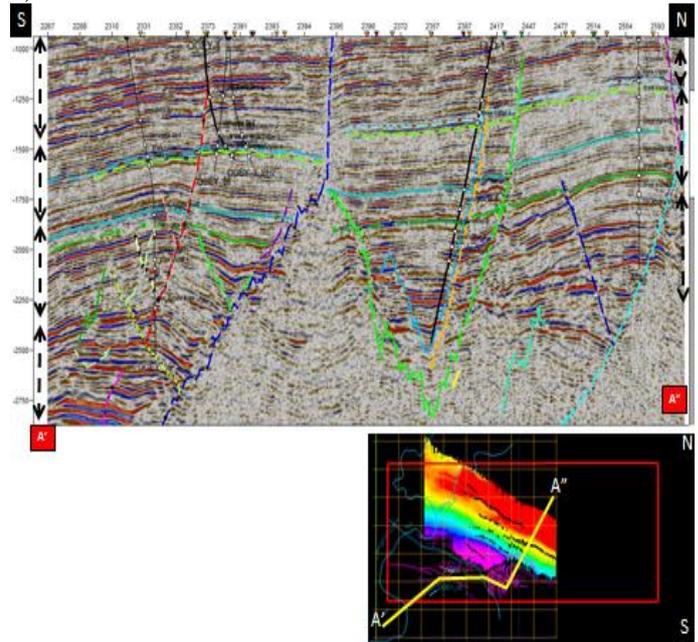


Figure 7: Interpreted faults across Block-X. (Inset shows an interpreted horizon and an arbitrary line A' to A'').

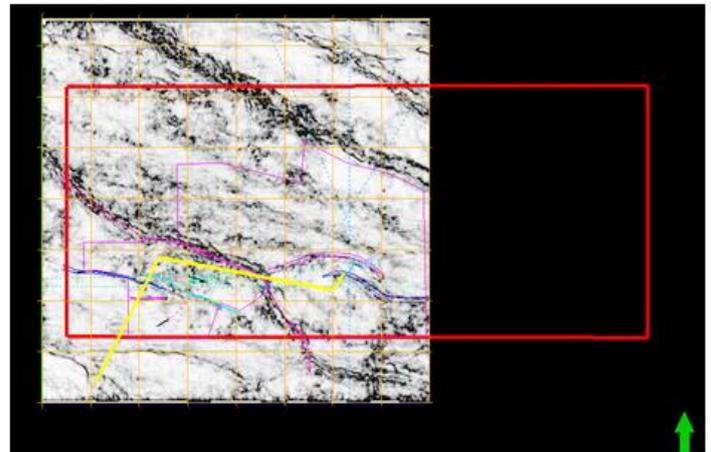


Figure 8: The Variance attributes supporting the interpreted fault pattern Seismic-well tie.

Checkshot survey acquired in drilled OGEY- 6 was used for generating synthetic seismogram which was used to tie the well to seismic. Fig. 9 shows the synthetic seismogram in OGEY-6 which was drilled in the northern part of OGEY-Field. A good match of the synthetic with the real seismic was achieved and picking of top shallow series (SM-3) hydrocarbon sands was greatly enhanced. OGEY-6 T-Z function was extrapolated so as to place markers and easy correlation with offset wells. Hence, reservoirs below the Upper Agbada shale series which are located at much greater depths compared to the shallow series sands were identified on the seismic. This served as a useful guide in correlating wells on seismic. Based on the synthetic process, the key seismic reflectors which correspond to markers and reservoir sands were identified on seismic data for mapping.

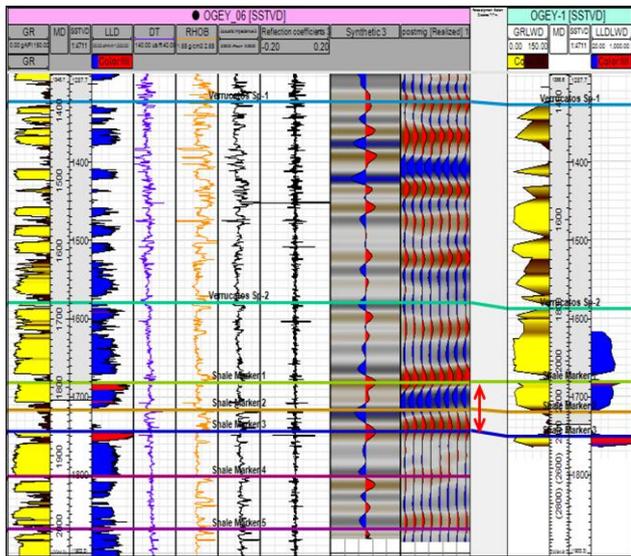


Figure 9: The synthetic seismogram in OGEY-6 which was drilled in the northern part of OGEY- field.

Shale Marker 3(SM-3) Time Structure Map

Time interpretation was carried out on shallow series sand (shale marker 3- SM-3) in the shallow levels and the Upper Agbada Shale. This shale marker gave a broad picture of the lateral extent of the cap rock for the deeper series sand body. Although identified markers below this series seem difficult mapping across a fault block, it confirms the possibility of the sand body not being laterally extensive. Hence, few sand bodies were mapped on field basis.

Checkshot was not acquired on FLO well; hence near SM-3 marker was interpreted.

This horizon was interpolated to generate the time structure map shown in (Fig. 10).

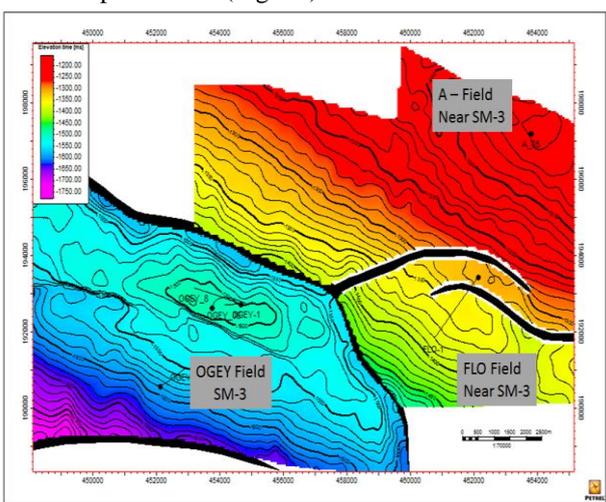


Figure 10. Shale Marker 3 Time Structure Map

Checkshot data was utilized for OGEY field time depth conversion. Two shallow sand reservoirs occur in the Transition Benin Formation (SM-1 and SM-3) and this interval represents the shallowest hydrocarbon potential as established from OGEY- 1 and 6 wells. The single average time-depth function (Fig.11) was used, the resultant depth map (Fig. 12) showed a reasonable match in areas around the wells. As evident, the structure is a simple anticline partially depending on the fault, trending in NE- SW direction.

Single polynomial function had been used in the depth conversion method. The depth map shows a simple anticline dip closure with partial roll over as seen from the maps and typical on Niger Delta structural style.

The generated depth structure map is then well tied to the available wells as represented in (Fig.16) below.

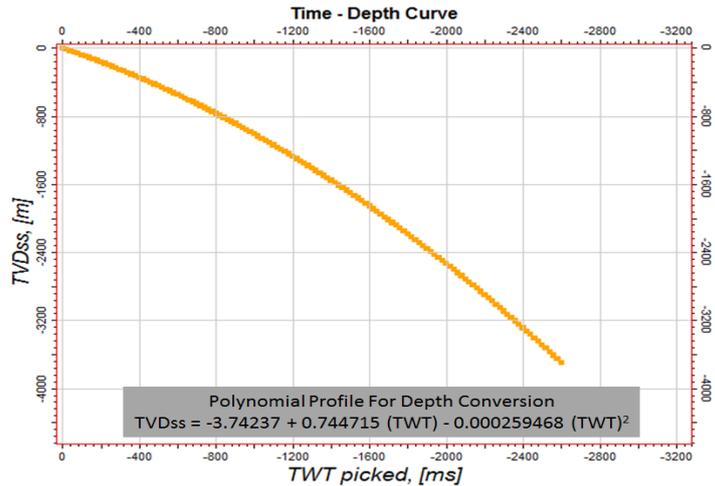


Figure 11: Showing Polynomial Profile use for Depth Conversion.

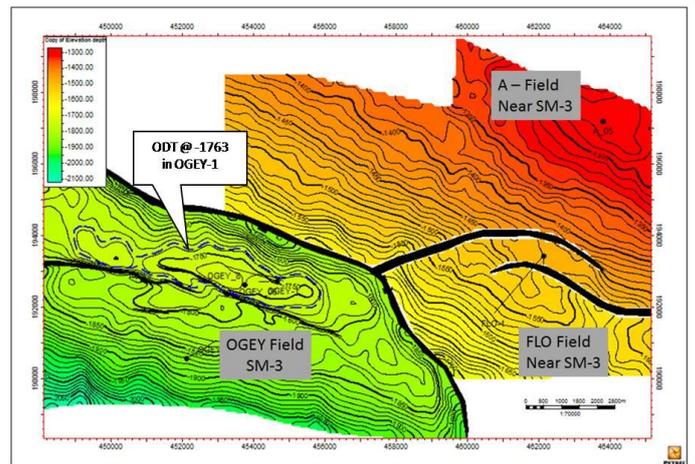


Figure 12: The depth structure maps of SM-3 using a single time-depth polynomial function calculated from well tied checkshot in OGEY-6.

In OGEY-6, oil-down-to case (ODT) was encountered at - 1763 m SSTVD in shallow sand (shown in blue contours on the map). However, the fluid contact depth -1763m SSTVD is then posted on the depth structure map as seen in Figure 13 below showing Oil-Down-To as seen from the correlated wells. This was then used to estimate the GRV (Gross Rock Volume) of the SM-3. Therefore SM-3 GRV= 80m³

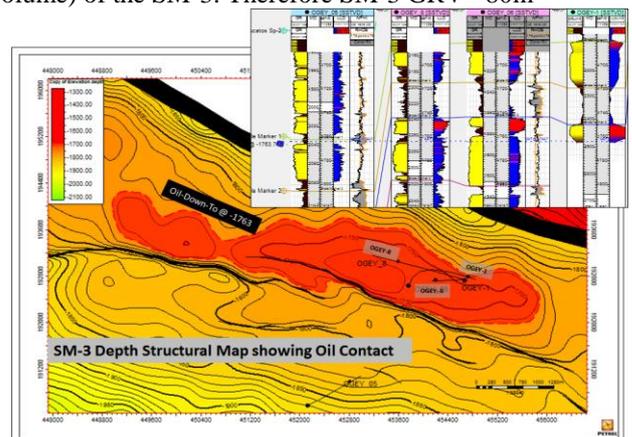


Figure 13: SM-3 depth structural map showing oil contact.

The final depth map after tying to the wells served as input for building the static models.

Static geological model

In view of the necessity to arrive at the production behaviour, it was necessary to build a static model that represented as closely as possible the subsurface reality of the shallow sand that were encountered by the wells.

First in order to characterize the reservoir, there is the need to establish a structural / stratigraphic correlation, identify appropriate tie between well tops and grids (Fig.14), zonation of the reservoir units also developing appropriate depositional and diagenetic model for the reservoir unit. This was achieved by integrating all available data from the four wells.

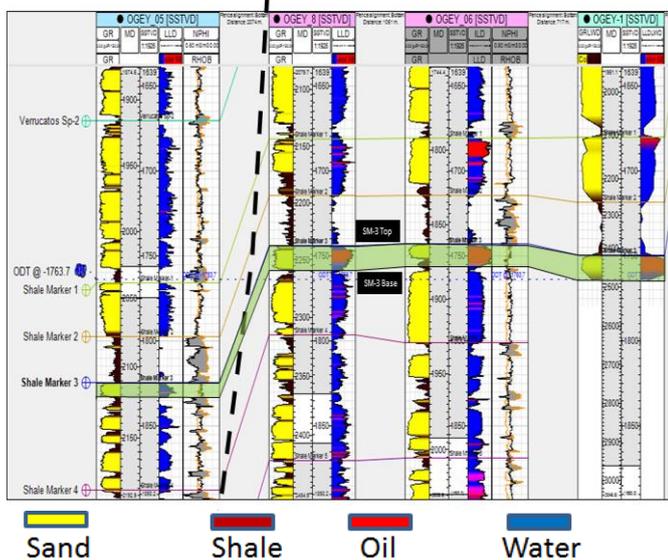


Figure 14: Established structural /stratigraphic correlation, an appropriate tie between well tops and grids.

The static geological model of shallow hydrocarbon bearing sand in OGEY field in transition paralic formation was built by integrating relevant sub-surface data such as: 3D seismic structural interpretation (Top & Base), interpreted fault polygons from seismic, lithological descriptions and facies interpretation, porosity, permeability, volume of shale and initial water saturation from log analyses (petrophysical logs) from the available wells were primarily used to build the static model.

The faults have been modelled mainly from the input fault polygons based on interpretation for structural model (Figs 15 and 16). The areal dimension of the grid cells has been optimized at 50 x 50 m, considering the reservoir description in hydrocarbon bearing shallow sand modelled. The grid was oriented parallel to the main northern bounding fault. The 3D static model contains 260,040 cells with the number of cells in the x, y and z directions of 132 X 97 X 10. Since it is ‘oil down to’ situation, proportional layering was used as to capture equal layer thickness from the top of the reservoir to the base (Fig. 17).

The layering is considered optimal because the mean thickness of the layers in each unit captured the entire reservoir sands and interbedded shales, thus ensuring that the layering scheme is fine enough to capture the heterogeneity if present, in lateral extent, although the heterogeneity in the sands is minimal.

Further, the mean thicknesses are less than the vertical variograms that have been derived from the well log data.

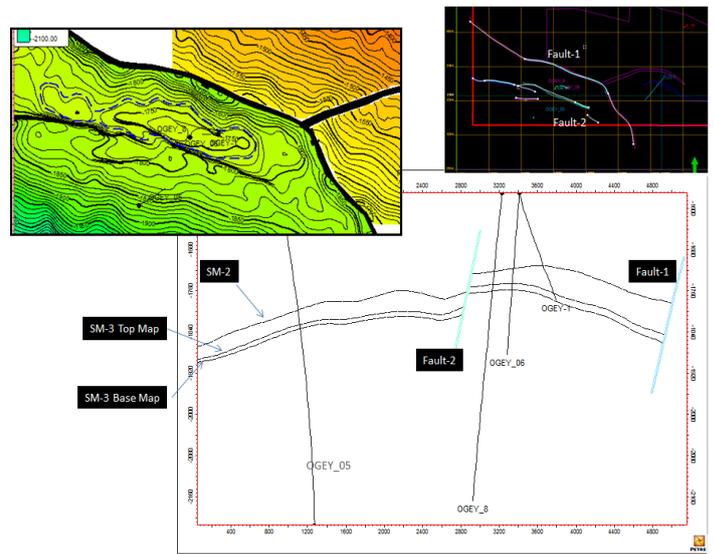


Figure 15: Section view showing Input for Structural modelling. Top/Base Depth Structure map and Fault Polygon.

Structural Model

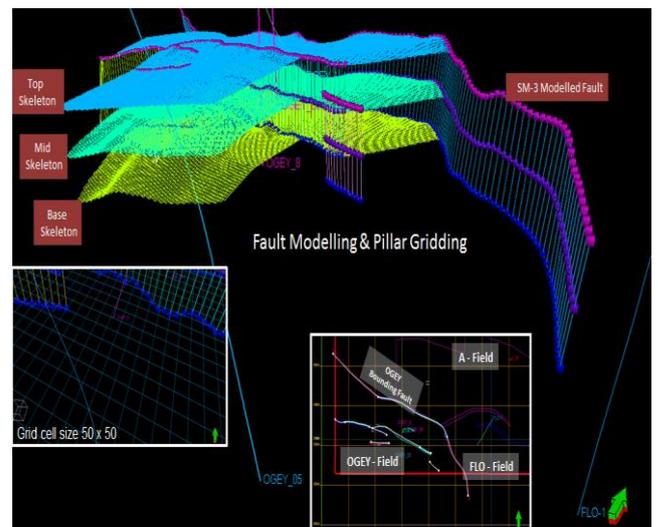


Figure 16: 3-D view of components of geological framework.

Structural

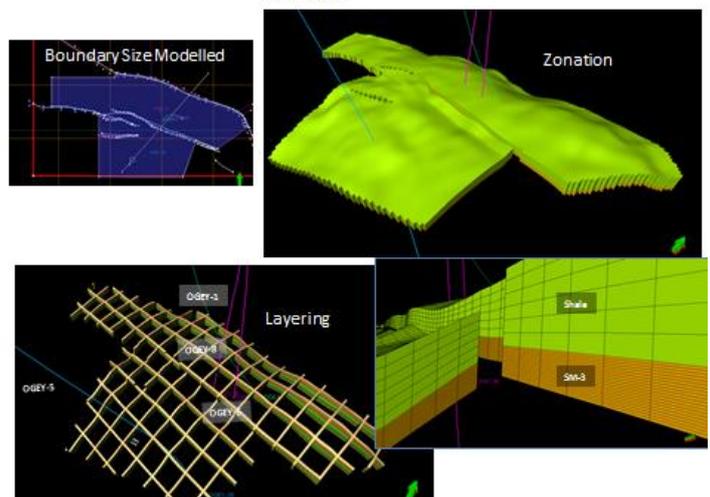


Figure 17: 3D grid zonation and layering.

Facies model

A pixel-based modeling technique was adopted for the shallow reservoir units in OGEY Field. Sequential Indicator Simulation (SIS) technique was used for Modelling. SIS is a stochastic modeling technique whereby the result is dependant upon, upscaled well log data, defined variogram, random seed, Frequency distribution of upscaled data points, or Trends in 1, 2 or 3D. The method allows easy modeling of facies environments where the facies volume proportions vary vertically, laterally, or both. Facies associations have been coded at the wells based on the available log data (primarily GR) in wells.

The petrophysical non-reservoir facies was determined with GR >75 API Units. The reservoir facies has been further divided into Good, Moderate & Shale (Figure 18) reservoir facies based on GR distribution. A 3D perspective view of the facies model of individual reservoir facies is shown in figure 20

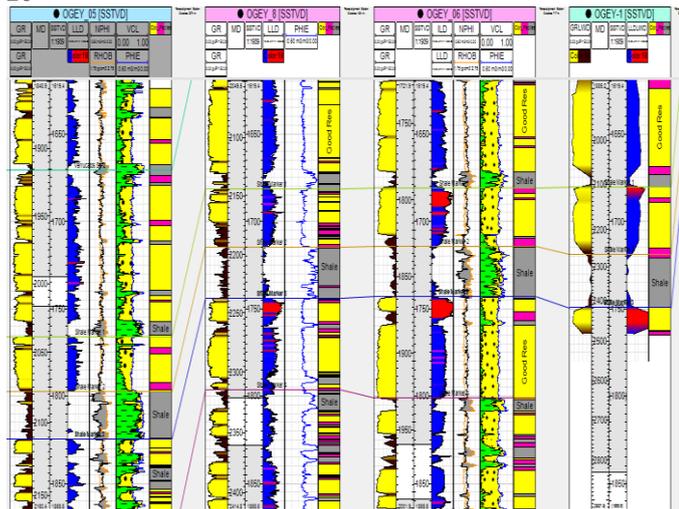


Figure 18: Petrophysical review for facies distribution.

Porosity modelling

The porosity model is based on the porosity logs provided for the wells used for the study OGEY-5, 8, 6 & 1. The logs were upscaled to the layering scheme using the facies as a controlling bias that ensures that the porosity is appropriate for the facies property of the cell. The porosity has been distributed in the model using “Sequential Gaussian Simulation” (SGS) that is conditioned to the facies model for the shallow reservoir units. Exponential variograms have been used for each facies depending on the facies.

A 3D perspective view of the porosity model in individual reservoir units are shown in figure 20. The distribution shows a dominant frequency of the porosity is 25-30% which is in consistent with the data inputs from log.

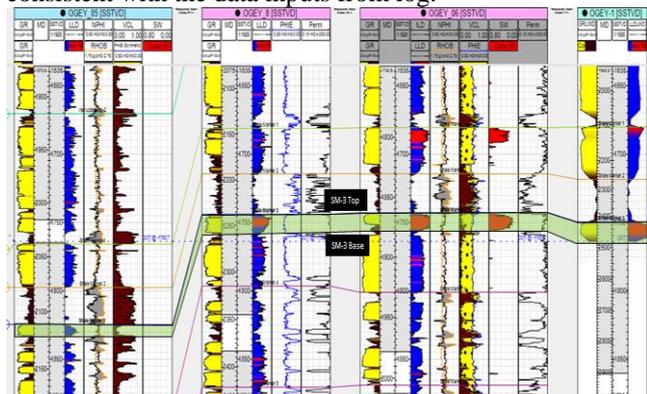


Figure 19: Input data for static property model, Raw Logs and Petrophysical data.

Permeability modelling

The permeability model is based on the permeability logs provided for the wells used for the study OGEY – 5, 8, 6 & 1. This effective in-situ permeability has been distributed in the static model using Sequential Gaussian Simulation conditioned to the facies for shallow sand.

A permeability cut-off of 200 mD has been applied to the model, consistent with the log observation. Permeability model conditioned to the respective facies and respective porosity as a secondary variable. A 3D perspective view of the permeability model in individual reservoir units are shown in fig. 20. The dominant frequency of the permeability is 2-4 Darcy for the shallow sand, which is consistent with the input data from log.

Saturation modelling

In the absence of core data, a deterministic average water saturation which is derived from petrophysical log using Waxman Smith equation[] was used. A saturation function equation derived was used in populating water saturation model (Depth (m) SSTVD Vs Sw plot). Saturation value of 27% is used. The model captures the input parameters from the petrophysical analysis. It is very evident from fig. 20 that the log and modelled reservoir parameters are in consistency with the above mentioned parameters.

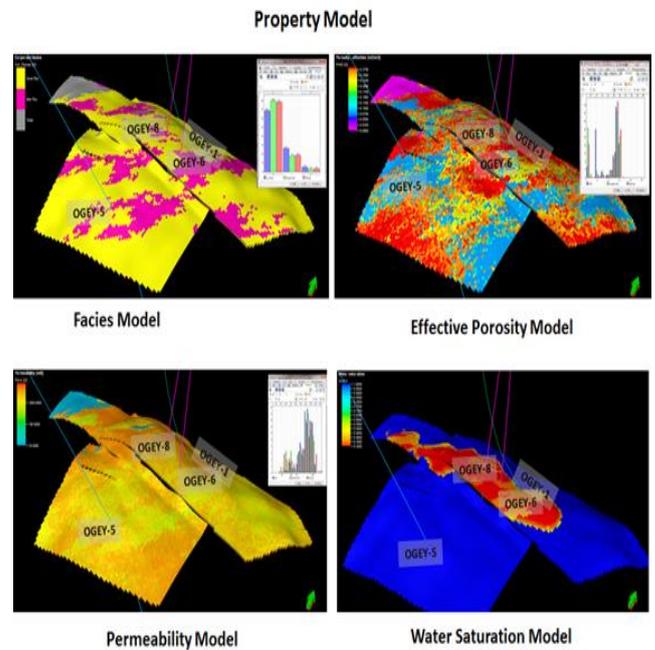


Figure 20: Facies and property models of SM-3

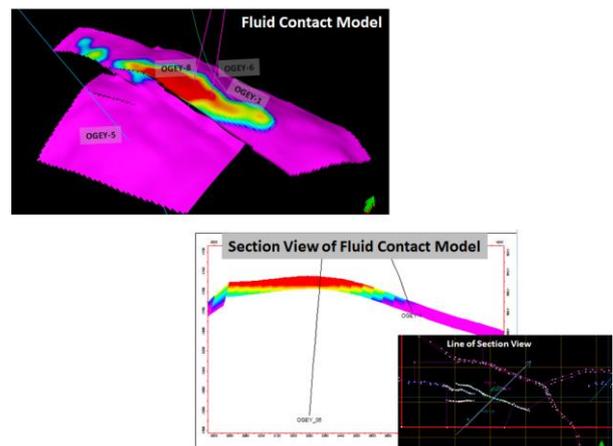


Figure 21: Fluid contact model of SM-3 Hydrocarbon in-place estimation

Hydrocarbon-in-Place Estimation, a realistic estimation of the STOIP for the shallow reservoir in OGEY field. The estimates were made based on the static model built within Petrel Software. Structural, facies and property models are inputs to the volume estimation and the formation volume factor defines the stock tank oil in-place.

Net Volume = Bulk Volume (GRV) x Net-To-Gross.

Pore Volume = Net Volume x Porosity Model

Hydrocarbon –In-place Volume = Pore Volume x Hydrocarbon Saturation.

Stock Tank Oil Initial In-place = HCPV /Formation Volume Factor Stock Tank Oil Initial In-place for SM-3 = 69.8×10^3 MMbbls

Conclusion

The well logs correlated from A-field, FLO-field and OGEY- field showed sediment prograding from proximal to distal. The structural well correlation shows a trend towards the south of the depobelt, revealing better reservoir quality on proximal positioned wells and reduced rock property towards the distal wells, hence improves recognition of reservoir architecture, description and depositional styles. Arbitrary seismic line confirm the prograding nature of this sediments, thereby sediment seen on A- field are structurally shallower as compared to the lateral equivalent Formation on the OGEY – field wells.

Well tie done using the available check shot data helped in determining the integrity of seismic – well calibration, stratigraphic and facies classification. Although large hydrocarbon reserve have been proven to be in the Agbada formation, however reservoir studied occur shallower, in the transition Benin Formation. This showed good lateral extent, good sealing capability of about 30m shale thick above the hydrocarbon bearing sand. Structural interpretation shows good roll over structure on the hanging walls prospect observed on OGEY- field. Well logs analysed showed hydrocarbon was observed in SM-3 of OGEY-field, this steered the building of a simple 3D pixel model for the SM-3 sand, coupled with available petrophysical logs. This approach enable the estimation of probabilistic hydrocarbon – in – place and not to use the average rock property to determine volume, which either over estimate or under estimate volume in place. Hence, the 3D spatial model takes cognizance of facies variation and property (effective porosity, permeability & water saturation) heterogeneity within a rock volume as it is in reality. The final reservoir model derived from the workflow presented was a success; this is attributed to the tight integration of the disciplines and data types involved. Integrated approach in determining the hydrocarbon potential of Block – X, Northern Depobelt of Niger delta reduces the effect of under estimation and over estimation of hydrocarbon –in – place volume, thus assisting in well planning and input into running Petroleum economics.

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