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Petrophysical Evaluation and Volumetric Estimation of Hydrocarbon Reserves in Otio Field, Niger Delta

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Abstract: This research presents a comprehensive petrophysical evaluation of the Otio Field, located in the onshore Niger Delta Basin, with a focus on characterizing hydrocarbon-bearing reservoirs. A multidisciplinary approach was employed, integrating well log data and seismic interpretation to analyze key petrophysical parameters across five hydrocarbon-bearing horizons (Sands D, E1, E2, H, and J). The petrophysical analysis revealed porosity values ranging from 18% to 27%, water saturation between 20% and 31%, and Net-To-Gross (NTG) ratios of 59% to 96%. These parameters were used to evaluate the reservoir quality and hydrocarbon potential of each horizon. The structural framework of the field was also evaluated, with 16 faults mapped, including major trapping structures F6 and F7. Time and depth structure maps were generated for each horizon, enabling accurate volume estimations. The results indicate that the North-Eastern prospect is the most promising, particularly in Sand E2, which exhibits the highest hydrocarbon volume in place. This study provides valuable insights into the petrophysical properties of the Otio Field reservoirs, offering a basis for prospect ranking and guiding future exploration efforts.

Keywords: Petrophysical analysis, volumetric estimation, hydrocarbon reserves, well logs, seismic interpretation.

Introduction

Geologic traps are the geologic reservoirs, i.e., any set of combinations of rock structure that will prevent the escapes of oil and gas either vertically or horizontally (Obiekezie and Bassey, 2015). Stratigraphic traps are not rare in the Niger Delta fields, most of the traps are structural traps (Tuttle et al.1999). Oil and gas exploitation aims at recognizing and defining these traps as they can be exploited profitably and defining the scope of the discoveries during field appraisals and field development (Nyantakyi et al., 2013).

In this research on-shore Niger Delta, three Dimensional (3D) seismic data was used with the help of well logs to define geologic structures and prospects at Otio Field. Most of the traps in the Niger Delta are structural (Obiekezie and Bassey, 2015). These structural traps include rollover anticlines, faulting-related and shale dome flanks. The discovery and correct categorization of these traps as prospects is the foundation of the additional exploration and economic decision. Otio Field is located onshore Niger Delta Field (Fig. 1) due to proprietary reasons and confidentiality agreement with the data, exact location of the field cannot be provided.

Reports have been made that thick sands do not necessarily contain economic accumulation of hydrocarbons compared with some thin sand with economic viability. This can be attributed to the trapping mechanism responsible for the accumulation. These tarps can be subtle but complicated making them challenging to map. There is therefore the need to properly identify and delineate structural traps and prospects in a field for exploratory purposes.

This study covers formation evaluation of Otio Field, structural and stratigraphic seismic interpretation, volume estimation of hydrocarbon in-place, identification and ranking of prospects. The workflow steps will be presented in the order as they are performed to enhance the full understanding of this report.

Engineering data derived from the integration of measurements from tests conducted at reservoir conditions, such as Drill Stem Test (DST) and pressure data are not available for this project. Other input engineering data such as Repeat Formation Test (RFT) are not available. The absence of these data from the field is a major uncertainty in the study as there are necessary for fluid contact determination.

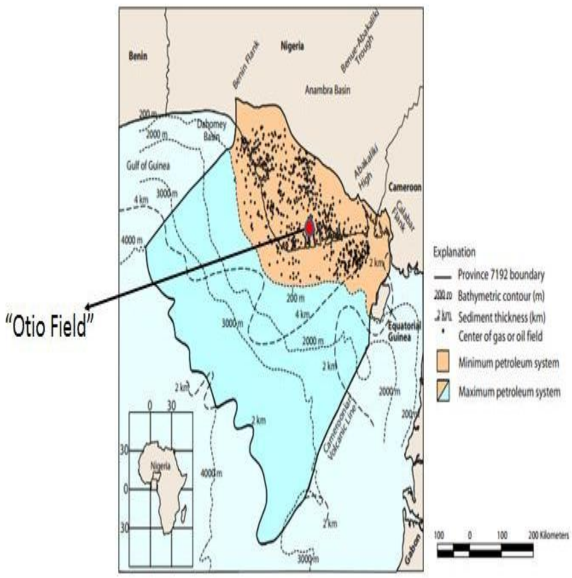

Fig.1 Location of Otio Field Onshore Niger Delta (Tuttle et al. 1999).

Geology of the Niger Delta

Regional Setting

Niger Delta is on aerial size of 75,000 km^2 (28,957 mi^2) and longitude 5° to 8° E, latitude 4° to 6° N (Fig. 2) (Ophori, 2007). The northern boundary is the Benin Flank (Fig. 2) which is a northeast trending hinge zone situated to the south of the West Africa Basement Massif. On the north-eastern side, the boundary traces Cretaceous exposures on the Abakaliki High and rounds off to the south east to the Calabar Flank (Fig. 2), a hinge line bordering the adjacent Precambrian one. The eastern offshore boundary of the province lies at the Cameroon volcanic line and the eastern boundary of the Dahomey Basin which marks the furthest eastern part of the West African transform-fault passive margin to the west (Michele et al., 1999).

During the Tertiary period, it expanded outwards into the Atlantic ocean at the location where the Benue Trough and the South Atlantic Ocean have formed a triple junction covering a drainage area of over one million square kilometers most of which is of lowland areas with savannah vegetation (Doust and Omatsola, 1990).The Cenozoic Niger Delta is located at the point where the Benue Trough and the South Atlantic Ocean have constructed a triple junction which covers most of the regions which are of lowlands with savannah vegetation (Doust and Omatsola, 1989). The two arms that branched off to the southwest and south east coasts of Nigeria and Cameroon evolved to the passive continental margin of West Africa, and the unsuccessful arm created the Benue Trough.

There were other depocenters in the African Atlantic coast, which also contributed to deltaic build-ups (Owoyemi, 2004). Following a pre-existing history of rift filling up in the late Mesozoic, the clastic wedge progressively extended into the Gulf of Guinea in the Tertiary when the drainage increased the African Craton with consequent passive margin subsidence (Nton and Adesina, 2009). The accumulation of syn-rift sediments covered the Cretaceous to Tertiary and the oldest sediments were of Albian age. This was due to the deposition of thickest successions of syn-rift marine and marginal marine clastics and carbonates in a number of transgressive and regressive phases (Doust and Omatsola, 1989).

Syn-rift phase reached its climax with a great tectonic occurrence in the Santonian period of Late Cretaceous period in the form of basin inversion. This was done through the inversion of preceding extensional forces, which caused uplifting of the areas that had been overriding before. Later on subsidence re-emerged as the African and the South American plates continued to move apart thus allowing the incurring of the marine waters into the Benue Trough what is known as marine transgression (Obaje, 2009; Nwachukwu and Chukwurah, 1986).

In the Middle Cretaceous, the Niger Delta experienced a massive increase in the deposition of sediments. These deposits eventually filled a large sedimentary basin (depocenter) that had formed along the descending boundary of the continental margin, coinciding with a geologically complex area where three tectonic plates had converged each other creating a triple junction (Doust & Omatsola, 1990).

The sediments were mainly flowed by the fluvial systems that were related to the inactive rift arms namely the Benue and the Bida Basin. But this progradation, the forward movement of the sediments was not even. It was periodically broken by repetitive marine trespasses in the Late Cretaceous that consequentially momentarily affected or ceased the deposition of sediments (Nwajide, 2013).

During the Tertiary period, the sources of sediment supply changed to include the north and east. Niger, Benue, and Cross rivers were the main routes of carrying these materials that were instrumental in further development of the Niger Delta and the neighboring basins (Reijers, 2011). Benue River and Cross River supplied large quantities of volcanic detritus of the Cameroon volcanic zone since the Miocene.

The Niger Delta clastic wedge moved into the Gulf of Guinea at progressively accelerating pace depending on development of these drainage basins and further basement subsidence. The rate of regime increased in the Eocene and the accumulated volume of the sediments accumulated after the Oligocene grew (Doust and Omatsola, 1990).

The progradation of the Deltas was on two large axes, the first one was along the direction of the Niger River, whereby the supply of sediments was higher than the subsidence rate. The second phase which was smaller than the first one occurred between the Eocene epoch and the Early Oligocene epoch, and was located deeper at the basin past the Cross River, where the coastline moved to the Olumbe-1 region (Short and Stauble, 1967).

Ihuo Embayment isolated this depositional region, which was quickly filled with deposits carried to it by the Cross River and other neighbouring rivers, which had separated this region of the main Niger Delta sedimentary area (Short and Stauble, 1967). These separate eastern and western depocenters came together in the Early to Middle Miocene, and resulted in the beginning of late stages of deposition.

The delta advanced to the point of making the shores widely concave into the basin in Late Miocene. This quick delta progradation brought about accelerated loading mobilizing underlying unstable shales. These shales were thrown up into diapiric walls and swells and distorted strata of overlay.

This brought about complex deformation structures that led to local uplift which contributed to some significant erosion events towards the frontal progradational edge of the Niger Delta. A number of deep canyons, which have been filled with clay, incision happens on the shelf, and are usually regarded to have developed through lowstands of the sea. The most familiar are the Afam, Opuama and Qua Iboe Canyon fills (Fig. 2).

During my course on sedimentary basins, I argue that Tertiary sedimentary basin of the Niger delta is conventionally broken down into three main depositional stages, as proposed by Short and Stauble (1967) and Doust and Omatsola (1990). The two initial phases occur primarily marine: the early reduction of the sea in the Middle Cretaceous was replaced by a large transgression of the sea in the Paleocene.

Meanwhile, the latter phase, which occurred during the end of the Paleocene, throughout the Eocene, demonstrates the evolution of a deltaic system, such a bow-shaped delta front developed due to the interaction of the wave and tidal processes. These sequences of sediments capture spatial and temporal heterogeneity, with older deposits being recorded in the north in the delta, and the latter, the Quaternary, being carried down to a further southward location.

The third stage is the most geologically complicated and consists of six geologically major depobelts or megasequences. All the depobelts are enclosed by conspicuous syn-sedimentary fault zones that did not only control the mode of sedimentation, but also played a significant role in the structural development of the basin and the prospects of the basin in the context of hydrocarbons (Doust and Omatsola, 1990).

These depobelts began when the routes of supply of sand were narrowed down by the relations of structural deformation, along the lines of which the sediment was concentrated in a limited number of channels of the delta. The changing depositional setting caused the urge to shift basin and caused a shift in the deposition locus with time, causing a change in position of these depobelts (Doust and Omatsola, 1990).

In where structural deformation is concerned normal faults caused by the movement of deep-seated, over-pressured, ductile marine shales have been severely deformed in the Niger Delta clastic wedge (Doust and Omatsola, 1989). Many of these faults were created in the process of delta progradation and they were syn-depositional in nature which affected the dispersal of sediments.

The instability of slopes along the continental margin was with fault growth. These faults also become flatter with depth, taking the form of growth faults (Fig. 4) which come to an end on a master detachment plane based on the apex of the over-pressurized marine shales at the bottom of the Niger Delta.

The process of structuring which is inherent to deltaic environments is largely regulated by the strength, structure and nature of fault systems underlying these environments (Davison et al., 2012). At faulting areas where the process has not developed a lot of complexities; there are not necessarily complex tectonic features and to the contrary, more straightforward features such as flank and crestal folds tend to appear alongthe isolated fault planes (Nelson, 2007).

On the other hand, more complex fault systems give way to a wider range of geological deformation in those geographical locations. One notable one is the development of hanging-wall rollover anticlines that occurs in reaction to listric normal fault curvature (concave-upward) (Withjack 2000).

These folds are tightly related to the phenomenon of differential sediment loading where accumulation of the overburden deltaic sediments makes pressure on the underlying ductile shale formations leading to folding as well as fault phenomenon (Rowan et al., 2004).

This can be well explained in Figure 2.3 which shows interaction of fault geometries and the rheological properties of material in the subsurface to produce unique rollover structures. Where tectonic complexity is much higher, the fault systems may often occur in dense cluster, or swarm, formations, with different levels of displacement or throw (Martinsen, 1994).

These faulted landscapes may contain failed crest along with dome-shaped formations that are created either by subsidence or breakdown of the higher strata. These areas are often antithetic, i.e. faults incline opposite each other, which leads to a high degree of heterogeneity of the subsurface structure, in particular, at a deeper stratigraphic position (Morley et al., 1990).

Fig. 4 also shows that it is due to the interaction between present multifaults that there exist highly compartmentalised and structurally diversified underground structures.

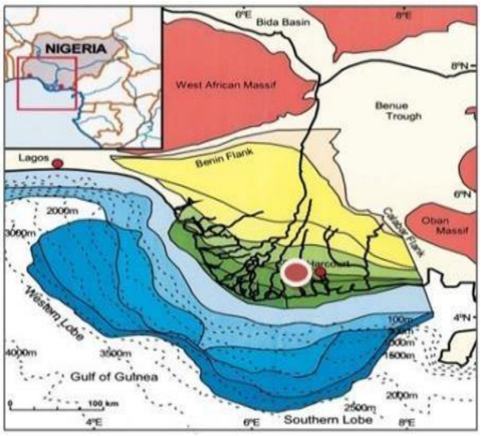

Fig. 2 Location of the Niger Delta (Adapted from Ibe and Anyanwu, 2014).

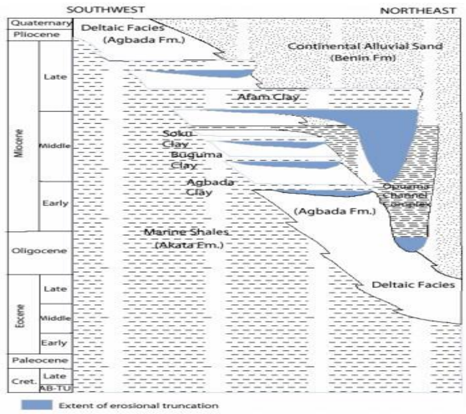

Fig. 3 Schematic representation of the diachronous nature of major lithofacies units, and the stratigraphic relationships of clay filled channels on the delta flanks (Adapted after Doust And Omatsola, 1990).

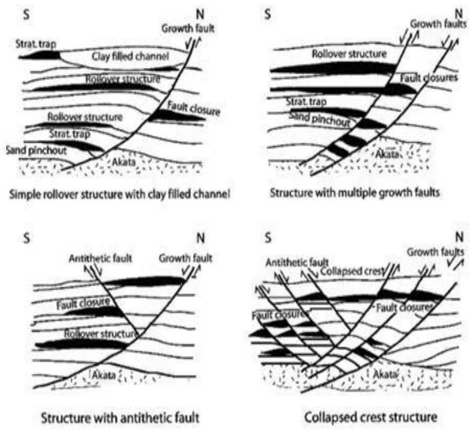

Fig. 4 Typical Niger Delta with structures: simple rollover, growth faults, antithetic fault, collapsed crest (modified after Doust and Omatsola (1990).

Niger Delta Petroleum System

The oil is found all across the Agbada Formation in the clastic wedge of Niger Delta. Although, the spatial distribution of hydrocarbons is naturally complicated, it has been observed that there is actually a trend in which the gas to oil ratio would be on the rising tendency towards the south of single deposition belts (Doust & Omatsola, 1989). Stacher (1995) proposed a hydrocarbon habitat model that is based on sequence stratigraphy to summarize the basin structural arrangement, traps, reservoirs, distribution of source rocks and the hydrocarbons of specific selected strata in the Niger Delta.

Later measurements of the gas-to-oil ratios in the reservoirs were presented by Evamy et al. (1978), Ejedawe (1981), and Doust and Omatsola (1990). The reservoir instances coincide with the northwest southeast oil rich belts and along various northsouth directional trails in the port Sokt area. According to Tuttle et al (1999), these belts estimate the boundary between the continental crust and the oceanic crust at the axis where maximum sediment is deposited. These oil rich belts have been linked to structural/depositional controls and high geothermal gradient by other scholars, as well as basinward movements in the sedimentation of successive deposition belt (Ejedawe, 1981; Weber, 1987; Doust and Omatsola, 1990; Haack et al., 1997).

The Niger Delta has potential source-rock consisting of marine shale derived when the Niger Delta was submerged by the ocean and the marine shale units of the Agbada Formation, the marine shale units of the Akata Formation, and the marine shale units of Late Cretaceous shale deposits were as well (Evamy et al., 1978; Ekweozor et al., 1979; Ekweozor et al., 1980; Lambert-Aikhionbare et al., 1984; Bustin, 1988). The Agbada Formation reservoir facies represents the deposits of the highstand and transgressive system tracts of the underlying shallow ramp settings (Evamy et al., 1978). The thicknesses of the reservoirs are below 45 feet to a few of the cases that are more than 150 feet (Evamy et al., 1978).

According to Kulke (1995), the point bars of distributary channels and the coastal barrier bars that were intermittently cut by sand-filled channels are the most productive units of hydrocarbons. The main reservoirs as initially envisaged by Edwards and Santogrossi (1990) were Miocene-aged paralic sandstones with a porosity of about 40 per cent, a 2-Darcy permeability, and a thickness of about 300 ft. Reservoirs can build up on the down-thrown side of the faults of growth (Weber and Daukoru, 1975).

There is grain-size difference between units of the reservoirs, the grain of a fluvial sandstone is usually coarser than the grain of a delta-front sandstone. The fining-upward decadencies are exhibited in point-bar deposits and the grain sorting is usually excellent in barrier-bar sandstones. Kulke (1995) noted that the sandstones are usually unconsolidated having small amounts of the argillaceous and siliceous cement. Possible type of the reservoirs in the outer delta complex are deep-channel sands, lowstand sand bodies, and proximal turbidite sandstones (Beka & Oti, 1995).

The most common reservoir locales within the complex of the Niger Delta are frontier by structural traps formed in the period of sedimentation of Agbada Formation (Evamy et al., 1978; Stacher, 1995) and stratigraphic traps that begin to appear preferentially at the deltaic flanks (Beka and Oti, 1995). The main seal bedrock is made out of interbedded shales in the Agbada Formation. There are three types of seals, which are (1) clay smears starting along fault planes, (2) interbedded sealing units which are juxtaposed against the reservoir sands as a result of faulting, and (3) vertical seals generated by vertically continuous, shale-rich strata (Doust & Omatsola, 1990).

Significant erosion events in the Early and Middle Miocene created canyons that were filled by shale; these cover cap seals on the deltaic flanks which are protecting various offshore fields of significance (Doust & Omatsola, 1990).

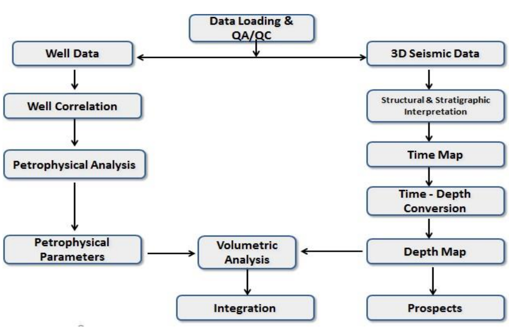

Fig. 5 Workflow for evaluation phase.

Materials and Methods

The principal databases used for this project are three Dimensional (3D) seismic cube, base map (Fig. 5), six well data in LAS format and check shot data for only one well, Otio-2, that was shared for the rest of the wells in the Field. The 3D seismic data is a high resolution Post-Stack Time Migration (PSTM) (Fig. 3) in SEG-Y format. The base map covers an approximate area of 55 square kilometres with Inlines range of 5800-6200 and Crosslines range of 1480-1700.

The six wells used for the project are named Otio-1, Otio-2, Otio-3ST, Otio-4, Otio-5 and Otio-6. Otio-3ST and Otio-6 are deviated wells and their deviation data were available. These wells were drilled to depth of 13020ft, 11669.10ft, 12090ft, 11440ft, 11700ft, and 13310ft, respectively.

The main software packages used for this project are the Openwork Suites with applications such as Siesworks and Zmap used for structural, stratigraphic interpretation and map generation. Powerlog software was used for well correlation and petrophysical analysis.

Identification of Hydrocarbon Bearing Zones

The hydrocarbon bearing zones were identified from lithology log (Gamma Ray, GR) and resistivity (RES and Deep Induction) logs. Zones with low gamma reading on the GR log are interpreted as sand units with a shale baseline set at 70 API. This was only done after establishing the Agbada Formation top interpreted as the first thick shale corresponding to sharp drop in resistivity indicating the transition zone from the Benin Formation freshwater to Agbada saline water. The resistivity logs were used to identify hydrocarbon bearing sands. These sands are identified as units with low gamma readings and high resistivity readings. Fluid typing was done using the combination of neutron and density logs.

Sand to Sand Correlation

Correlation of all sands in the field was done using Gamma Ray (GR), resistivity and porosity log motifs. Hydrocarbon bearing sands were then identified and correlated across the wells, and then evaluated to determine their petrophysical parameters which were limited to porosity and water saturation (S_W). Also, Net-to-Gross (NTG) was determined by subtracting shale thicknesses within the hydrocarbon bearing zones. These parameters were determined because of their direct application in determining the amount of hydrocarbons originally in-place.

Check Shot Loading

Check shot data available for only Otio-2 well was loaded in Openworks to display the well section on the seismic section. A display of the check shot data is seen in Table 2. This is only possible because check shot data is a velocity data that provides a common ground for depth and time. The check shot data was shared for all other wells to display them on seismic section.

To check the effect of the shared check shot, a multi-panel display cutting across all wells was taken. The panel showed good consistency of the reflections from well to well proving the competency of the check shot.

Petrophysical Evaluation Methods

According to SPE-PRMS (2018) for resource classification (1C/2C/3C as low/best/high estimates) and AAPG volumetric standards. Shale Volume (Vsh): Used Larionov (1969) Tertiary equation: [$V_{sh} = 0.33 \times (2^{2 \cdot I_{GR}} - 1)$], where [$I_{GR} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}$] (shale baseline 70 API). Vsh discriminates shales (Vsh > 0.3) from net pay.Porosity (φ): Effective porosity from density-neutron crossplot correction: [$\phi = \phi_N + \phi_D$] averaged, calibrated to well motifs; range 18-27%.Water Saturation (Sw): Applied Simandoux equation for shaly sands: [$S_w^n = \frac{a \cdot V_{sh}/R_{sh} + \sqrt{(V_{sh}/R_{sh})^2 + 4 \cdot b \cdot V_{sh}/R_t}}{2 \cdot b \cdot V_{sh}/R_t}$] (n=2, a/b tuned to Niger Delta analogs); range 20-31%. Net-to-Gross (NTG): [$NTG = 1 - \frac{\sum h_{shale}}{h_{gross}}$] from GR cutoffs (>70 API shale, Vsh>0.3).This aligns with SPE-PRMS volumetric workflow: STOIIP = GRV × NTG × φ × (1 - Sw) / Boi.Data Presentation AdditionsAdd figures post-Table 4.2:Log panels (GR, RES, N-D crossplot) for key wells (Otio-1, Otio-5) showing horizons D-J. Crossplots: Vsh vs. depth, φ vs. Sw color-coded by sand. Seismic-well ties with inline/crossline through reservoirs. Example table for petrophysical averages.

Results and Discussion

Maps Generation

Depth structural maps were generated from the time values of the five interpreted horizons. This conversion to depth was achieved with the use of a third order polynomial function which was generated from the check shot data provided. The structural maps were then contoured to reveal structures (highs and lows).

Identification of Prospects

On depth -structure maps, the prospects were outlined. The identified traps can be considered as drillable traps, as they have adequate quality data to allow the full evaluation of the hydrocarbon play (Redfern, 1824). These prospects in the Otio Field can be associated with areas that have a fault-dependent or fault-independent structural closure. The existence of such closures is easily identifiable on the depth structure maps, and this is due to a phased-depletive trend in the values of the contours, starting at the terminal closing contour.

Petrophysical Analysis

Fluid typing: Fluid types determined from neutron-density logs are represented in Table 1

Shale volume: Fig. 4 represents shale units discriminated from sandy portions using Larinov Tertiary algorithm. The figure reveals two (2) thin shale units in Sand D.

Porosity determination and water saturation: Table 2 summarizes porosity and water saturation of the evaluated sands in the wells of Otio Field.

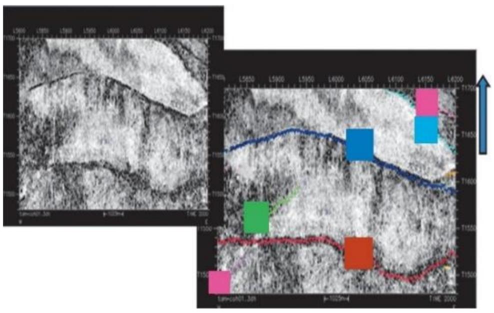

Fig. 6 Coherence timeslice showing interpreted fault trend (Openworks, 2011).

Fig 7 Interpreted faults polygons on basemap (Openworks, 2011).

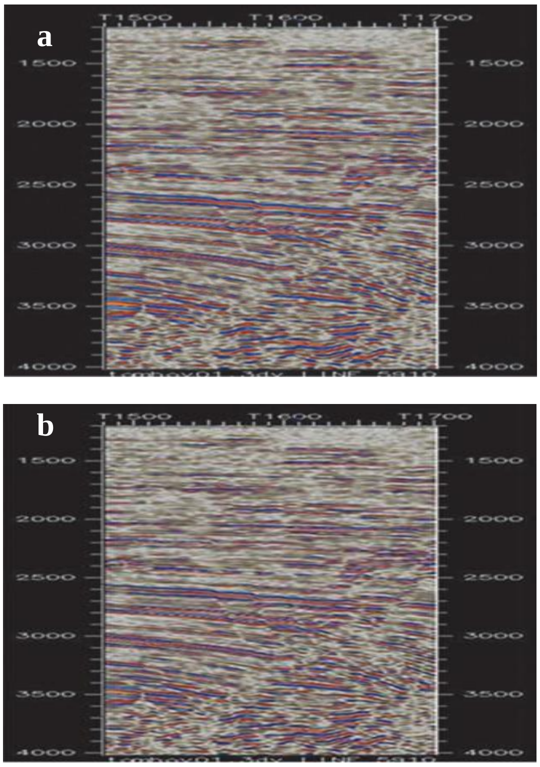

Fig. 8 Post-stack time migration seismic section along crossline1580 (a) and inline 5910 (b) (Openworks, 2011).

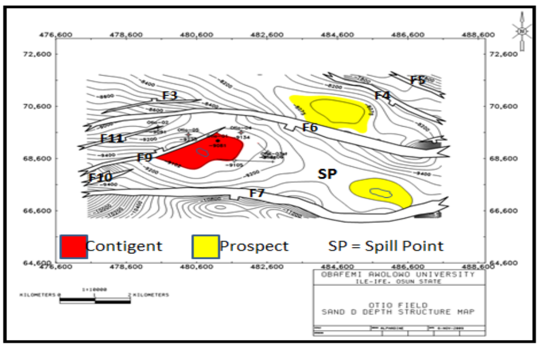

Fig. 9 Sand D depth structure map (Openworks, 2011).

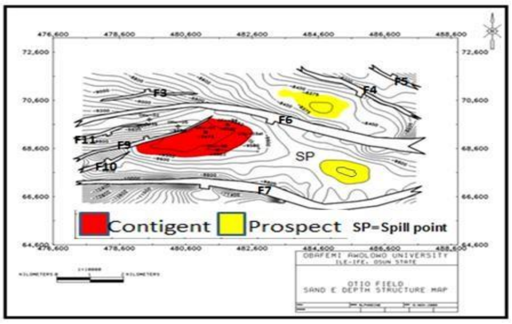

Fig. 10 Sand E1 depth structure map (Openworks, 2011).

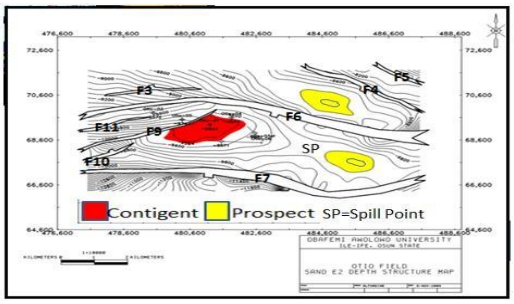

Fig. 11 Sand E2 depth structure map (Openworks, 2011).

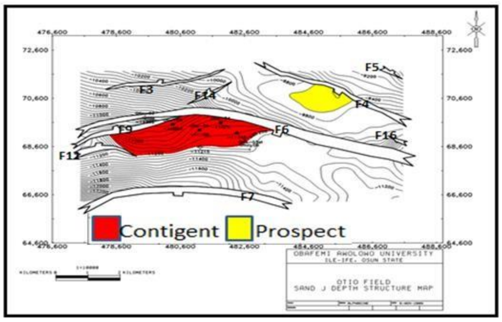

Fig. 12 Sand H depth structure map (Openworks, 2011).

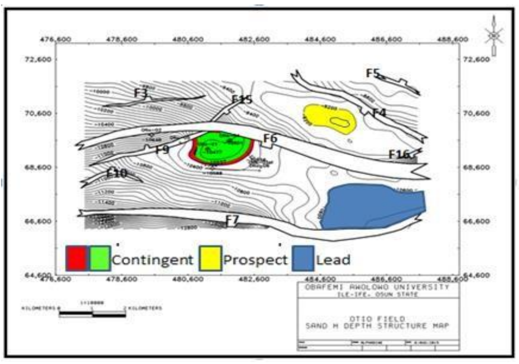

Fig. 13 Sand J depth structure map (Openworks, 2011).

Table 1. Showing fluid types in the wells (Note: Otio-2 is completely wet).

Sands	Otio-5	Otio-1	Otio-4	Otio-3ST	Otio-6
D	Wet	Oil	Wet	Wet	Wet
E1	Wet	Oil	Oil	Wet	ODT
E2	Wet	Oil	Wet	Wet	Wet
H	Faulted out	Gas/oil	Gas/oil	Wet	Wet
J	Oil	Oil	Oil	Oil	Wet

Table 2. Petrophysical summary table.

Sand	φ (%)	Sw (%)	NTG (%)	Vsh (avg)	Key Wells	Fluid Type
D	22-25	25-28	75-85	0.20	Otio-1,4	Oil/Wet
E1	21-24	24-27	80-90	0.18	Otio-1,4	Oil
E2	24-27	20-25	85-96	0.15	Otio-1	Oil (best)
H	20-23	22-26	70-82	0.22	Otio- 4,3 ST	Gas/Oil
J	18-23	28-31	59-70	0.25	Otio-1,5	Oil

Volumetric Analysis

Contingent resource volumetrics: The following tables (Tables 3-5) provides the results of volumetric analysis carried out on the contingent resource in “Otio Field” for proven (1C) contingent, proven and probable (2C) contingent and proven, probable and possible (3C) contingent.

Resource ranking: Contingent resource is ranked based on relative volume of the respective reservoirs (Sands D, E1, E2, H and J). Table 6 shows the ranking of the reservoirs.

Sand E2 is ranked first (1) because of its largest volume compared to lower ranked sands, D, E1, J and H in that order. This ranking is important for field optimization purposes. Higher ranked sands should be considered first in field development

Prospect volume estimation: The following Tables 7-8 provide the results of volumetric analysis carried out on the identified prospects (NE and SE) in Otio Field low case, mid case and high case. The GRV was estimated as 9,294 –

13,876 acre-ft for low and high case respectively by ZMAP application on Openworks software.

Uncertainty analysis: Quantify via Monte Carlo (experimental design): ±10% GRV (fault/seal), ±5% φ/Sw (log resolution), ±15% NTG (correlation). Yields P10/P50/P90 matching 3C/2C/1C tables (e.g., E2 OOIP: 20.9-24.7-29.2 MMBO). Discuss risks: shared check shots, no DST/RFT (fluid contacts).

Prospect ranking: Prospects in Otio Field were ranked based on relative volumes of reservoir sands in each prospect. Tables 9-10 shows the ranking of the prospects.

NOTE: In-place volumes are based on project assessment and are unrisked. Table 3. 1C.

Table 3. 1C Volumetric analysis.

Reservoir 1C	OOIP (MMBO)	B_o/B_g	GIIP (MMscf)	STOIIP (MMBO)	RF (%)	**Resource** (MMBO)	Free Gas (MMscf)
D	24.74	1.4		17.67	0.35	6.18	
E1	26.38			18.84		6.60	
E2	29.24			20.89		7.31	
H Gas		0.004	3.36		0.70		2.35
H Oil	3.98	1.4		2.84	0.35	0.99	
J	15.77			11.26		3.94	
TOTAL			**3.36**	**71.50**		**25.02**	**2.35**

Table 4. 2C Volumetric analysis.

Reservoir 2C	OOIP (MMBO)	B_o/B_g	GIIP (MMscf)	STOIIP (MMBO)	RF (%)	**Resource** (MMBO)	Free Gas (MMscf)
D	27.80	1.4		19.86	0.35	6.95	
E1	26.78			19.12		6.70	
E2	34.61			24.72		8.65	
H Gas		0.004	3.36		0.70		2.35
H Oil	5.29	1.2		3.77	0.35	1.32	
J	19.74			14.10		4.94	
TOTAL			**3.36**	**81.57**		**28.56**	**2.35**

Table 5. 3C Volumetric analysis.

Reservoir 3C	OOIP (MMBO)	B_o/B_g	GIIP (MMscf)	STOIIP(MMBO)	RF (%)	**Resource** (MMBO)	Free Gas (MMscf)
D	32.04	1.4		22.89	0.35	8.01	
E1	27.65			19.75		6.91	
E2	38.79			27.71		9.70	
H Gas		0.004	3.36		0.70		2.35
H Oil	5.09	1.2		3.64	0.35	1.27	
J	22.33			15.95		5.58	
TOTAL			**3.36**	**89.94**		**31.47**	**2.35**

Table 6. Resource ranking of reservoirs in Otio Field.

Reservoirs	**Resource Volume (MMBO)**	**Rank**
Sand E2	24.72	1
Sand D	19.86	2
Sand E1	19.12	3
Sand J	14.10	4
Sand H	3.77	5

Table 7. North-eastern prospect volumes of Otio Field.

Reservoir (Low Case)	OOIP (MMBO)	B_o (MMBO)	STOIIP (MMBO)	RF (%)	Resource (MMBO)	Reservoir (Mid Case)	OOIP (MMBO)	B_o (MMBO)	STOIIP (MMBO)	RF (%)	Resource (MMBO)
D	14.57		10.41		3.64	D	14.95		10.68		3.74
E1	12.10		8.64		3.02	E1	12.51		8.94		3.13
E2	17.37	1.4	12.41	0.35	4.34	E2	17.43	1.4	12.45	0.35	4.36
H	13.72		9.8		3.43	H	13.91		9.99		3.49
J	9.31		6.65		2.33	J	10.31		7.36		2.58
TOTAL			47.91		16.76	TOTAL			49.42		17.30

Reservoir (High Case)	OOIP (MMBO)	B_o (MMBO)	STOIIP (MMBO)	RF (%)	Resource (MMBO)
D	15.82		11.30		3.96
E1	13.01		9.29		3.25
E2	19.05	1.4	13.61	0.35	4.76
H	16.31		11.65		4.08
J	11.70		8.36		2.93
TOTAL			54.21		18.98

Table 8. South-eastern prospect volumes of Otio Field.

Reservoir (Low Case)	OOIP (MMBO)	B_o (MMBO)	STOIIP (MMBO)	RF (%)	Resource (MMBO)	Reservoir (Mid Case)	OOIP (MMBO)	B_o (MMBO)	STOIIP (MMBO)	RF (%)	Resource (MMBO)
D	12.04		8.60		3.01	D	12.61		9.01		3.15
E1	8.82		6.30		2.45	E1	10.81		7.72		2.70
E2	13.50	1.4	9.64	0.35	3.37	E2	15.84	1.4	11.31	0.35	3.96
H	12.43		8.88		3.11	H	13.48		9.63		3.37
J	-		-			J	-		-		-
TOTAL	46.79		33.42		11.94	TOTAL	52.74		37.67		13.18

Reservoir (High Case)	OOIP (MMBO)	B_o (MMBO)	STOIIP (MMBO)	RF (%)	Resource (MMBO)
D	15.29		10.92		3.82
E1	11.84		8.46		2.96
E2	18.72	1.4	13.37	0.35	4.68
H	14.66		10.47		3.67
J	-		-		-
TOTAL	60.51		43.22		15.13

Table 9. North-eastern prospect volume ranking.

Reservoirs (NE)	Prospect Volume (MMBO)	Rank
Sand E2	10.68	1
Sand D	3.85	2
Sand H	9.99	3
Sand E1	8.94	4
Sand J	7.36	5
Total	49.42	

Table 10. South-eastern prospect volume.

Reservoirs (SE)	Prospect Volume (MMBO)	Rank
Sand E2	11.31	1
Sand H	9.63	2
Sand D	9.01	3
Sand E1	7.72	4
Sand J	-	-
Total	37.63	

Conclusion

The comprehensive petrophysical analysis of Otio Field has provided valuable insights into its reservoir potential. The evaluation of key petrophysical parameters, including porosity, water saturation, and Net-To-Gross ratios, reveals promising reservoir properties, with ranges of 18-27%, 20-31%, and 59-96%, respectively. These findings, combined with structural analysis, indicate that the field's hydrocarbon-bearing sands (Sands D, E1, E2, H, and J) have significant potential.

Volumetric analysis highlights Sand E2 as the most prolific reservoir (24.72 MMBO), while prospect NE emerges as a promising area with a higher STOIIP (49.42 MMBO). The integration of petrophysical analysis with seismic data and well logs has proven instrumental in understanding the subsurface structure and identifying potential prospects, providing a solid foundation for future exploration and development efforts in Otio Field.

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