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Hydrocarbon Play Assessment of "Oswil" Field, Onshore Niger Delta Region

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ABSTRACT

Hydrocarbon play assessment of any field involves the evaluation of the production capacity of hydrocarbon reservoir unit in the field. This involves detail study of the reservoir petrophysical properties and geological interpretation of structures suitable for hydrocarbon accumulation in the field as observed from seismic reflection images. This study details the assessment of hydrocarbon play in OSWIL field onshore in Niger Delta, with the intent of appraising its productivity using a combination of seismic, well logs, petrophysical parameters and volumetric estimation using proven techniques which involves an integrated methodology. Two reservoir windows "R1" and "R2" were defined from five wells OSWIL-02, 04, 06, 07 and 12. The top and base of each reservoir window was delineated from the wells. Structural interpretation for inline 6975 revealed two horizons (X and Y) and eight faults labelled (F1, F2, F6, F8, F10, F16, F17 and F18). Five faults (F1, F6, F10, F17 and F18) were identified as synthetic faults and dip basin wards while three faults (F2, F8 and F16) were identified as antithetic faults and dips landwards. Time-depth structural map at top of reservoirs R1 and R2 revealed structural highs and closures. These observations are characteristics of growth structures (faults) which depicts the tectonic style of the Niger Delta. Results of petrophysical evaluation for reservoirs "R1" and "R2" across the five wells were analysed. For reservoir "R1" effective porosity values of 27%, 26%, 23%, 20% and 22% were obtained for wells OSWIL-04, 12, 07, 06 and 02 respectively with an average of 23.6%, while for reservoir "R2" effective porosity values of 26%, 22%, 21%, 24% and 23% for wells OSWIL-04, 12, 07, 06 and 02 were obtained respectively with an average of 23.2%. This porosity values correspond with the already established porosity range of 28-32% within the Agbada formation of the Niger Delta. Permeability index of the order (K > 100mD) were obtained for both reservoirs across the five wells and is rated very good. Hydrocarbon saturation (Shc) across the five wells averages at 61.6% for reservoir "R1" and 67.4% for reservoir "R2". Result of petrophysical model for porosity, permeability and water saturation reveal that the reservoir system in R1 and R2 is fault assisted and fluid flow within both reservoirs is aided by presence of effective porosity and faulting. Volumetric estimation for both reservoirs showed that reservoir R1 contains an estimate of 455 × 106 STB of hydrocarbon in place, while reservoir R2 contains an estimate of 683 × 106 STB of hydrocarbon in place. These findings impact positively on hydrocarbon production in the field and affirm that the two reservoirs R1 and R2 are highly prospective.

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1. Introduction

Nigeria oil and gas industries presently are faced with the challenge of meeting up with the national crude oil reserve target of 40 billion barrels due to inadequate exploration and exploitation of the available natural hydrocarbon deposit in the nation. Records show that only one-third of oil in place has been recovered through the conventional method of production [1-4]. The domestic need is bolstered by the current government policy thrust for additional gas turbines for power generation and industrial projects. Therefore, the future reserve/production ratio for oil/gas in Nigeria will be a cause for serious concern based on the present available reserves data, if additional reserves are not discovered. Hence, this necessitates the assessment of hydrocarbon play of the subsurface geology using different proven and cost effective techniques in the exploration of oil and gas within the Niger Delta region in achieving its national demand. A petroleum play, or simply a play, is defined as a group of oil fields or prospects in the same region that are controlled by the same set of geological circumstances [5]. The geological component of consideration in the assessment of hydrocarbon play are migration pathway, reservoir rock, a matured source rock, trap and seal. Nevertheless, an effective play is only made up of a reservoir rock, a trap and its sealing mechanism which are located within a sedimentary terrain [6].

If the various elements that make up a play are identified on a play assessment map, then exploration of the entire prospects in the field is possible not just a single prospect. The geophysical method that provides the most detailed picture of subsurface geology to delineate the various elements that constitutes a hydrocarbon play in an oil field is the seismic methods. The seismic reflection method ever since its discovery in the late 1920s, has and still remains one of the most effective tools in the search for hydrocarbons. Reflections are due to contrast in acoustic impedance in the subsurface caused by difference in physical properties of rocks with different lithologies, which can be density and compressional wave velocity and can be explained in terms of lithology, porosity and porefill [7-10].

The goal of a 3D seismic survey is to delineate subsurface structures, as well as acquire exact definition of rock physical properties which aid in mapping of geological structures suitable for hydrocarbon accumulation [4,11]. Structural traps, made up of the reservoir rock and its sealing mechanism are usually more evident on seismic records, and forms the basis of structural seismic interpretation aided by conventional interpretation platforms [12,13]. With advancement in technology, the use of seismic data has extended to other areas such as hydrocarbon play exploration beneath existing fields and pore-fluid estimation. These applications have led to the discovery of potential oil and gas reserves which have not been exploited. Hydrocarbon play assessment of any hydrocarbon reservoir depends on structural disposition of the reservoir and reservoir properties such as porosity, permeability and water saturation distribution of the reservoir. These petrophysical properties are key contributors to hydrocarbon reservoir characterization. Estimation of the structural and petrophysical evaluation of every reservoir unit require the integration of seismic and well log data, to describe the reservoir properties in terms of its structural disposition as observed from seismic records within a particular field [3]. This study intends to resolve the ambiguities that are associated with hydrocarbon play assessment of "OSWIL" field onshore Niger Delta, through the adoption of an integrated methodology which combines result of structural seismic interpretation and petrophysical analysis to evaluate the production capacity of the reservoirs delineated in the field.

2. Geology of the Study Location

OSWIL Field is basically an onshore field located within the Niger Delta between latitudes $5^0 24'0''$ N and $5^0 30' 0''$ N and longitudes $6^0 0' 30''$ E and $6^0 7' 0''$ E. The Field has five wells identified as OSWIL-02, 04, 06, 07 and 12 (Figure 1).
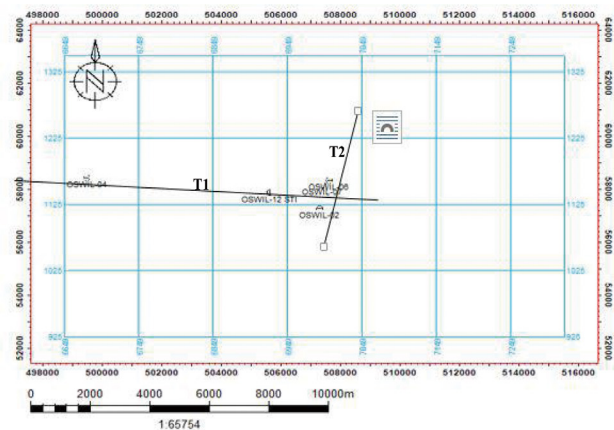

Figure 1. Base map of the study area Oswil Field, showing the grid seismic lines and well locations along traverses T1 and T2

The Niger Delta basin evolved in early Cenozoic times where rapid deposition and subsidence have occurred overtime [14]. Thickness of sediments in the Niger Delta is over 12 km on the basin depocentre [4,15]. The early Niger Delta is interpreted as being a river-dominated delta, how-

ever the post-Oligocene delta is a typical wave-dominated delta with well-developed shoreface sands, beach ridges, tidal channels, mangrove and freshwater swamps [16,17,18]. Obaje [18], opined that the Niger Delta is one of the world's largest deltas and shows an overall upward transition from marine shales (Akata Formation) through a sand-shale paralic interval (Agbada Formation) to continental sands of the Benin Formation.

Depending on relative sea level changes, local subsidence and sediment supply, the delta experiences episodes of regressions and transgressions [4,19,20]. Tectonics in the Niger delta rifting diminished in the Late Cretaceous. After rifting ceased, gravity tectonics became the primary deformational process. The stratigraphic arrangement of the Niger Delta is made up of three lithostratigraphic units namely; a continental shallow sand unit - the Benin Formation, a coastal marine unit of alternating sands and shales - the Agbada Formation and a basal marine shale unit-the Akata Formation. The Akata Formation consists of clays and shales with minor sand alternations [18]. The sediments were deposited in prodelta environments, with sand percentage less than 30% [4,20]. The Agbada Formation consists of alternating sand and shales representing sediments of the transitional environment comprising the lower delta plain (mangrove swamps, floodplain and marsh) and the coastal barrier and fluvio marine realms. According to Obaje [18], the sand percentage within the Agbada Formation varies from 30 to 70%, which results from the large number of depositional off lap cycles. A full cycle generally consists of thin fossiliferous transgressive marine sand, followed by an offlap sequence which commences with marine shale and continues with laminated fluvio marine sediments followed by barriers and/or fluviatile sediments terminated by another transgression cycle [21,22] as cited in [20]. The Benin Formation is characterized by high sand percentage (70-100%) and forms the top layer of the Niger Delta depositional sequence (Alao et al. 2013). According to Obaje (2009), the massive sands were deposited in continental environment comprising the fluvial realms (braided and meandering systems) of the upper delta plain[23].

3. Methodology

Available data used for this study includes; 3D Seismic data volume (in SEG-Y format), Well logs (Gamma Ray, Resistivity, Neutron and Density logs), Check shot, and Well deviation. The suite of data were obtained from Shell Petroleum Development Company (SPDC). The workflow algorithm adopted for this study is shown below (Figure 2).
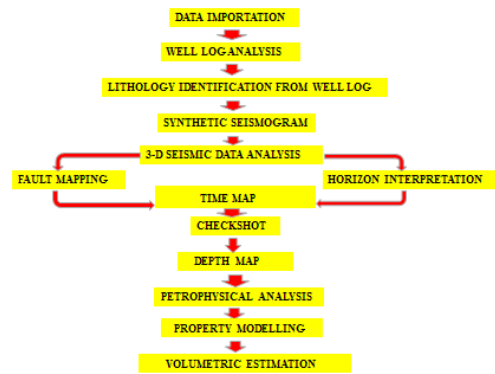

Figure 2. Research Workflow

Lithology identification was done using gamma ray log signature. Two reservoir windows R1 and R2 (sand units) were identified at top and base across the five wells following deflection of the gamma ray and resistivity log signatures. Since shale most times behaves like a radioactive element, the volume of shale (V_{sh}) in the reservoir sand was calculated using gamma ray log. Also gamma ray log was used to discriminate porous from non-porous beds, and to determine bed boundaries within the Formation. From GR log and Neutron-density crossover within porous and permeable Formations, three lithologies were delineated as Sand, Shaly sand and Shale (Figure 4a & b). Litho-stratigraphic correlation which is the determination of the continuity and equivalence of lithologic units, particularly across reservoir sands was carried out across the wells along traverses T1 and T2 shown on the base map (Figure 1). Wells Oswil-04, 12 and 07 along traverse T_1 runs from West-East of the base map, while wells Oswil-02, 07 and 06 along traverse T_2 runs from North-South on the base map (Figure 1). This formed the basis for correlation of the wells along traverses T1 and T2 to determine the lateral extent of the reservoir window across the wells.

Well-to-seismic tie, which seek to import well information into the seismic, was carried out using checkshot data from well Oswil-12. The major reflection lines that represent the tops and bases of reservoirs R1 and R2 identified on wells were mapped on the seismic section as time surfaces, this was thereafter converted to depth maps using lookup function (a relationship between time and depth) generated from the check-shots data. The well was tied to the full stack seismic data. A zero phase wavelet which was flattened with a choice filter (Butterworth wavelet) was used for the convolution of the impedance log (product of sonic velocity and density logs from OSWIL-12 well) with a bulk shit of -15ms to ensure the synthetic ties with the field seismogram. The synthetic seismogram is an artificial seismic section and considered as the convolution

of the assumed source function (seismic wavelet) with the reflectivity function [24]. By means of the synthetic seismogram, valuable insights can be obtained about the subsurface geology responsible for a particular seismic event as observed from seismic records.

It represents the acoustic impedance in a layered model. The synthetic seismogram provides a means for well-to-seismic tie which gives a better geologic meaning to the seismic reflection data [25].
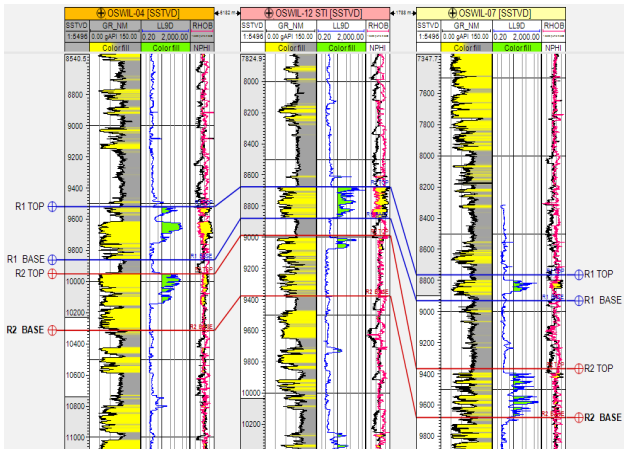

Figure 3a. Litho-Stratigraphic Correlation of the Studied Wells along traverse T_1 Oswil Field Niger Delta

3.1 Reservoir Petrophysical Parameters and Hydrocarbon Volumetric Estimation

Petrophysical estimations were carried out for the five wells that penetrated the two reservoirs (R1 and R2) in the area of study. From wireline logs, empirical expressions were used to determine the following parameters Net-to-Gross (NTG), Volume of shale (V_{sh}), porosity (Φ), permeability (K) and water saturation (S_w).
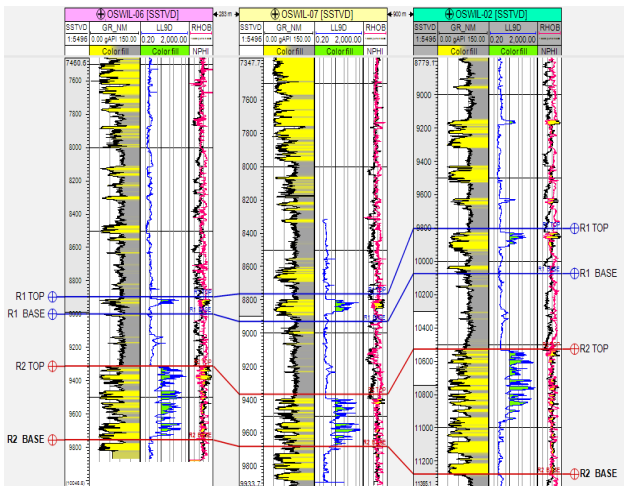

Figure 3b. Litho-Stratigraphic Correlation of the Studied Wells along traverse T_2 Oswil Field Niger Delta

Net-to Gross (NTG) measures the potential productive part of a reservoir either as a percentage or fraction of the producible (Net) reservoir within the entire (Gross) reservoir zone.

Net-to gross was computed as a percentage using the expression [3,26]:

$$NTG = (h/H) \times 100\% \tag{1}$$

where; NTG= Net to Gross, h = Net reservoir thickness and H= Gross reservoir thickness.

The volume of shale (V_{sh}) was calculated from gamma ray log using the linear method of estimation which requires determining the gamma ray response of clean sand associated with no shale (GR_{min}) and a zone of 100% shale (GR_{max}). Presence of shale within a sand unit makes the porosity log record a high porosity value, low hydrocarbon saturation and thus, low resistivity reading. This however, makes it challenging to control productive zones of a reservoir volume of shale in unconsolidated Tertiary Niger Delta basin. The formula we adopted was the linear equation proposed by [27]:

$$GR_{index} = \frac{GRiog - GR\min}{GR\max - GR\min} \tag{2}$$

where; GR_{index} = gamma ray index, GR_{Log} = GR log reading of the formation, GR_{min} = minimum GR log value in clean sand and GR_{max} = maximum GR log value in 100% shale.

Volume of Shale (V_{sh}) was obtained for the two reservoirs R1 and R2 within the five wells using Larionov tertiary rock method [26,28] given as:

$$(V_{sh}) = 0.083(2^{3.7*IGR}-1) \tag{3}$$

where; V_{sh} = Volume of Shale and IGR = Index gamma ray.

Porosity is described as the percentage of pore spaces to total bulk volume of the rock. Porosity is taken as the measure of the void space relative to the entire reservoir volume and shows the storage strength of the given reservoir to pore fluids.

Porosity was determined from bulk density log using:

$$\phi(Den) = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \tag{4}$$

Where; f_{Den} = density derived Porosity, r_{ma}= Matrix density usually 2.65 g/cm^3 for sandstones, r_b = bulk density of formation, r_{fl} = Fluid density usually 0.9 g/cm^3.
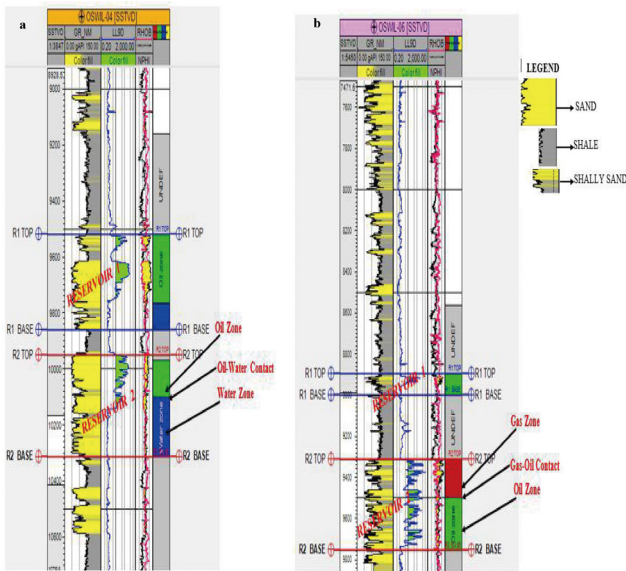
Figure 4 (a). Reservoir window and fluid distribution on OSWIL-04 Well (b). Reservoir window and fluid distribution on OSWIL-06 Well. The top and base of reservoirs R1 and R2 is shown for both wells, and fluid distribution within the reservoir shows Oil-Water contact for OSWIL-04 Well and Gas-Oil contact for OSWIL-06 Well

The porosity value computed above is regarded as total porosity $\{\Phi_{Total}\}$. When the pore spaces are interconnected the porosity is described by the term "effective porosity" and this porosity accounts for the free flowing fluid within the reservoir.

For effective porosity estimation we adopted the expression:

$$(\Phi_{eff}) = (1-V_{sh})* \Phi_{Total} \tag{5}$$

where; Φ_{eff} = effective porosity, V_{sh} = volume of shale and Φ_{Total} = total porosity.

Permeability which is the degree or measure of the ease of flow through a medium via its interconnected pores, capillaries or fractures. It is expressed in Darcy.
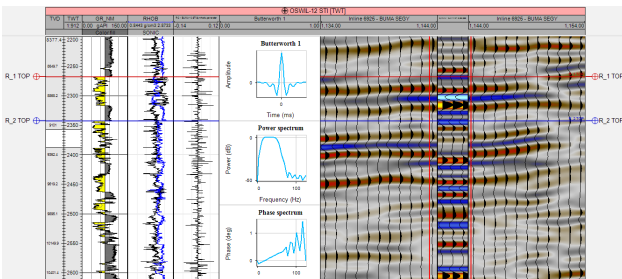

Figure 5. Seismic-to-well Tie for OSWIL-12 Well

Empirically, it is observed that very few rocks have a 1Darcy value of permeability. In practice, permeability computation in static reservoir modelling is done in a

given direction in an anisotropic sandstone material, and often in the horizontal direction ($Ki_{(x)}$) along the principal axis of the permeability tensor ellipsoid [29]. Permeability index is usually expressed in millidarcies or as a fraction in 1/1000 of a Darcy.

Usually, increase in porosity could imply an increase in permeability prospect although porosity is not directly related to permeability. Factors such as Pore size, shape and continuity (pore geometry) and porosity influences the permeability of a rock formation.

The Tixier [30] model was used in computing permeability index (k) given as:

$$K= \sqrt{\{250 * \Phi_{eff}^{3}\}} / S_{wirr} \tag{6}$$

where; K = permeability index, Φ_{eff} = effective porosity and S_{wirr} = irreducible water saturation defined by [31] as:

$$S_{wirr} = (F/2000)^{1/2} \tag{7}$$

F is the formation factor (F) given by Archie [32] as:

$$F = a / \phi^{m} \tag{8}$$

where; a = Empirical constant = 0.62, and
m = cementation factor = 2.15.

Water saturation (Sw) was determined using the Archie [32] model (for clean sand formations) [3,33].

$$S_w = \left(\frac{aR_w}{\phi^m R t}\right)^{1/n} \tag{9}$$

where; S_w = water saturation of un-invaded zone, R_w = Formation water resistivity, R_t = True Formation Resistivity (Un-invaded zone), ϕ = Effective Porosity,
a = Empirical constant defined in Equation (8),
m = Cementation exponent defined in Equation (8),
n = Saturation exponent.

For hydrocarbon saturation (S_h) we adopted the expression;

$$S_h = (1- S_w) \tag{10}$$

3.2 Fault / Horizon Mapping, Creation of Surface and Depth maps and Petrophysical Models

Fault mapping was done by picking fault segments on vertical seismic sections. Faults were identified on inline 6975 of the seismic section and two horizons (A and B) were picked on inline 6975. Eight faults were mapped on inline 6975. Structural time map and depth map were generated at top of reservoirs R1 and R2. Petrophysical fluid distribution models of porosity, permeability and fluid sat-

uration were generated as surface maps for reservoirs R1 and R2. These models were generated by distributing the estimated petrophysical properties (porosity, permeability and water saturation) along each well path across the entire reservoir structure using geo-statistical techniques. The geo-statistical algorithm applied in distributing the facies is the Sequential Indicator Simulation (SIS) [34], while the geo-statistical algorithm applied in distributing the petrophysical properties across the wells in the field is the Sequential Gaussian Simulation (SGS) [35].

3.3 Estimation of Stock Tank Oil in Place (STOIIP) within the Reservoir

Attempts were made to estimate the stock tank oil initially in place (STOIIP) for both reservoirs R1 and R2 to appraise the prolific nature of both reservoirs for field development. To determine the Stock Tank Oil Initially in Place (STOIIP), we adopted the expression:

$$STOIIP = 7758*A*h*\Phi*(1-S_w)*1/B_o \tag{11}$$

where; 7758 = Acre-feet conversion for oil, A = Area in acres, h = Net Pay thickness in feet, Φ = Porosity

S_w = Water saturation, $(1-S_w)$ = hydrocarbon saturation, B_o = Formation volume factor [36].

Table 1. Petrophysical parameters of Reservoir R1

	Parameters	OSWIL-04	OSWIL-12	OSWIL-07	OSWIL-06	OSWIL-02
Reservoir	Top(ft)	9520	8660	8660	8900	9800
	Base(ft)	9860	8880	8920	9000	10,180
	Gross Thickness(ft)	340	220	260	100	380
	Net Thickness(ft)	254	186	96	32	148
	Net/Gross	74	84	36	32	38
	V_{sh} (%)	7	12	14	12	11
R1	Φ_{Eff} (%)	27	26	23	20	22
	F	20.46	26.28	31.87	48.06	36.88
	K (mD)	1164	1440	626	477	727
	S_{wrr} (%)	0.094	0.102	0.11	0.133	0.12
	S_w (%)	43	29	52	32	36
	Sh (%)	57	71	48	68	64

Table 2. Petrophysical parameters of Reservoir R2

	Parameters	OSWIL-04	OSWIL-12	OSWIL-07	OSWIL-06	OSWIL-02
Reservoir	Top(ft)	9950	8988	9366	9312	10,527
	Base(ft)	10,313	9376	9680	9754	11,277
	Gross Thickness(ft)	363	388	314	442	750
	Net Thickness(ft)	339	342	212	297	543
	Net/Gross	93	88	68	67	72
	V_{sh} (%)	8	11	15	10	13
R2	Φ_{Eff} (%)	26	22	21	24	23
	F	18.04	31.19	31.71	24.25	26.49
	K (mD)	827	345	631	774	1078
	S_{wrr} (%)	0.091	0.12	0.11	0.103	0.106
	S_w (%)	45	21	32	23	42
	Sh (%)	55	79	68	77	58

4. Result Presentation and Discussion

The well log and 3D seismic data volume were analysed for hydrocarbon play assessment of the study area by adopting the methodology outlined above. The base map of OSWIL Field showing the grid seismic lines and location of the wells along traverses T1 and T2 is shown in Figure 1. The reservoir windows (R1 and R2) defined from well logs were correlated from top to base across OSWIL-04, 12 and 07 wells along traverse T1 oriented West-East in the field (Figure 3a) and across OSWIL-06, 07 and 02 wells along traverse T2 oriented North-South in the field (Figure 3b) using gamma ray log, resistivity log and neutron-density crossover. Figures 4a and 4b shows the reservoir fluid distribution for OSWIL-04 well (along T1) and OSWIL-06 well (along T2). For OSWIL-04 well, presence of Oil and Water was observed within reservoir windows R1 and R2 based on neutron-density crossover (Figure 4a) while for OSWIL-06 well, presence of Gas and Oil was observed within reservoir R2 (Figure 4b). Reservoir R1 has a thickness of 340 ft (9520-9860 ft) on well OSWIL-04, a thickness of 220 ft (8,660-8,880 ft) on well OSWIL-12 and a thickness of 260 ft (8,660-8,920 ft) on well OSWIL-07 (Figure 3a). This shows that reservoir R1 thins out in the eastward direction from OSWIL-04 to 07 wells. Similarly, reservoir R2 has a thickness of 363ft (9,950-10,313 ft) on well OSWIL-04, a thickness of 388ft (8988-9376ft), on well OSWIL-12 and a thickness of 314ft (9366-9680ft) on well OSWIL-07. Reservoir R-1 has a thickness of 100ft (8900-9000ft) on well OSWIL-06, a thickness of 170ft (8760-8930ft) on well OSWIL-07 and a thickness of 380ft (9800-10,180ft) on well OSWIL-02. Reservoir R1 thickens out southwards direction of the Field, while reservoir R2 has a thickness of 442ft (9312-9754ft) on well OSWIL-06, a thickness of 310ft (9370-9680ft) on well OSWIL-07 and a thickness of 750ft (10,527-11,277ft) on well OSWIL-02.

Petrophysical parameters computed for the two reservoirs "R1" and "R2" within the five wells is shown in Tables 1 and 2. The parameters of interest includes: gross thickness, net thickness, net-to gross, volume of shale, effective porosity, permeability, water saturation and hydrocarbon saturation.

The petrophysical parameters revealed reservoir R1 (Table 1) has an average net to gross of 52.8% and average shale volume of 11.2% across the wells. Effective porosity of R1 ranges from 20 to 27%, permeability index ranges from 477 to 1440 mD and hydrocarbon saturation from 48 to 71% across the wells. Porosity and permeability values obtained for reservoir R1 is rated very good based on Rider [37] criteria. Similarly, reservoir R2 has an

average net to gross of 77.6% and average shale volume of 11.4%. Effective porosity of R2 ranges from 21 to 26%, permeability index ranges from 345 to 1078 mD and hydrocarbon saturation from 55 to 79% across the wells (Table 2). Similar to reservoir R1, porosity and permeability values obtained for reservoir R2 is also rated very good based on Rider [37] criteria. This imply that the reservoirs are highly connected. The effective porosity values obtained for reservoirs R1 and R2 validates the established porosity range of 28-32% in the Niger Delta.

Structural interpretation of inline 6975 on the seismic section, revealed two horizons "X" and "Y" (Figure 6) and eight faults (F1, F2, F16, F8, F10, F18, F17 and F6) which cut across the horizons (Figure 7). Five faults (FI, F10, F18, F17 and F6) were identified as synthetic faults as they dip basinward.
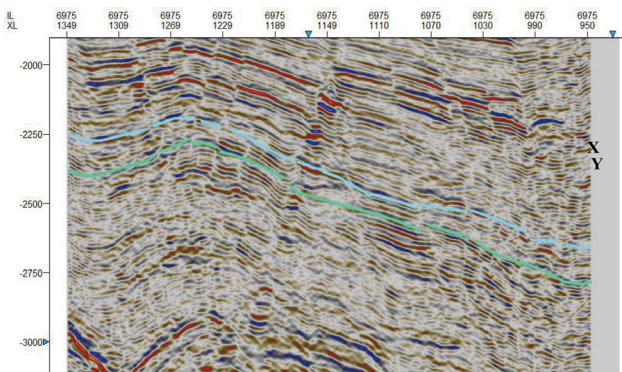
Figure 6. Horizon Mapping on inline 6975

Three faults (F2, F16 and F8) were identified as antithetic faults and dips landward. This observation is characteristic of growth structures (faults) which depicts the tectonic style of the Niger Delta. The geological structure observed (Normal faults) are favourable for hydrocarbon accumulation and will keep it from migrating vertically or laterally [11]. Figures 8a and 8b is the structural time map at top of reservoirs R1 and R2 showing the structural highs and network of faults observed in the field. Figures 9a and 9b is the depth structure map of reservoirs R1 and R2. The depth structure map shows the depth equivalence of the structures observed in the structural time map and was produced using an appropriate velocity model for time-depth conversion. The structures observed on the time-depth maps validates the existence of geological structures suitable for hydrocarbon accumulation in the study area.

Result of petrophysical models for porosity, permeability and water saturation is shown in Figures 10, 11 and 12 for reservoirs R1 and R2 respectively. The models show the distribution of the petrophysical parameters (porosity, permeability and water saturation) along well paths across the reservoir structure for reservoirs R1 and R2.
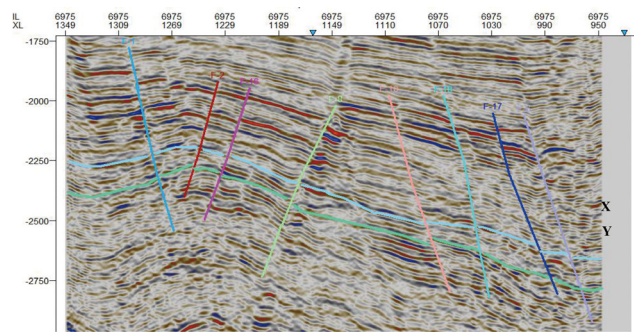

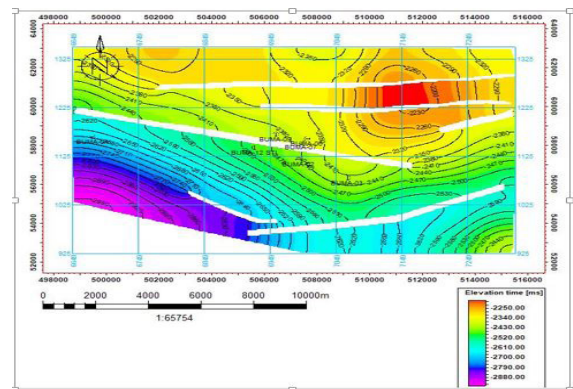**Figure 7.** Interpreted Seismic Section of inline 6975

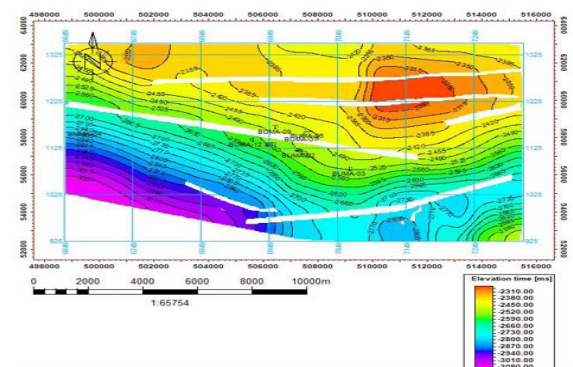**Figure 8a.** Time Structure Map for Reservoir R1 Top

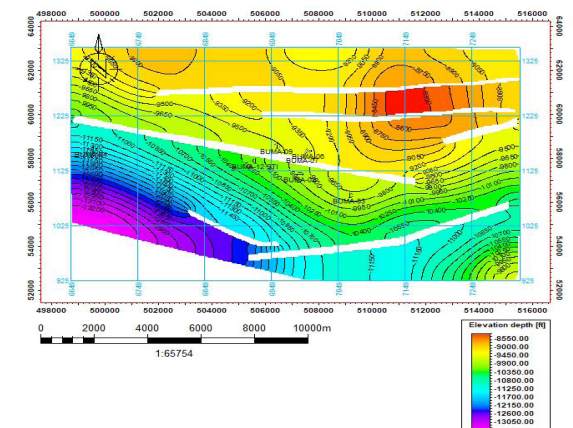**Figure 8b.** Time Structure Map for Reservoir R2 Top

Figure 9a. Depth Structure Map for Reservoir R1 Top

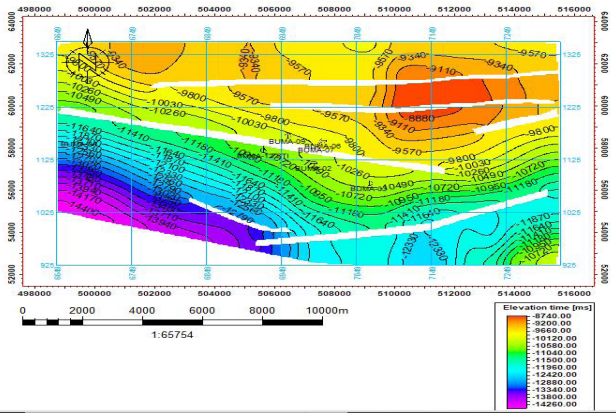DOI: https://doi.org/10.30564/jgr.v3i1.2783

Figure 9b. Depth Structure Map for Reservoir R2 Top

Figures 10a and 10b shows effective porosity model of reservoirs R1 and R2. The model shows porosity distribution across the wells and geological structures (faults) which cuts across the reservoir penetrated by the wells. For reservoir R1, effective porosity values (in fraction porosity unit) of 0.27, 0.26, 0.23, 0.2 and 0.22 were obtained for wells OSWIL-04, 12, 07, 06 and 02 respectively with an average of 0.236 (23.6%). In Figure 10a, it was observed that porosity value of well OSWIL-04 is highest, while for other wells OSWIL-02, 06, 07 and 12, porosity values are compatible with that obtained in the Niger Delta. Figure 10b is the porosity model for reservoir R2 showing the wells penetrating the highly faulted reservoir system.
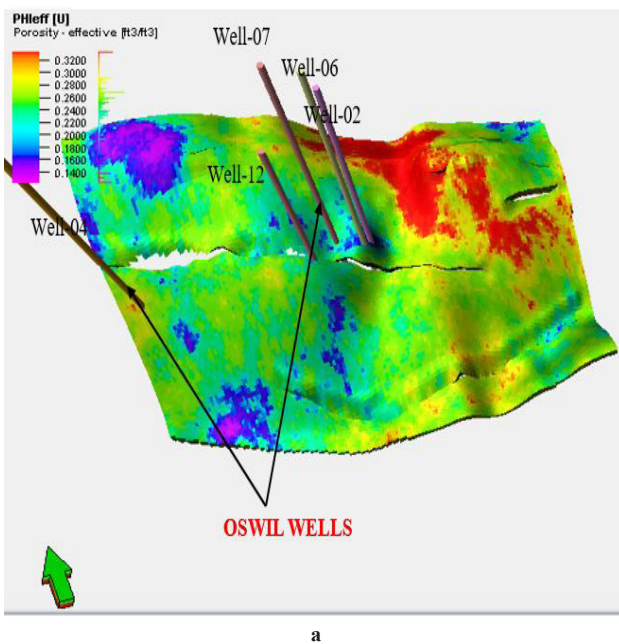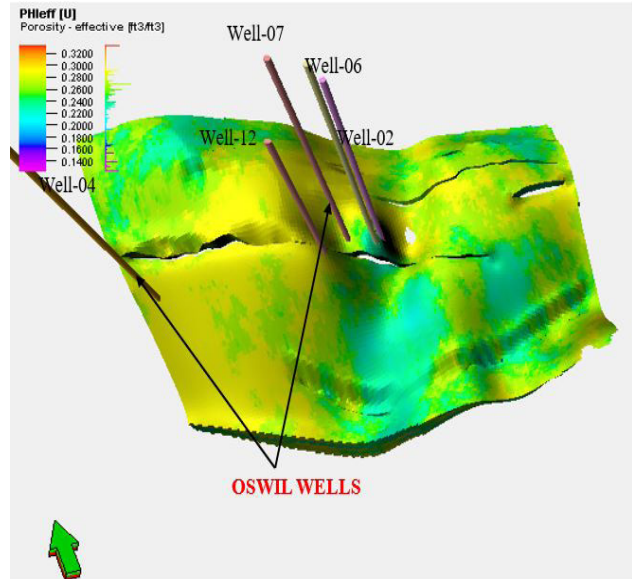

b

Figure 10. (a) Effective Porosity Model of Reservoir R1; (b) Effective Porosity Model of Reservoir R2

For reservoir R2, effective porosity values (in fraction porosity unit) obtained for wells OSWIL-04, 12, 07, 06 and 02 are 0.26, 0.22, 0.21, 0.24 and 0.23 respectively with an average of 0.232 (23.2%). Well OSWIL-04 has the highest value of porosity in reservoir R2 compared with other wells and these porosity values are compatible with that obtained in the Niger Delta. This indicates that the pore spaces within the reservoirs R1 and R2 are interconnected, and reservoir system is fault assisted hence fluid flow within the reservoir system is aided by presence of effective porosity and faulting.
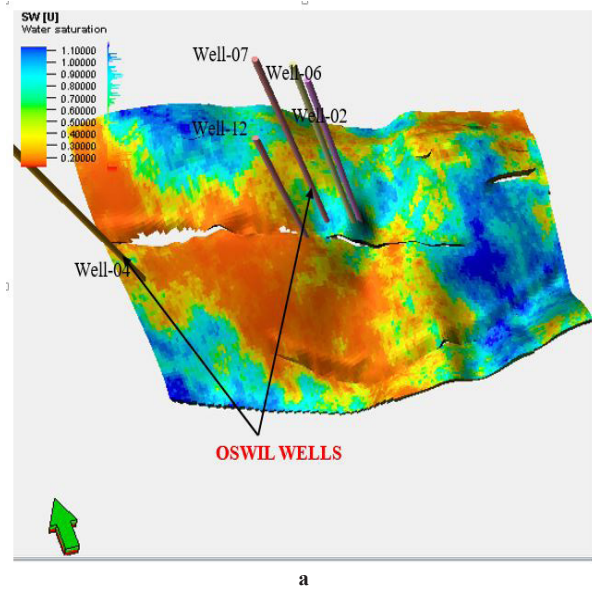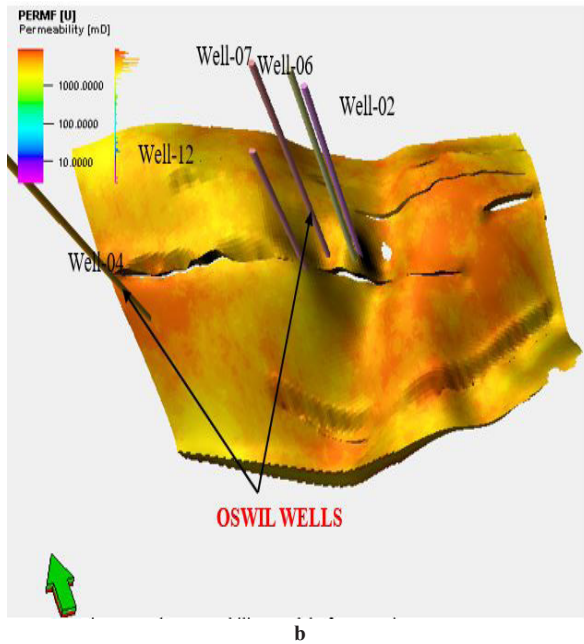

a
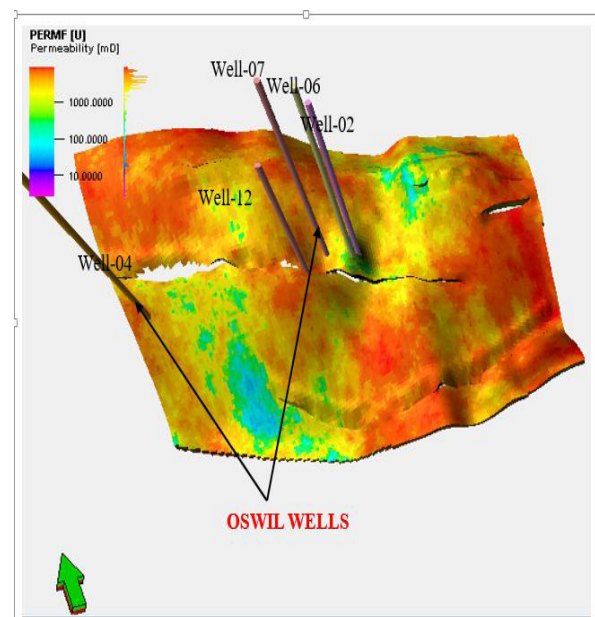
a

Figure 11. (a) Permeability (horizontal permeability) Model of Reservoir R1; (b) Permeability Model of Reservoir R2

Permeability model of reservoirs R1 and R2 is shown in Figures 11a and 11b. The permeability parameter (horizontal permeability) was modelled using the relationship that exists between core porosity and core permeability by populating the permeability logs generated. The model shows permeability in the horizontal direction for an anisotropic reservoir system, which is the direction fluid flow takes place [29]. The model reveal the two reservoirs R1 and R2 have permeability values ranging from hundreds to thousands milliDarcy (K > 100md) across the wells, which is rated very good (Rider [37]). Water saturation model for reservoirs R1 and R2 is shown in Figures 12a and 12b. The water saturation model shows fluid content distribution within the reservoirs for the various wells. The

Model also provides a pictorial view of predicting hydrocarbon saturation within the reservoirs for each well in the field. In Figure 12a, it was observed that the wells are located in areas of low water saturation within reservoir R1 with average water saturation value of 0.384 (38.4%), while in Figure 12b, the wells are also located in regions with low water saturation value which averages at 0.326 (32.6%). This observation implies that hydrocarbon saturation within reservoirs R1 and R2 for the wells averages at 0.616 (61.6%) for R1 and 0.674 (67.4%) for R2. These findings, reveal that the existing wells in the field are located in areas with high hydrocarbon saturation and validates the prolific nature of the wells.
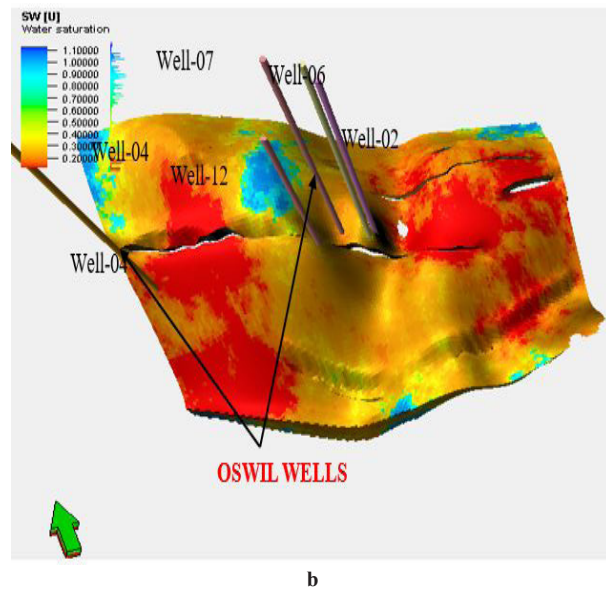

Figure 12. (a) Water Saturation Model of Reservoir R1; (b) Water Saturation Model of Reservoir R2

The volume of hydrocarbon in place within the two reservoirs R1 and R2 were estimated and results show that reservoir R1 contains an estimate of 455×10^6 STB of hydrocarbon while reservoir R2 contains an estimate 683×10^6 STB of hydrocarbon. These findings affirms that the two reservoirs R1 and R2 delineated in OSWIL field are highly prospective.

5. Conclusion

We have employed an integrated methodology which utilizes well log and seismic data to study the structural pattern and petrophysical parameters for hydrocarbon

play assessment of OSWIL field. Petrophysical parameters estimated for reservoirs R1 and R2 indicates that the reservoirs have high connectivity and hydrocarbon potential. Time-depth structural maps and petrophysical models produced for reservoirs R1 and R2 indicate a highly faulted reservoir system which aids fluid flow. The structural pattern observed in the field comprises of normal faults which is expected of the Niger Delta Basin. Effective porosity within each well is aided by faulting and this accounts for the high permeability index (K > 100md) observed across the wells in the field. These findings affirm that the two reservoirs R1 and R2 have good hydrocarbon potentials and the trapping mechanism in the field consist of fault assisted closures.

Acknowledgement

Declarations

Funding

Conflicts of interest/Competing interests

We declare that this research work has never been submitted previously by anyone to any journal for peer review and publication, hence it is an original work. All the ethical principles of research in the data collection, preparation, analysis and interpretation were implemented.

Code Availability (Software Used)

PETREL, 2014 Version.

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