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Original Paper

Prospect Analysis and Hydrocarbon Reservoir Volume Estimation in an Exploration Field, Shallow Offshore Depobelt, Western Niger Delta, Nigeria

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The daunting challenge in the exploration and production of oil and gas in the face of continual rise in the world's energy consumption has long been how to economically recover bypassed reserves within existing assets. This research is focused on the analysis of prospects and volumetric estimation of the hydrocarbon reservoirs delineated within an exploratory field using 3D seismic data and suites of wireline logs. The prospectivity of the delineated reservoir was carried out using seismo-structural interpretation and formation evaluation towards the assessment of the prolific hydrocarbon occurrence within the field. The reservoirs have porosity (0.29–0.32) for H1, (0.20–0.31) for H2 and (0.30–0.40) for H3 and the average computed hydrocarbon saturation of (0.31–0.62) for H1, (0.16–0.52) for H2 and (0.64–0.73) for H3, hydrocarbon pore volume (HCPV) of 28,706.95, 33,081.2 and 45,731.49 barrels for H1, H2 and H3, respectively, while the estimated stock tank oil initially-in-place (STOIIP) range (136.8–140.73) MMSTB for H1, (36.77–489.64) MMSTB for H2 and (166.62–308.14) MMSTB for H3. The observed porosity and hydrocarbon saturation for the delineated reservoirs as well as the estimated hydrocarbon pore volume and storage total oil in place indicate that the reservoirs are highly prolific. The study has therefore contributed to the understanding of hydrocarbon resource potential within the study area.

KEY WORDS: Hydrocarbon resource evaluation, Play analysis, Reservoir characterization, Formation evaluation, Prospect mapping, Niger Delta.

INTRODUCTION

Niger Delta basin covers ~ 75,000 km^2 and is situated at the southern end of the Nigeria bordering the Atlantic Ocean and the Gulf of Guinea (Ejedawe et al. 1984). The north-western, north-eastern and eastern boundaries of the basin are the Benin basin, Anambra basin and the Calabar Flank, respectively. The uplifted Cretaceous rocks belong to the Abakaliki anticlinorium outcrops in the northern part of the Niger Delta basin. The Niger Delta is divided into five extensional depobelts, namely Northern Delta, Greater Ughelli, Central Swamp, Coastal Swamp and Shallow Offshore depobelts (Fig. 1). Sediments contained in these depobelts become progressively younger seaward. In deep water, the delta is divided into three structural belts developed in a compressional regime: inner thrust belt, fold belt and outer thrust belt.

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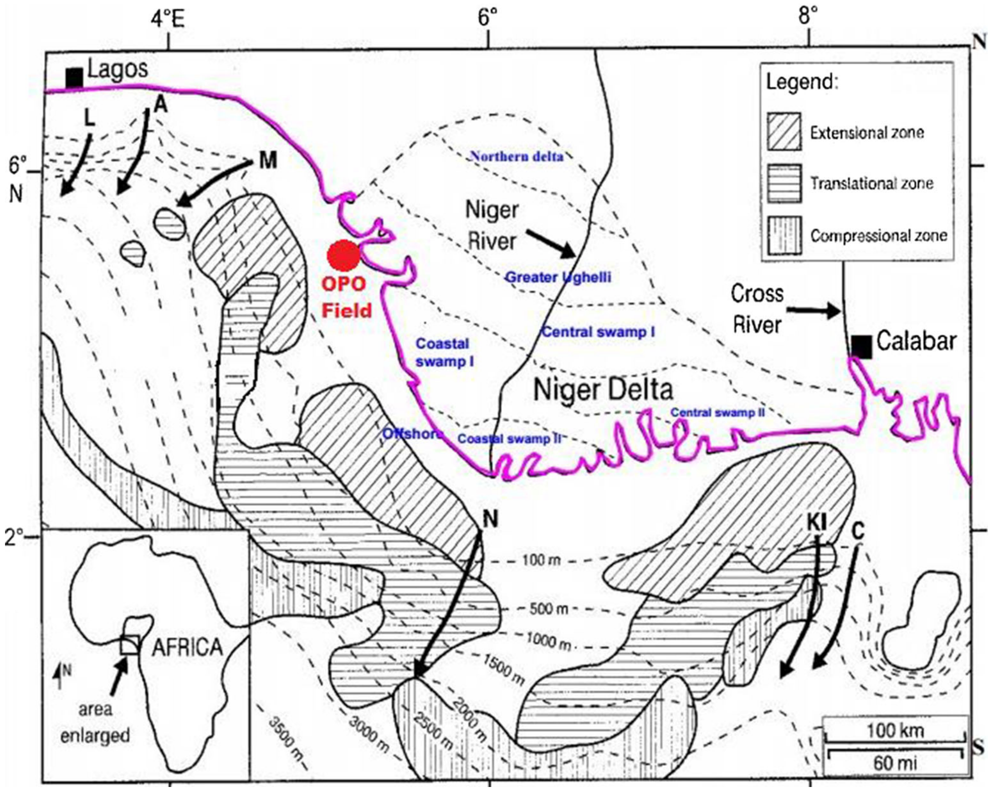

Fig. 1. Map of the Niger Delta showing the study area and the major depobelts. Modified from Damuth (1994).

The petroleum field of study is the OPO field in the shallow offshore depobelt, with water depths of about 50–100 metres within the western parts of the Niger Delta basin (Fig. 1) and situated between 5°00′E–5°02′E longitudes and 5°50′N–5°52′N latitudes. The area is situated between the bifurcated Mina-Ewan regional NW–SE fault systems. Several works have been carried out to evaluate the reservoir prospectivity and hydrocarbon resource potential of several fields within the Niger Delta basin (Chapin et al. 2002; Anomneze et al. 2015; Oyeyemi et al. 2017a, b; Sanuade et al. 2017). Factors dictating the occurrence and distribution of oil reserves are the availability of petroleum system elements, namely (a) source rocks, (b) reservoir rocks, (c) time, (d) temperature and (e) seal rocks. Other factors include tectonic control, stratigraphic control, sedimentology controls and hydrocarbon migration effects (Ejedawe 1981). The objective of this research is to analyse prospects and plays within the OPO field with the sole intention of evaluating its hydrocarbon potential for oil and gas exploration.

Geologic Setting and Stratigraphy

The geology of western Niger Delta has been discussed extensively by various authors (e.g., Allen 1965; Damuth 1994; Deptuck et al. 2007; Reijers 2011). This portion of the basin is flanked by 50–70-km-wide shelf, with a 150–200-m-deep shelve break (Deptuck et al. 2007). The western Niger Delta consists of a series of NNE-trending down-to-basin normal faults, which show up as several subtle lineations on the seafloor, with less than 5 m of offset. The most prominent feature among the structural elements on the seafloors is a structurally elevated region termed ‘‘Escravos high’’ by Deptuck et al. (2007). The sedimentary infill of the OPO field is part of the Niger Delta stratigraphic succession (Fig. 2), which has been subdivided into three distinct lithostratigraphic facies from Eocene to Recent in age. They are Akata, Agbada and Benin formations (Avbovbo 1978). The Akata Formation is the deepest lithostratigraphic unit, chiefly represented by plastic, low density, under-compacted and highpressured shallow to deepwater marine shales. This formation was deposited as the high energy delta was advancing into the deepwater. It is matured thermally and regarded as the main source rocks in Niger Delta. The Agbada Formation is a paralic sequence of interbedded, coastal, fluvio-marine sands and/or sandstones with intercalated marine shales. The upper part of this formation is mostly sand unit, where major hydrocarbon reservoirs in Niger Delta are localized with minor shale intercalations that serve as seals (or caprocks). The Benin Formation is the shallowest unit of the Niger Delta clastic wedge. It occurs mostly in the entire onshore and part of the offshore environments of the delta. Quite very little hydrocarbon accumulation has been associated with the highly porous and generally freshwater bearing Benin Formation.

Table 1. Available log suites for each well

OPO 1	OPO 2	OPO 3	OPO 4
Gamma ray	Gamma ray	Gamma ray	Gamma ray
P-wave	P-wave	P-wave	P-wave
Resistivity	Resistivity	Resistivity	Resistivity
	Density	Density	Density
	Caliper	Caliper	Caliper
	Neutron	Neutron	Neutron

MATERIALS AND METHODS

The dataset used comprises of well logs and 3D seismic reflection data with 496 inlines and 780 crosslines covering about 83.85-km-square area within the shallow offshore Niger Delta (Fig. 3). The number of samples per trace of the seismic data is

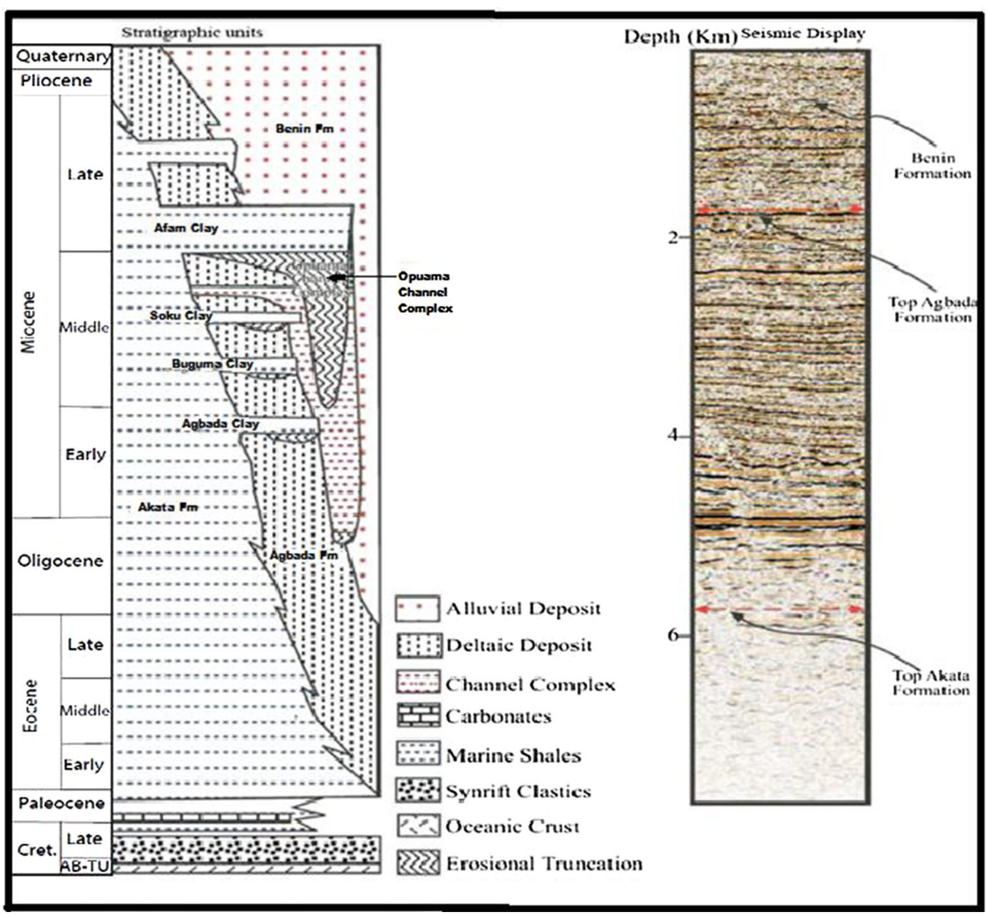

Fig. 2. Stratigraphy of the Niger Delta and variable density seismic display of the main stratigraphic units (Lawrence et al. 2002).

Table 2. Summary of equations used to compute petrophysical parameters

Petrophysical parameters	
Volume of shale	$V_{Sh} = 0.083\,[2^{(3.7*I_{GR})} - 1.0)]$
Porosity	$\varphi_D = \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_f}$
Water saturation	$S_w = \left(\frac{0.81*R_w}{R_t*\varphi^2}\right)^{1/2}$, when $a = 0.81$, $m = 2$ and $n = 2$
Hydrocarbon saturation	$S_{hc} = 1 - S_w$
Bulk volume of water	$BVW = \phi \times S_w$

I_{GR} = gamma ray index, ρ_{ma} = matrix density, ρ_b = bulk density, ρ_f = fluid density, R_w = formation water resistivity, R_t = true formation resistivity

751, with sample interval of 4 ms. The reflection quality of the seismic data is good such that fault and horizons were easily identifiable for picking and mapping. The available suite of wireline logs from the four wells (OPO 1, 2, 3 and 4) are gamma ray log, sonic (P-wave) log, caliper log, resistivity log, density log and neutron log (Table 1). The 3D seismic reflection, well logs and checkshot data were loaded into the interactive Petrel software workstation. The pertinent suite of wireline logs including gamma ray and resistivity logs were employed for the lithofacies analyses and delineation (and mapping) of hydrocarbon-bearing reservoirs, as shown in the methodology workflow (Fig. 4). Five reservoirs were delineated within the field but only three (H1, 2 and 3) were considered and correlated due to their optimal prospectivity. The regionally correlatable stratigraphic surface, such as a candidate maximum flooding surface (cMFS), was used as a distinct marker for correlation to ensure that the delineated and mapped reservoirs belong to same age (Fig. 5). The tops of the mapped reservoirs on well logs were tied to seismic data using the available checkshot data of OPO 3. This process involved sonic calibration and subsequent generation of the synthetic seismic that was later used for seismic-to-well tie in order to identify and map corresponding horizons on the seismic section (Fig. 6). A velocity model was

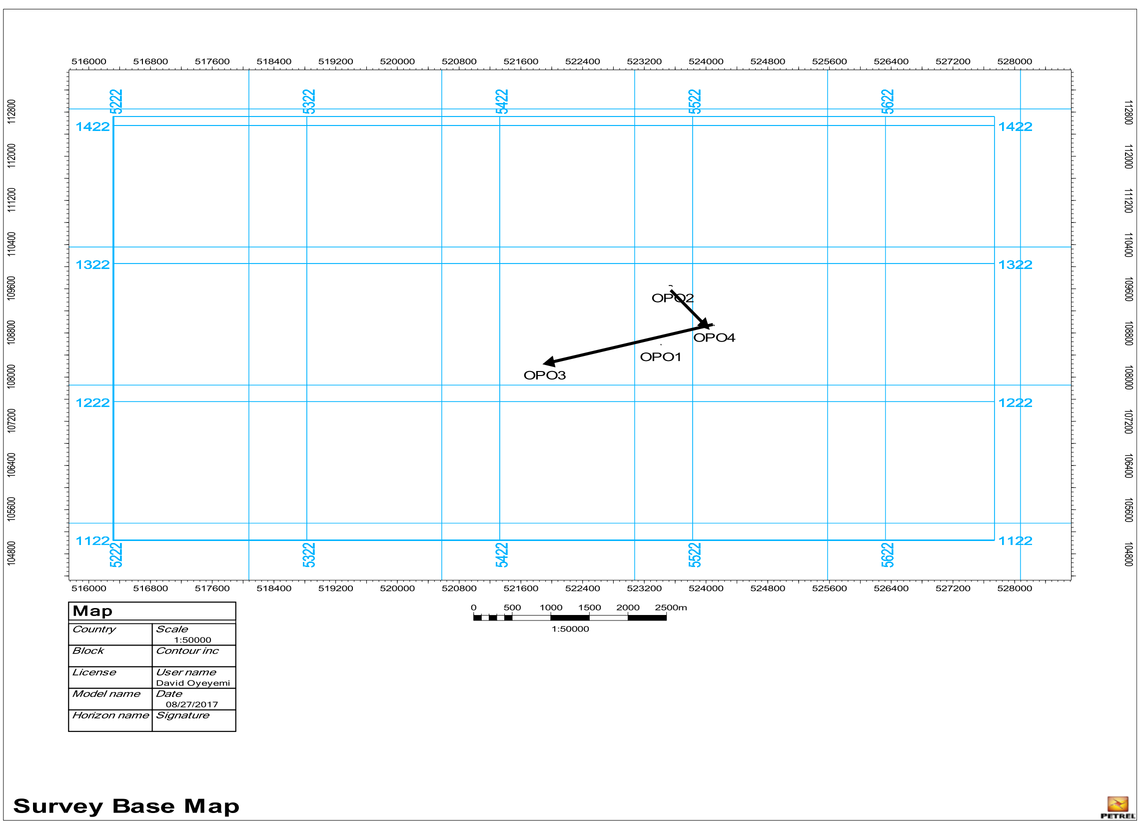

Fig. 3. Survey basemap in the study area showing the seismic survey profile lines (inlines and crosslines) and well locations. The arrows indicate the direction of wireline logs correlation.

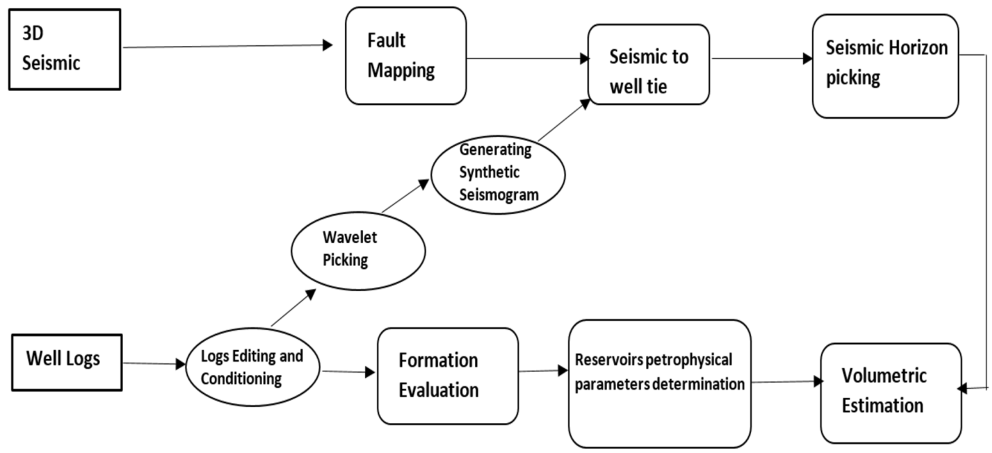

Fig. 4. Flow chart of the methodology.

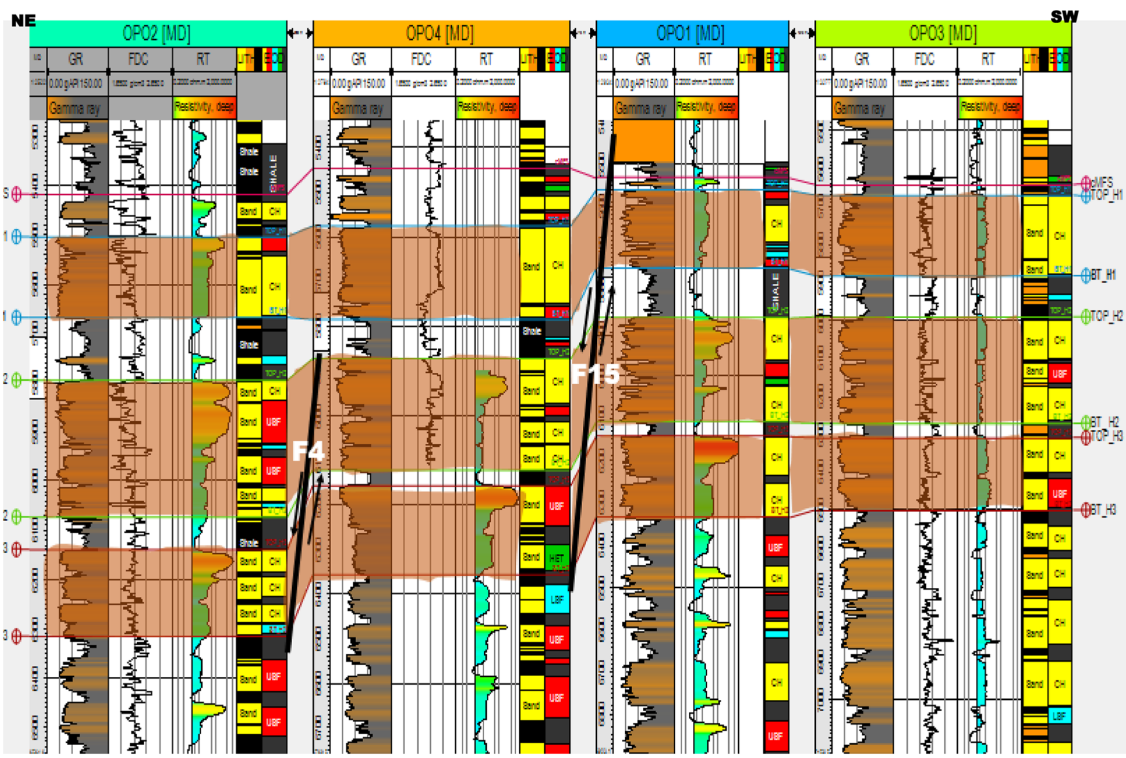

Fig. 5. NE–SW well correlation using a regional stratigraphic surface (cMFS) in the OPO field showing three delineated reservoir sands.

also constructed for depth conversion of the interpreted horizons on the seismic section. This time to depth conversion process was carried out using a linear equation (TVDSS = 4.60526 * TWT + 1563.99) derived from the available checkshot data. Several relations were adopted for the computations of petrophysical properties of the reservoirs, as presented in Table 2. Volume of shales was computed using the Larionov (1969) equation for tertiary unconsolidated rocks. The density porosity was computed using Asquith (2004) relation, whereas both water and hydrocarbon saturation indices were estimated using the Archie's method (Archie 1942). Within each reservoir, the reserve or volumetric

Table 3. Summary view of equations used for volumetric estimation

Volumetric parameters equations and equalities	
Original oil-in-place (MMSTB)	$OOIP = 7758 * A * h * \phi * (1 - S_w) * NTG$
Stock tank oil initially-in-place (MMSTB)	$STOIIP = \frac{7758 * A * h * (1 - S_w) * NTG}{B_{oi}}$
HCPV (Acre-Ft)	$HCPV = A * h * \phi * (1 - S_w) * NTG$

A = area, h = reservoir thickness, φ = porosity, NTG = net-to-gross, B_{oi} = oil formation volume factor at reservoir pressure

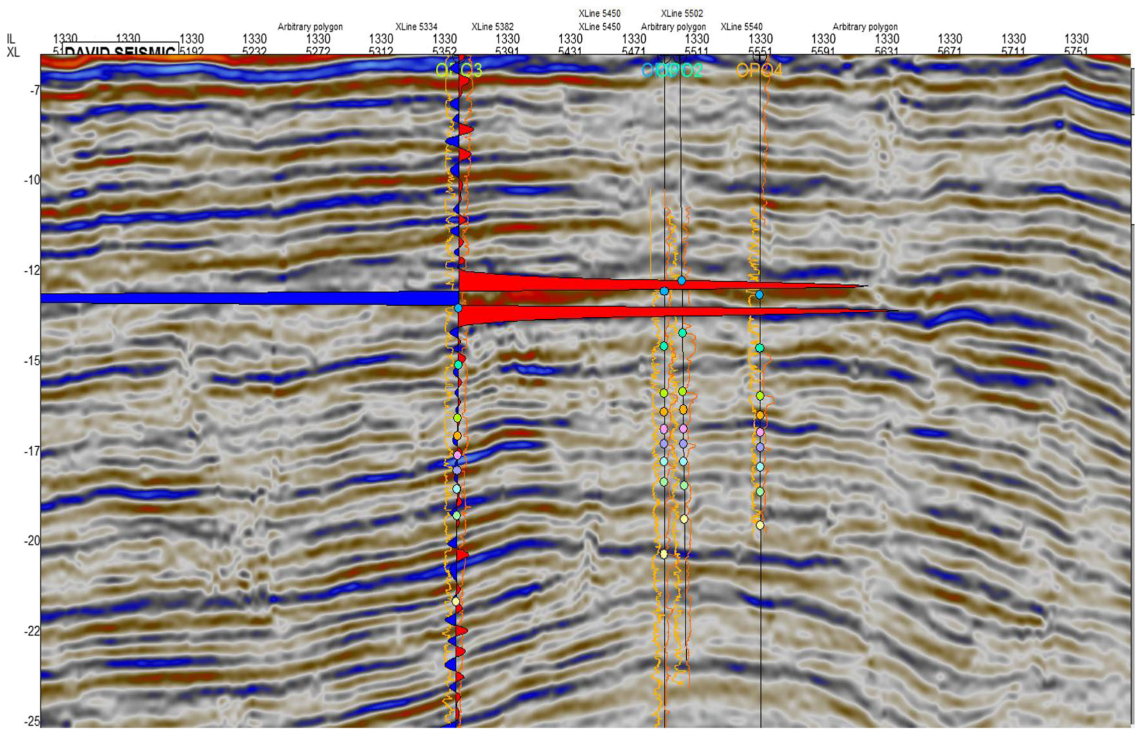

Fig. 6. Seismic to well tie on inline 1330.

estimations in terms of original oil-in-place (OOIP), stock tank oil initially-in-place (STOIIP) and hydrocarbon pore volume (HCPV) of mappable prospects were carried out using a deterministic approach of classic volumetric reserve calculation method (CVRC), as shown in Table 3.

RESULTS AND DISCUSSIONS

Seismic Structural Interpretation and Hydrocarbon Prospects Evaluation

Structural features such as faults configurations and orientations determine the degree of hydrocarbon accumulations and make them differ from one field to another. Structural traps are generally the major hydrocarbon trapping mechanisms within the Niger Delta (Doust and Omatsola 1990). Structural trapping styles delineated within the field include the regional hanging wall (RHW), regional footwall (RFW), counter regional fault closure (CRFC), collapsed crested structure (CCS) and simple fault rollover (SFR) (Figs. 7 and 8). The delineated faults are generally listric in nature with major large and regional faults (F1 and F7) extending down the basin. Buried faults F23 and F5 are synthetic in terms of dipping directions making them counter regional and form a closure. The entire structural framework of the field is in consonance with the geology of the Niger Delta (Doust and Omatsola 1990). Several delineated direct hydrocarbon indicators such as

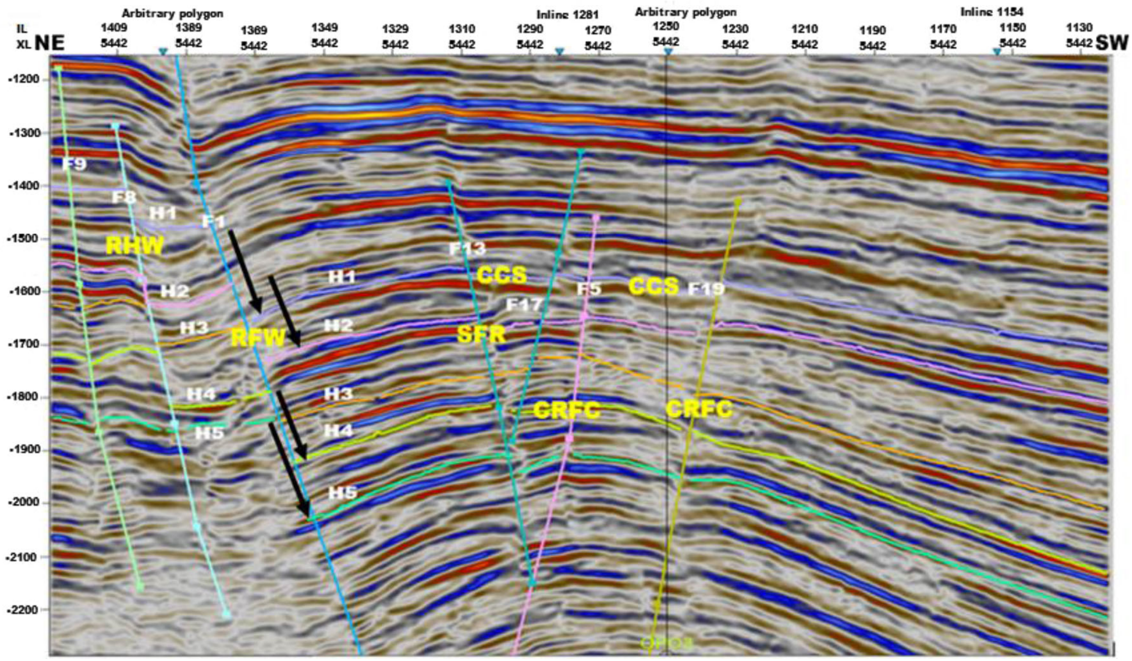

Fig. 7. Seismic structural interpretation of crossline 5542 showing faults and horizons.

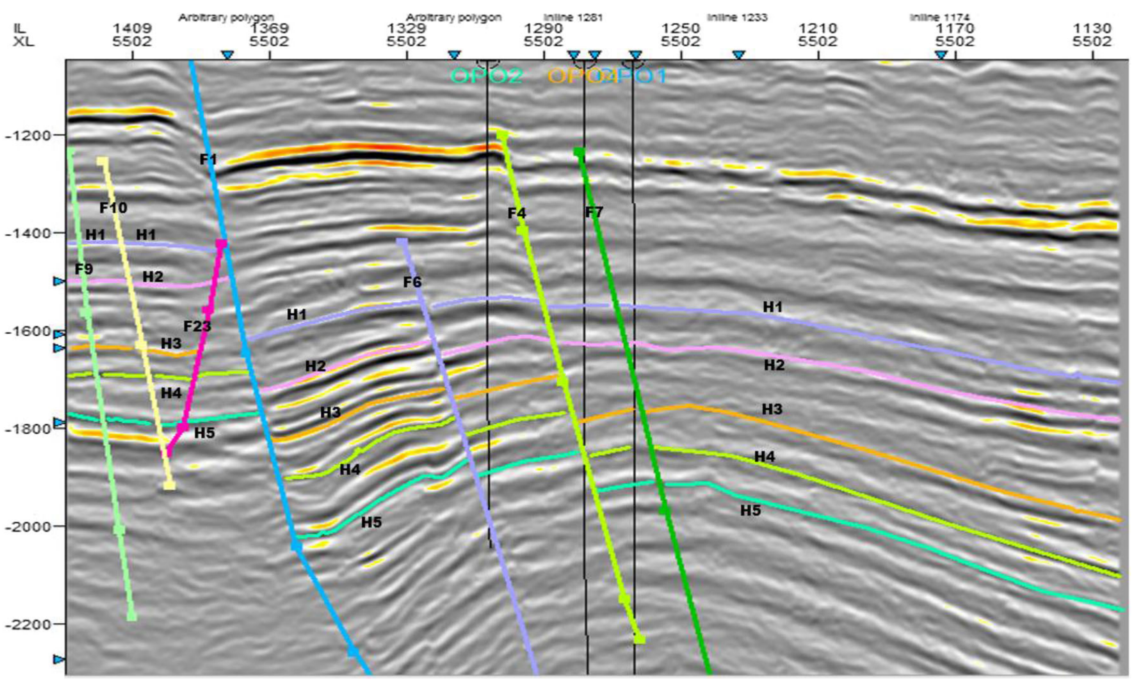

Fig. 8. Seismic structural interpretation of crossline 5502 with colour blending attributes.

bright spots were observed on the seismic section localizing within the fault-controlled hydrocarbon leads (Fig. 8). The hydrocarbon-bearing reservoirs in the field are generally fault-controlled as evident on the depth structure maps (Figs. 9, 10 and 11). The probable hydrocarbon prospects within the field as

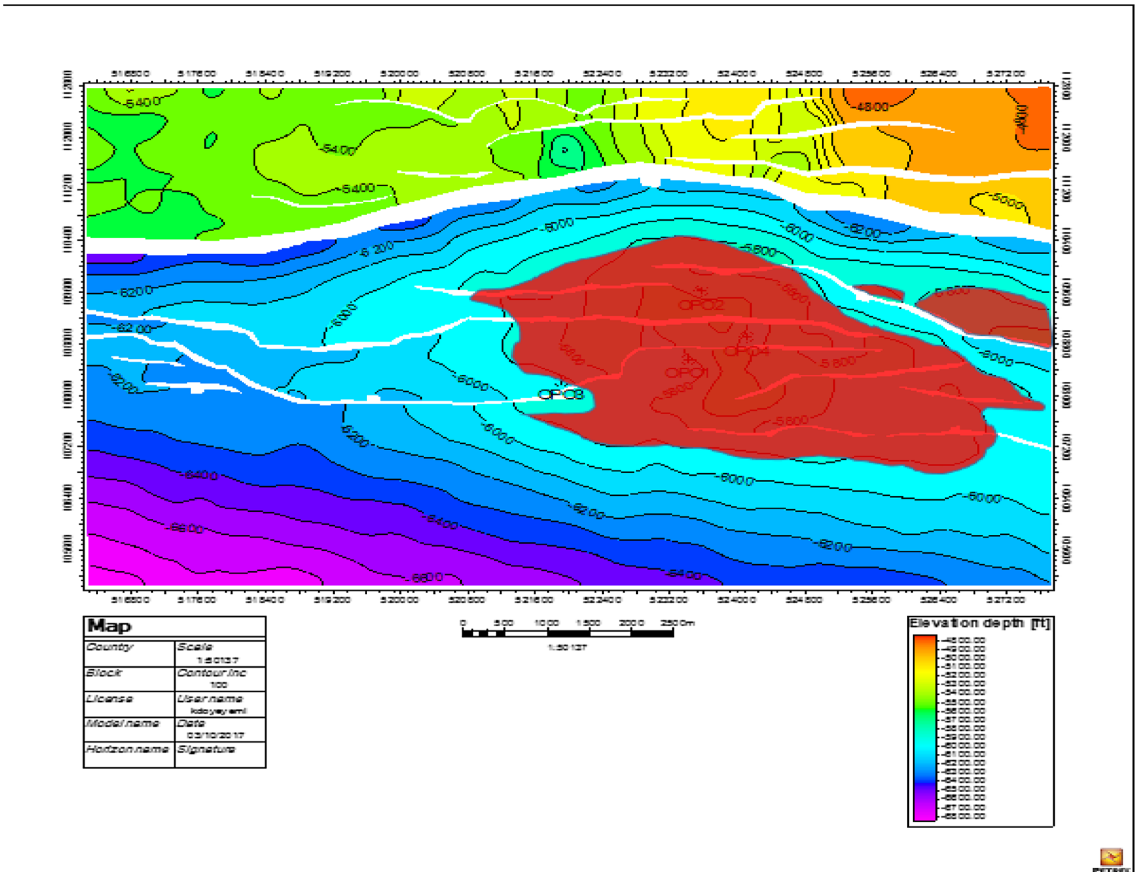

Fig. 9. Structural depth map of reservoir H1 showing the delineated prospects.

shown on the structure map of reservoirs H1, H2 and H3 are associated with large, medium and small fault-controlled closures against a series of down-to-south growth faults, rollovers and other few synthetic faults. These structural features constitute viable trapping mechanisms for hydrocarbon in the field.

Reservoir Geology

Three lithofacies were identified and correlated within the sedimentary sequences in the field using the gamma ray motifs (Fig. 5). They include sand facies, sand shale facies and shale facies. The sand facies are generally porous with better interconnected pore spaces (high permeability), and so they can be impregnated with hydrocarbon. Sand shale facies equally have good porosity and can accommodate hydrocarbon, but fluid flow rate through them is slow due to shale intercalations. Though shale facies have higher gamma ray values and total porosity than sand facies, their pore spaces are never interconnected and thus have quite low effective porosity. The shale facies constitute adequate source rocks, traps and cap rocks in the Niger Delta basin. Three hydrocarbon bearing reservoirs (H1, H2 and H3) with very low gamma ray and high resistivity values were mapped and correlated across the wells (Fig. 5). The quality of these reservoirs in terms of type and occurrence of hydrocarbon within the reservoirs depends on the geochemical constituents and maturity of the source rocks (Akaegbobi et al. 2000), trapping styles (Oyeyemi and Aizebeokai 2015), migration, seals and retention capacity. Figure 12 depicts a north-to-south deposition of massive sand sediments in a channel fills system. The lower values of the volume of shales in Figure 12 further confirm that the reservoir sands within the field have high potential for good porosity and permeability.

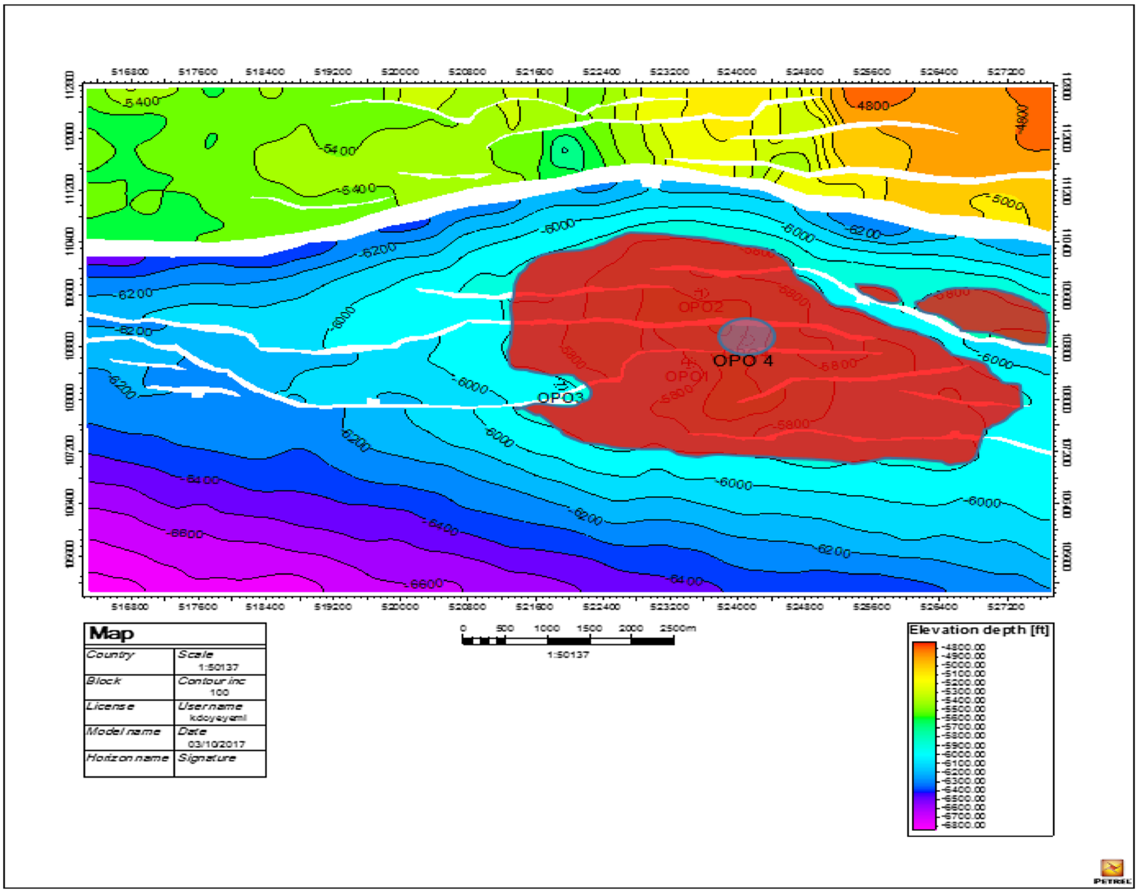

Fig. 10. Structural depth map of reservoir H2 showing the delineated prospects.

Formation Evaluation and Reserve Estimate

The quantitative petrophysical parameters of the delineated reservoirs including net sand thickness (NST), net pay thickness (NPT), net-to-gross (NTG), volume of shale (V_{sh}), water saturation (S_w), hydrocarbon saturation (S_h), bulk water volume (BVW) and porosity across the wells (OPO 1, 2, 3 and 4) are estimated and summarized in Tables 4, 5 and 6 for reservoir H1, H2 and H3, respectively. The computed porosity estimate in the reservoirs varied from 0.29 to 0.31 for H1, 0.20 to 0.31 for H2 and 0.30 to 0.40 for H3. Estimated hydrocarbon saturation ranges are 0.62–0.32, 0.16–0.52 and 0.64–0.73 for H1, H2 and H3, respectively. The relationship between porosity and volume of shale for reservoir H1 is such that the well with highest volume of shale for same reservoir has the lowest porosity (29%).

Figure 8 shows the map of volume of shale for reservoir H1 with an inset of the log motifs to give more insight into the environment of deposition within the field. The depositional environment is that of a channel deposit with reworked sediments moving down-to-south, closer to shoreface environment of the shallow marine shelf. Reduction in the volume shale across the channel deposit will probably lead to increase in porosity within the pay zone of the reservoir H1. Volumetric estimation of the producible amounts of hydrocarbon within each reservoir is presented in Tables 7, 8 and 9. Hydrocarbon pore volume in barrels for the reservoirs H1, H2 and H3 are 28,706.95, 33,081.2 and 45,731.49 respectively (Table 10).

Stock tank oil initially-in-place (STOIIP) reserves for OPO1 wells across all the delineated reservoirs are between 140.73 MMSTB and 489.64 MMSTB, while those for OPO2 well are between 136.8 MMSTB and 205.68 MMSTB. The OPO3 well is completely wet, and its wetness is perhaps due to well drilling off structures within the field, and this has been reported to be a serious exploration challenge within the Niger Delta, leading to well failure and

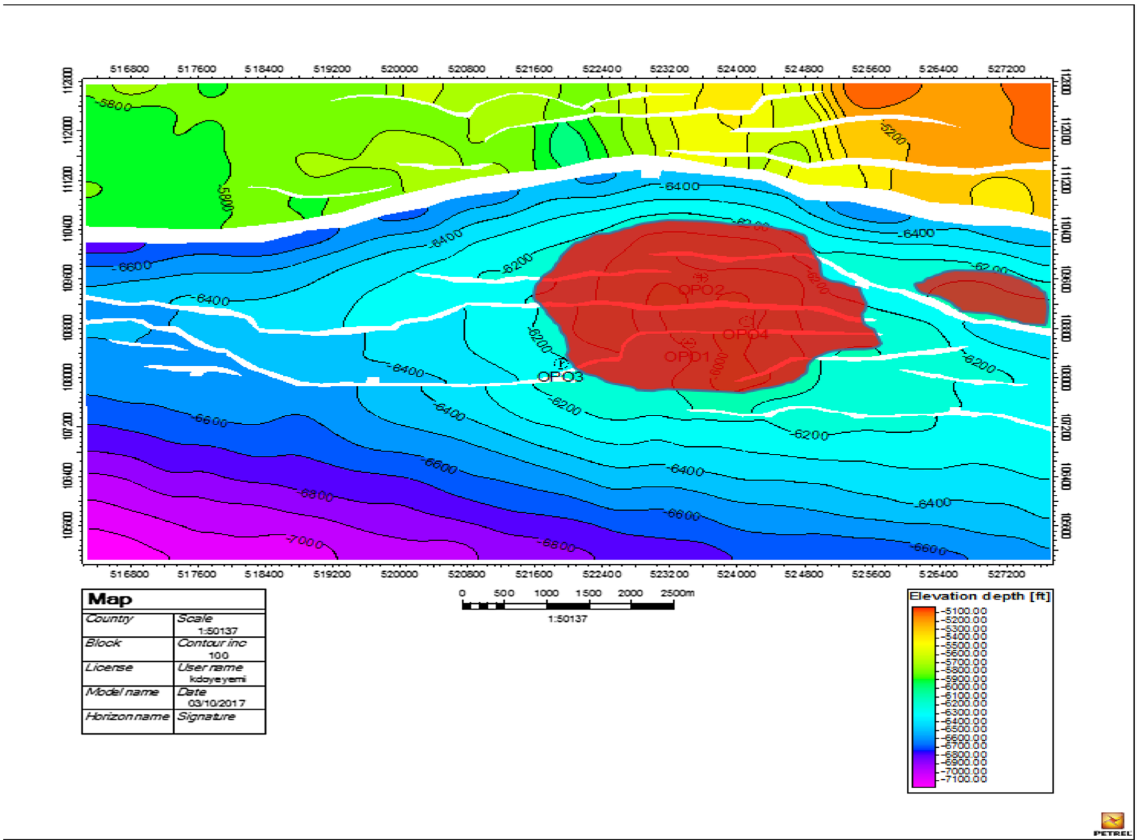

Fig. 11. Structural depth map of reservoir H3 showing the delineated prospects.

abandonment (Nigerian Oil and Gas Sector Report 2014). This issue most of the times may be related to the structural complexity of some hydrocarbon traps delineated within the field. The OPO4 well is, however, the least hydrocarbon productive well with STOIIP reserve estimates in the range 36.77–308.14 MMSTB across only reservoirs H2 and H3 (Tables 8 and 9).

CONCLUSION

The hydrocarbon resource potential of the OPO field within the western Niger Delta has been evaluated using seismic-driven and well logs-based methodologies. Hydrocarbon reservoirs and prospects were delineated, and volumetric estimations of hydrocarbon in place were carried out. Seismic structural interpretation of the field reveal listric faults with several synthetic faults, regional hanging wall, regional footwall, simple fault rollover, collapsed crested faults and fault-dependent closures that form hydrocarbon entrapment styles in the study area. Computed petrophysical attributes for the three delineated reservoirs favour the optimal prospectivity of the reservoir with very good quality and high porosity and hydrocarbon saturation. Volumetric reserve estimation of the hydrocarbon in place within the reservoirs reveals that H2 in OPO1 well has the highest volume in MMSTB, followed by the reservoir H3 in OPO1 well. The OPO1 well is the most productive of all the wells, followed by OPO2 and OPO4. The OPO3 well is completely wet with 100 per cent water saturation. The wetness of this well is perhaps due to well drilling off structures, which has formed a serious exploration challenge within the Niger Delta. However, this well can be used for field development and management in term of enhanced oil recovery through water flooding.

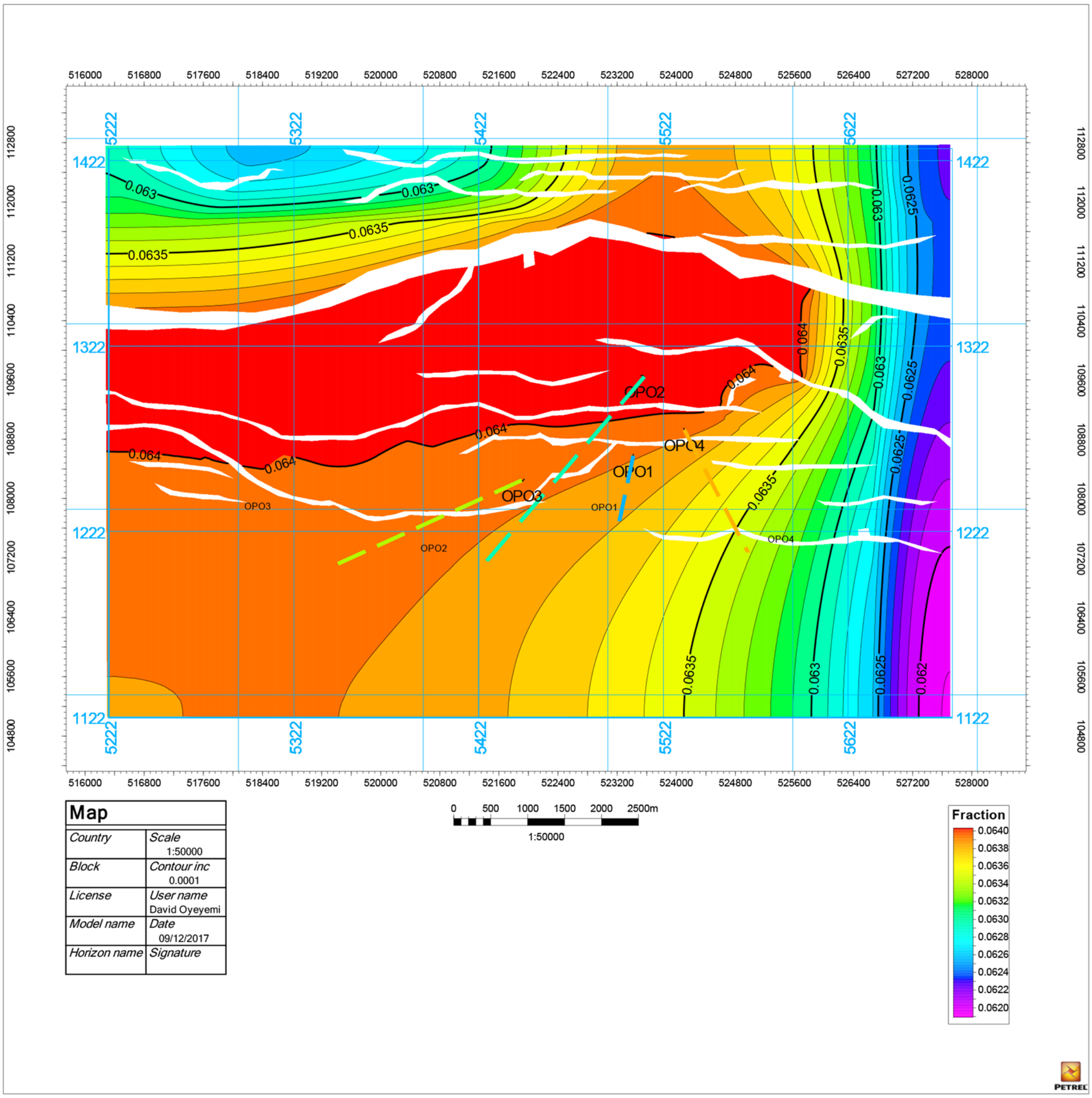

Fig. 12. Volume of shale map of reservoir H1 for interpretation of the probable environment of deposition.

Table 4. Computed petrophysical parameters of reservoir H1

Well name	NST (Ft)	NPT (Ft)	NTG (%)	BVW (%)	VSH (Frac)	Sw	Sh	Swirr	POR
OPO 1	147.88	89.48	80.40	0.214	0.04	0.69	0.31	0.065	0.31
OPO 2	151.02	39.88	90.60	0.114	0.012	0.38	0.62	0.067	0.30
OPO 3	199.92	NIL	95.0	0.32	0.041	1.0	NIL	0.063	0.32
OPO 4	159.27	NIL	94.40	NIL	0.33	NIL	NIL	0.069	0.29

NST net sand thickness, *NPT* net pay thickness, *NTG* net- to- gross, *BVW* bulk volume of water, *POR* porosity

Table 5. Computed petrophysical parameters of reservoir H2

Well name	NST (Ft)	NPT (Ft)	NTG (%)	BVW (%)	VSH (Frac)	Sw	Sh	Swirr	POR
OPO 1	221.63	116.0	90.40	0.15	0.024	0.48	0.52	0.065	0.31
OPO 2	222.24	99.73	79.20	0.22	0.25	0.71	0.29	0.065	0.31
OPO 3	262.38	NIL	94.0	0.29	0.039	1.0	NIL	0.069	0.29
OPO 4	216.02	45.6	87.0	0.17	0.03	0.84	0.16	0.101	0.20

NST net sand thickness, *NPT* net pay thickness, *NTG* net-to-gross, *BVW* bulk volume of water, *POR* porosity

Table 6. Computed petrophysical parameters of reservoir H3

Well name	NST (Ft)	NPT (Ft)	NTG (%)	BVW (%)	VSH (Frac)	Sw	Sh	Swirr	POR
OPO 1	165.71	127.6	88.0	0.108	0.016	0.36	0.64	0.067	0.30
OPO 2	159.57	48.43	90.32	0.132	0.007	0.33	0.67	0.050	0.40
OPO 3	174.93	NIL	90.0	0.31	0.049	1.0	NIL	0.065	0.31
OPO 4	160.42	117.95	83.93	0.081	0.05	0.27	0.73	0.067	0.30

NST net sand thickness, *NPT* net pay thickness, *NTG* net-to-gross, *BVW* bulk volume of water, *POR* porosity

Table 7. Volumetric reserve estimate of reservoir H1

Well name	Area (acres)	NPT (Ft)	NTG	Volume (acre-ft)	POR	Sh	OOIIP (MMSTB)	STOIIP (MMSTB)
OPO 1	3384.66	89.48	0.804	302,859.38	0.31	0.31	181.54	140.73
OPO 2	3384.66	39.88	0.906	134,980.24	0.30	0.62	176.47	136.8
OPO 3	3384.66	NIL	0.905	N/A	0.32	NIL	N/A	N/A
OPO 4	3384.66	NIL	0.944	N/A	0.29	NIL	N/A	N/A

Table 8. Volumetric reserve estimate of reservoir H2

Well name	Area (acres)	NPT (Ft)	NTG	Volume (acre-Ft)	POR	Sh	OOIIP (MMSTB)	STOIIP (MMSTB)
OPO 1	4816.40	116.0	0.904	558,702.4	0.31	0.52	631.63	489.64
OPO 2	4816.40	99.73	0.792	480,339.6	0.31	0.29	265.33	205.68
OPO 3	4816.40	NIL	0.94	N/A	0.29	NIL	N/A	N/A
OPO 4	4816.40	45.6	0.87	219,627.84	0.20	0.16	47.44	36.77

Table 9. Volumetric reserve estimate of reservoir H3

Well name	Area (acres)	NPT (Ft)	NTG	Volume (acre-Ft)	POR	Sh	OOIIP (MMSTB)	STOIIP (MMSTB)
OPO 1	2363.35	127.6	0.88	301,563.46	0.30	0.64	395.29	306.42
OPO 2	2363.35	48.43	0.9032	114,457.04	0.40	0.67	214.94	166.62
OPO 3	2363.35	NIL	0.90	N/A	0.31	NIL	N/A	N/A
OPO 4	2363.35	117.95	0.8393	278,757.13	0.30	0.73	397.5	308.14

Table 10. Hydrocarbon pore volume (HCPV) for the delineated reservoirs (H1–H3)

Reservoir name	Area (acres)	Average NPT (Ft)	NTG	Volume (acre-Ft)	Average POR	Average Sh	HCPV (barrel)
H1	3384.66	64.68	0.90	218,919.81	0.31	0.47	28,706.95
H2	4816.4	87.11	0.88	419,556.6	0.28	0.32	33,081.2
H3	2363.35	97.99	0.88	231,584.67	0.33	0.68	45,731.49

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