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Reservoir Evaluation and Volumetric Analysis of Rancho Field, Niger Delta, Using Well Log and 3D Seismic Data

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Abstract

Exploration and exploitation for hydrocarbon are associated with a lot of complexities, it is therefore necessary to integrate available geologic models for accurate hydrocarbon prospecting and risk analysis. This study is aimed at determining the structural, petrophysical and volumetric parameters for reservoir evaluation within the Rancho field. 3D seismic data was used for evaluating the hydrocarbon potential of the field. A suite of well logs but not limited to gamma ray logs (GR), deep resistivity log (DRES), neutron log (NPHI) and density log (RHOB) from four (4) wells were employed in characterising dynamic properties of the reservoirs. The GR log was used in lithology identification while the resistivity log was used in identifying probable hydrocarbon bearing sands. A correlation exercise was carried out to identify lateral continuity and discontinuity of facies across the wells. Thereafter petrophysical parameters were analysed from the suite of wire line logs. Major faults were mapped on the 3D seismic data and identified hydrocarbon bearing sand tops from the well logs were mapped as horizons on the seismic section, maps were generated and volumetric analysis was done. Nine (9) hydrocarbon sands (Sands A - I) were identified within the study area. The well log revealed an alternation of sand and shale layers as well as shale layers increased in thickness with depth, while the sand bodies reduced in thickness with depth which characterized the Abgada Formation of the Niger Delta. The effective porosities of the sands range from 21% - 31%, the permeability ranges from 28% - 44%, 70% - 80% for the net to gross, volume of shale range from 14% - 40% and hydrocarbon saturation ranges from 63% - 82%. Twelve (12) faults were mapped within the study area and the structural styles revealed a fault assisted closures. The volumetric analysis showed that Sand F had Stock Tank Oil Initially In Place (STOIIP) of 5,050,000,000 bbls of oil and Sand G had STOIIP of 17,870,000,000 bbls, these sands are proposed to be developd because of the volume of oil in them and area covered by the reservoir, calculated Gross Rock Volume (GRV) of 29.5 km^3 and 104.5 km^3 respectively.

Keywords

Neutron Log, Density Log, Stock Tank Oil Initially In Place, Gross Rock Volume

1. Introduction

The search for hydrocarbon reservoir rocks is a goal in the exploration phase in the oil and gas industry. The exploration and production asset teams are faced with great challenges in predicting and making decisions on the life cycle of hydrocarbon bearing reservoirs. Accurate modeling of field scenarios is therefore needed before making decisions, as good decisions optimize hydrocarbon extraction and finally save precious time and capital. Earlier to decision making by the asset team some geologic exercises are carried out which include identifying and mapping structures and describing the stratigraphy of the economic hydrocarbon reservoirs. Some mathematic computations such as calculating for porosity, permeability, hydrocarbon saturation, net to gross ratio, oil in place, stock tank and volume of shale among others are done to evaluate prospective hydrocarbon bearing reservoirs.

The amount of oil in a subsurface reservoir is called oil in place (OIP) [1]. Only a fraction of this oil can be recovered from a reservoir. This fraction is called the "Recovery factor" [2]. The portion that can be recovered with improved technology is considered to be a potential. The portion that is not recoverable is not included unless and until methods are implemented to produce it [3]. Stock Tank Original Oil in Place (STOOIP) refers to the oil in place before the commencement of production, while Stock Tank Oil Initially in Place (STOIIP) is being referred to the volume of oil after production at surface pressure and temperature.

The enormous cost of exploration and production for hydrocarbon makes it a thing of necessity to strive for high level of perfection in the methods to be adopted for its detection and quantification. Also drilling time and cost-effectiveness are one of the driving factors in the oil and gas industry, interest in reservoir evaluation is being channeled towards qualifying and quantifying hydrocarbon reservoirs. This has been done to reduce the level of uncertainty associated with geological models. The integration of well log analysis and 3-D seismic interpretation are among the most efficient techniques and approaches that can be adopted to estimate the reserve of any hydrocarbon bearing field in the oil and gas industry for profitability and effective productivity in commercial quantity, the need for evaluating the reserve of the Rancho field hence this study.

2. Geology of the Study Area

Rancho field is located within the onshore Niger Delta. The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta Province (Figure 1). The Niger Delta province contains only one identified petroleum system, known as the Tertiary Niger Delta (Akata-Agbada) petroleum system [4] [5]. The Niger Delta has been the focus of hydrocarbon exploration since 1937. Now it is Africa's leading oil province. Today, the Niger Delta is covered with a dense grid of 2-D and 3-D seismic data and it has been penetrated by more than 5000 wells. Petroleum occurs throughout the Agbada formation of the Niger Delta. The Akata Formation is Paleocene in age. It is composed of thick shales, turbidite sands, and small amounts of silt and clay. Akata formation is formed during low stands in sea level and in oxygen deficient conditions. This formation is estimated to be up to 7000 meters thick. While the Agbada Formation dates back to Eocene. It is a marine facies with both freshwater and deep sea characteristics. This is the major oil and natural gas bearing facies in the basin. The hydrocarbons in this layer formed when this layer of rock became sub aerial and was covered in a swamp type of environment that contained lots of organics. It is estimated to be 3700 meters thick. The Benin Formation is Oligocene and younger in age. It is composed of continental flood plain sands and alluvial deposits.

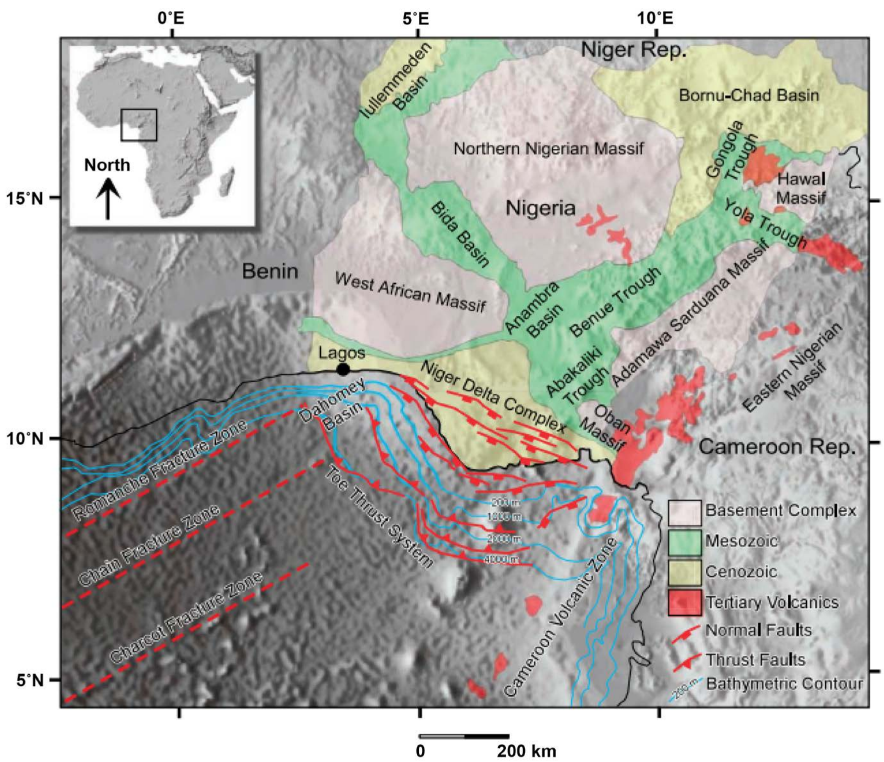

Figure 1. Location Map of the Niger Delta Region Showing the Main Sedimentary Basins and Tectonic Features. The Delta is bounded by the Cameroon Volcanic Zone, The Dahomey Basin, and the 4000-M (13,100-Ft) Bathymetric Contour. Topography and Bathymetry are shown as a Shaded Relief Gray-Scale Image [6].

3. Method of Study

The data used in this study consist of digital three-dimension seismic data and a suite of wire line logs consisting but not limited to Gamma ray, Deep Resistivity, Neutron and Density logs. The well logs were used to delineate the stratigraphic sections of the study area. The stratigraphic correlation of the four (4) wells was carried out by using gamma ray log and the deep resistivity log. Hydrocarbon bearing sands were identified and mapped as sections with low gamma ray reading and high resistivity log readings from the well section. A cross plot of the sands formation density and neutron logs were done for hydrocarbon typing. Thereafter petrophysical analysis was calculated for the reservoirs of interest the parameters calculated for are as follows:

Shale volume (Vsh) was estimated, using the [7] formula in Equation (1), which uses values from the gamma ray (GR) [8] in Equation (2).

$$Vsh = \left(0.083^{(2(3.7\times IGR))} - 1.0\right) \tag{1}$$

$$IGR = \frac{GR\log - GR\min}{GR\max - GR\min} \tag{2}$$

where IGR = gamma ray index, $GR\log$ = picked log value, $GR\min$ = minimum gamma ray reading, $GR\max$ = maximum gamma ray reading.

For porosity values, $\varnothing_D$ was determined from [7] equation by replacing the bulk density readings gotten from the density log within each reservoir into the Equation (3)

$$\varnothing_D = \frac{\rho_{ma-\rho_b}}{\rho_{ma} - \rho_f} - V_{sh}\frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \tag{3}$$

where ρ_{ma} = matrix density, ρ_b = formation bulk density and ρ_f = fluid density.

Effective porosity formula is used to compute the effective porosity is shown below:

$$\varnothing eff = \varnothing \text{total} \times (1 - Vsh) \tag{4}$$

where Vsh = volume of shale, $\varnothing$total = total porosity, $\varnothing eff$ = effective porosity.

The effective porosity was recorded in percentage (%) by multiplying the value of effective porosity by 100 shown below:

$$\varnothing(\%) = \varnothing eff \times 100.$$

To calculate water saturation (Sw), the equation requires the determination of water resistivity (Rw) value at formation temperature calculated from the porosity and resistivity logs within clean water zone, using the Ro from the equation below:

$$R_w = \frac{\varnothing^{2.15} R_0}{a}. \tag{5}$$

R_w = water resistivity at formation temperature, R_0 = deep resistivity in water zone, $\varnothing$ = total porosity, a = tortuosity factor.

Water saturation (*Sw*) can be calculated using [9] equation.

$$S_w = \left\{\frac{R_w}{R_{wa}}\right\}^{1/2} \tag{6}$$

where R_w = water resistivity at formation temperature, R_{wa} = water resistivity in the zone of interest.

Hydrocarbon Saturation (*Sh*) is the percentage of pore volume in a formation that is occupied by hydrocarbon. *Sh* can be determined by subtracting the value obtained for water saturation from 100% *i.e.*

$$S_h = \left(100 - S_w\right)\% . \tag{7}$$

Permeability (*K*), of each identified hydrocarbon reservoir is calculated using Equation (7) where S_{wir} is the irreducible water saturation [10]

$$K = \left\{\frac{250 \times \varnothing^3}{S_{wir}}\right\}^2 . \tag{8}$$

The petrophysical parameters of the delineated hydrocarbon bearing reservoirs were estimated using Equations (1) - (8). Seismic to well tie was done using the available check shot data, so as to bring information in the unit of depth to time. Faults were mapped as planar fracture or discontinuity in a volume of rock, across which there has been significant displacement as a result of rock mass movement on the seismic section. Tops of hydrocarbon reservoir of interest were then mapped as horizon on the seismic data for map generation. Reservoir area estimation was done using the base map, the map was divided into grids and the area of each grid was calculated. The grids were then counted for the oil, gas and general prospects and multiplied by the box area to get area of prospect. The following calculations were done to compute the volume of hydrocarbon.

$$STOIIP = \frac{CF \times GRV \times NTG \times \varnothing \times S_h}{B_O} \tag{9}$$

where *STOIIP* = Stock Tank Oil Initially in Place, *NTG* = Net to grossratio, θ = Effective porosity, *Sh* = Hydrocarbon Saturation, B_O = Shrinkage factor for oil, *CF* = Conversion factor.

4. Results and Discussion

4.1. Well Log Analysis and Correlation

The gamma ray log which is a type of lithology aided the litho-stratigraphic interpretation of well logs, the lithology within the area of study is mainly layers of sedimentary rock within the depth of 500 - 3600 m depth. The wells exhibit a dominantly shale/sand/shale sequence, typical of the Niger Delta Formation. The wells were analyzed in terms of fluid type and lithology. Shale lithology was delineated as high gamma ray readings. Regions of low gamma ray, high resistivity and low water saturation were mapped as sand lithology, which are also regions of high hydrocarbon saturation (**Figure 2**).

Hydrocarbon bearing sand units were delineated using the gamma-ray (GR) and resistivity logs to identify zones that are hydrocarbon bearing in all the wells studied. Nine (9) probable hydrocarbon bearing sand units (Sand A to Sand I) were delineated, all of which are laterally continuous (**Figure 2**). Sand A was observed to contain hydrocarbon due high resistivity signature in three wells (Rancho 1, 2 and 4), while the sand was interpreted to contain saline water in Rancho well 3 due to low resistivity signature reading. Sand B and Sand C were observed to contain hydrocarbon only in Rancho well 2 and interpreted wet in the other three wells (Rancho 1, 3 and 4) in the study (**Figure 2**).

Sand D was observed to be a thick sand unit ranging between 70 - 81 meters and this sand was interpreted to be hydrocarbon bearing in only well Rancho 2. Sand E contained hydrocarbon across two wells (Rancho 1 and 4). Sand F is hydrocarbon bearing as depicted by the high resistivity values in Rancho 1 and Rancho 2 respectively. Sand G is hydrocarbon bearing in Rancho wells 1, 2 and 4 due to high resistivity log reading in the sand zone and in Rancho well 3 the sand was interpreted to be water bearing due to low resistivity reading. Sand H was observed to contain hydrocarbon in all the four Rancho wells. Sand I was observed to be the thickest sand unit in the study area with reservoir thickness ranging from 101 - 136 meters and this sand unit was interpreted to be hydrocarbon bearing in the four wells due to high resistivity reading from the sand units. A good lateral continuity was observed across the correlated sand units within the wells (**Figure 2**).

4.2. Fluid Differentiation

The fluids present in the identified hydrocarbon reservoir sands were differentiated using the resistivity and neutron-density combination logs. The resistivity

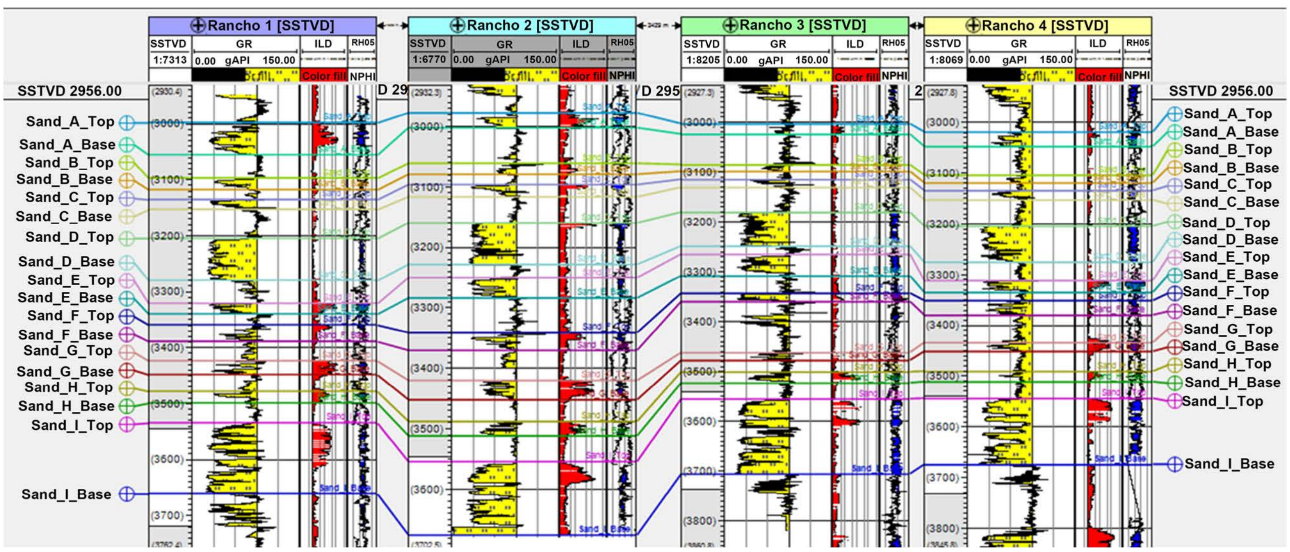

Figure 2. Stratigraphic correlation of rancho wells.

log was first used to differentiate between hydrocarbon bearing sands and water bearing sands while the neutron-density logs were used for hydrocarbon typing *i.e.* differentiate between oil and gas units. All the sands (Sands A to I) are oil bearing reservoirs (**Figure 3**). When neutron-density logs are superimposed, the two curves will cross over in hydrocarbon zones. Gas is of higher density to oil therefore density log (black) deflect to the left and neutron (red) deflecting to the right showing a balloon shape for gas and linear cross over for oil (**Figure 3**).

4.3. Petrophysical Analysis

Petrophysical parameters were computed to characterize the nine (9) hydrocarbon reservoir sand units (Sand A to Sand I). The volume of shale, water saturation, hydrocarbon saturation, water saturation of the flushed zone, effective porosity, irreducible water saturation, effective permeability and bulk volume of water were computed for the nine reservoir sand units in **Tables 1-9**. The summary of the petrophysical parameters needed in the volumetric estimation was calculated in **Table 10**.

4.4. Seismic Interpretation

A total of twelve (12) faults were picked on the seismic sections. All the faults intersected the horizons of interest which are the tops of hydrocarbon bearing

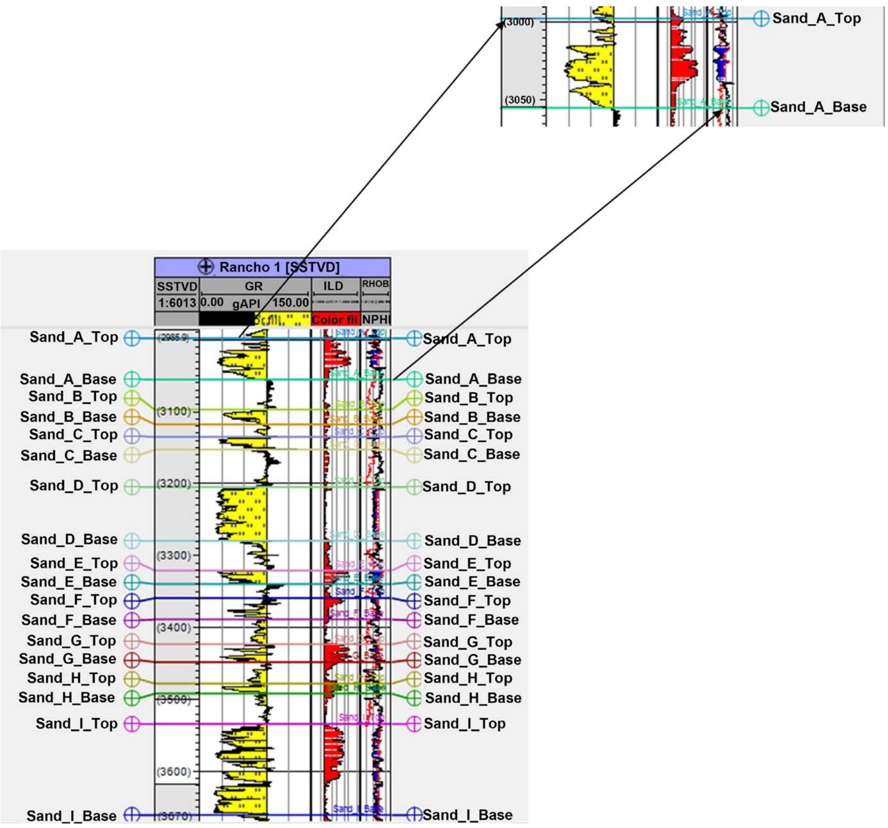

Figure 3. Rancho well 1 and magnified neutron-density logs used for hydrocarbon typing for sand A.

Table 1. SandA.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	2975	2970	3008	3019
Base	3015	2985	3028	3047
Porosity	32%	30%	29%	31%
Effective Porosity	25%	23%	21%	22%
Permeability	32%	34%	33%	30%
Oil Saturation	80%	79%	81%	82%
NTG	69%	70%	71%	68%
V-Shale	14%	15%	15%	13%

Table 2. Sand B.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	3095	3060	3080	3110
Base	3110	3079	3090	3125
Porosity	32%	30%	32%	29%
Effective Porosity	28%	26%	28%	25%
Permeability	40%	39%	39%	40%
Oil Saturation	78%	77%	75%	77%
NTG	68%	70%	69%	70%
V-Shale	17.5%	17%	16.5%	17.5%

Table 3. Sand C.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	3135	3096	3115	3138
Base	3151	3117	3128	3147
Porosity	30%	29%	28%	29%
Effective Porosity	28%	27%	26%	27%
Permeability	39%	40%	28%	36%
Oil Saturation	73%	75%	71%	70%
NTG	77.5%	77.5%	74.5%	75.5%
V-Shale	19%	19%	18%	16%

Table 4. Sand D.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	3204	3160	3179	3203
Base	3279	3229	3247	3276
Porosity	29%	30%	31%	28%
Effective Porosity	27%	28%	27%	25%
Permeability	40%	41%	40%	38%
Oil Saturation	75%	75%	75%	73%
NTG	77.5%	76.5%	75.5%	76.5%
V-Shale	18%	20%	19%	17%

Table 5. Sand E.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	3319	3251	3268	3309
Base	3412	3288	3307	3353
Porosity	26%	30%	27%	30%
Effective Porosity	28%	30%	30%	31%
Permeability	40%	44%	44%	43%
Oil Saturation	72.5%	71.5%	71.5%	70.5%
NTG	78%	80%	80%	79%
V-Shale	21%	23%	23%	22%

Table 6. Sand F.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	3358	3344	3346	3352
Base	3387	3369	3354	3380
Porosity	35%	33%	35%	35%
Effective Porosity	29%	26%	29%	27%
Permeability	43%	40%	42%	40%
Oil Saturation	70%	69%	70%	68%
NTG	74%	73%	74%	72%
V-Shale	29%	28%	29%	27%

Table 7. Sand G.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	3428	3419	3465	3435
Base	3447	3451	3478	3450
Porosity	31%	30%	29%	30%
Effective Porosity	25%	25%	23%	25%
Permeability	39%	40%	40%	40%
Oil Saturation	60%	65%	63%	64%
NTG	75%	77%	75%	78%
V-Shale	35%	40%	41%	40%

Table 8. Sand H.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	3478	3491	3502	3498
Base	3489	3512	3524	3510
Porosity	32%	35%	36%	35%
Effective Porosity	28%	29%	30%	29%
Permeability	41%	42%	39%	42%
Oil Saturation	68%	70%	65%	69%
NTG	72%	74%	69%	74%
V-Shale	29%	25%	29%	23%

Table 9. Sand I.

Parameter	WELL 1	WELL 2	WELL 3	WELL 4
Top	3534	3555	3556	3544
Base	3659	3702	3706	3677
Porosity	32%	31%	33%	30%
Effective Porosity	28%	25%	28.5%	25.5%
Permeability	40%	41%	39%	35%
Oil Saturation	69%	71.5%	70%	71.5%
NTG	74%	76%	76%	78%
V-Shale	30%	29.5%	24.5%	29.5%

Table 10. Petrophysics analysis.

SAND	GRV (km^3)	FVF	NET SAND (bbl)
Sand A	18.50	1.14	2.98
Sand B	12.50	1.11	1.97
Sand C	87.15	1.03	1.48
Sand D	17.50	1.03	2.96
Sand E	24.25	1.12	3.72
Sand F	29.50	1.06	5.05
Sand G	30.50	1.00	10.05
Sand H	104.50	1.06	17.87
Sand I	20.00	1.06	3.38

sands of interest. The variance edge attribute was used to aid the interpretation of the faults. This attribute is also effective for detecting edge effects, channels, discontinuous features and to measure the continuity between seismic traces in a specified window. Fault polygon maps of the horizons were generated to show the distribution of faults and the structure trapping the oil in the field. Also, a depth structure map of the subsurface showed that the structure trapping the oil in the field is a fault assisted closures (**Figures 4-7**).

4.5. Volumetric Analysis

The stock tank oil initially in place (STOIIP) was estimated. The estimation was done for Sand A to Sand I, and the average porosity and oil saturation values for the sand units (Sand A - Sand I) were used in calculating the STOIIP (**Table 11**).

Sand A was evaluated for STOIIP calculation with 980,000,000 mbls of oil present with porosity of 0.32 and oil saturation of 0.82. Sand B was estimated for Stock Tank Oil Initially in Place with 1,970,000,000 bbls of oil present with porosity of 0.32 and oil saturation of 0.78 (**Table 11**). STOIIP of 1,480,000,000 bbls with porosity of 0.30 and oil saturation of 0.75 was evaluated for Sand C. Sand D Stock Tank Oil Initially in Place is 2,960,000,000 bbls of oil present with porosity of 0.30 and oil saturation of 0.75. Sand E Stock Tank Oil Initially in Place is 3,720,000,000 bbls of oil present with porosity of 0.30 and oil saturation of 0.715

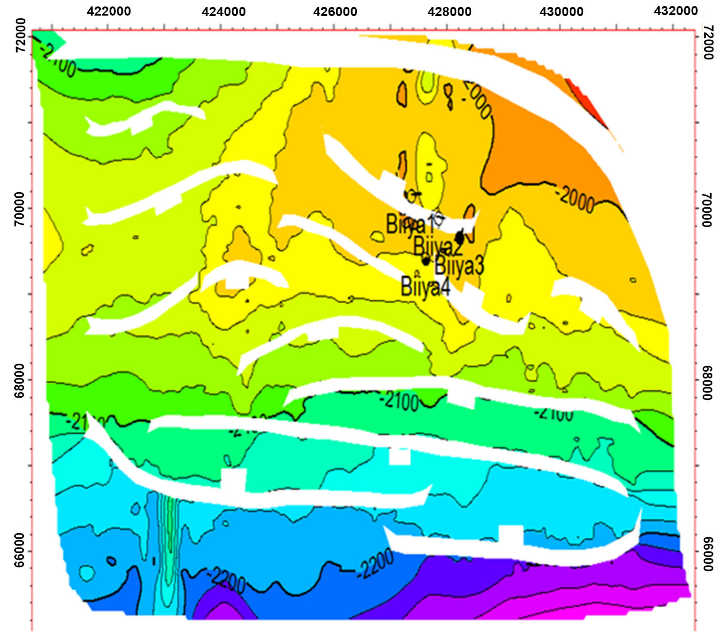

Figure 4. Depth structure map 1.

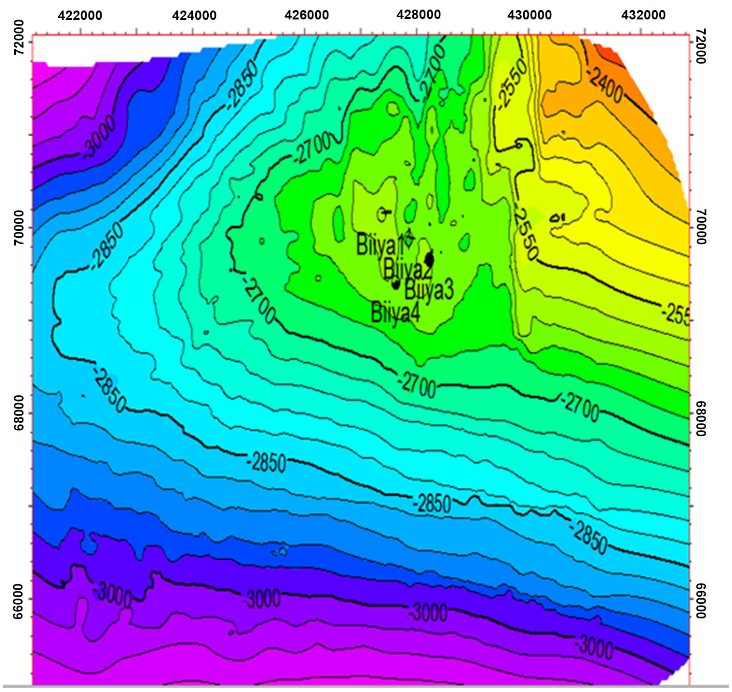

Figure 5. Depth structure map 2.

and Sand F STOIIP is 5,050,000,000 bbls of oil present with porosity of 0.35 and oil saturation of 0.7. Sand G the STOIIP is 1,840,000,000 bbls with porosity of 0.4 and oil saturation of 0.65 (Table 11). Sand H STOIIP is 17,870,000,000 bbls with porosity of 0.35 and oil saturation of 0.7; Sand I evaluated Stock Tank Oil Initially in Place is 3,380,000,000 bbls of oil present with porosity of 0.33 and oil saturation of 0.715.

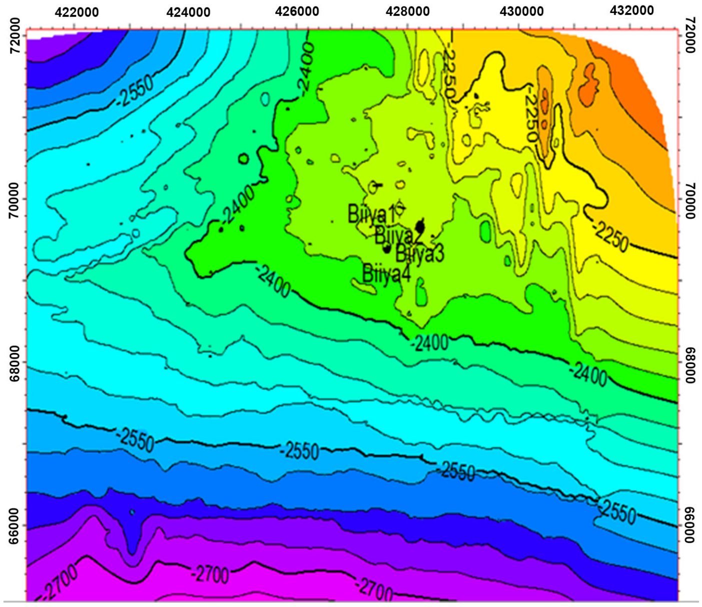

Figure 6. Depth structure map 3.

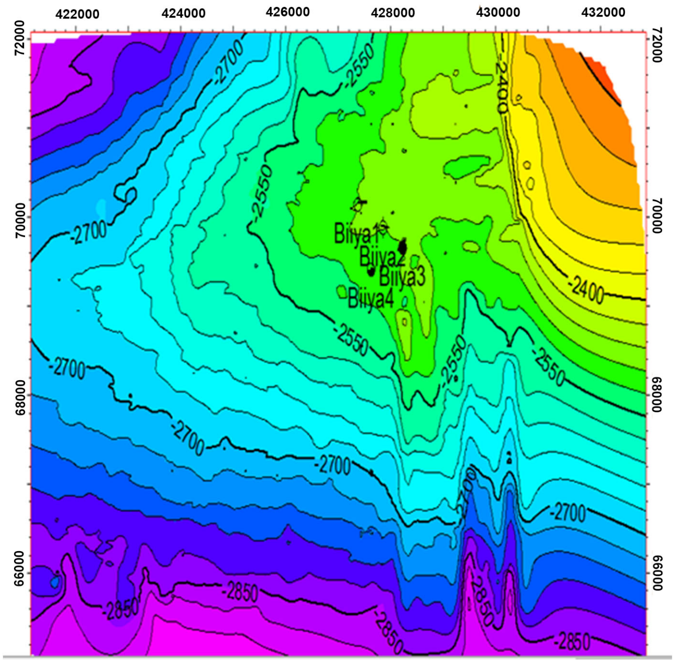

Figure 7. Depth structure map 4.

5. Conclusion

The litho-stratigraphic interpretation of well logs of the lithology within the area of study is mainly layers of sedimentary rock within the depth of 500 - 3600 m depth and the wells exhibit a dominantly shale/sand/shale sequence, typical of the Niger Delta Formation. Gamma-ray (GR) and resistivity logs aided the identification of hydrocarbon bearing sand units in all the Rancho four (4) wells studied. Nine (9) probable hydrocarbon bearing sand units (Sand A to Sand I) were

Table 11. Stock tank oil initially in place (STOIIP).

Sand	GRV (km^3)	NTG (%)	Porosity (%)	Oil Saturation (%)	FVF	STOIIP (bbl)
Sand A	18.50	70.0	30.0	82.0	1.14	2.98
Sand B	12.50	70.0	29.0	78.0	1.11	1.97
Sand C	87.15	77.5	30.0	75.0	1.03	1.48
Sand D	17.50	77.5	30.0	75.0	1.03	2.96
Sand E	24.25	80.0	30.0	71.5	1.12	3.72
Sand F	29.50	74.0	31.0	70.0	1.06	5.05
Sand G	23.52	77.0	25.0	65.0	1.10	1.84
Sand H	104.50	74.0	29.0	70.0	1.06	17.87
Sand I	20.00	76.0	30.0	71.5	1.06	3.38

delineated, all of which are laterally continuous in the well section. The effective porosities of the sands range from 21% - 31%, the permeability ranges from 28% - 44%, 70% - 80% for the net to gross, volume of shale ranges from 14% - 40% and hydrocarbon saturation ranges from 63% - 82%. Twelve (12) faults were mapped within the study area and the structural styles revealed a fault assisted closures. The Stock Tank Oil Initially in Place (STOIIP) ranges from 980,000,000 mbls to 17,870,000,000 bbls. Sand F had STOIIP of 5,050,000,000 bbls of oil and Sand G had STOIIP of 17,870,000,000 bbls, these sands are proposed to be developed because of the volume of oil in them and area covered by the reservoir, calculated Gross Rock Volume (GRV) of 29.5 km^3 and 104.5 km^3 respectively. Well logs give information at a point, while seismic data give details over alarger area. The integration of well log and seismic data for reservoir evaluation and volumetric analysis aids accurate reservoir geometry prediction and quantification in this study area.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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