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PETROPHYSICAL PROPERTIES AND 3D GEOLOGIC MODELLING OF THE RESERVOIR SANDS OF JIO FIELD, NIGER DELTA, NIGERIA

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Abstract
Reservoir modelling of JIO field was carried out to do a detailed evaluation of the petrophysical properties and to estimate the reserves of the identified reservoirs in the field. Methodology employed includes well log interpretation and delineation of the reservoir sands, 3-D seismic analysis and a 3D static modelling of the identified reservoir sands (D3A, D4, D5 and D6). These were achieved by integrating all the available data provided for the field. Fault and Horizon interpretations were carried out in Petrel software while well log interpretation, correlation and estimation of petrophysical parameters were done using Geographix software. Petrel software was also employed in facies modelling. Structural, stratigraphic and petrophysical models produced were integrated to generate a high resolution geological model (3D static model). The model was used to re-assess the reserves of the identified reservoirs (D3A, D4, D5 and D6). Volume (bulk volume, net volume, hydrocarbon pore volume, STOIIP, and recoverable reserves) calculation was also achieved using the Petrel software. Across the four reservoir sands, average value ranges for petrophysical properties are porosity 21.64- 24.23%, permeability 5.33 to 6796 md, water and hydrocarbon saturation 40.03 to 53.38% and 46.62 to 59.98% respectively, net- to- gross thickness 0.72 to 0.98 and shale volume 0.07 to 0.187%. Structural and stratigraphic analyses revealed that the field consists of rollover anticlinal structures with dip fault bounded closures as well as lateral continuity of the reservoir sands with pinch out in the southern and eastern parts. Depositional environment is interpreted as predominantly deltaic. The estimated recoverable reserve include D3A = 37049mbbl, D4= 658650mbbl, D5= 4979308mbl and D6= 1117080mbbl. D5 has the highest permeability as well as computed STOIIP. The field is characterized by quality reservoirs, large hydrocarbon zone and good deliverability. The 3D static model developed can serve as an input into reservoir simulation model which will help in proper well planning and management.

Keywords: Petrophysical Properties, Geologic model, Static Model, Facies Modelling, Reservoir

Introduction
The study area is located within the Coastal Swamp Depo-belt of the Niger Delta (Fig.1). There have been instances where wells have been drilled based on dataset that did not fully resolve some structural details of the subsurface within the study area. Although most of the wells found hydrocarbons but the wells were however, drilled using a 2D dataset. 3D seismic volume with a better resolution is very vital tool in the determination of the structural styles of hydrocarbon-bearing closures as well as the volumes of oil and gas trapped in them.

Reservoir characterization involves calculation of reservoir thickness, net-to-gross ratio, pore fluid, porosity, permeability, water saturation, structure, reservoir extent, and volume [1,2]. Proper reservoir characterization is very necessary for safe, cost-effective, optimal well production and critical for assessing exploration risk and economic viability of the reservoirs. The requirements for reservoir characterization include the construction of a comprehensive 3D petrophysical property models enclosed within geological framework and structural interpretation of seismic data [2]. The latter is very important in the generation of the framework of the reservoir model. Toba [3] defined reservoir models as computer-aided designs which shows distribution of the reservoir properties/characteristics and thus, not only help in the prediction of the reservoir's future outcome but also are very useful in determination of the best and safest drilling, completion and recovery option for the reservoir as well as the most economic, efficient and effective field development for the reservoir. Success of reservoir characterization depends on the tools integrated in the building of the reservoir geological model [2].

This paper is aimed at integrating property modelling with structural interpretation of 3D seismic data and well log analysis in reservoir characterization and reserve estimation.

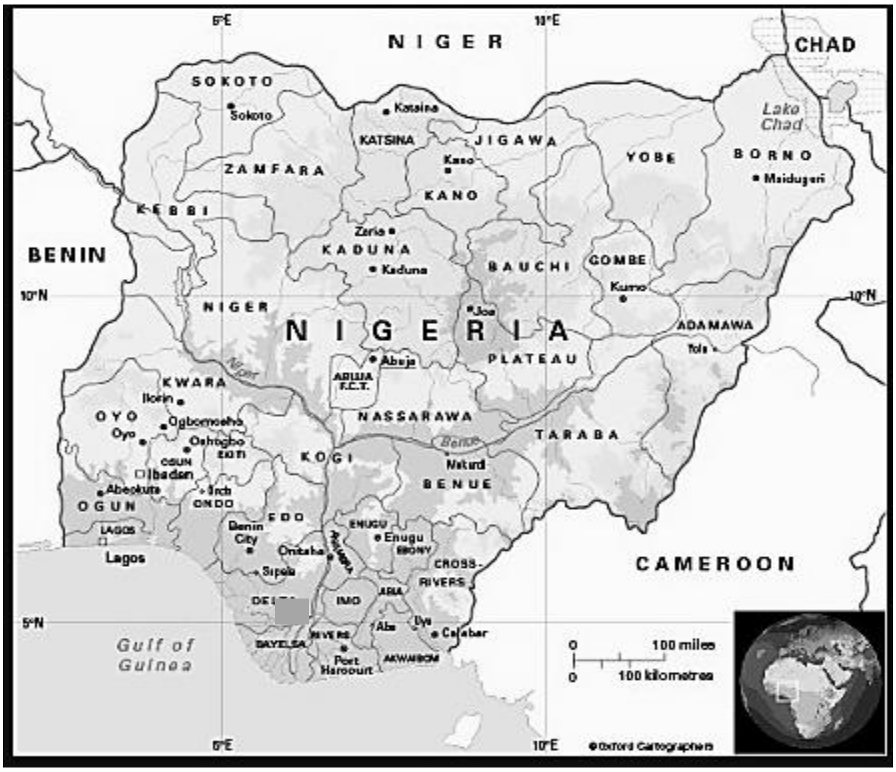

Fig. 1: Map of Nigeria showing the study area (shaded in Red)

Regional Tectonics and Stratigraphic Setting

The Niger Delta formed from a failed arm (the Benue Trough) of a triple junction that was installed during the breakup of the South American and African plate in the late Jurassic [4]. Syn-rifting and continuous subsidence were known to have supplied sediments into the basin up to the middle Cretaceous time [5]. During the Tertiary, sediment supply was mainly from the north and east through the Niger, Benue, and Cross Rivers. Three major depositional cycles have been identified within Tertiary Niger Delta deposits [5,6] and this coincides with the three major stratigraphic units present in the Niger Delta (Akata, Agbada and Benin Formations).

The Akata Formation, the basal lithostratigraphic unit of the basin was deposited under marine transgression. The formation is conformably overlain by the Agbada Formation which was laid down during the Eocene to Oligocene regressive phase. Deposition in the basin was capped by the continental (fluviatile) Benin Formation [7,8,9]. Niger Delta Basin is characterized by structures such as growth faults, rollover anticlines, shale ridges and diapiric structures. The stratigraphic units of the Niger Delta, Nigeria is shown in Figure 2.

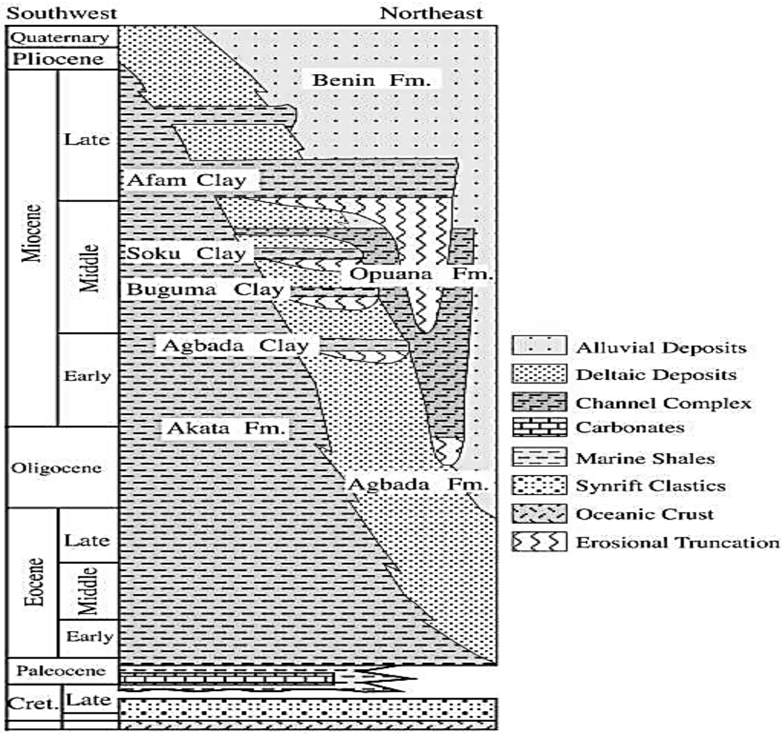

Fig 2: Stratigraphic column showing the three formations of the Niger Delta [4]

Materials and Methods

3D seismic volume, well logs (Gamma Ray and Resistivity) and check shot data from the study area were employed in this study. The data provided were quality checked and then loaded into Geographix 2008 and Petrel 2013 software. Identification and lithostratigraphic correlation of potential reservoir sands were carried out for six (6) wells provided using the Gamma Ray Log. Hydrocarbon bearing units were discriminated from the water bearing intervals with the aid of Resistivity Log. Both Density and Sonic Logs were used to infer the amount of pore spaces in the identified permeable zones (potential reservoirs) and fluid typing was done using Neutron/Density Logs. Petrophysical evaluation was carried out using the equations stated below which were input into the software for auto computation.

The Gamma Ray Index was calculated first using equation (1) from which the volume of shale was determined from [10; equation 2].

$GR_{index} = (GRlog - GR_{min})/ (GR_{max}- GR_{min})$ -- 1

Where GR_{index} = gamma ray index, GRlog = gamma ray log reading, GR_{min} = Minimum gamma ray reading (clean sand) and GR_{max} = maximum gamma ray reading (100% shale).

Volume of shale (V_{sh}) = $(0.5 * GR_{index})/(1.5 * GR_{index})$ ------------------------------------- 2

Total porosity (Φ) was calculated from the equation of [11] and was employed together with volume of shale in the calculation of effective porosity (equations 3 and 4).

Total porosity (Φ) = $(\rho_{ma} – \rho_b)/(\rho_{ma} – \rho_f)$ -- 3

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

Effective porosity (Φ_{eff}) = $\Phi * (1- V_{sh})$ --- 4

Permeability (k) = $[250 (\Phi^3/SWirr)]^2$ -- 5
where SWirr = Irreducible water saturation

Water Saturation (S_w) = $[Rw/(ILD * \Phi^{1.74})]^{1/2}$ -- 6

Where Rw = water resistivity and ILD = true resistivity

Well to seismic calibration, fault and horizon mapping were carried out on the seismic volume provided. Faults and prevalent geologic features were identified while the formation tops (reservoir tops) earlier identified were mapped across the seismic section. The models built for the identified reservoir sands include static reservoir, structural and stratigraphic, lithological and petrophysical models.

3D Static Reservoir Modelling: The stratigraphic, structural and porosity models were merged into a single model. The reservoir architecture (structural and stratigraphy) was populated or filled with rock properties. Cell sizes of 182x 152x20, 157x157x85, 183x180x50 and 155x159x50 were selected in building the 3D Grid for reservoirs 3DA, D4, D5 and D6 respectively. This is considered to be small enough to capture all the reservoir details.

Structural and Stratigraphic Modelling: Fault Modelling, Pillar Gridding and Horizon Making were carried out. The modelled faults and horizon structure formed the basis of the 3D structural framework. Make zone process in Petrel was then employed in zoning the reservoir model into flow units. Gas-Oil and Oil-Water contacts were then specified. Well to well correlation of the identified reservoir sands was carried out using well logs.

Lithological and Petrophysical Modelling: Sedimentologic model was created to enable classification and distribution of identified facies. The facies model was done using a stochastic function which allowed the generation of 3D distribution of significant characteristics such as porosity and permeability. This was done with the understanding that petrophysical behaviors of reservoir are closely linked to the lithofacies.

All the property logs prepared in Geographix were imported into Petrel and property values were sampled from well logs into the 3D grid in such a way that each grid cell has a single value for each property. Properties were distributed in inter-well grid cells. Data analysis was carried out and then modelling of the properties followed. Variogram map of each property was generated. The stochastic and deterministic methods were applied to modelling the properties.

Reserve Estimation: The volumetric method was adopted and the basic formulae employed in the calculations are:

Bulk volume = reservoir thickness (m) * area extent (m^2) --------------------------------------- 7

Where 1 m3 = 6.29 oil barrels

Net Volume = Bulk volume * Net/Gross --- 8

Pore Volume = Bulk volume * Net/Gross * Porosity

Hydrocarbon Pore Volume (HCPV) = Bulk volume * Net/Gross * Porosity * Sh ------ 9

Where Net = Net thickness of the reservoir, Gross = Gross thickness of the reservoir
Sh = Hydrocarbon saturation

Original oil in place (OOIP) = 7758 * Net Rock * Volume * Porosity * (1- Sw) -------- 10

Stock tank original oil in place (STOOIP) = [7758 * Area * Net thickness * Φ* (1- Sw)]/Bo --11-

Where 7758 = conversion factor from acre ft. to barrel, Φ = porosity, 1- Sw = Hydrocarbon saturation and Bo = Formation volume factor (FVF)

FVF of 1.3 was used for the calculation.

The methods and interpretation workflow employed are shown in Figure 3.

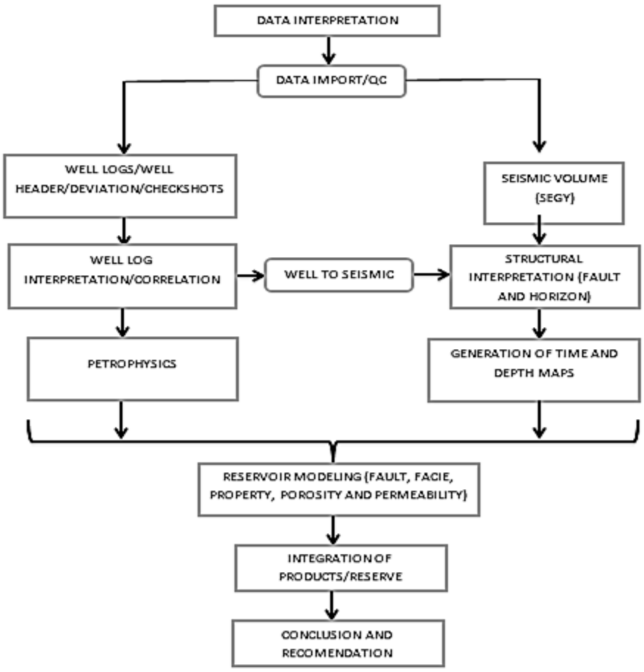

Fig. 3: Interpretation workflow

Results

Well Log Interpretation

Well correlation was carried out using six (6) wells provided. The six wells include JIOs 5, 3,1,6,8 and 10 (Fig. 4). Lithologically, the field consists predominantly of sandstones with minor shales and siltstones. Intercalation of sand and shale is an attribute of the field. Vertical and lateral facies changes are largely the function of the variability in the sand and shale thickness known as sand percentage. A total of eight sand units (potential reservoirs) were delineated and correlated. The sand units are D1, D2, D3A, D3B, D4, D5, D6 and D7. Six (6) out of the eight sand units correlated were interpreted as hydrocarbon bearing units.

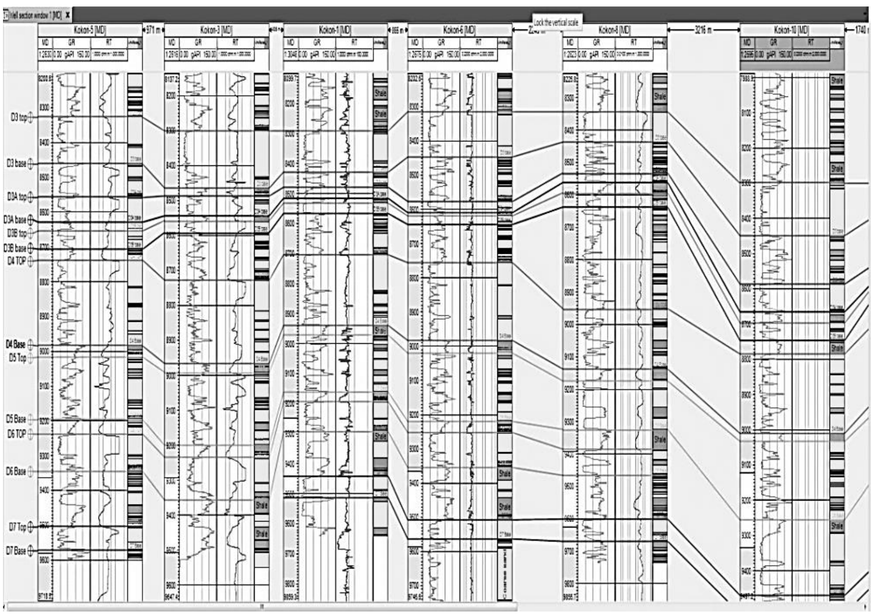

Fig 4: Lithostratigraphic correlation of different sands across six wells

Evaluation of Petrophysical Parameters

The result of petrophysical parameters of reservoirs D3A, D4, D5 and D6 is shown in Tables 1-4.

Reservoir D3A: Table 1 shows the result of computed petrophysical parameters for reservoir D3A which cuts across JIO wells 3, 5, 6 and 10. The gross thickness of the reservoir varies from 32.17 to 72.44ft, net thickness ranges from 32.17 to 71.44ft, whereas average net/gross (N/G) thickness is 0.97 across the wells. Porosity ranges from 21.10 to 27.70% and permeability varies from 15 to 2112 md, water and hydrocarbon saturations (S_w and S_h) show an average values of 40.02% and 59.98% respectively.

Table 1: Summary of computed Petrophysical Parameters for Reservoir D3A

Wells	Top (Ft.)	Bottom (Ft.)	Gross (Ft.)	Net (Ft.)	N/G (Ft.)	Porosity (V/v) (%)	S_w (%)	S_h (%)	V_{sh} (%)
JIO 3	8485.93	8542.27	55.74	55.24	0.96	27.70	49.20	50.80	0.074
JIO5	8555.67	8628.11	72.44	71.44	0.99	23.50	37.50	62.50	0.079
JIO 6	8575.76	8607.96	32.17	32.17	1.00	21.10	32.50	67.50	0.35
JIO 10	8581.20	8653.64	69.48	68.48	0.95	24.60	40.90	59.10	0.025

Reservoir D4: Reservoir D4 cuts across JIO 3, 5, 6, 8 and 10. Computed petrophysical parameters for the reservoir is shown in Table 2. Gross thickness is between 175.71 and 237.82ft, net thickness varies from 175.71 to 235.27ft, and net/gross (N/G) thickness averaged 0.95 across the wells. Porosity and permeability range from 19.00 to 32.60% and 10 to 509 md respectively whereas water and hydrocarbon saturations of the reservoir averaged 53.38% and 46.62% respectively.

Table 2: Summary of computed Petrophysical Parameters for Reservoir D4

Wells	Top (ft.)	Bottom (ft.)	Gross (ft.)	Net (ft.)	N/G (ft.)	Porosity (V/v)(%)	S_w (%)	S_h (%)	V_{sh} (%)
JIO 3	8801.98	9030.16	216.14	216.14	0.95	19.00	57.80	42.20	0.135
JIO5	8737.14	8991.12	237.82	235.32	0.93	24.10	44.70	55.30	0.092
JIO 6	8747.66	8984.25	225.27	224.27	1.00	32.60	56.00	44.00	0.084
JIO 8	8722.50	8913.71	175.71	175.71	0.92	19.60	54.30	45.70	0.237
JIO 10	8784.24	9007.14	203.20	195.20	0.96	25.80	54.10	45.90	0.104

Reservoir D5: Reservoir D5 also cuts across JIO wells 3, 5, 6, 8 and 10. The gross and net thickness varies from 145.532 to 177.94ft and from 59.37 to 165.00ft respectively. Net/gross (N/G) thickness averaged 0.72 across the wells. Porosity and permeability range from 13.40 to 29.10% and 5.33 - 6796 md respectively whereas water and hydrocarbon saturations averaged 49.86% and 49.94% respectively (Table 3).

Table 3: Summary of computed Petrophysical Parameters for Reservoir D5

Wells	Top (Ft)	Bottom (Ft)	Gross (Ft)	Net (Ft)	N/G (Ft)	Porosity (V/v)(%)	S_w (%)	S_h (%)	V_{sh} (%)
JIO 3	9001.19	9191.31	147.62	59.37	0.74	23.90	40.80	59.20	0.148
JIO5	9014.52	9211.16	162.14	140.00	0.71	13.40	58.80	41.20	0.349
JIO 6	9014.17	9216.05	145.53	138.03	0.69	29.10	53.70	46.30	0.136
JIO 8	8949.01	9137.19	177.94	137.01	0.73	20.10	56.80	43.20	0.196
JIO 10	9033.52	9258.86	177.94	165.00	0.73	21.70	40.20	59.80	0.105

Reservoir D6: JIO wells 3, 5, 6, 8 and 10 encountered reservoir D6. The reservoir net thickness ranges from 81.01 to 157.00ft, the gross thickness lies between 81.01 and 177.57ft while the average net/gross (N/G) thickness of the reservoir is 0.85 across the wells. The porosity ranges from 21 to 25.9% and permeability from 10 to 690 md. Water and hydrocarbon saturations averaged 45.30% and 54.70% respectively (Table 4).

Table 4: Summary of computed Petrophysical Parameters for Reservoir D6

Wells	Top (ft.)	Bottom (ft.)	Gross (ft.)	Net (ft.)	N/G (ft.)	Porosity (V/v)(%)	S_w (%)	S_h (%)	V_{sh} (%)
JIO 3	9229.33	9331.71	102.38	102.38	1.00	25.10	35.60	64.40	0.100
JIO5	9233.90	9462.06	177.57	157.57	0.69	25.90	31.40	68.60	0.035
JIO 6	9251.38	9254.70	88.17	82.17	0.80	21.10	42.10	51.90	0.075
JIO 8	9166.59	9254.70	81.01	81.01	0.92	21.70	59.50	40.50	0.118
JIO 10	9288.13	9448.35	138.00	135.00	0.84	24.90	57.90	42.10	0.022

Structural and Stratigraphic Interpretations

The well to seismic tie shows that the reservoir tops and bases corresponded to the peaks and troughs respectively. Four horizons (HD3A, HD4, HD5 and HD6) corresponding to the four identified reservoir sands (D3A, D4, D5, and D6) respectively were mapped across the seismic section (Fig. 5). Five major faults were also identified (F1, F2, F3, F4, and F5) and mapped across the seismic section. These faults played a major role in forming traps and closures for the reservoirs (Fig. 6).

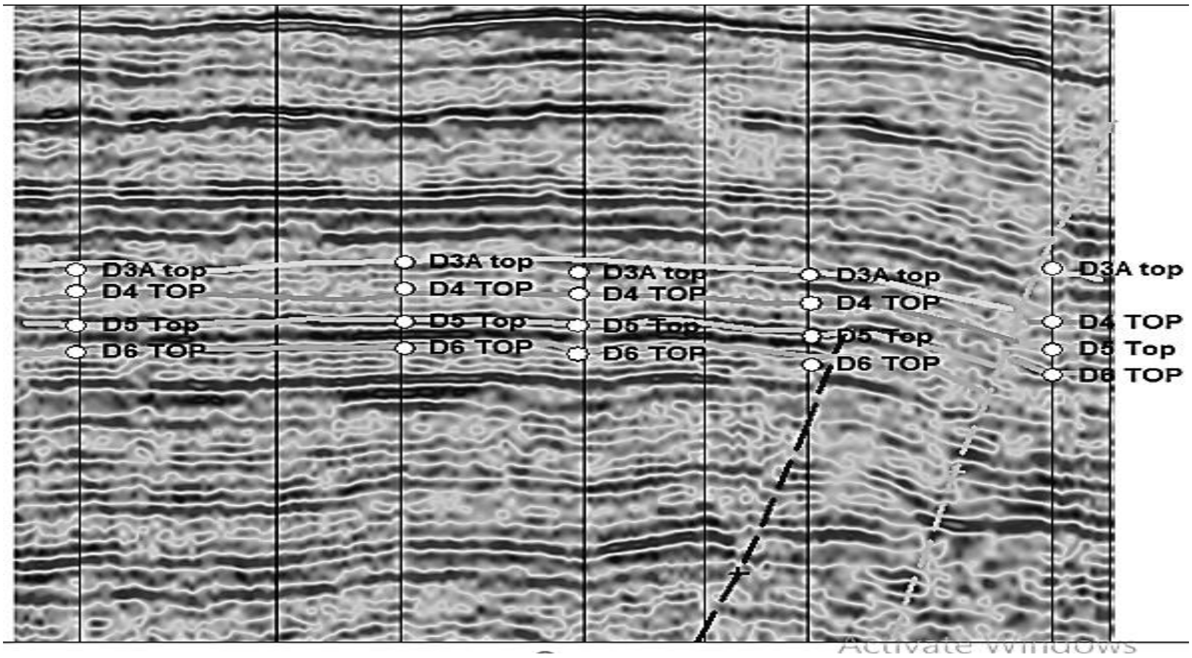

Fig 5: Horizon Interpretation on the seismic section

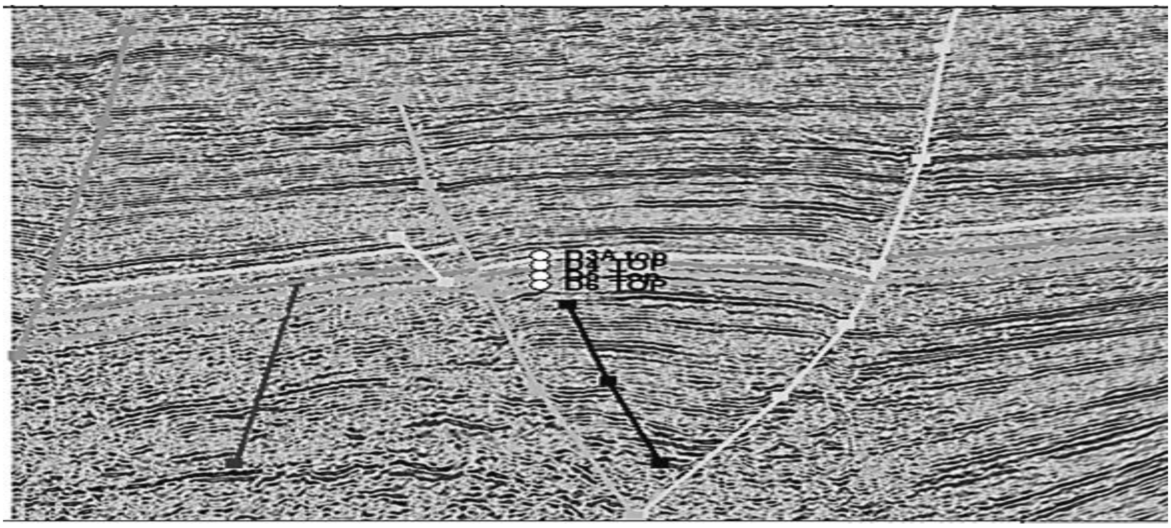

Fig 6: Horizon and Fault interpretation

Static Modelling

The structural model forms the background to static modelling. The interpreted fault polygons from the seismic analysis were modelled to arrive at a structural framework for the model. Grid was used to define the zone of the model (Fig. 7). The grid for sand D3A contained 553280 3D total number of cells, sand D4 has a total number of 2121855 3D cells, sand D5 has 164700 3D cells while sand D6 has a total of 1232250 3D cells. The cell height used is 2ft. The facies log was created for porosity, permeability and water saturation (Fig. 8)

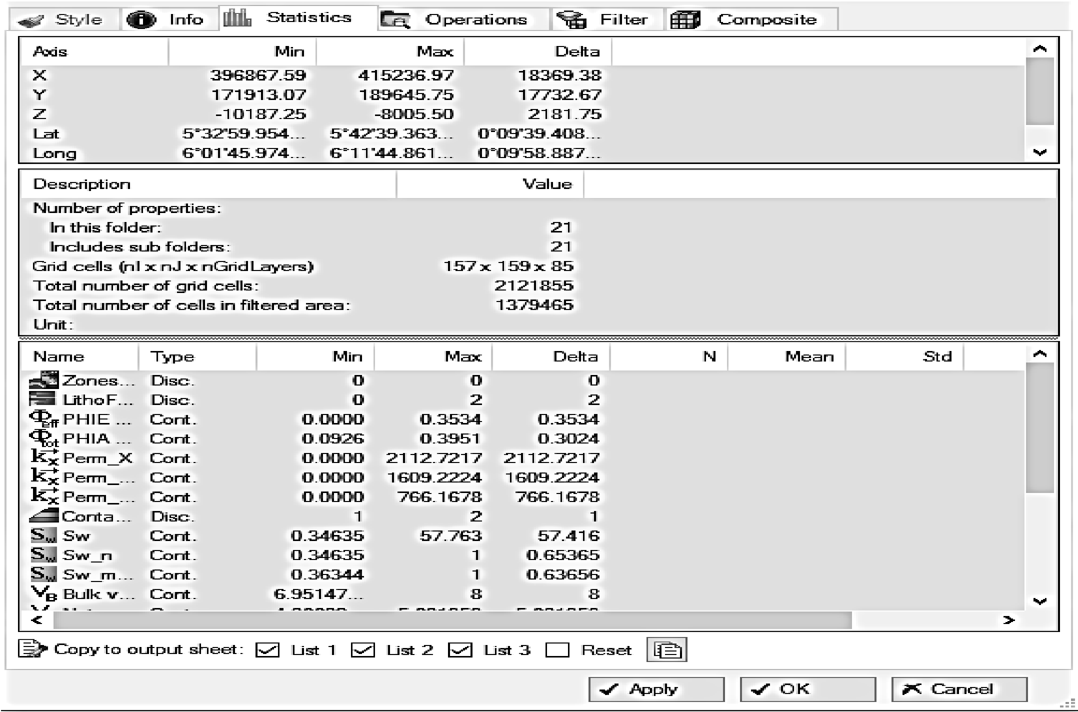

Fig 7: Grid Dimensions

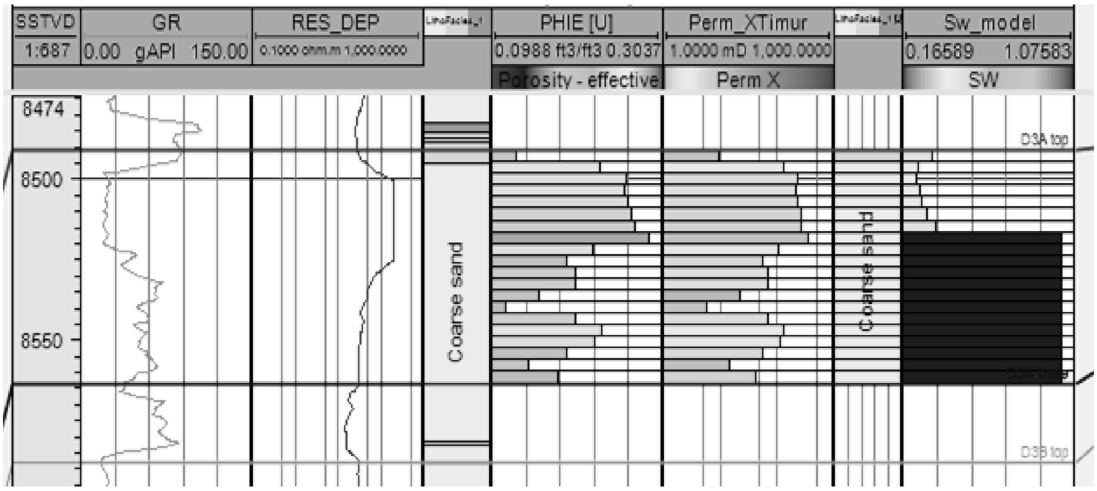

Fig 8: Facies Log showing porosity, permeability and water saturation

Porosity models, permeability models, facies models, water saturation models, net to gross models, and fluid contact models of the reservoirs D3A, D4, D5 and D6 were created (Figs. 9a-f). The models generated show that the four reservoirs delineated (D3A, D4, D5 and D6) are all rollover anticline with dip closure to the south, east and west and bounded by growth faults to the north and north-west located on the footwall of the major (northern) growth fault. A major regional fault trending in the east-west direction obviously played a very important role in the reservoir dip closure and eventually in the trapping of the reservoir oil.

The depositional settings of the reservoirs is interpreted as predominantly deltaic (paralic facies) as suggested by the GR log signatures which generally coarsens upward. Shore-face/barrier bar sand deposits also occur. Well correlation shows lateral continuity of the reservoir sands (typical of barrier bar deposits) which pinch out in the southern and eastern parts. This suggests reservoir producibility to be poor towards the south due to poor sand development.

Examination of the porosity models for the different reservoir units revealed a 12-32% porosity range for the JIO field. Again the permeability models reveal a 10-1000 md range. This indicates a well-connected pore spaces which eventually will permit a high reservoir performance. With the good pore volume and pore connectivity in the reservoir, high deliverability is expected within the producing zones of the reservoirs. The water saturation models went further to reveal a range of 10 to 30%.

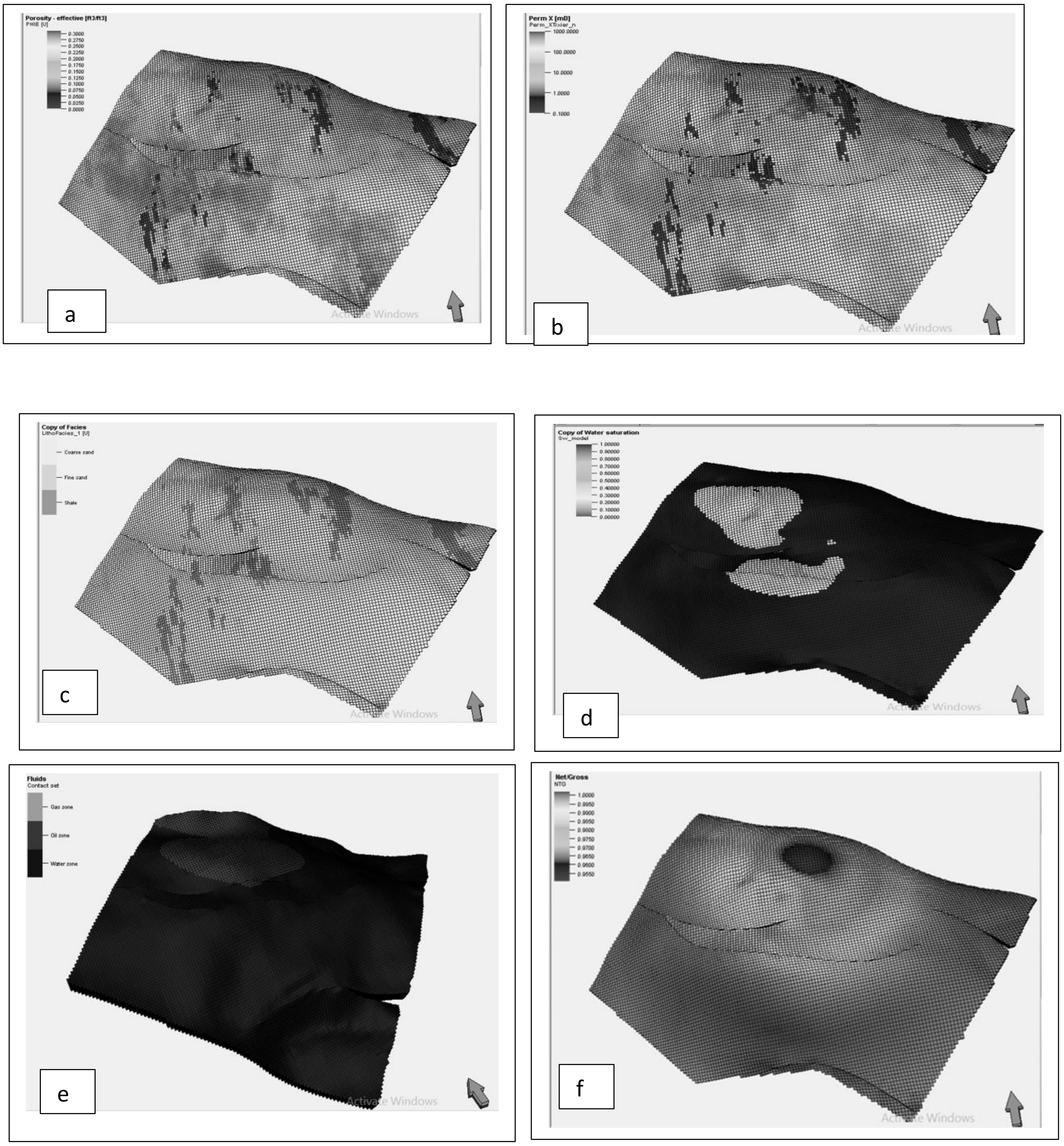

Fig 9: (a) Porosity (b) Permeability (c) Facies (d) Water Saturation (e) Fluid Contact and (f) Net to gross models of JIO field

Volume Calculation

Table 5 shows the calculated volume for the field. Probabilistic approach of reserve estimation which takes into account geologic risks shows that reservoir D5 has the highest computed STOIIP (stock tank oil initially in place).

Table 5: Calculated volume for JIO field

Reservoir	STOIIP			Recoverable Oil		
	P10	P50	P90	P10	P50	P90
D3A	105849.47	105855.00	105860.53	37043.35	37048.98	37054.44
D4	2195493.40	2195499	2195504	658644.4	658650	658655.5
D5	16597688	16597694	16597700	4979302	4979308	4979313
D6	3723587.5	3723597	3723599	1117074	1117080	1117085

Discussion

The potential and performance of a reservoir sand depend on certain characteristics and properties among which, the most important are porosity and permeability [13]. According to [14], porosity within the range of 13.40 and 32.60 with an average range of 21.64 and 24.23% indicates good to excellent whereas permeability that varies from 5.33 to 6796 md is rated fair to excellent. This suggests good interconnectivity of pore spaces and hence entails free flow of fluid within the reservoir sands. Hydrocarbon saturation across the wells that penetrated the reservoir sands revealed accumulation of reasonable quantities of hydrocarbon compared to water. Net-to-gross is high whereas shale volume is low in all the four reservoir sands. The rollover anticlinal structures with dip fault bounded closures as well as pinch outs which are attributes of the reservoir sands are indicatives of good trapping mechanisms responsible for hydrocarbon accumulation [13]. Based on the calculated STOIIP, it is obvious that there is high potential of hydrocarbon accumulation and the reservoir performance is considered satisfactory for production of hydrocarbon. It is advisable not to drill wells towards the southern part because reservoir producibility will be poor due to poor sand development.

The values of porosity, permeability, fluid saturation, shale volume as well as STOIIP obtained in this work are within the ranges which have been published for the Niger Delta (e.g. 13, 15- 20].

Conclusion

Integration of geophysical, geologic and petrophysical data reveals that the JIO Field has relatively quality reservoirs, large hydrocarbon zone and good deliverability. Characterization of these reservoir sands has led to detailed description and understanding of the field and has provided a very effective reservoir management strategy. The consistent high resolution 3D static model of the identified reservoir sands built across all the wells analyzed can serve as input into reservoir simulation model which eventually will help in proper well planning and management. Reservoir D5 has the highest computed STOIIP.

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