Petrophysical characteristics and reservoir quality of the Inda Field, Niger Delta, Nigeria

Ameloko Anthony Aduojo, Oseghe Emmanuel
Department of Petroleum Engineering, Covenant University, Ota, Nigeria
Corresponding E-mail:tonyameloko@yahoo.com

Abstract
Porosity and permeability are the main petrophysical properties of a reservoir rock and have a vital impact on the evaluation processes at all stages. This project involved the analysis of well logs [Well-1 and Well-2] from a field in the eastern part of the Niger Delta by identifying candidate sand formations in each well and then calculating petrophysical parameters for these potential reservoirs. As a result of this study, six different units [A to F] ware identified in the Formation by using the gamma ray log data. The predicted porosities and permeabilities for each unit show poor to moderate quality reservoirs. The average porosity values are moderate and approximately the same, but have very low permeability due to the presence of high volume of shale in the reservoirs. The thicknesses of the reservoirs are small [averaging between 5.5 and 24.5 m]. Also from the results, there are indications that sand D and F may be one continuous sand body. This is because the two sand bodies have the same porosity, similar formation thickness and their depth values are also very close. In all, the part of the Inda field under study does not have good prospect for exploration and production because of the high level of water saturation in the reservoirs and consequently low hydrocarbon saturations. However, reservoirs A and E comparatively show promising reserve for hydrocarbon.
Keywords: Hydrocarbon saturation, petrophysical properties, reservoirs, water saturation

Introduction

The first essential element of a petroleum reservoir is a reservoir rock. It is very important to determine and understand the petrophysical properties and mechanical properties of reservoir rocks. Accurate estimates on porosity and permeability values in certain stratigraphical intervals can be derived from several well log types, i.e. the sonic, neutron or bulk density log. As the purpose of this study is to produce petrophysical estimates from well logs that generally lack core-measured porosity and permeability values, theoretical methods of calculation are preferred over empirical relationships between the well log signal and available porosity and permeability measurement data from drilling cores. Theoretically based calculations are less influenced by local conditions and therefore more widely applicable. The objectives of the present work are to make detailed use of available wireline log data to delineate the reservoir units in the wells in the field, determine the geometric properties (porosity and permeability) of the reservoir rocks using petrophysical calculation (Wyllie and Rose, 1950), and infer reservoir geometry distribution and reservoir quality trends using the reservoir correlation. Detailed study of the petrophysical results of the “Inda field” Niger Delta [Figure 1] will provide an understanding of the geometric properties of the reservoirs, lateral variation in thickness and possible hydrocarbon accumulations.

Location & Geology of the Study Area

The “Inda” field is located around the eastern part of the Niger Delta [figure 1]. The geology of the Tertiary section of the Niger Delta is divided into three Formations, representing prograding depositional facies distinguished mostly on the basis of sand-shale ratio (Short and Stable, 1965; Doust and Omatsola, 1990; Kulke, 1995). They are namely Benin Formation, the Paralic Agbada Formation and Prodelta Marine Akata Formation [Table 1]. They range in age from Paleocene to Recent. The Benin Formation is a continental latest Eocene to Recent deposit of alluvial and upper coastal plain sands. It consists predominantly of freshwater baring massive continental sands and gavels deposited in an upper deltaic plain environment. The Agbada Formation consists of paralic siliciclastics, which underlies the Benin Formation. It consists of fluviomarine sands, siltstones and shales. The sandy parts constitute the main hydrocarbon reservoirs. The grain size of these reservoir ranges from very coarse to fine. The Akata Formation is the basal unit of the Tertiary Niger Delta complex. It is of marine origin and composed of thick shale sequences (potential source rock), turbidities sand (potential reservoirs in deep water and minor amount of clay and silt. Beginning in the Paleocene and through the Recent, the Akata Formation formed during low stands, when terrestrial organic matter and clays were transported to deep-sea water areas characterized by low energy conditions and oxygen deficiency (Stacher, 1995). It is the major source rock in the Niger Delta.

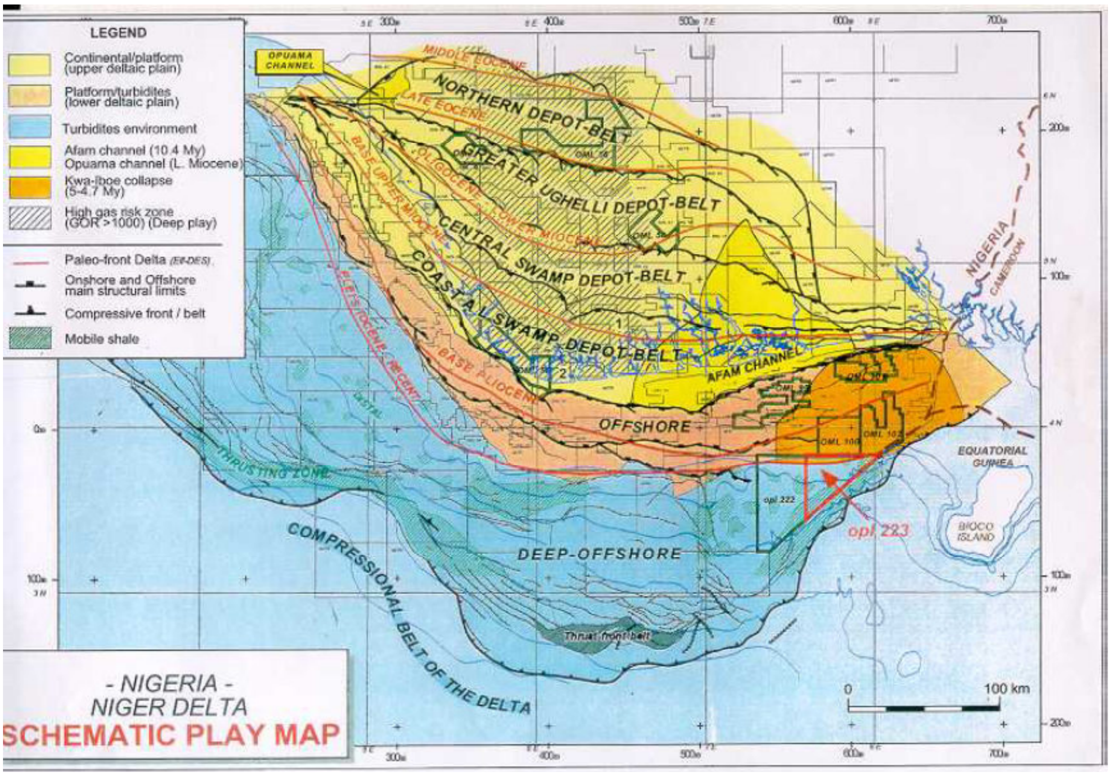

Fig.1 Map showing location of Niger Delta

Table 1: Table of formations in Niger Delta area, Nigeria. Modified from Short and Stauble (1965).

Subsurface			Surface Outcrops		
Youngest known Age		Oldest known Age	Youngest Known Age		Oldest Known Age
Recent	Benin Formation (Afam clay member)	Oligocene	Plio/Pleistocene	Benin Formation	
Recent	Agbada Formation	Eocene	Miocene Eocene	Ogwashi-Asaba Formation Ameki Formation	Oligocene Eocene
Recent	Akata Formation	Eocene	Lower Eocene	Imo shale Formation	Paleocene
Unknown			Paleocene	Nsukka Formation	Maestrichtian
			Maestrichtian	Ajali Formation	Maestrichtian
			Campanian	Mamu Formation	Campanian
			Campanian/Maestrichtian	Nkporo Shale	Santonian
			Coniacian/Santonia	Awgu Shale	Turonian
			Turonian	Eze Aku Shale	Turonian
			Albian	Asu River Group	Albian

Methodology

1. Reservoir sand candidate formations (i.e. hydrocarbon containing sands) are identified on logs using basically the following logs:
   a. Gamma ray log
   b. Spontaneous Potential or Gamma ray log
   c. Resistivity log.

   d. Neutron density log.
2. Determination of porosity/permeability of the reservoir sands from the wireline logs using petrophysical calculations (Archie, 1942; Asquith and Krygowski, 2004)
3. Interpretation of the results

Petrophysical Evaluation of the Reservoirs

Four major reservoirs (A-D) each were delineated for Well-1, while two reservoirs (E-F) each were also delineated for Well-2, using the gamma ray log.

Well-1

The reservoirs in this well have average thicknesses from 5.5 ft in reservoir A to 24.5 ft in reservoir C. The average shale volume content (Vshale) of the reservoirs in Well-1 is between 0.677 to 0.879v/v decimal [table 3]. This suggest that all the reservoirs, A to D with these high Vsh values are above the limit of 15% that can effect the water saturation value (Hilchie,1978).The average neutron-density derived porosity for the reservoirs are between 27.5 to 46.3%, which indicates high porosity. The average total resistivity and water saturation (42.3-65.5%) for the reservoirs suggest that the reservoirs are hydrocarbon bearing, with reservoir A showing about 53.7% hydrocarbon saturation. Their volume of shale (Vshale) is so high that their presence can hamper the free flow of fluids in the reservoir. Their water saturation (Sw) are generally high (42%, 65% 71% and 60%), which invariably are indications that the hydrocarbon saturations are lower.

A plot of formation depth against porosity for well 1 indicates a decrease in porosity with depth [fig. 2]. This is due to compaction caused by overburden pressure from overlying rocks.

Well P-2

The reservoirs in this well are basically two and they have average thicknesses from 18 ft in reservoir E to 13.5 ft in reservoir F [table 4]. The average shale volume content, (Vsh) of the reservoirs is between 0.64v/v decimal in reservoir E to 0.87v/v decimal in reservoir F. These Vsh values are above the limits that could affect the value of water saturation (Hilchie, 1978) and suggests that the reservoirs are not too clean as well. This is reflected in the poor average permeability values that range from 21 md in reservoir E to 07 md in reservoir F. The average porosities of the reservoirs are moderate (27-28%) and the two reservoirs show evidence of hydrocarbon saturation as the average total resistivity values are greater than the water bearing resistivity values (Hingles, 1959). The low water saturation in reservoir E & high water saturation in reservoir F (30% and 60% respectively) indicates 70% and 40% hydrocarbon saturation respectively

Table 2: Tables showing the data for the various candidate reservoirs and calculated petrophysical parameters for the sand bodies.

0.204642											
0.205629	0.463240532	1.795915	0.184747	0.815252547	0.407626	0.037989347	0.167639183	0.423195979	0.537123333	0.33	0.676646707
0.204967			0.380355	0.619645229	0.309823	0.077960203	0.127006867				
0.202786			0.363349	0.636650768	0.318325	0.073682189	0.129103954				
0.203387			0.372637	0.627362912	0.313681	0.075789587	0.12759754				
0.202896			0.395296	0.604703658	0.302352	0.08020395	0.122691807				
0.20245			0.41443	0.58557049	0.292785	0.083901148	0.118548596				
0.207318			0.426265	0.573734801	0.286867	0.088372486	0.118945602				
0.213664			0.447089	0.552911441	0.276456	0.095526873	0.118137447				
0.21936			0.487124	0.512876401	0.256438	0.106855643	0.112504789				
0.225661			0.548391	0.451609137	0.225805	0.1237506	0.101910709				
0.228084			0.597041	0.402958813	0.201479	0.136175626	0.091908515				
0.226735											

Sand A

Key: Blue = Porosity; **Yellow** = Water resistivity; **Green** = Water saturation; **Purple** = Hydrocarbon saturation; **Red** = Permeability; **Brown** = Volume of shale

0.171074											
0.174975	0.359329273	0.121962	0.530618	0.469381969	0.234691	0.092844678	0.082129922	0.655048174	0.344951826	0.337397873	0.878655679
0.175504			0.516953	0.483047473	0.241524	0.090727116	0.084776652				
0.173259			0.504113	0.495887335	0.247944	0.087341847	0.085916738				
0.172552			0.518199	0.481801112	0.240901	0.089416134	0.083135634				
0.174619			0.540802	0.459198138	0.229599	0.094434443	0.080184858				
0.177809			0.562605	0.437395272	0.218698	0.100036424	0.077773003				
0.181056			0.58062	0.419380075	0.20969	0.105124866	0.075931383				
0.184303			0.604644	0.395356208	0.197678	0.111437708	0.072865363				

Sand B

Key: Blue = Porosity; **Yellow** = Water resistivity; **Green** = Water saturation; **Purple** = Hydrocarbon saturation; **Red** = Permeability; **Brown** = Volume of shale

0.167888											
0.172612	0.345747948	0.121647	0.457809	0.542190781	0.271095	0.079023477	0.093588767	0.708540838	0.291459162	0.382571078	0.795158438
0.175447			0.541494	0.458505798	0.229253	0.095003572	0.080443499				
0.178044			0.585455	0.414544903	0.207272	0.104236634	0.073807139				
0.178577			0.609099	0.390901237	0.195451	0.108770859	0.069805861				
0.177809			0.638656	0.3613442	0.180672	0.113559022	0.064250405				
0.178161			0.666566	0.333433749	0.166717	0.118756074	0.059404872				
0.178928			0.690062	0.309937935	0.154969	0.12347159	0.055456649				
0.180467			0.712037	0.287962975	0.143981	0.128498905	0.0519677				
0.182179			0.697982	0.302018325	0.151009	0.127157492	0.055021348				

Sand C

Key: Blue = Porosity; **Yellow** = Water resistivity; **Green** = Water saturation; **Purple** = Hydrocarbon saturation; **Red** = Permeability; **Brown** = Volume of shale

0.123479											
0.126869	0.275107065	0.085376	0.370042	0.629957602	0.314979	0.046947084	0.07992239	0.601790188	0.398209812	0.214211908	0.861054086
0.128861			0.382825	0.617175184	0.308588	0.049331347	0.079530066				
0.130162			0.4373	0.562700226	0.28135	0.056919662	0.073241992				
0.132286			0.503252	0.49674755	0.248374	0.066573195	0.065712689				
0.135113			0.57514	0.424860452	0.21243	0.077708917	0.057404234				
0.136761			0.608781	0.3912185	0.195609	0.083257646	0.053503484				
0.136761			0.625031	0.374969243	0.187485	0.085479913	0.051281218				

Sand D

Key: Blue = Porosity; **Yellow** = Water resistivity; **Green** = Water saturation; **Purple** = Hydrocarbon saturation; **Red** = Permeability; **Brown** = Volume of shale

0.112659	0.259884692	1.9	0.168019	0.0625	0.9375	0.007041145	0.105617946	0.308866	0.6911344	0.214	0.6434656
0.116727				0.065041	0.934959	0.007592054	0.109135219				
0.118318				0.066701	0.933299	0.007891971	0.110426211				
0.117227				0.067153	0.932847	0.007872158	0.109355115				
0.1175				0.061722	0.938278	0.007252313	0.110247687				
0.143149				0.058971	0.941029	0.008441664	0.134707106				
0.116614				0.060187	0.939813	0.007018633	0.109595003				
0.116659				0.062108	0.937892	0.007245492	0.109413599				

Sand E
Key: Blue = Porosity; **Yellow** = Water resistivity; **Green** = Water saturation; **Purple** = Hydrocarbon saturation; **Red** = Permeability; **Brown** = Volume of shale

0.105341	0.275489198	0.9	0.088396	0.615996	0.384004	0.064889588	0.040451321	0.603853	0.3961472	0.07777556	0.8677035
0.106727				0.602368	0.397632	0.064289086	0.042438187				
0.107045				0.586535	0.413465	0.062785886	0.044259568				
0.129978				0.577406	0.422594	0.075049901	0.054927728				
0.129838				0.574667	0.425333	0.074613489	0.055224318				
0.128272				0.574667	0.425333	0.073713563	0.054558249				
0.126342				0.578468	0.421532	0.073084938	0.053257344				

Sand F
Key: Blue = Porosity; **Yellow** = Water resistivity; **Green** = Water saturation; **Purple** = Hydrocarbon saturation; **Red** = Permeability; **Brown** = Volume of shale

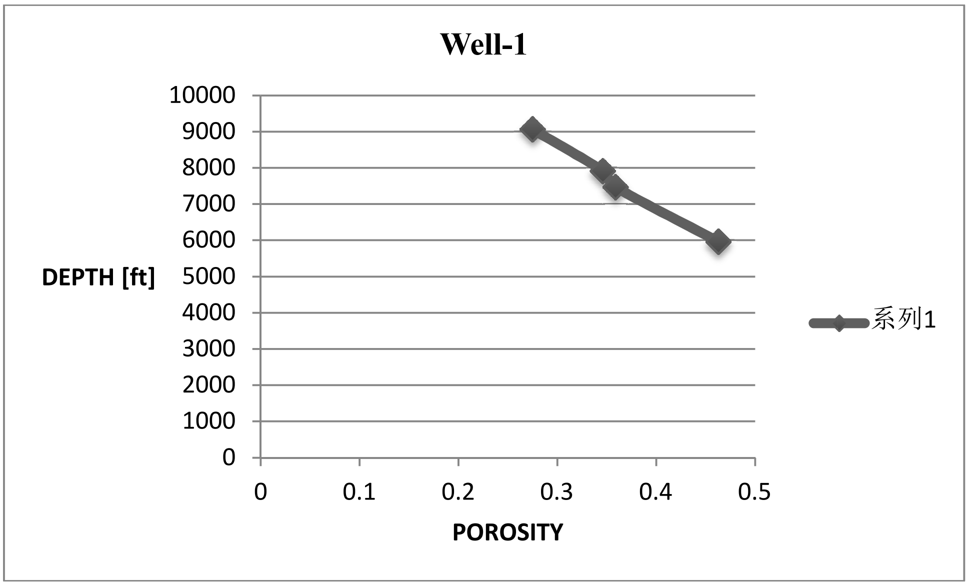

Figure 2: The graph of depth versus porosity for well 1.

Table 3: Average Petrophysical Values for the Well-1

SAND	DEPTH (ft)	POROSITY	THICKNESS[m]	Sw	Vsh
A	5959.5	0.463	5.5	0.423	0.677
B	7465.5	0.359	11.5	0.655	0.879
C	7911	0.346	24.5	0.71	0.795
D	9061.5	0.275	14	0.601	0.861

Table 4: Average Petrophysical Values for the Well-2

SAND	DEPTH (ft)	POROSITY	THICKNESS	Sw	Vsh
E	8829	0.2899	18	0.3089	0.64
F	8894	0.2755	13.5	0.604	0.87

Also, form the tables above there is an indication that sand D and F may be one continuous sand body. This is because the two sand bodies have the same porosity, similar formation thickness and their depth values are also very close. One possible reason why they are not occurring at the same depth is possibly due to the presence of a fault which may be between the two wells or there may be more overburden in the second well.

Discussion and Conclusions

The quality of the reservoirs in the part of the "Inda field" under study is poor owing to the analysis of the petrophysical parameters determined from the two wells. The average porosity values are moderate and approximately the same, but have very low permeability due to the presence of high volume of shale in the reservoirs. The thicknesses of the reservoirs are also small [averaging between 5.5 and 24.5 m]. The escalator regression sedimentation model of the Niger Delta makes it clear that younger sediments are found in the distal part of the basin with pronounced thickness greater than that on the proximal part. Compaction initiates early in the older rocks of proximal facies and grades down basinward. In all, the part of the Inda field under study does not have good prospect for exploration and production because of the high level of water saturation and consequently low hydrocarbon saturations.

References

1. Archie, G.E. 1942. "The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics". Journal of Petroleum Technology. 5:54-62.
2. Asquith, G. and D. Krygowski. 2004. "Basin Well Log Analysis". *AAPG Methods in Exploration*. Series,No. 16.
3. Doust, H., and Omatsola, E. (1990). Niger Delta, in, Edwards, J. D., and Santogrossi, P. A., Eds., Divergent/Passive Margin Basins, AAPG Memoir 48: Tulsa, Americam Association of Petroleum Geologists, Pg. 239-248.
4. Kulke, H., (1995). Nigeria, In, Kulke, H., Ed., Regional Petroleum Geology of the World. Part II: Africa; America; Australia And Antarctica: Berlin, Gebrüder Borntraeger, Pg. 143-172.
5. Short, K. C., and Stauble, A. J. (1965). Outline of Geology of Niger Delta: American Association of Petroleum Geologists Bulletin Vol. 51, Pg. 761-779.
6. Stacher, P. (1995). Present Understanding of the Niger Delta Hydrocarbon Habitat, In, Oti, M. N., and Postman Eds., Geology of Deltas: Rotterdam, A. A., Balkema, Pg. 257-267.
7. Wyllie, M.R.J. and W.D. Rose. 1950. "Some Theoretical Considerations Related to the Quantitative Evaluations of the Physical Characteristics of Rock from Electric Log Data". *Journal of Petroleum Technology*. 189:105-110.