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Petrophysical evaluation of reservoirs in 'y' prospect Niger delta

Petrofizikalna ocena rezervoarjev na raziskovalnem območju 'y' v delti Nigra

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Abstract

A suite of well logs of two wells (1 and 2) from 'Y' Prospect Niger Delta were evaluated using GeoGraphix software, with the aim of computing the petrophysical characteristics of the reservoirs as well as identify reservoir lithology within and between wells for information on stratigraphic and lithological parameters of the wells. Three reservoirs were correlated at depth range of 1 524 m to 1 800 m, with thicknesses of 10–45 m. Cross plot of neutron porosity and density porosity were used to discriminate the fluid types. Computation of petrophysical properties and reservoir evaluation were carried out to determine recoverable hydrocarbon in place in the reservoirs. Well log data shows that area was characterized by sandy shale interbeds. Porosity values for the reservoir ranged from 30–40 %, water saturation 30–45 % and hydrocarbon saturation 65–80 %. Gas zone of economic importance was detected in reservoir L300 in well 2. The reservoir properties of the wells showed that they could be fair to very good for hydrocarbon accumulation.

Key words: petrophysical properties, hydrocarbon reservoir, GeoGraphix, Nigeria

Izvleček

Karotažne podatke iz dveh vrtin (1 in 2) v raziskovalnem območju 'Y' v delti Nigra so ovrednotili z GeoGraphixovimi programi z namenom izračunati petrofizikalne značilnosti rezervoarjev ogljikovodikov, opredeliti litološke lastnosti v vrtinah in med njima ter dobiti ustrezne podatke o stratigrafskih in litoloških parametrih. V globini med 1 524 m in 1 800 m so povezali prereze treh rezervoarjev debeline od 10 m do 45 m. Tipe fluidov v plasteh so določili iz podatkov o nevtronsko ugotovljeni poroznosti in gostoti. Količine pridobljivih ogljikovodikov v rezervoarjih so ocenili iz izračunanih petrofizikalnih lastnosti in značilnosti rezervoarjev. Karotažni podatki nakazujejo prisotnost peščeno-muljastih vmesnih plasti. Vrednosti poroznosti v rezervoarjih se gibljejo med 30 % in 40 %, nasičenosti z vodo med 30 % in 45 % in nasičenosti z ogljikovodiki med 65 % in 80 %. Navzočnost ekonomsko pomembnih zalog plina so ugotovili v rezervoarju L300 v vrtini 2. Lastnosti rezervoarjev v vrtinah pričajo o dobri do zelo dobri sposobnosti za nakopičenje ogljikovodikov.

Ključne besede: petrofizikalne lastnosti, rezervoar ogljikovodikov, GeoGraphix, Nigerija

Introduction

A well log can be defined as an indirect record showing the rock and fluid properties along borehole. Such physical properties include electrical, radioactive, and some special kinds of measurements like electrical resistivity, spontaneous potential, gamma ray intensity, density, acoustic velocity etc.[1]. Most quantitative log analyses are aimed at defining petrophysical parameters, but only few of these parameters(-Formation lithology, thicknesses and depths of the reservoirs and even non-reservoirs) can be measured directly. Others have to be derived or inferred from the measurement of other physical parameters of the rocks. Three basic logs (lithology, resistivity and porosity logs) are needed for proper formation evaluation. One is required to indicate permeable zones; another is needed to measure the resistivity of the formation, while the third is important for estimating porosity values.

Well logs furnish the data necessary for the quantitative evaluation of hydrocarbon in-situ. From the view point of decision making, well logging is the most important aspect of drilling and completion process[2]. The information obtained from these logs can be used to interpret geology in general and in reservoir, identify productive zones, and estimate hydrocarbon reserves.

This study therefore assesses the reservoir quality of two wells: well 1 and well 2 (Figure 1) using GeoGraphix Software. The main focus is to determine some reservoir properties with a view to ascertaining if the results generated make possible to predict economic saturation and production.

Geology of the study area

The Niger Delta (Figure 2) is a regressive sequence of clastic sediments developed in series of offlap cycles[3]. The base of the sequence consists of massive and monotonous marine shales. These grade into interbedded shallow-marine and fluvial sands, silts, and clays, which form the typical paralic facies portion of the delta[3]. The uppermost part of the sequence is a massive non-marine sand section. The established Cainozoic sequence in the Niger delta consists, in ascending order of the marine shales (Akata Formation), paralic clastics (Agbada Formation), and continental sands (Benin Formation)[4]. Akata Formation is composed of shales, clays and silts at the base of the delta sequence. They contain a few streaks of sand, possibly of turbiditic origin, and were deposited in holomarine (delta-front to deeper marine) environments. Agbada Formation forms the hydrocarbon perspective sequence in the Niger delta. It is represented by an alternation

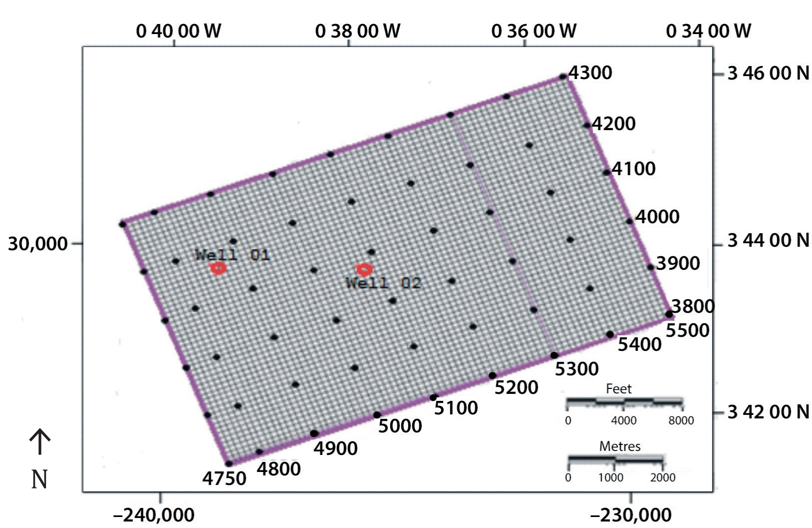

Figure 1: *Base map of "Y" prospect, showing the positions of the two wells (well 1 and 2) and 3D seismic survey.*

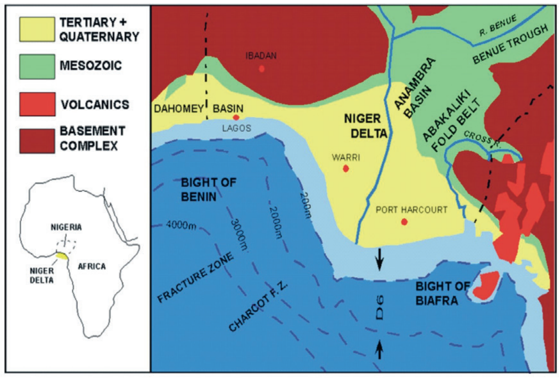

Figure 2: *A geological map showing the Niger delta*[13].

of sands, silts, and clays of various proportions and thicknesses, representing cyclic sequences of offlap units. The shallowest part of the sequence is composed almost entirely of non-marine sand. It was deposited in alluvial or upper coastal plain environments following a southward shift of deltaic depobelts (structural and stratigraphic belts)[5]. This mechanism, called the escalator regression model, postulated that the base of the Benin Formation in any of the six depobelts is coeval with the Agbada Formation in the adjacent depobelt to the south.

This principle implies an abrupt shift in the age of the base of the Benin Formation across the bounding faults of depobelts and had been used to define the Northern limit of the Northern Delta depobelt[6]. Weber[7] discussed in detail the sedimentology, growth faults dynamics and hydrocarbon accumulation in the Niger Delta. Short[8] and Avbovbo[9] also, studied the hydrocarbon potentials of the Niger Delta using well data. Oomkens[10] discussed lithofacies relations in the late Quaternary period. The stratigraphy, sedimentation and structure of Niger Delta was reviewed by Schlumberger[11].

The importance of longshore drift and submarine canyons and fans in the development of the basin has been emphasized by Burke[12].

Method of study

Two wells namely well 1 and well 2 exist in "Y" Prospect. Well 1 is a vertical well with a total depth of 2 332 m, and gamma-ray (GR) log, deep laterolog (LLD), compensated sonic log (BCSL), and compensated formation density log (FDC) were used in this well.

Well 2 is also a vertical well with a total depth of 2 160 m. The logs used in this well include, caliper log (CALI), gamma-ray (GR) log deep, laterolog (LLD), compensated sonic log (BCSL), and compensated formation density log (FDC).

Petrophysical Evaluation: The analysis of the data was done using GeoGraphix software. The data consist of logs (from two wells) namely the caliper log, the gamma ray log (GR), deep laterolog, and porosity logs (sonic, density and neutron logs).

Identification and Delineation of Lithologies: The *GR* log was used to identify the permeable and impermeable beds. *GR* values greater or equal to 75 API° were identified as shale beds while zones with *GR* readings below 75 API° were identified as sandstones. Intervals where the caliper logs read values lower than 24 cm were considered as permeable zones. This is because reduction in borehole diameter is indicative of the build-up of mudcake in permeable zones.

Identification of Fluids: Fluids in the permeable beds were identified, using the deep laterolog resistivity logs and a combination of the neutron and density logs. High resistivity values of deep-reading resistivity log in permeable beds are indicative of either the presence of hydrocarbon or fresh water.

Determination of Volume of Shale: The presence of shale in a reservoir can adversely affect the correct evaluation of petrophysical parameters particularly resistivity, porosity and water saturation. Hilchie[13] notes that the most important effect of shale in a formation is to reduce the resistivity contrast between oil or gas and water. With sufficient shale in a reservoir, it becomes very difficult to detect a productive zone[14]. Porosity and water saturation values must be corrected for shale effect to allow for a reliable formation evaluation. The first step in making this correction is to determine the volume of shale present in the reservoir.

For this study, shale volume was determined using the GR_{log}. The Gamma Ray Index (I_{GR}) was calculated first from the log using the formula[15];

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \quad (1)$$

Where are;
$GR_{\log}$ = gamma ray reading of formation.
$GR_{\min}$ = minimum gamma ray reading (clean sand)
$GR_{\max}$ = maximum gamma ray reading (shale)

Subsequently, the calculated I_{GR} was used in the formula[10] for Cainozoic unconsolidated rocks to determine the volume of shale (V_{sh}).

$$V_{sh} = 0.083(2^{3.7 \times I_{GR}} - 1) \quad (2)$$

The calculated volumes of shale are expressed in percentage.

Determination of Porosity: Porosity values were obtained from sonic log, density log and a combination of neutron and density logs. Sonic porosity values were calculated using the formula proposed by Dewan[2] for undercompacted sandstones:

$$\phi_s = 0.63 \left(1 - \left(\frac{54}{\Delta t}\right)\right) \quad (3)$$

The calculated sonic porosity was subsequently corrected for both shale and hydrocarbon effects.
The density porosity (ϕ_D) was computed from eqn. 4;

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \quad (4)$$

Where are:
ρ_{ma} = matrix (sandstone) density = 2.638 g/cm^3
ρ_b = formation bulk density
ρ_{fl} = fluid density

The 3.5 p.u (0.035) is subtracted from the calculated density porosity to convert from apparent limestone porosity unit to apparent sandstone porosity unit. Shale effect was subsequently corrected for to give the effective density porosity (PhiDe or ϕ_{De}).
Correcting for shale effect;

$$\phi_{De} = \phi_D - V_{sh} \times \phi_{D_{sh}} \quad (5)$$

Where are:
ϕ_{De} = effective density porosity
V_{sh} = volume of shale = 8.26 %
$\phi_{D_{sh}}$ = density porosity of adjacent shale = 0.10

The neutron log values were in API Neutron Unit and had to be converted to apparent limestone porosity. The values obtained were converted to apparent sandstone unit by the addition of 3.5 p. u (0.035). Shale effect was also corrected for to obtain the effective neutron porosity (PhiNe or ϕ_{De}).

Porosity values were also computed from a combination of neutron and density logs as follows.

$$\phi_{NDe} = \frac{\phi_{Ne} + \phi_{De}}{2} \quad \text{(for oil zones)} \quad (6)$$

$$\phi_{NDe} = \sqrt{\frac{\phi_{Ne}^2 + \phi_{De}^2}{2}} \quad \text{(for gas zones)} \quad (7)$$

Where are:
ϕ_{NDe}= effective neutron-density derived porosity
ϕ_{Ne} = effective neutron porosity
ϕ_{De} = effective density porosity

Determination of Formation Water Saturation and Hydrocarbon Saturation
The water saturation of the uninvaded zone (S_w) was computed from

$$S_w = \sqrt{\frac{R_0}{R_t}} \text{ [11]} \quad (8)$$

The hydrocarbon saturation (S_{hc}) was calculated from the equation;

$$S_{sh} = 1 - S_w \quad (9)$$

The water saturation of the flushed zone (S_{xo}) was estimated from the Archie's formula;

$$S_{x0} = \sqrt{\frac{FR_{mf}}{R_{x0}}} \quad (10)$$

The other saturation values calculated are the Moveable Hydrocarbon Saturation (*MHS*) and the Residual Hydrocarbon Saturation (*RHS*).

$$MHS = S_{x0} - S_w \quad (11)$$
$$RHS = 1 - S_{x0} \quad (12)$$

Tables 1 and 2 show the calculated parameters at sampled intervals for the calculated reservoirs.

Table 1: *Statistical data derived from GeoGraphix software for Well 1*

DEPTH	*PHIN*	*RHOB*	*PHID*	*DT*	*PHIA*	*GR*	V_{shl}	*PHIE*	*RT*	*Ro*	*SwA*	*BVW*
---------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
4 060	0.414 9	2.158	0.311	128.86	0.363	85.7	0.821	0.064 8	1.56	9.54	1	0.064 8
4 070	0.350 4	2.109	0.34	146.48	0.345	57.2	0.465	0.184 5	4.39	1.18	0.518	0.095 5
4 080	0.349 3	2.119	0.334	146.63	0.342	62.5	0.532	0.16	4.04	1.56	0.621	0.099 5
4 090	0.294 4	2.118	0.335	141.96	0.315	32.2	0.152	0.266 7	13	0.56	0.208	0.055 5
4 100	0.308 3	2.061	0.368	127	0.338	31.2	0.141	0.290 8	0.68	0.47	0.835	0.242 8
4 110	0.329 8	2.113	0.337	126.89	0.333	38.1	0.227	0.257 9	0.75	0.6	0.896	0.231
4 120	0.366 2	2.108	0.341	132.88	0.353	53.9	0.423	0.203 9	0.85	0.96	1	0.203 9
4 130	0.337 7	2.025	0.39	135.53	0.364	38.7	0.234	0.278 5	0.64	0.52	0.895	0.249 3
4 140	0.334 7	2.129	0.328	133.92	0.331	38.7	0.234	0.253 7	0.77	0.62	0.9	0.228 5
4 150	0.349 9	2.091	0.351	127.07	0.35	34	0.175	0.288 9	0.74	0.48	0.807	0.233 1
4 160	0.401 2	2.249	0.257	123.31	0.329	95.1	0.939	0.020 1	1.4	99.45	1	0.020 1
4 170	0.486 8	2.259	0.251	133.41	0.369	93.7	0.922	0.028 9	1.25	47.8	1	0.028 9
4 180	0.273 4	2.121	0.333	146.24	0.303	35.8	0.198	0.243 3	6.83	0.68	0.315	0.076 5
4 190	0.277	2.093	0.35	172.96	0.313	34.5	0.181	0.256 4	50.55	0.61	0.11	0.028 1
4 200	0.313 5	2.063	0.367	152.52	0.34	38.4	0.231	0.261 9	36.9	0.58	0.126	0.032 9
4 210	0.39	1.984	0.414	147.52	0.402	56.3	0.454	0.219 6	3.53	0.83	0.485	0.106 5
4 220	0.373 7	2.196	0.288	121.78	0.331	89.6	0.87	0.042 9	1.04	21.77	1	0.042 9
4 230	0.345	2.179	0.298	122.71	0.322	75.7	0.696	0.097 7	1.24	4.19	1	0.097 7
4 240	0.377 1	2.03	0.387	137.36	0.382	53.3	0.416	0.223 1	0.83	0.8	0.983	0.219 3
4 250	0.394 2	2.186	0.294	129.94	0.344	65.1	0.564	0.150 1	0.92	1.77	1	0.150 1
4 260	0.387 9	2.122	0.332	131.27	0.36	65.7	0.571	0.154 3	0.78	1.68	1	0.154 3
4 270	0.341 8	2.066	0.365	122.53	0.354	34.2	0.177	0.291	0.68	0.47	0.833	0.242 4
4 280	0.315 2	2.116	0.336	118.99	0.326	28.1	0.102	0.292 5	0.73	0.47	0.803	0.234 8
4 290	0.346 2	2.05	0.375	125.45	0.36	49.5	0.369	0.227 6	0.69	0.77	1	0.227 6
4 300	0.427 7	2.141	0.321	128.93	0.374	61.7	0.522	0.179	0.84	1.25	1	0.179
4 310	0.322 2	2.085	0.354	122.46	0.338	38.6	0.233	0.259 4	0.82	0.59	0.853	0.221 2
4 320	0.379 5	2.064	0.367	130.16	0.373	59.4	0.492	0.189 3	0.7	1.12	1	0.189 3
4 330	0.298 2	2.184	0.295	119.78	0.297	65	0.563	0.129 7	0.95	2.38	1	0.129 7
4 340	0.279 3	2.106	0.341	119.1	0.31	31.4	0.143	0.266 1	0.77	0.56	0.856	0.227 9
4 350	0.350 5	2.137	0.323	118.23	0.337	32.8	0.16	0.283 1	0.82	0.5	0.78	0.220 8
4 360	0.320 6	2.121	0.333	121.58	0.327	56.2	0.452	0.178 9	0.89	1.25	1	0.178 9
4 370	0.328 4	2.078	0.359	123.19	0.344	39.8	0.248	0.258 4	0.68	0.6	0.939	0.242 7
4 380	0.344 1	2.037	0.383	127.57	0.364	47.7	0.346	0.237 8	0.64	0.71	1	0.237 8
4 390	0.381 5	2.313	0.219	116.05	0.3	95	0.937	0.018 9	1.25	111.6	1	0.018 9
4 400	0.358	2.25	0.256	118.82	0.307	88.1	0.851	0.045 6	1.2	19.26	1	0.045 6
4 410	0.374 4	2.134	0.325	124.35	0.35	88.5	0.856	0.050 2	0.86	15.86	1	0.050 2
4 420	0.295 9	2.108	0.341	121.8	0.318	30.6	0.133	0.276 1	0.78	0.52	0.823	0.227 1
4 430	0.302 7	2.046	0.377	127.43	0.34	30.3	0.129	0.296 3	0.63	0.46	0.85	0.251 9
4 440	0.429 4	2.307	0.222	119.7	0.326	82.2	0.778	0.072 3	1.01	7.66	1	0.072 3
4 450	0.383	2.321	0.214	112.16	0.299	95.5	0.943	0.016 9	1.53	139.39	1	0.016 9
4 460	0.450 9	2.242	0.26	123.42	0.356	94.7	0.934	0.023 5	1.24	72.26	1	0.023 5
4 470	0.347 2	2.039	0.381	131.02	0.364	43	0.287	0.259 7	21.09	0.59	0.168	0.043 5
4 480	0.298 8	2.043	0.379	132.67	0.339	38.2	0.228	0.261 7	27.5	0.58	0.146	0.038 1
4 490	0.343 4	2.054	0.373	131.13	0.358	29.4	0.118	0.315 9	15.21	0.4	0.162	0.051 3
4 500	0.333 1	2.12	0.333	124.25	0.333	44	0.3	0.233 3	0.7	0.73	1	0.233 3

PHIN – Neutron Porosity *RHOB* – Bulk Density *DT* - Sonic log *PHIND* – Density Porosity *PHIA* – Average Porosity *GR* – Gamma Ray V_{shl} – Volume of Shale *PHIE* – Effective Porosity *RT* – True Resistivity *Ro* – Wet Resistivity *SwA* – Average Water Saturation

Table 2: *Statistical data derived from GeoGraphix software for Well 02*

DEPTH	PHIN	RHOB	PHID	DT	PHIA	GR	V_{shl}	PHIE	RT	Ro	SwA	BVW
-------	-------	-------	-------	-------	-------	-------	------	-------	-------	-------	-------	-------
4 600	0.46	2.21	0.28	115.63	0.37	93.03	0.913	0.032 2	1.22	38.54	1	0.032 2
4 610	0.157	2.07	0.364	121.66	0.261	41.38	0.267	0.191	106.67	1.1	0.101	0.019 4
4 620	0.131	2.1	0.348	126.12	0.24	45.25	0.316	0.164	30.77	1.49	0.22	0.036 1
4 630	0.259	2.19	0.289	124.21	0.274	75.92	0.699	0.082 5	5.13	5.87	1	0.082 5
4 640	0.48	2.14	0.32	147.01	0.4	90.64	0.883	0.046 8	2.39	18.26	1	0.046 8
4 650	0.129	2.03	0.39	143.56	0.26	61.89	0.524	0.123 6	26.89	2.62	0.312	0.038 6
4 660	0.135	2.18	0.297	142.82	0.216	45.7	0.321	0.146 7	21.77	1.86	0.292	0.042 9
4 670	0.232	2.06	0.369	136.74	0.301	78.5	0.731	0.0808	3.14	6.13	1	0.080 8
4 680	0.195	2.07	0.362	137.64	0.279	52.89	0.411	0.164 3	10.7	1.48	0.372	0.061 1
4 690	0.058	1.95	0.434	137.59	0.246	52.09	0.401	0.147 2	13.22	1.85	0.374	0.055
4 700	0.208	2.09	0.354	133.05	0.281	39.91	0.249	0.210 9	57.14	0.9	0.125	0.026 5
4 710	0.199	2.13	0.327	131.45	0.263	42.75	0.284	0.188 1	18.82	1.13	0.245	0.046 1
4 720	0.166	2.04	0.384	135.5	0.275	62.98	0.537	0.127 2	5.83	2.47	0.651	0.082 8
4 730	0.043	1.86	0.488	139.37	0.265	45.33	0.317	0.181 2	533.33	1.22	0.048	0.008 7
4 740	0.03	1.85	0.496	151.07	0.263	47.36	0.342	0.173 1	57.14	1.34	0.153	0.026 5
4 750	0.214	2.19	0.292	142.68	0.253	38.34	0.229	0.195 2	200	1.05	0.072	0.014 1
4 760	0.018	1.9	0.465	131.11	0.241	52.89	0.411	0.142 2	24.81	1.98	0.282	0.040 2
4 770	0.197	2.02	0.393	136.45	0.295	51.5	0.394	0.179	10.67	1.25	0.342	0.061 2
4 780	0.24	2.05	0.377	152.03	0.308	42.09	0.276	0.223 3	31.37	0.8	0.16	0.035 7
4 790	0.066	1.92	0.453	147.89	0.259	53.05	0.413	0.152 2	25	1.73	0.263	0.04
4 800	0.026	1.82	0.511	140.37	0.269	45.69	0.321	0.182 4	39.51	1.2	0.174	0.031 8
4 810	0.408	2.2	0.283	131.81	0.346	96.41	0.955	0.015 5	1.08	166	1	0.015 5
4 820	0.048	1.97	0.42	125.08	0.234	56.06	0.451	0.128 7	25.4	2.42	0.308	0.039 7
4 830	0.061	1.95	0.433	137.63	0.247	50.88	0.386	0.151 5	72.73	1.74	0.155	0.023 5
4 840	0.046	1.98	0.415	128.52	0.231	46.25	0.328	0.155 1	31.37	1.66	0.23	0.035 7
4 850	0.338	2.13	0.33	130.21	0.334	76.42	0.705	0.098 3	7.05	4.14	0.766	0.075 3
4 860	0.182	2.05	0.373	133.48	0.278	75.23	0.69	0.086	4.96	5.41	1	0.086
4 870	0.442	2.08	0.355	143.16	0.399	101.48	1	0	1.95			
4 880	0.117	1.97	0.424	131.52	0.27	50.59	0.382	0.166 9	19.39	1.44	0.272	0.045 4
4 890	0.021	1.94	0.442	129.29	0.232	44.78	0.31	0.16	34.41	1.56	0.213	0.034 1
4 900	0.093	1.98	0.418	135.37	0.256	42.72	0.284	0.183 1	42.1	1.19	0.168	0.030 8
4 910	0.04	1.96	0.428	136.79	0.234	50.56	0.382	0.144 5	106.67	1.92	0.134	0.019 4
4 920	0.282	2.18	0.299	134.6	0.29	83.52	0.794	0.059 8	3.11	11.18	1	0.059 8
4 930	0.013	1.82	0.512	133.72	0.263	40.2	0.253	0.196 5	228.57	1.04	0.067	0.013 2
4 940	0.125	2.01	0.396	123.34	0.261	61.94	0.524	0.124 1	13.01	2.6	0.447	0.055 5
4 950	0.04	2.03	0.386	122.22	0.213	37.39	0.217	0.166 7	118.51	1.44	0.11	0.018 4
4 960	0.034	1.9	0.467	129.7	0.251	50.23	0.378	0.155 8	61.54	1.65	0.164	0.025 5
4 970	0.246	2	0.403	137.19	0.325	81.81	0.773	0.073 8	6.28	7.35	1	0.073 8
4 980	0.08	1.96	0.426	135.98	0.253	59.89	0.499	0.126 9	20.25	2.48	0.35	0.044 4
4 990	0.348	2.21	0.282	123.25	0.315	90.98	0.887	0.035 5	2.09	31.78	1	0.035 5
5 000	0.082	2	0.404	129.35	0.243	48.86	0.361	0.155 4	10.03	1.66	0.406	0.063 1

PHIN – Neutron Porosity *RHOB* – Bulk Density *DT* - Sonic log *PHIND* – Density Porosity *PHIA* – Average Porosity *GR* – Gamma Ray V_{shl} – Volume of Shale *PHIE* – Effective Porosity *RT* – True Resistivity *Ro* – Wet Resistivity *SwA* – Average Water Saturation

Reserve Estimation

The volumes of hydrocarbons in place were estimated from the following formulae;

$$OIP = 7758\phi(1 - S_w)Ah \quad (13)$$
$$GIP = 43560\phi(1 - S_w)Ah \quad (14)$$

Where are:
OIP = oil in place (barrels)
GIP = gas in place (cubic feet)
The constants 7 758 and 43 560 are conversion factor for oil and gas barrels or cubic meter respectively.
ϕ = porosity (decimal)
S_w = formation's water saturation (decimal).
Area = area of the reservoir (in acres)
h = net thickness of reservoir (wet with oil or gas) (in feet)

Discussion of results

Gamma-ray (GR) logs were used to identify the lithology in both wells penetrated. The lithology was identified by defining shale base line (Figure 3), which is a constant line in front of the shale and in front of the sand. Thick sand at a depth of 304.8 m to 926.7 m (1 000–3 040 ft) was delineated in well 1. Well 2 contain thick sand layer at a depth of 100 m to 914.4 m (328–3 000 ft). At a depth of 1 237.5 m to 1 371.6 m (4 060–4 500 ft), and 1 402.1 m to 1 524 m (4 600–5 800 ft) thick sand (identified reservoir sand) was also observed in well 1 and well 2 respectively. Figure 3 shows the stratigraphic cross section within the study area. The major lithologies encountered in the study area were basically shale and sand, some of which occurs as interbeds. The reservoir sandstone was evaluated quantitatively for effective porosity, water & hydrocarbon saturation and net pay (Tables 3 and 4).

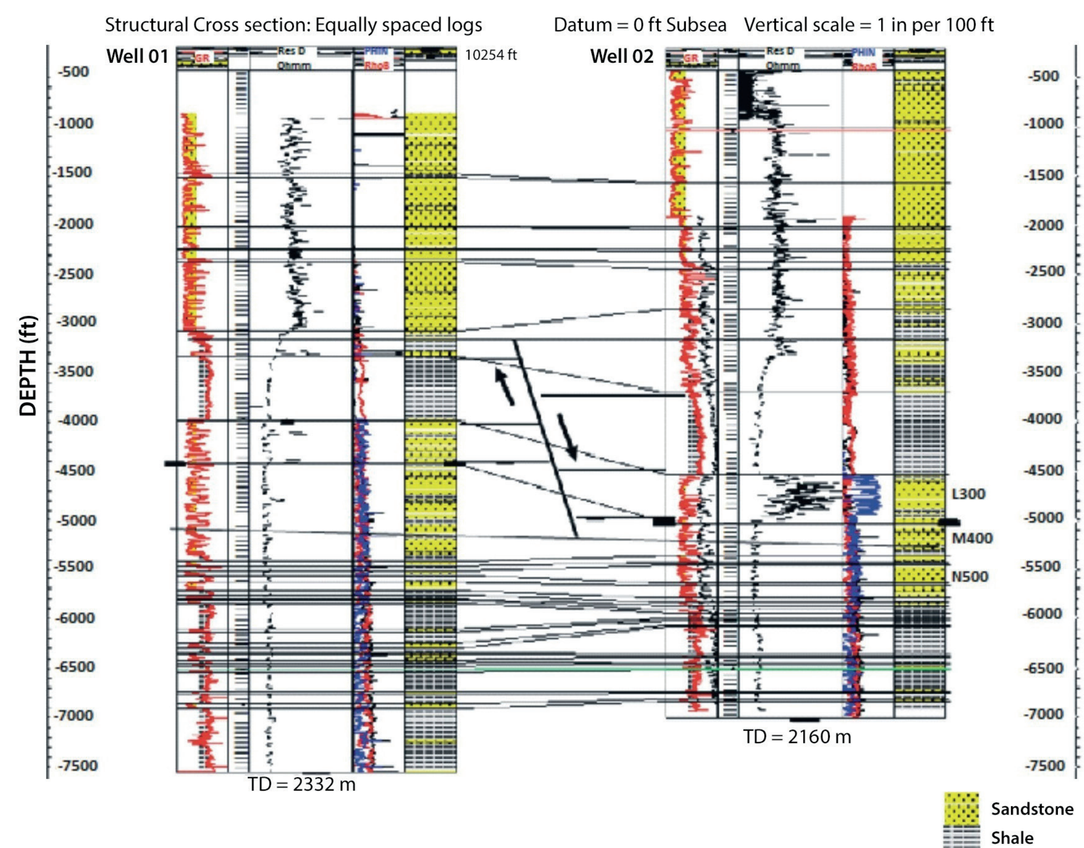

Figure 3: *Correlation across the wells of "Y" Prospect showing mapped sands.*

Table 3: *Petrophysical Parameters for Well 01*

SANDS	ZONE	TOP *MD*/m	BASE *MD*/m	*PHIE*/%	S_w/%	S_{hc}/%	GROSS (m)	Net sand thickness (m)	*NTG*	*PAY*/m
L300	1	1 240.54	1 524	19.95	48.5	51.5	283.46	43.65	0.154	22.9
M400	2	1 539.24	1 630.68	21.56	76.91	23.1	91.44	14.08	0.154	0.87
N500	3	1 685.54	1 699.25	12.25	98.52	1.48	13.72	3.88	0.283	–

MD – Measured Depth PHIE – Effective Porosity S_w – Water Saturation S_{hc} – Hydrocarbon Saturation *NTG* – Net-to-Gross

Table 4: *Petrophysical Parameters for Well 02*

SANDS	ZONE	TOP *MD*/m	BASE *MD*/m	*PHIE*/%	S_w/%	S_{hc}/%	GROSS (m)	Net sand thickness (m)	*NTG*	*PAY*/m
L300	1	1 402.08	1524	13.46	30.82	69.18	121.92	101.07	0.829	80.75
M400	2	1 542.88	1 615.44	17.73	55.78	44	73.15	8.266	0.113	1.37
N500	3	1 676.4	1 706.88	20.26	92.38	7.62	30.48	6.858	0.225	0.14

MD – Measured Depth PHIE – Effective Porosity S_w – Water Saturation S_{hc} – Hydrocarbon Saturation NTG – Net-to-Gross

Neutron density logs were used to define hydrocarbon type (gas) present in “Y” Prospect. Petrophysical analysis of the reservoir bed was based on examination of the well logs. The combination of neutron and density logs was used for reservoir L300 in both wells to detect gas zone. At these intervals, density porosity was observed to be greater than neutron porosity and the curves cross over each other, therefore were identified as gas bearing zones (Figure 4). This is because gas in pores causes the density porosity to read very high values (gas has a lower density than oil or water) and causes the neutron porosity to be too low (there is a low concentration of hydrocarbon atoms in gas than in oil and water). Figure 5 shows the crossplot of neutron porosity with *RhoB* (Formation Bulk Density).

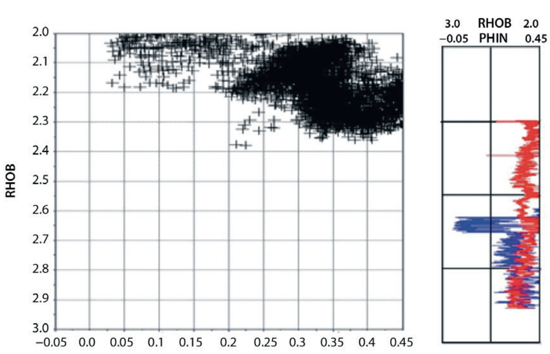

Figure 4: *Pickett crossplot of Neutron porosity(PHIN) with Bulk Density (RhoB).*

Gas has a very marked effect on both density and neutron logs. If it is assumed that the formation fluid is water and the invasion zone is shallow, then gas will result in a lower bulk density (note on the cross plot, this results in a point higher on the *y*-axis), and a lower apparent neutron porosity (Figure 6).

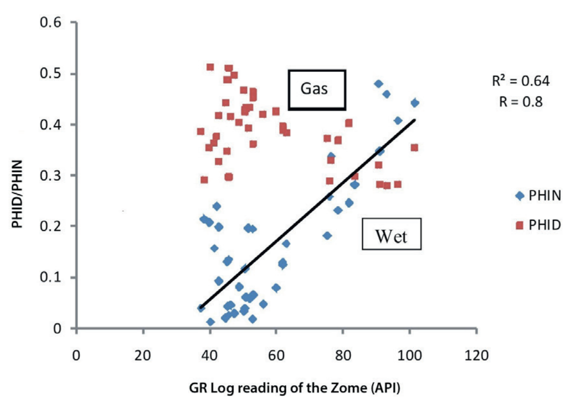

Figure 5: *Crossplot of Neutron Porosity (PHIN) with Density Porosity (PHID).*

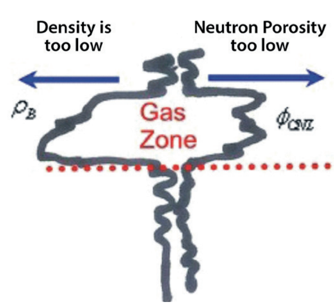

Figure 6: *Typical log curve showing gas zone and its effect on density and neutron.*

Conclusion

Reservoir evaluation is an attempt to find appropriate reservoir rocks and then to estimate the porosity, permeability and water saturation. In Niger Delta sands more than 15 m thick in most places represent composite bodies, and may consist of two to three stacked channels. They are poorly consolidated and have porosities as high as 40 % in oil- bearing reservoirs. Porosity reduction is gradual. All sands shallower than 3 000 m have porosities of more than 15 %, but below 4 000 m only a few sands have more than 15 % porosity. Gross, net and net-to-gross values for sandstones in well -1 are 13.72–283.46, 3.88–43.65 and 0.154–0.283, while those for well - 2 are 30.48–121.92, 6.858–101.07 and 0.113–0.829 respectively. Reservoir which contain hydrocarbon is referred to as pay zone and the porosities range 20–40 %. The average porosity (*PHIA*) which is the average porosity within the net is 0.23 (23 %) for well 01, it is 0.28 (28 %) for well 2. The porosity values are within the porosities of producing reservoirs in the Niger Delta. Water saturation is generally low in hydrocarbon bearing zone ranging from 1–30 % thereby implying high hydrocarbon saturation. The water saturation, values in “Y” Prospect at well 1 and well 2 are 0.85 (85 %), and 0.62 (62 %) respectively. The reservoir properties evaluated for the wells showed that they could be fair to very good for hydrocarbon accumulation.

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