Porosity Estimation in the Niger-Delta Basin of Nigeria using Sonic Log.

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ABSTRACT

The *sonic* or *acoustic* log measures the travel time of an elastic wave through a geological formation. This information can also be used to derive the velocity of elastic waves through the formation. Its main use is to provide information to support and calibrate seismic data and to derive the porosity of a formation. Porosity of subsurface formations can vary widely, for instance carbonates (limestone and dolomites) and evaporities (salts, anlydrite, gypsum, sylvite, etc.) may show practically zero porosity. Consolidated sandstones may have 30% porosity or more. Shales or clays may contain over 40% water-filled porosity.

In an effort to estimate the formation porosity of the Niger-Delta of Nigeria, a case study of a well was carried out. It's petrophysical parameters were computed while borehole parameters were estimated using the Wyllie Time-Average equation was used the porosity at intervals 3495m-311m of well. After applying a gas correction of 0.7, the porosity of the formation was found to be 22%, showing that the formation of the area might be might be unconsolidated sands.

(Keywords: porosity, Wyllie Time Average equation, geological formations, sonic log, acoustic log)

INTRODUCTION

The *sonic* or *acoustic* log measures the travel time of an elastic wave through a geologic formation. This information can also be used to derive the velocity of elastic waves through the formation. Its main use is to provide information to support and calibrate seismic data and to derive the porosity of a formation. The sonic sonde types are shown in Figures 1 and 2, respectively.

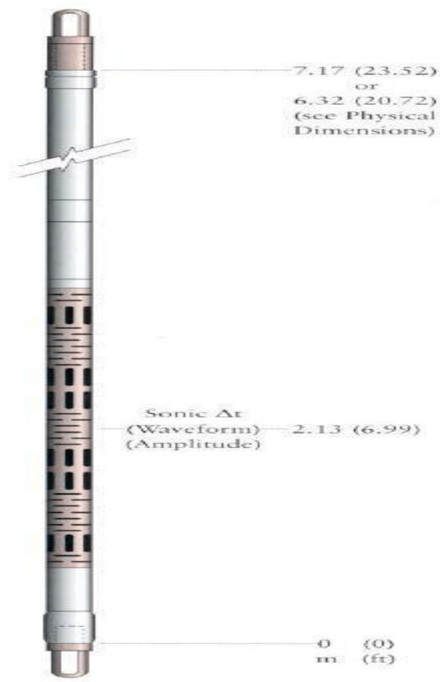

Figure 1: Compensated Sonic Sonde (courtesy of Schluberg).

Porosity is the percentage of pore volume or void space, or that volume within rock that can contain fluids. Porosity can be a relic of deposition (primary porosity, such as space between grains that were not compacted together completely) or can develop through alteration of the rock (secondary porosity, such as when feldspar grains or fossils are preferentially dissolved from sandstones). Effective porosity is the interconnected pore volume in a rock that contributes to fluid flow in a reservoir. It excludes isolated pores. Total porosity is the total void space in the rock whether or not it contributes to fluid flow. Thus, effective porosity is typically less than total porosity. Used in geology, hydrogeology, soil science, and building science, the porosity of a porous medium (such as rock or sediment) describes how densely the material is packed. It is the proportion of the non-solid volume to the total volume of material, and is defined by the ratio:

$$\phi = \frac{V_p}{V_m}$$

Where: Vp is the non-solid volume (pores and liquid) and V_m is the total volume of material, including the solid and non-solid parts.

Both φ and n are used to denote porosity.

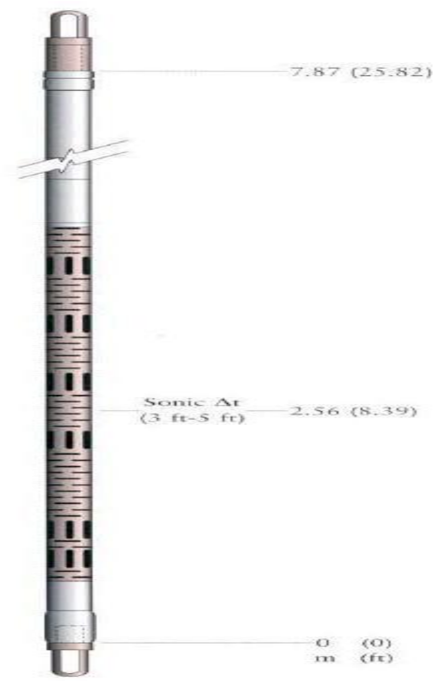

Figure 1: Long Spaced Sonic Sonde (courtesy of Schluberg).

Porosity is a fraction between 0 and 1, typically ranging from less than 0.01 for solid granite to more than 0.5 for peat and clay, although it may also be represented in percent terms by multiplying the fraction by 100%.

The porosity of a rock, or sedimentary layer, is an important consideration when attempting to evaluate the potential volume of hydrocarbons it may contain. Sedimentary porosities are a complex function of many factors, including but not limited to: rate of burial, depth of burial, the nature of the connate fluids, and the nature of overlying sediments (which may impede fluid expulsion).

A value for porosity can be calculated from the bulk density and particle density. Porosity can be determined at ambient or reservoir pressure conditions and is an indication of the storage capacity of the reservoir. Core porosities are used to calibrate logs and for reserves calculations.

A number of techniques are employed for the measurement of porosity in consolidated rocks. Boyle's-law helium-expansion is a standard method for measuring either pore volume or grain volume. Bulk-volume measurements are determined by fluid displacement (Archimedes principle) or by calipering plug samples. With Boyle's law and bulk-volume data, bulk and grain densities can be determined by also weighting the sample.

Porosity is determined using the helium expansion technique (porosimeters). Pore volume can be measured directly when a core is confined at stress or the grain volume and bulk volume can be used to provide a room condition value.

Porosity is defined as the ratio of the pore volume to the bulk volume of a material. Porosity is measured on plug samples after they have been cleaned and dried to remove all reservoir fluids and residual salts by injecting the sample with helium. Porosity can also be measured on sidewall cores and full diameter core sections, as well as at overburden conditions. Rock with porosity exceeding eight percent is usually permeable no matter which saturation model you use (Archie, Dual-Water, Indonesia, Waxman-Smits etc.).

In the absence of density log (or NMR) data, total porosities are best calculated by empirical calibration to core data.

Once a total or effective porosity has been determined, it must be used in a water saturation equation to determine hydrocarbon saturations. If you've used a total porosity model, then there's no concern about which shale fraction model you've used. If you've gone down the effective porosity route too early, you must adjust the saturation model to account for the conductivity of the clay-bound water that is measured by the resistivity logs, but not accounted for in the porosity.

Types of Geologic Porosities

Primary porosity is the main or original porosity system in a rock or unconfined alluvial deposit. Secondary porosity is a subsequent or separate porosity system in a rock, often enhancing overall porosity of a rock. This can be a result of chemical leeching of minerals or the generation of a fracture system. This can replace the primary porosity or coexist with it.

Fracture porosity is porosity associated with a fracture system or faulting. This can create secondary porosity in rocks that otherwise would not be reservoirs for hydrocarbons due to their primary porosity being destroyed (for example due to depth of burial) or of a rock type not normally considered a reservoir (for example igneous intrusions or metasediments).

Vuggy porosity is secondary porosity generated by dissolution of large features (such as macrofossils) in carbonate rocks leaving large holes, vugs, or even caves. Effective porosity (also called open porosity) refers to the fraction of the total volume in which fluid flow is effectively taking place (this excludes dead-end pores or non-connected cavities). This is very important in solute transport.

Dual porosity refers to the conceptual idea that there are two overlapping reservoirs which interact. In fractured rock aquifers, the rock mass and fractures are often simulated as being two overlapping but distinct bodies. Delayed yield, and leaky aquifer flow solutions are both mathematically similar solutions to that obtained for dual porosity; in all three cases water comes from two mathematically different reservoirs (whether or not they are physically different). Macro porosity refers to pores greater than 50 µm in diameter. Flow through macropores is described by bulk diffusion.

Since a total porosity system is more reliably calibrated to core and simpler to work in, this is the approach recommended for petrophysical evaluation. If there are conductive shales present, correct for these using total porosity and either the Waxman-Smits or Dual Water models to get water saturations. Use effective porosity only to calibrate a permeability transform. If you need effective porosities and water saturations for some other reason (e.g. your volumetric model is "effective"), calculate them from your calibrated total porosity system.

Measuring Porosity

There are several ways to estimate the porosity of a given material or mixture of materials, which is called your material matrix. The volume/density method is fast and surprisingly accurate (normally within 2 % of the actual porosity). To do this method you pour your material into a beaker, cylinder or some other container of a known volume. Weigh your container so you know its empty weight, and then pour your material into the container. Tap the side of the container until it has finished settling and measure the volume in the container. Then weigh your container full of this material, so you can subtract the weight of the container to know just the weight of just your material. So now you have both the volume and the weight of the material. The weight of your material divided by the density of your material gives you the volume that your material takes up, minus the pore volume. (The assumed density of most rocks, sand, glass, etc. is assumed to be 2.65 g/cm^3. If you have a different material, you may look up its density). So, the pore volume is simply equal to the total volume minus the material volume, or more directly (pore volume) = (total volume) - (material volume).

The water saturation method is slightly harder to do, but is more accurate and more direct. Again, take a known volume of your material and also a known volume of water. (Make sure the beaker or container is large enough to hold your material as well.) Slowly dump your material into the water and let it saturate as you pour it in. Then seal the beaker (with a piece of Para film tape or if you don't have Para film tape a plastic bag tied around the beaker will do.) and let it sit for a few hours to insure the material is fully saturated. Then remove the unsaturated water from the top of the beaker and measure its volume. The total volume of the water originally in the beaker minus the amount of water not saturated is the volume of the pore space, or again more directly (pore volume) = (total volume of water) - (unsaturated water).

The water evaporation method is the hardest to do, but is also the most accurate. Take a fully saturated, known volume of your material with no excess water on top. Weigh your container with the material and water and then place your container into a heater to dry it out. Drying out your sample may take several days depending on the heat applied and the volume of your sample. Then weigh your dried sample. Since the density of water is 1 g/cm^3, the difference of the weights of the saturated versus the dried sample is equal to the volume of the water removed from the sample (assuming you are measuring in grams), which is exactly the pore volume. So once again, (pore volume in cubic centimeters) = (weight of saturated sample in grams) - (weight of dried sample in grams).

THEORY

The velocity of elastic waves through a given lithology is a function of porosity. Wyllie proposed a simple mixing equation to describe this behavior and called it the *time average equation*. It can be written in terms of velocity or Δt. After numerous laboratory determinations, M.R.J. Wyllie proposed for clean and consolidated formations with uniformly distributed small pores, a linear time-average or weighted-average relationship between porosity and transit time:

$$t_{log} = \Phi t_f + (1 - \Phi) t_{ma} - - - - equation\ 1$$

or

$$\Phi = \frac{t_{\log} - t_{ma}}{t_f - t_{ma}} - - - - - equation\ 2$$

where,
t_{log} is the reading on the sonic log in µs/ft
t_{ma} is the transit time of the matrix material, and
t_{log} is the transit time of the saturating fluid (about 189 µs/ft for fresh water mud system)

STRUCTURE AND STRATIGRAPHY OF THE NIGER DELTA (STRATIGRAPHY)

The Niger Delta formation is divided into three stratigraphic units. The Benin formation forms the uppermost unit of the delta complex. It consists of fresh water bearing massive continental sands and gravels deposited in an upper deltaic plain environment. The Benin formation is the thickest unit in the central area of the Niger Delta.

Immediately below the Benin formation is the Agbada formation, which consists of alternation of sands and shales of paralic origin. The sandstones are very coarse to fine grained, well to poorly sorted and generally unconsolidated. The shales are light to dark grey, and become more indurated with depth. The thickness of the Agbada formation ranges form 9000 – 14000ft.

The basal unit of the Niger Delta is the Akata formation which is composed mainly of marine shales, deposited as the high energy delta advanced into deep water. The subsea depth of the Akata formation ranges between 12000ft to18000ft in onshore and between 5000ft and 10000ft in offshore.

STRUCTURE OF THE NIGER DELTA

Detailed description of the geology of the Niger Delta has been done by several geologists. Among these are Stauble and Short (1967), Daukoru and Weber (1975), and more recently Olear (1992).

Throughout the geologic history of the Delta, its structure and stratigraphy have been controlled by the interplay between rates of sediment supply and subsidence.

Sedimentation rate has been greatly influenced by eustatic sea level changes and climatic variations in the hinterland while subsidence has been controlled largely by initial basement morphology, crustal type (stable or unstable shale, oceanic or continental) and differential sediment loading on unstable shale.

NIGER DELTA GROWTH FAULT AND ROLLOVER ANTICLINES

In order to have a meaningful picture of the pattern of hydrocarbon distribution in the Niger Delta, it is essential to examine the dynamics of growth faulting, rollover anticline, shale dispirits and, other associated structural features in the Niger Delta. In the simplest form, growths are gravity slumps, which operate as sedimentation takes place.

They result from surface tectonic effects caused by sedimentary density contrast and gravity instability, which develop in regressive deltaic sequence. As sands prograde over the almost incompact delta, foot marine clays gravity slumping is initiated in the underlying know shear strength clays because of the density contrast between sand and incompact loopy clays. As this process continuous and as deltas built builds basin ward, younger clays ridges and growth fault are formed. Down dip structure become more complex, involving large scale “clay upheaval structures (diapers) and the migration of Akata “muds” towards the delta front. Continued growth fault of mud diapers induced expansion in fault patterns and back-to-back faults develop bounding large-scale diapirs. The combination of the vertical component of this process with a horizontal displacement of the down block induces the formation of the rollover anticlines and emphasizes the sedimentation into the seaward block. Growth fault may be associated with each regressive rhythm and therefore tend seaward.

OIL AND GAS OCCURRENCE WITHIN THE NIGER DELTA

Almost all oil and gas occurrence in the Niger Delta complex are located in the Agbada formation sands and hydrocarbons are frequently trapped in dip closed crestal areas or against one or more faults especially on their up thrown side (Figure 3).

Evamy et al (1978) reported that:

1. Hydrocarbon-rich belts cuts across the depositional and structural trends of the delta from southeast to Northwest, North and East of the hydrocarbon rich belt, the gas/oil ratio is much higher and the recoverable oil reserves of the accumulations found to date are smaller south of the main hydrocarbon rich belt is a series of narrow oil rich zone. Otherwise a predominant gassy province occupies a fairly wide part of the central delta.

2. Know commercial oil accumulations occur predominantly in the structurally highest part of a given macrostructure in the strike sense, despite viable trapping conditions down plunge.

3. Dry holes and marginal oil and gas structures are located mainly on the South flanks of macrostructures.

4. In a given macrostructure, the gas to oil ratio increases down plunge and in a generally seaward direction. Hence northern blocks with pronounced landward dips are regarded as highly prospective.
5. The more down dip a macrostructure is within a megastructure, the greater is the probability of a higher Gas to oil ration (GOR).

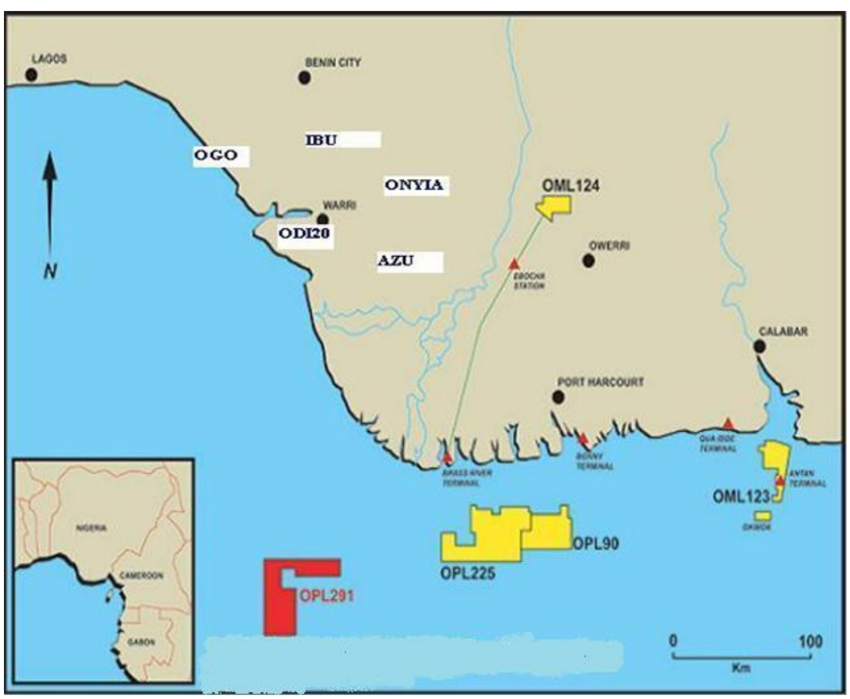

Figure 3: Oil and Mineral Layout of the Niger Delta.

Hydrocarbon Migration

What constitutes the exact source rock, (whether the Alats Shale or lower Agbada shales) and the major migration pathway along bedding planes or growth faulty planes) are still hotly debated by geologists.

Weber and Daukoru (1975) postulated that fault migration is probably the most effective way in which hydrocarbon and gas field and water have migrated into rollover anticline. However another school of thought claims that flank migration involving a seaward facies – change up dip into flanks of a rollover anticline structure is the most probable situation. In the main, migration is thought to have been local in the Niger Delta.

CALCULATIONS

The computation of the petrophysical parameters of the well was for the interval 3369m-4066m.

Formation Water Resistivity:

Ssp recording on the self potential log in millivolt =35mv

R^{16} Normal= short normal reading in Ohm-meter = 13Ωm

R_{6ff40} = deep induction reading in Ohm-meter = 20Ωm

R_{mf} = 1.42 Ωm at 81^0f

R_{mf} At BHT of 250^0f = 0.404^aΩm (using chart Gen 9 from elf petroleum)

Since 84^0f is greater than 0.1Ωm. By entering ssp reading into sp.1 at BHT, where:

R_{weg} = equivalent water resistivity, R_{mfeg} = equivalent mud filtrate resistivity.

$$\frac{\mathrm{R_{mfeg}}}{R_{weg}} = 2.4\Omega\mathrm{m}(\mathrm{from\ sp} - 1)$$

R_{mfeg} = 0.85x R_{mf}, 0.85x0.404 = 0.3434 Ωm

$$R_{weg} = \frac{R_{mfeg}}{2.4} = \frac{0.3434}{2.4} = 0.1431\Omega\mathrm{m}$$

R_{weg}= 0.1431 Ωm, from sp-2R_w = 0.23 Ωm.

WATER SATURATION COMPUTATION

R_0 7.5 Ωm. R = R_{6ff46}= 60Ω

$$S_w - \left(\frac{R_0}{R_t}\right)^{\frac{1}{2}} - - - - - 3$$

$$S_w = 0.35$$

Porosity computation from sonic log:
t_{ma}=51.0µs/ft
t_f=189 µs/ft
t_{log}=95 µs/ft

Substituting into Equation 2, gives:

$$\Phi = \frac{(95-51)\mu s/ft}{(189-51)\mu s/ft} = \frac{44}{138} = 0.3188 = 0.32 = 32\%$$

It becomes 0.22 (by applying Gas correction factor of 0.7)

Φ=0.22=22%

It may be noted that oil correction factor of 0.9 has been applied (Schlumberger, 1989).

DATA PRESENTATION /ANALYSIS

Computed borehole parameters from a well section (Figure 4), where R_{mf} = B_{HT} = 0.404 Ωm, t_{ma}=51.0µs/ft, t_f=189 µs/ft, t_{log}=95 µs/ft. The Evaluation of which is shown in Table 1:

Where,
R_{mf} = Resistivity of mud filtrate,
t=internal transit,
S_w = water saturation,
R_w = Resistivity of formation water,
Tf= Interval transit time of fresh drilling mud,
R6$_{ff40}$= Deep induction reading,
Tma= Internal transit time of sound matrix,
S_{wav} = average water saturation,
R16 = Shallow resistivity reading,
S.$_p$ = Self potential reading,
R_0= Resistivity of nearby water saturated sand,
Φs= Sonic porosity,
and Φ_{AV} = Average sonic porosity.

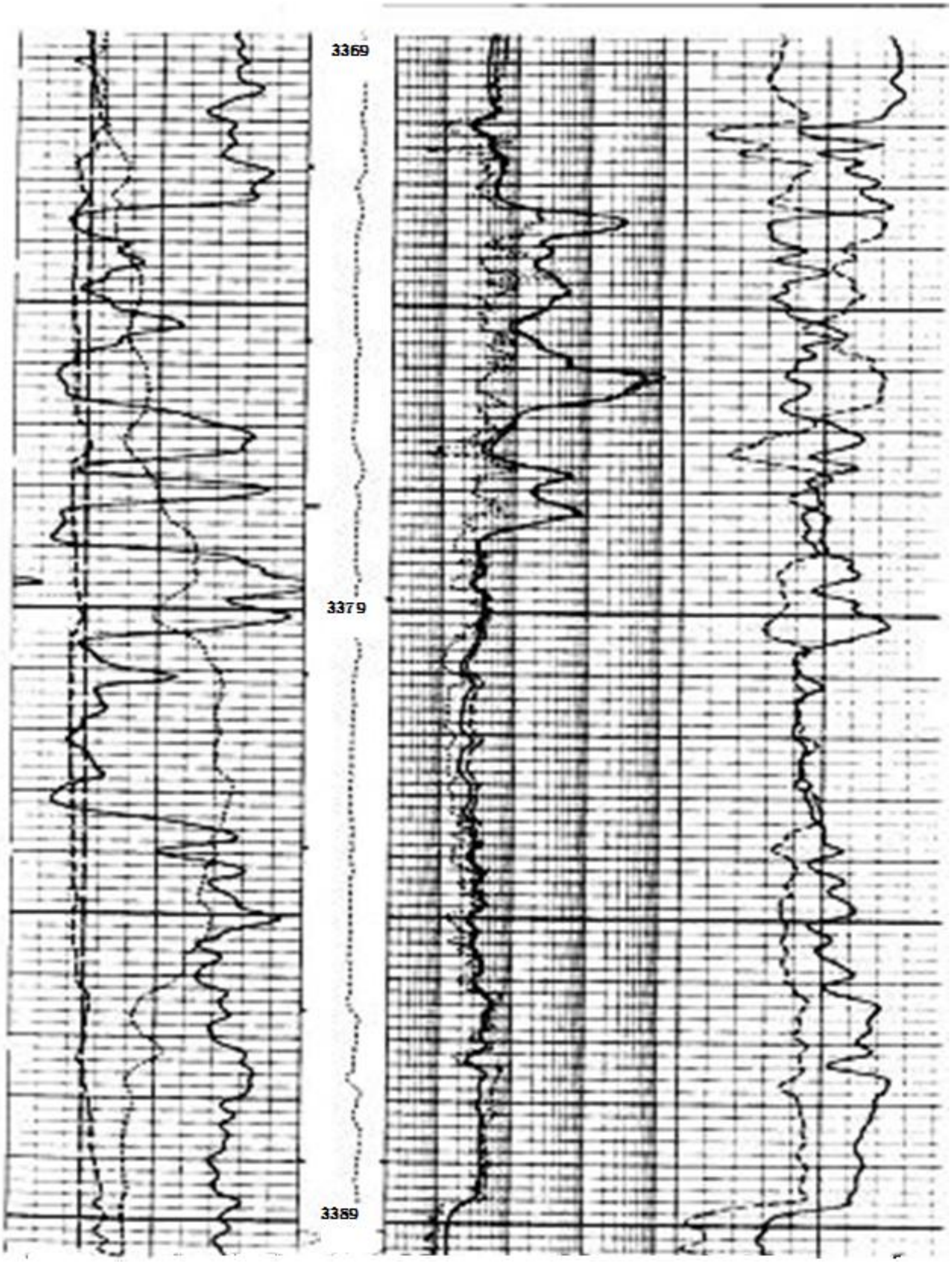

Figure 4: Section of the Considered Well.

Table 1

Interval (Meter)	S.P (MV)	R_{16} (Ωm)	$R6_{ff40}$ (Ωm)	R_o (Ωm)	R_w (Ωm)	T (µs/ft)	Φ_s	S_w	Φ_{AV}	S_{war}
3369-3389	+40	4.5	3	2.5	0.25	80	0.21	0.91	-	-
3458-3474	+35	8	11	7.5	0.23	85	0.25	0.83	-	-
3475-3511	+35	13	60	7.5	0.23	95	0.22	0.35	-	-
3541-3558	+37	20	60	7.5	0.24	87	0.23	0.35	-	-
3599-3608	+37	10	40	6	0.24	77.5	0.18	0.40	0.20	0.78
3660-3672	+32	8	6	6	0.22	75	0.17	1.00	-	-
3679-3729	+35	10	8	6	0.23	75	0.17	0.87	-	-
3736-3776	+35	8	10	7	0.23	78	0.20	0.84	-	-
3779-3874	+32	9	8	8	0.22	70	0.14	1.00	-	-
3946-3982	+32	6	6	6	0.22	80	0.21	1.00	-	-
3987-4066	+28	8	6	6	0.20	75	0.17	1.00	-	-

DISCUSSION OF RESULTS

Generally, consolidated and compact sandstones have porosities from 15 to 25%. In formations, the response of the sonic log seems to be relatively independent of exact contents of the pores: water, oil, gas or even determined shale. However, in some higher porosity sandstones (30% or greater) that have very low water saturation (high hydrocarbon saturation) and very shallow invasion; the t values may be somewhat greater than those in some formations when water saturated. If any shale laminae exist within the sandstone, the apparent sonic porosity values are usually increased by an amount proportional to the bulk volume fraction of laminae. The t readings are increased because t_{sh} is generally greater than t_{ma} of the sandstone matrix.

CONCLUSIONS

The possibility of estimation of porosity of the Niger-Delta basin has been successfully estimated by the application of Wyllie Time-Average Equation.

The computation of porosity from sonic log, using the computed petrophysical characteristics of well for the interval 3495-3511m, shows that the estimation of porosity is 22%. The estimated porosity shows that at 3495-3511m, the formation is characterized by consolidated and compacted sandstones.

Finally, the response of sonic log seem to be relatively dependent of exact content of pores; water, oil, gas or even determined shale.

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