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NMR AND WELL LOGS PETROPHYSICAL CHARACTERIZATION OF SANDSTONE FROM THE MARACANGALHA FORMATION, BAHIA, BRAZIL

Nathália de Souza Penna¹; Joelson da Conceição Batista²; Suzan Sousa de Vasconcelos³

¹Mestranda em Geofísica, Departamento de Geofísica, USP (USP), São Paulo/SP, Brasil.

ORCID: <https://orcid.org/0000-0002-0682-0582>

Email: nathaliapenna.s@gmail.com

²Doutor em Geofísica, Departamento de Geofísica, Universidade Federal da Bahia (UFBA), Salvador/BA, Brasil.

ORCID: <https://orcid.org/0000-0001-9256-6586>

Email: jdbatista@ufba.br

³Doutora em Geofísica, Departamento de Geofísica, Universidade Federal da Bahia (UFBA), Salvador/BA, Brasil.

ORCID: <https://orcid.org/0000-0001-9111-2603>

Email: suzan.vasconcelos@ufba.br

Abstract

The storage and production capacity of reservoir rocks can be estimated through some petrophysics characteristics involving the lithological identification of the constitute rocks, fluids nature in the porous space, porosity, permeability, saturation and clay content. The most popular tools for obtaining these petrophysical parameters are the conventional geophysical well logs. However, the determination of petrophysical parameters from tools based on the phenomenon of nuclear magnetic resonance (NMR) has gained prominence in recent decades. In this work, we analyzed rock samples from outcrops in Frades Island region, Bahia, Brazil, through laboratory NMR measurements, to estimate and evaluate the petrophysical properties of the Maracangalha Formation, one of the main hydrocarbons reservoirs in the Recôncavo Basin. The sandstone samples were characterized in terms of porosity, permeability, saturation, and petrofacies. Finally, we calculated porosity, permeability, and clay content using data from gamma-ray, electrical and density logs, measured in a depth interval interpreted for Maracangalha Formation. These

results corroborate with the obtained by NMR since, despite the effects of weathering and erosion on the samples used, the values of porosity and permeability obtained in NMR are in the range of values calculated from these profiles.

Keywords: NMR; Geophysical well logs; Petrophysics; Reservoir rocks.

RMN E PERFÍS GEOFÍSICOS DE POÇOS NA CARACTERIZAÇÃO PETROFÍSICA DE ARENITO DA FORMAÇÃO MARACANGALHA, BAHIA, BRASIL

Resumo

A capacidade de armazenamento e produção de rochas reservatório pode ser estimada através de características petrofísicas como identificação litológica das rochas, natureza dos fluidos no espaço poroso, porosidade, permeabilidade, saturação e teor de argila. As ferramentas mais populares para a obtenção desses parâmetros petrofísicos são os perfis geofísicos de poços. No entanto, a determinação de parâmetros petrofísicos a partir de ferramentas baseadas no fenômeno da ressonância magnética nuclear (RMN) tem ganhado destaque nas últimas décadas. Neste trabalho, analisamos amostras de rochas de afloramentos na região da Ilha dos Frades, Bahia, Brasil, por meio de medições de RMN em laboratório, para estimar e avaliar as propriedades petrofísicas da Formação Maracangalha, um dos principais reservatórios de hidrocarbonetos da Bacia do Recôncavo. As amostras de arenito foram caracterizadas em termos de porosidade, permeabilidade, saturação e petrofácies. Por fim, calculamos a porosidade, permeabilidade e teor de argila usando dados de perfis de raios gama, elétricos e de densidade, medidos em profundidade na Formação Maracangalha. Esses resultados corroboram os obtidos por RMN uma vez que, apesar dos efeitos do intemperismo e da erosão nas amostras utilizadas, os valores de porosidade e permeabilidade obtidos em RMN estão na faixa dos valores calculados a partir desses perfis.

Palavras-chave: RMN; Perfis geofísicos de poços; Petrofísica; Rochas reservatório.

RMN Y PERFILES GEOFÍSICO DE POZOS PARA LA CARACTERIZACIÓN PETROFÍSICA DE ARENISCA DE LA FORMACIÓN MARACANGALHA, BAHÍA, BRASIL

Resumen

La capacidad de almacenamiento y producción de las rocas de yacimientos se puede estimar a través de características petrofísicas como la identificación litológica de las rocas constituyentes, naturaleza de los fluidos en el espacio poroso, porosidad, permeabilidad, saturación y contenido de arcilla. Las herramientas más populares para obtener estos parámetros petrofísicos son los registros geofísicos de pozos. Sin embargo, la determinación de parámetros petrofísicos a partir de herramientas basadas en el fenómeno de la resonancia magnética nuclear (RMN) ha ganado protagonismo en las últimas décadas. En este trabajo, analizamos muestras arenisca de rocas de afloramientos en la región de la Isla Frades, Bahía, Brasil, a través de mediciones de RMN de laboratorio, para estimar y evaluar las propiedades petrofísicas de la Formación Maracangalha, uno de los principales reservorios de hidrocarburos en la Cuenca Recôncavo. Nosotros calculamos la porosidad, la permeabilidad y el contenido de arcilla utilizando datos de registros de rayos gamma, eléctricos y de densidad, medidos en la formación Maracangalha. A pesar de los efectos de la intemperie y erosión sobre las muestras utilizadas, los valores de porosidad y permeabilidad obtenidos en RMN se encuentran en el rango de valores calculados a partir de estos perfiles.

Palabras-clave: RMN; Registros geofísicos de pozos; Petrofísica; Roca reservatório.

1. INTRODUCTION

The oil industry has always been involved in the development of technologies focused on characterizing and improve the exploration efficiency of hydrocarbon reservoirs. In the middle of the 20th century, when the Nuclear Magnetic Resonance (NMR) signal was observed for the first time and scientists discovered the applicability of this phenomenon in the study of matter, many oil companies understood that this phenomenon could be applied in the field of petrophysics investing resources in the development of new tools based on NMR. These efforts serve to understand the properties of the rocks and the fluids that saturate them, fundamental parameters to evaluate the storage and production capacity of hydrocarbon reservoirs (DUNN, 2002). The most popular tools to obtain these parameters, such as geophysical well profiles, usually reflect several aspects inherent to the technique used, the geometry of the tool and the environmental conditions. Considering it, corrections need to be applied to the acquired data to obtain reliable results (NERY, 2013).

The NMR tools have gained prominence because of their ability to provide more accurate porosity values than most traditional techniques. In NMR technique, the porosity values are measure in the function of fluid and porous space properties, in this case, the rock matrix does not have a substantial influence on the measured physical parameter (MARTINEZ *et al.*, 2000; GE *et al.*, 2015). Studies have made the NMR measurements a routine in many petrophysical applications, mainly those related to siliciclastic rocks (EHRlich *et al.*, 1991; KENYON 1997;

MARTINEZ and DAVIS, 2000; YAN *et al.*, 2017; JÁCOMO *et al.*, 2018).

This research analyzes laboratory petrophysical measurements performed in rock samples from the Caruaçu Member of the Maracangalha Formation, one of the main and most complex hydrocarbon reservoirs in the Recôncavo Basin, Bahia, Brazil. The present research seeks to obtain and disseminating petrophysical information about this important study formation, estimating the porosity, free fluid, bound fluid index and permeability, through laboratory NMR measures on sandstone samples taken from outcrops of the Maracangalha Formation. Also, we compared petrophysical parameters obtained from NMR, conventional techniques and well geophysical logs data, analyzing and integrating these results, providing a more detailed description of the petrophysical properties that define the reservoir sandstones of Caruaçu Member.

2. GEOLOGY OF THE STUDY AREA

The Recôncavo Basin is located in the Northeast of Brazil, in the center-east of Bahia and comprises an area of approximately 11,500 km². Its limits to the north and northwest are marked by Alto de Aporá, to the west by the fault of Maragogipe, to the south by the fault system of Barra, which separates it from the Camamu Basin and to the east by the fault system of Salvador (Figure 1).

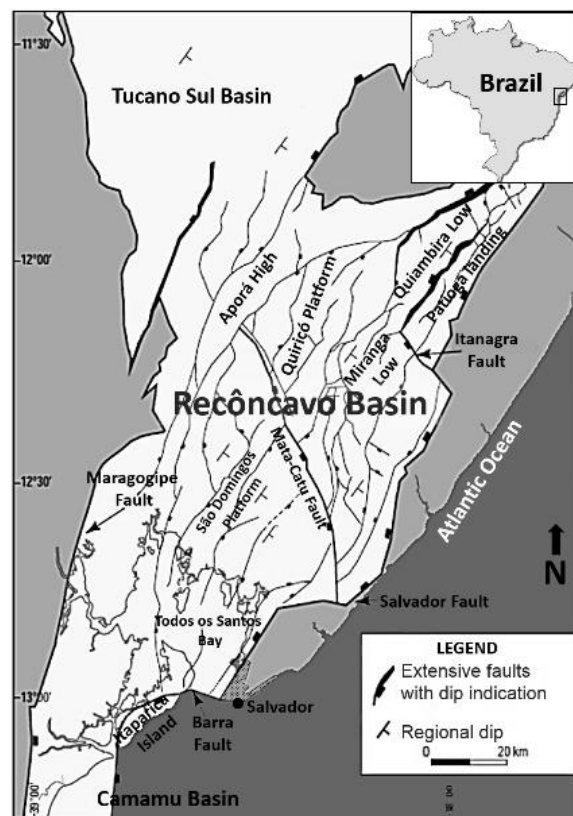


Figure 1 – Location and structural framework of the Recôncavo Basin. Source: Modified by Milhomem *et al.* (2003).

This basin constitutes a aborted segment of the intracontinental rift, whose origin is associated with the process of crustal stretching that culminated in the fragmentation of the Gondwana paleocontinent and the opening of the South Atlantic Ocean, during the Eocretaceous (ALMEIDA *et al.*, 2000 and CORDANI *et al.*, 2000). Sedimentary deposits are associated with four distinct tectonic phases: synclisis, pre-rift, rift and post-rift (SILVA *et al.*, 2007). Regarding oil exploration and production, the Recôncavo Basin is classified as a mature basin, with reserves estimated at 221.8 million barrels of oil and 5.4 billion m³ of gas (Prates and Fernandes, 2015). The main oil-generating system in the Recôncavo Basin consists of the shales of the Gomo and Tauá members of the Candeias Formation, with an average organic carbon content estimated at 4% (MILANI and ARAUJO, 2003). In turn, the main reservoirs consist of fluvial-deltaic sandstones of the Marfim and Pojuca Formations, sandstones of fluvial-eolic facies of the Sergi and Água Grande Formations, as well as turbidites of the Gomo Member of

Formation Candeias and the Caruaçu Member of the Maracangalha Formation.

The object of this study is the Maracangalha Formation, a part of the rift phase of the deposition sequence of the Recôncavo Basin. This formation was divided into two members: Caruaçu and Pitanga. The Pitanga Member, which is characterized by the presence of more clayey sandstones and facies with a higher degree of deformation, would have its deposition associated with debris flows. Whereas the Caruaçu Member, composed of sandstones of fine to medium granulometry, with plane-parallel stratification and tangential crossings, would have been deposited from sliding or turbidity flows (CAIXETA, 1988; MAGALHAES, 1990).

The samples used in this research came from the outcrops of the Maracangalha Formation in Frades Island, specifically from the outcrops in the Loreto (LOR) and Ponta de Nossa Senhora (PNS) locality. Figure 2 shows the Frades Island location and these outcrops mentioned.

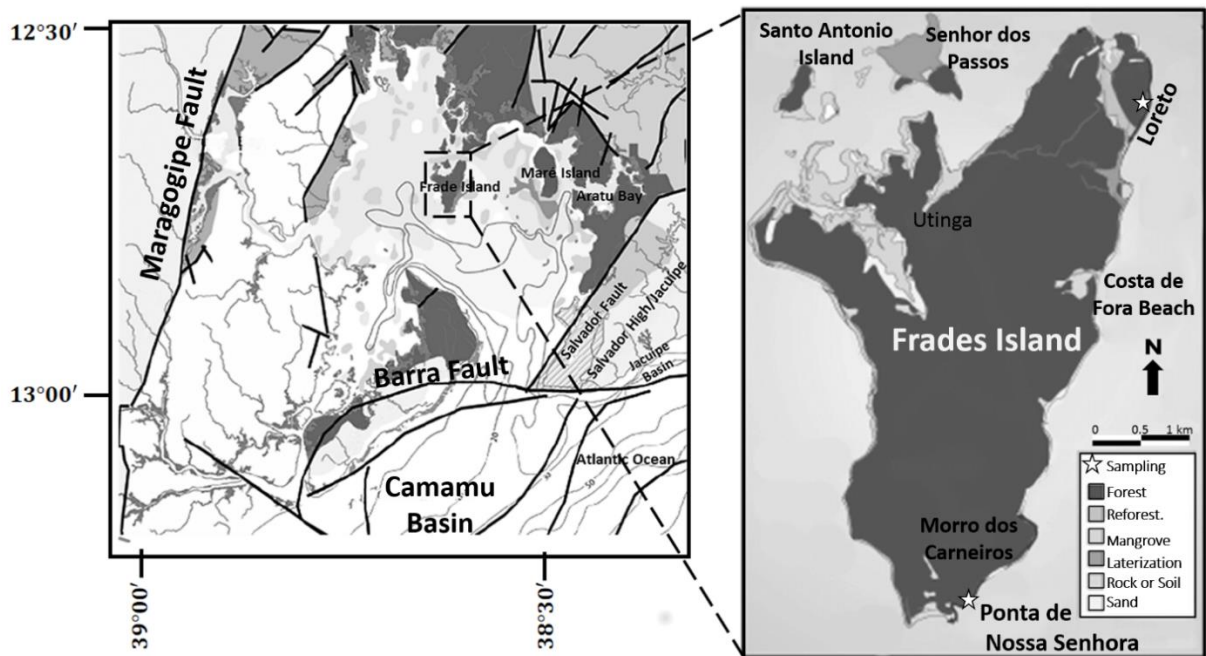


Figure 2 – Frades Island and sampling location. Source: Modified by Magnavita *et al.* (2005), Bittencourt *et al.* (1976) and Medeiros (2008).

The analyzed samples of the outcrop in Loreto, include sandstones with predominantly fine granulometry and abundant plant fragments. The PNS samples, consist of fine-grained, clayey and grayish-colored sandstones (Figure 3). A good description of

these outcrops can be found at Scherer *et al.* (2007). According to these descriptions, samples from Loreto locality would be representative of Fc facies sandstones, while Ponta de Nossa Senhora samples would consist of D5 facies sandstones.

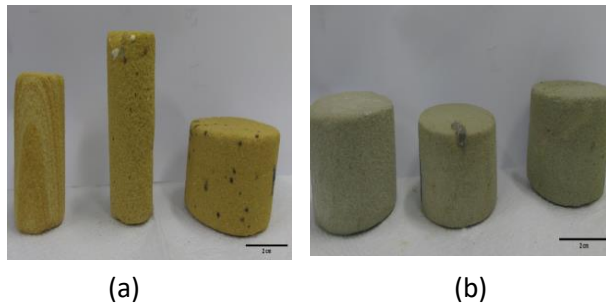


Figure 3 – Samples of rocks representative of the (a) LOR group and (b) PNS group.

According to Scherer *et al.* (2007), Fc facies sandstones are described as fine to very fine sandstones, rarely thick, with abundant vegetable fragments, arranged in tabular layers in situ. In turn, D5 facies sandstones are fine, clayey, grayish-colored sandstones with pendular load characteristics.

3. METHODOLOGY

In this section, we will describe the methodology related to sample preparation for laboratory measurements, as well as the parameters obtained and physical principles associated with NMR measurements and the treatment of data from the geophysical profiles used. Finally, we will describe the use of two conventional techniques for the estimation of porosity values in the samples used.

3.1. Sample preparation

The samples used in this research were the result of sampling procedures performed by the team at the Petrophysics Laboratory (LaPetro) at the Federal University of Bahia. To obtain the petrophysical parameters analyzed, Nuclear Magnetic Resonance (NMR) techniques were used. Traditional methods were also used to obtain porosity values: the Ultrapycnometer and for obtaining nominated “gravimetric porosity”.

Before this laboratory analysis, the samples were subjected to the cleaning process based on the Dean-Stark technique, in which the solvent is continuously heated, condensed and distilled over them. Due to the efficiency in dissolving salts, the solvent used was Methanol (methyl alcohol, CH₃OH). On average, the samples were subjected to a distillation of the solvent for six hours and after cleaning they were placed in a Thelco oven at 100 °C to, from evaporation, eliminate methanol residues in the porous space.

Obtaining porosity information from the NMR equipment requires that the samples are 100% saturated. We saturate these samples with a 70,000 ppm NaCl solution, to simulate salinity conditions in the oil reservoir field. These samples were placed in a container with 3/4 of its volume filled with the saturating saline solution so that they were almost completely immersed in the fluid. This container containing samples and saturating solution was placed in a desiccator associated with a vacuum pump to improve the efficiency of the degassing process of the porous medium.

The estimate of NMR permeability measurements must be carried out under conditions of irreducible saturation. For this reason, the desaturation of the samples was obtained using the Soilmoisture CAT 1500 equipment, in which the saturated samples were subjected to a pressure of approximately 8 bar, for an average time of 96 hours.

3.2. Nuclear Magnetic Resonance (NMR)

Nuclear Magnetic Resonance is a non-destructive investigation technique developed since the 20th century, with extensive application in medicine, physics, chemistry, and biology. The NMR signal results from the interaction between the precession movement of the nuclear magnetic moments and the applied external field (COATES *et al.*, 1999; MARTINEZ and DAVIS, 2000). Only atoms with several odd protons and/or neutrons can enable the observation of the NMR signal. As the H¹ isotope has high natural abundance, greater absolute sensitivity and gyromagnetic constant, most NMR tools are based on the responses of the hydrogen atom nucleus.

As highlighted by Rios (2011), NMR tools usually make use of low-intensity magnetic fields, hence the signal from the rock matrix (poor in hydrogen) is weak enough to be detected. For this reason, NMR tools are calibrated by enabling measurements independent of lithology and influenced essentially by the fluids present in the pores.

The transverse magnetic relaxation constant (T₂) is the physical parameter preferably used in the NMR tools to obtain information on porosity, pore distribution, water saturation, irreducible saturation and permeability of the porous medium. T₂ time is associated with the magnetic properties of protons, their interactions with other protons and adjacent molecules. The transverse magnetic relaxation process that determines the T₂ constant involves three mechanisms: intrinsic transverse (or bulk) relaxation of the fluid (T_{2bulk}), the relaxation associated with the contact of the fluid with the surface of the rock grain (T_{2super}) and the relaxation associated with molecular diffusion (T_{2dif}). Mathematically, T₂ can be defined as:

$$\frac{1}{T_2} = \frac{1}{T_{2bulk}} + \frac{1}{T_{2super}} + \frac{1}{T_{2dif}} \quad (1)$$

As highlighted by Coates *et al.* (1999), the degree of influence of each of these components of the time of magnetic relaxation T₂ is determined by the nature of the fluid in the porous medium. For saline solutions, the main mechanism of magnetic relaxation is superficial relaxation. For heavy hydrocarbons, the component T_{2bulk} predominates, and for gas, the magnetic relaxation induced by diffusion T_{2dif}. Considering that in this research the rock sample was saturated with saline solution, the superficial magnetic relaxation would consist of the predominant magnetic relaxation phenomenon. The surface magnetic relaxation constant is defined as:

$$\frac{1}{T_{2super}} = \rho_2 \frac{S}{V} \quad (2)$$

where: ρ₂ is the transversal relaxivity, S is the surface of pore area and V is the volume of the fluid.

The expression of the decay of magnetization over time can be expressed as a function of $T_{2\text{super}}$ as follows:

$$M(t) = M_0 e^{-\rho_2 \frac{t}{T_2}}, \quad (3)$$

this equation show the relationship between the T_2 relaxation constant and the pore size in the sample, an aspect explored in the characterization of the pore distribution from the NMR measures.

3.2.1. Porosity, free fluid index and connected fluid index

Since the T_2 distribution curve describes the linear pore size distribution, the porosity value is calculated by the area under this curve (Figure 4).

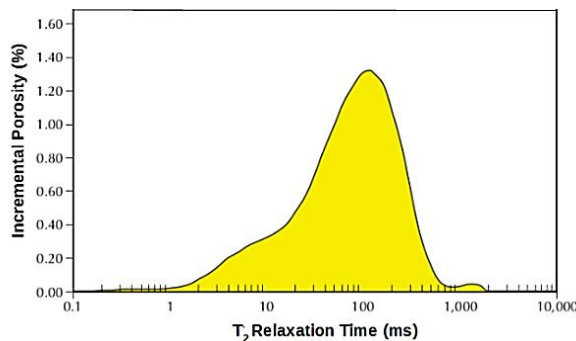


Figure 4 – T_2 distribution and pore size. Source: Coates et al. (1999).

To calculate porosity from the NMR measurements in the laboratory, it is first necessary to calibrate the tool to a fluid volume corresponding to the volume of the sample to be used. Then, we recorded the T_2 time curve distribution and the area under this curve, to obtain the volume of saline solution corresponding to the porosity of this 100% saturated sample ($A_{\text{eq.vol}}$) and then, a new area under T_2 curve distribution is obtained, but from this effectively saturated sample (A_{sample}). The percentage value of these areas concerning the magnitude of the signal associated with the reference fluid volume will consist of the measurement of porosity:

$$\Phi_{RMN} = \left(\frac{A_{\text{sample}}}{A_{\text{eq.vol}}} \right) 100\%. \quad (4)$$

The magnetic relaxation time distribution (T_2) gives information on the pore size distribution and was used to differentiate the pores volume filled with free fluid and the bound fluid associated with the micro-pores. One of the ways to quantify the volumes of free and bound fluid is to determine the Free Fluid Index (FFI) and the Bound Fluid Index or BVI (Bulk Volume Irreducible) from the definition of the Cutting cross-sectional magnetic relaxation time ($T_{2\text{cut}}$). This $T_{2\text{cut}}$ time divides the T_2

distribution curve into two parts: the times to the left of $T_{2\text{cut}}$ are associated with fluids retained by molecular and/or capillary pressures, while the times on the right refer to the pores in which the fluids have the freedom to move around (Figure 5).

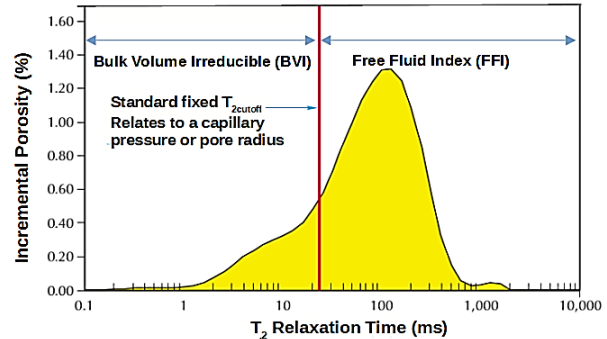


Figure 5 – Determination of free fluid and bound fluid indexes from $T_{2\text{cut}}$. Source: Coates et al. (1999).

The process for defining $T_{2\text{cut}}$ consists of obtaining the NMR signals for a given sample in the condition of 100% saturated and the condition of irreducible saturation (S_{wirr}) and then calculating the accumulated porosity values ($T_{2\text{U}}$), integral of the associated curve distribution of the accumulated porosity in T_2 intervals. The point of intersection of the accumulated porosity curves for the 100% saturated sample and the same in irreducible saturation condition (S_{wirr}) will correspond to the $T_{2\text{cut}}$ point. Frequent $T_{2\text{cut}}$ values for clastic rocks are around 33 ms and for carbonates, approximately 90 ms.

3.2.2. Permeability Estimates

The permeability is directly related to the pore throats size and not to the size of the pores. However, as there is a correlation between the size of the pore throat and the pore size, since large pores tend to have larger pore throats, from NMR it is possible to estimate permeability values. There are two widely used methods to estimate permeability from NMR data: the Timur-Coates model and the average T_2 model.

Timur - Coates model

The Timur-Coates equation estimates permeability values based on the relationship between porosity, free fluid index (FFI) and bound fluid index (BVI):

$$K_c = \left(\frac{\Phi_{RMN}}{c'} \right)^{a'} \left(\frac{FFI}{BVI} \right)^{b'}. \quad (5)$$

The constants a' , b' and c' are empirical and depend on the samples lithology. Common values for these constants are $a'=4$, $b'=2$ and $c'=10 \text{ mD}^{-1}$ (GOMEZ et al., 2007; MAO et al., 2013). The permeability unit is given in mDarcy (mD).

Average T₂ model

The permeability estimated from this model is a function of the porosity and geometric mean of the T₂ values (T_{2GM}):

$$K_{average} = c' \Phi^{a'} T_{2GM}^{b'}. \quad (6)$$

Again, a', b' and c' are empirical constants whose values depend on the lithology of the analyzed rock. It is common to attribute to such constants the values: 4, 2 and 4.5 mD/ms², respectively (DAILGLE and DUGAN, 2009; MAO *et al.*, 2013).

3.3. Geophysical Profiles

The gamma-ray, density and electrical profiles of well 1-ALV-10-BA, in the REC-T-256 block of the Recôncavo Basin, provided by the National Petroleum Agency (ANP), were used to characterize sandstones of the Maracangalha Formation in terms of clay, porosity and permeability. The analyzed points belong to the interval between 1 and 1.2 km of depth, an interval that comprises the sandstones of the Caruaçu Member of the Maracangalha Formation and in which the caliper profile does not suggest significant collapse or cementation in the well wall. The gamma radiation index (IGR) and clayiness (V_{Sh}) in the analyzed sandstone deposits were calculated from the equations below, as described in Nery (2013):

$$IGR = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}, \quad (7)$$

where: GR is the profile reading at the desired depth, GR_{min} is the profile reading for the cleanest sandstone in the analyzed range and GR_{max} is the value chosen as representative of the shales. We use the following expression to estimate clay content for pretertiary age rocks:

$$V_{Sh} = 0.33(2^{2IGR} - 1). \quad (8)$$

Porosity values were estimated from the density profile using the equation:

$$\Phi_D = \frac{\rho_m - \rho_B}{\rho_m - \rho_f} \quad (9)$$

and to correct the effect of shale density on the calculation of the porosity of clayey sandstones, we use the equation (NERY, 2013):

$$\Phi_{Dcorr} = \Phi_D - V_{Sh} \Phi_{Sh}, \quad (10)$$

where Φ_{Dcorr} is the effective porosity corrected for the clayiness effect, Φ_D is the porosity of the sandstone and Φ_{Sh} is the apparent porosity of the adjacent shales.

Concerning electrical profiles, porosity and permeability values were estimated from the following equations developed by Lima and Niwas (2000) and Lima *et al.* (2005):

$$\Phi_e = \frac{\frac{1}{\sigma_0^m} - \frac{1}{\sigma_{x0}^m}}{\frac{1}{\sigma_w^m} - \frac{1}{\sigma_{mf}^m}}, \quad (11)$$

$$\sigma_{cs} = \frac{\sigma_0 - \Phi_e \sigma_{x0}^{\frac{1}{m}}}{1 - \Phi_e} \quad (12)$$

e

$$K = \alpha_0 \left(\frac{\Phi_e^{m-1+\frac{1}{q}}}{1 + \delta_c \sigma_{cs}} \right), \quad (13)$$

where Φ_e is the effective porosity, σ_{cs} is the conductivity of the matrix, σ_0 is the conductivity of the virgin zone, σ_{x0} is the conductivity of the invaded zone, σ_w is the conductivity of the formation water, σ_{mf} is the conductivity of the mud filtrate, m is a geometric factor of sand grains, α_0 is a geometric constant, δ_c is a lithological constant that depends on the size and distribution of sand and clay particles and q is a fractal dimension of the porous space, whose value varies between 2 and 3.

For porosity calculation, since the well does not provide a value for the resistivity of the mud filtrate (R_{mf}), but the resistivity of the mud (R_m), the following approximation was used: $R_{mf} = 0.75R_m$ (NERY, 2013). The formation water resistivity value (R_w) is given in the well data and consists of 1 ohm.m. The resistivities in the invaded and virgin zones were obtained from a Micro electrical profile (Micro-inverse, MI) and an inductive profile with greater radial penetration (AHT90 -- Array Induction Two Foot Resistivity A90), respectively. Temperature measurements at three different depths provided in the data for this well were used to estimate an average temperature gradient (Figure 6) and thus proceed with the correction of the resistances R_w and R_m . Only these resistivities were corrected for temperature variations because they are associated with conductive fluids (electrolytes). The effect of temperature variation on the formation was neglected because the rocks are treated as naturally resistant bodies, the well is not very deep and the geological context studied is not associated with anomalous geothermal gradients. The values of the lithological constants m , q , α_0 and δ_c were, respectively: 1.82, 2.78, 180,000 μm^2 and 100 m/S, determined by Lima and Niwas (2000) for sandstones.

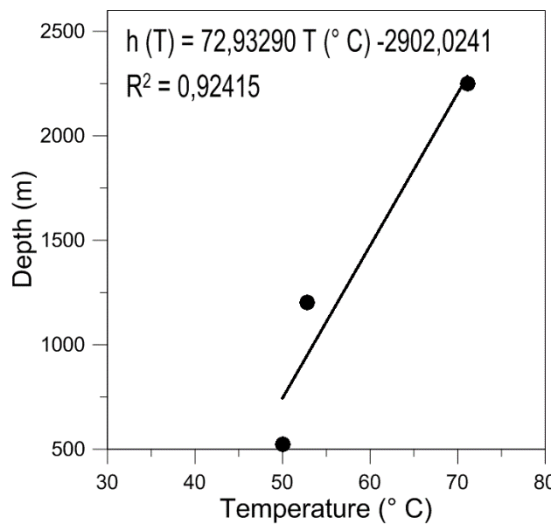


Figure 6 - Correlation between depth and temperature (°C) used to estimate an average geothermal gradient.

3.4. Conventional methods used to calculate porosity

3.4.1. Porosity from Ultrapycnometer

At the UFBA Petrophysics Laboratory, the Ultrapycnometer 1000, manufactured by Quantachrome, was used, whose physical principle for an estimate the non-porous volume (ΔV_{NP}) of the samples consists of the injection of helium gas. The empty volume spaces (ΔV_v) defined as:

$$\Delta V_v = \Delta V_t - \Delta V_{NP}, \quad (14)$$

where ΔV_t is the total sample volume. From the measurements on the Ultrapycnometer, we calculated the porosity by replacing the value of ΔV_v in the equation:

$$\phi = \frac{\Delta V_v}{\Delta V_t} 100\%. \quad (15)$$

3.4.2. Gravimetric porosity

In this estimative, the volume of the porous space (ΔV_v) is defined based on the relationship between the difference between the masses of the dry sample (m_{dry}) and completely saturated ($m_{100\%sat}$), and the specific mass of the solution (ρ). In this way, the gravimetric porosity is expressed by:

$$\phi_t = \frac{(m_{100\%sat} - m_{dry})/\rho}{\Delta V_t} 100\%. \quad (16)$$

4. RESULTS AND DISCUSSION

4.1. Laboratory results

Of the 31 samples analyzed in this work, 13 were of the Ponta de Nossa Senhora location (PNS samples) and 18 from the outcrops in Loreto (LOR samples). For these samples, the porosity values calculated from the NMR method were similar to the porosity values obtained from the difference in mass between the dry and saturated samples (gravimetric porosity). Figure 7 shows the distribution of calculated porosity values from NMR and gravimetric porosity besides the correlation between these two porosities. The correlation coefficient between porosity values NMR and gravimetric is approximately 0.73, showing a strong correlation between these estimates.

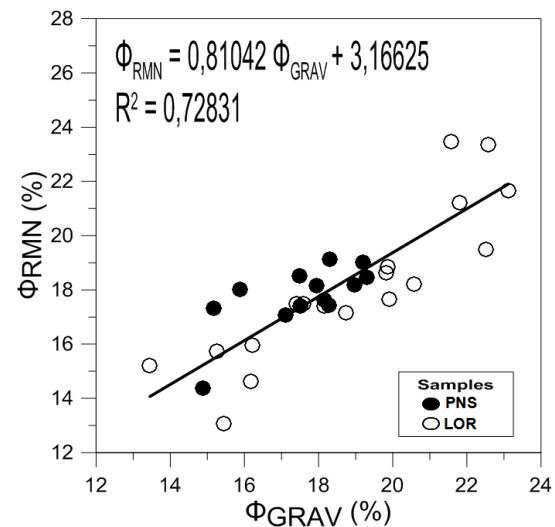


Figure 7 – Correlation between the porosity calculated from the NMR method and the Gravimetric porosity.

On average, the porosity values obtained through the Ultrapycnometer were higher than those obtained through NMR measurements. Figure 8 shows the distribution of porosity values calculated from the Ultrapycnometer and NMR and the low correlation coefficient between them ($R_2 \sim 0.02$). The low correlation between these two sets of values represents the differences in the physical principle of measurement. To NMR porosity measures, the samples were saturated with a saline solution, and for this measure in the Ultrapycnometer, the Helium gas was inserted in the porous space. The Helium gas molecule is smaller than the water molecule and has a greater capacity to penetrate micro-pores. Thus, the porosity calculated from the measurements on the Ultrapycnometer represents the total porosity, while the NMR porosity represents the largest interconnected pores and, therefore, the effective porosity. That explains the discrepancy between these two measures.

The average porosity values obtained from the Ultrapycnometer, NMR and the gravimetric method, for samples from the Ponta de Nossa Senhora locality are, respectively: 23.97%, 17.74% and 17.55%. For samples from Loreto, the values of these porosities were, respectively: 27.56%, 18.15% and

18.90%. According to Rosa *et al.* (2006), rocks with these porosity values are classified as intermediate to very good porosity rocks.

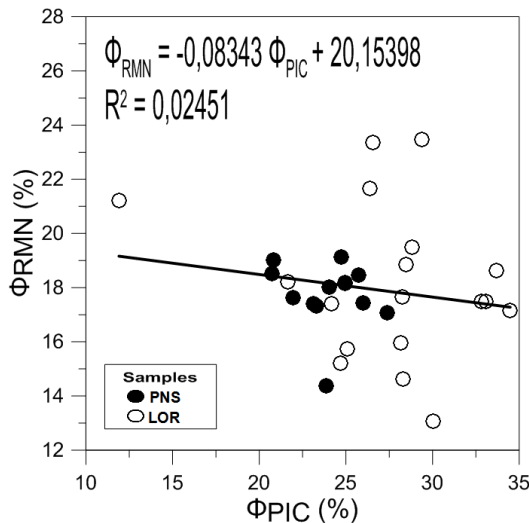


Figure 8 – Correlation between the porosity calculated using the NMR method and the obtained from Ultrapycnometer.

To estimate and analyze the indices of free fluid, fluid retained by capillary pressure (or irreducible fluid) and permeability, the samples were subjected to a new saturation process and placed under pressure in the porous plate to reach the condition of irreducible saturation, required to determine these parameters by NMR. The saturation process usually culminates in some level of degradation in the rock samples, especially in more clayey rocks. Thus, this process, associated with the pressure applied in the samples confined in the porous plate, implied in the reduction of the number of samples that were analyzed in terms of permeability and free and bound fluid indexes. After this second saturation, of the 31 initial samples, it was possible to perform measurements of NMR in 20 samples. Of these 20 remaining samples, 9 samples were PNS and 11 samples were LOR.

After obtaining the distribution curves of the transverse magnetic relaxation times (T_2) for the samples considered 100% saturated and in the condition of irreducible saturation, were determined T_{2cut} values for each set. Figure 9 shows the distribution of T_{2cut} according to the samples and average values of this times for LOR and PNS samples groups. In such figure, the T_{2cut} values obtained vary in the range between 8 and 41 ms and the average values for the LOR and PNS group samples are 21.71 ms and 25.29 ms, respectively.

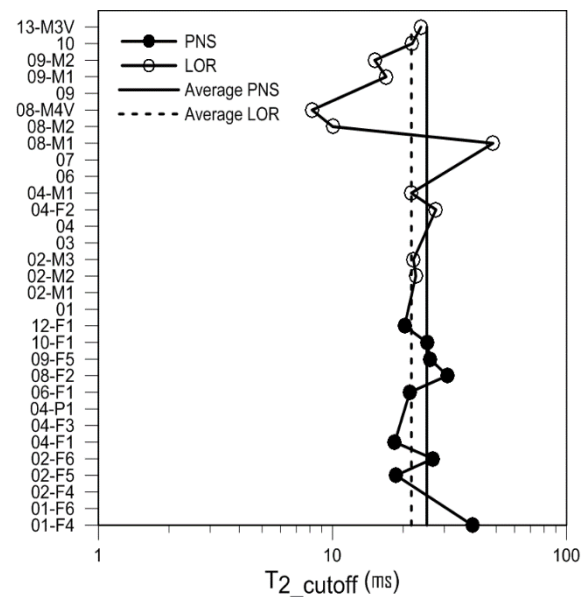


Figure 9 – Distribution of T_{2cut} values according to the samples, as well as average values associated with the LOR and PNS samples.

Despite the difficulties associated with determining measures in conditions of rock 100% saturated and irreducible saturation, the mean values of T_{2cut} obtained from this laboratory measurements are close to the average values associated with literature for sandstones (33 ms). Besides, the T_{2cut} value divides the T_2 distribution curve in terms of the area associated with fluids retained by capillary pressures (the area to the left of T_{2cut}) and free fluids (the area to the right of T_{2cut}). The highest value of T_{2cut} obtained for the PNS samples indicates that the pore space related to the micropores in these samples is larger than in the LOR group samples.

The percentages of volume of the porous space associated with the fluid retained by capillary pressure and the free fluid can be estimated from the calculation of the free-fluid index (FFI) and of bulk volume irreducible (BVI) because T_2 distribution curve area it is proportional to the porosity. The fluid retained by capillary pressures also encompasses the porous space associated with clay minerals and these are generally the main constituents of cement that clogs pores and implies a reduction in the permeability of reservoir rocks. Therefore, determining the percentage of fluid retained by capillary pressure related to the clay (that is, the bulk volume irreducible associated with clay minerals, BVI_{clay}) consists of a simple method of assessing the influence of clay on the properties that determine storage capacity and transmission of fluids in the rocks. To estimate the bonded fluid index to clay minerals, was necessary to use a theoretical T_2 established in the literature as the cutoff time for micropores associated with clay equal to 3 ms (COATES *et al.*, 1999). Then, was calculated the area of the T_2 distribution curve together with an estimate of the percentages of the area associated with fluids retained by the micropores (BVI) and the area associated exclusively with the microporous clay (BVI_{clay}). The expression

below demonstrates the BVI as a function of the BVI_{clay} and other micropores (BVI^*):

$$BVI = BVI_{clay} + BVI^* \quad (17)$$

Figure 10 shows the distribution of the FFI, BVI_{clay} and fluid bound to other micropores (BVI^*) for PNS and LOR samples, as well as the mean values of the indexes for each group. On the horizontal axis, the numbers associated with the samples in the graphs correspond to the sequence in which the data refer to such samples in Figure 9. The average values obtained of the FFI, BVI_{clay} and BVI^* from the PNS locality were, respectively: 12.08%, 23.83% and 64.09%. The values of these parameters for the LOR locality were, respectively: 26.27%, 23.09% and 50.64%.

These results show that the LOR samples have an average FFI value corresponding to more than twice the average value of this index for PNS samples, which indicates that the effective porosity of LOR samples is greater than that of PNS samples. Besides, as suggested from the analysis of the average times of $T2_{cut}$, the average values of BVI_{clay} reinforce, even if subtly, the more clayey composition of sandstones from the outcrop in Ponta de Nossa Senhora.

The values of free fluid and fluid retained by capillary pressure indices are used to estimate permeability values from the Timur-Coates model. The average permeability values associated with samples from the LOR and PNS groups, obtained from the referred model, were respectively: 1.49 mD and 0.31 mD. The mean values of permeability obtained from the use of T2GM, were, respectively: 0.48 mD and 0.30 mD. Figure 11 shows the distribution of permeabilities estimated from the two methods, as well as the correlation coefficient between them. The positive correlation moderate, observed in the expression of the adjustment curve in Figure 11, is due to the difference between the methodologies adopted to estimate the permeabilities. Despite the differences regarding the permeability estimates provided by the two methods, the results obtained indicate that the LOR samples tend to have higher permeability values than the rocks of the PNS group.

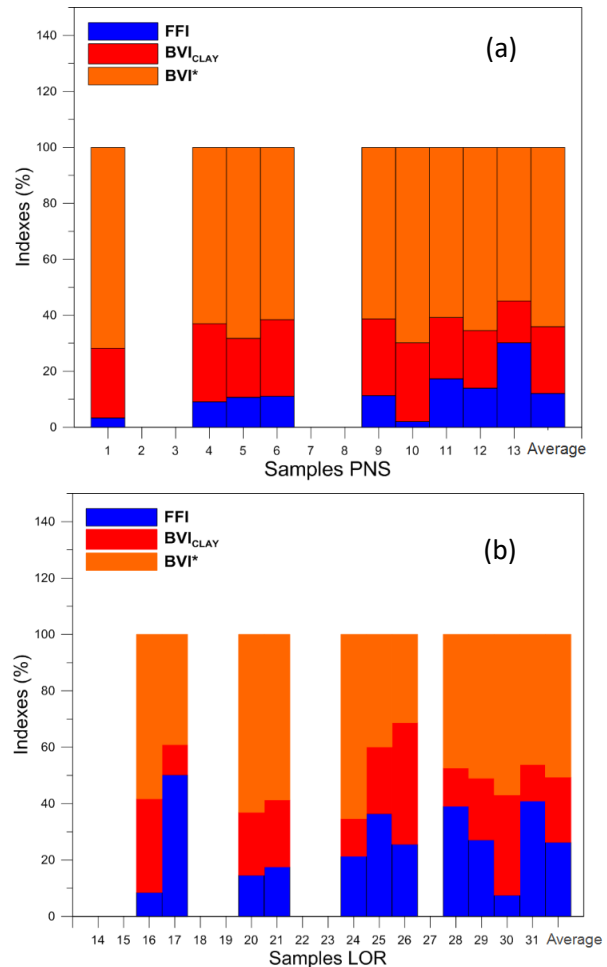


Figure 10 – Distribution of the FFI, BVI_{clay} and BVI^* for (a) PNS samples and (b) LOR samples. The last column of each graph presents the average values of these indices for each group of samples

Estimates of the permeability and porosity values derived from NMR were used to evaluate how samples from the Maracangalha Formation would be classified according to the petrofacies proposed by Pittman (1992). Figure 12 presents the results of the classification of the LOR and PNS samples according to such petrofacies, for permeability values estimated by the Timur-Coates model and the average T_2 model, respectively.

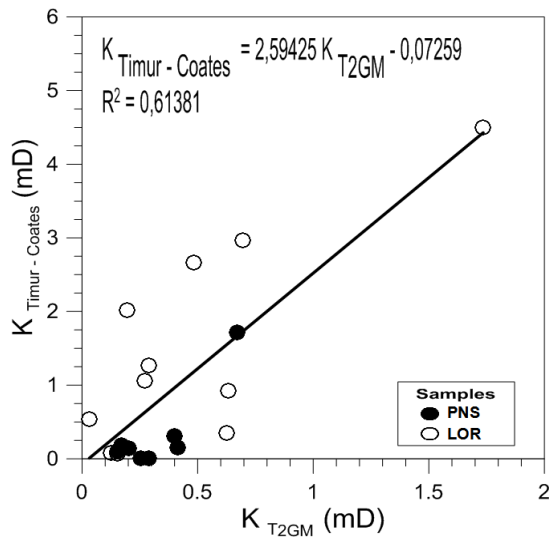


Figure 11 – Correlation between permeabilities estimated from the Timur–Coates model and the average T_2 model.

Figure 12 shows that the samples are nanoporous (pore throat radius less than $0.1 \mu\text{m}$) or microporous (pore throat radius between $0.1 \mu\text{m}$ and $0.5 \mu\text{m}$). According to the permeability values estimated by the average T_2 model, approximately 86% of the PNS samples and 60% of the LOR samples were classified as nanoporous (PITTMAN, 1992), the others were classified as microporous. Regarding the classification based on the Timur–Coates permeability model, the percentages of PNS samples classified as nanoporous and microporous were the same as those of the average T_2 model. However, the distribution of LOR samples with the permeability values estimated by the Timur–Coates model has changed: 80% of the samples were classified as microporous and 20% as nanoporous. Therefore, the analysis of the petrofacies proposed by Pittman (1992) subtly suggests that samples from Loreto locality tend to have pore throat rays larger than samples from Ponta de Nossa Senhora locality.

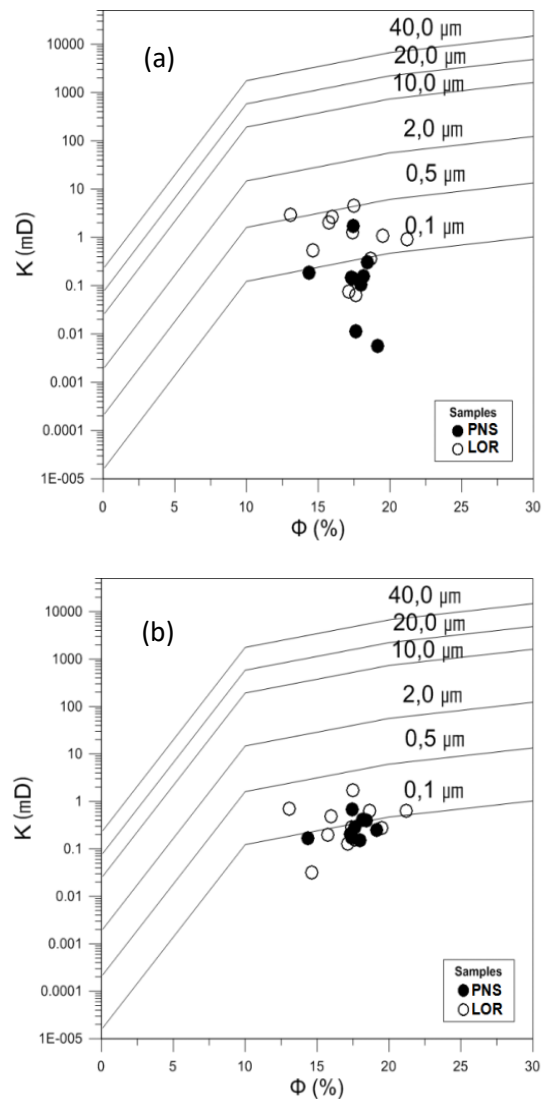


Figure 12 – Classification of the samples as to the petrofacies proposed by Pittman (1992). (a) Permeability estimated by the Timur–Coates model. (b) Permeability estimated by the average T_2 model.

4.2. Profiles Interpretation

Figure 13 shows the well logs data of Gamma-ray, density and electrical associated with the investigated interval, as well as a lithological representation of the profiled layers. In this figure, the corresponding porosity, permeability and clay fraction values are also presented. These values were calculated for the entire study range. However, as the objective is to analyze the petrophysics properties of the sandstone of Caruaçu Member of the Maracangalha Formation, we will focus our analysis on these lithologies. As can be seen in Figure 13, the porosity values obtained from the profiles for the sandstones are in the range between 7% and 24%. The average porosity values obtained from the density profile (Φ_D) and electrical profiles (Φ_E) were: 22.04%

and 20.94%, respectively. The high average values of porosity indicate that in most of the analyzed points, within the sandstone deposits, the values obtained for this property are higher than 7% and therefore, confirm such rocks present good porosity. Regarding permeability, the values obtained from the electrical profiles indicate that such sandstones have intermediate permeability. The maximum permeability value obtained was approximately 11 mD and the average value was 4 mD. The average clay content calculated was approximately 7.32%, with a maximum of 26%.

Comparing these results from the profiles with those estimated from laboratory analyzes, it is possible to notice that the porosity and permeability values are of the same order of magnitude and therefore, consistent with laboratory measures. It is also noted that the analyzed sandstones in the Loreto locality show similarities with the sandstones of the Caruaçu member since they present intermediate to high porosity values, intermediate permeabilities, and, as described by Scherer et al. (2007), tend to present low content of clay minerals when compared to other sandstones of the same formation.

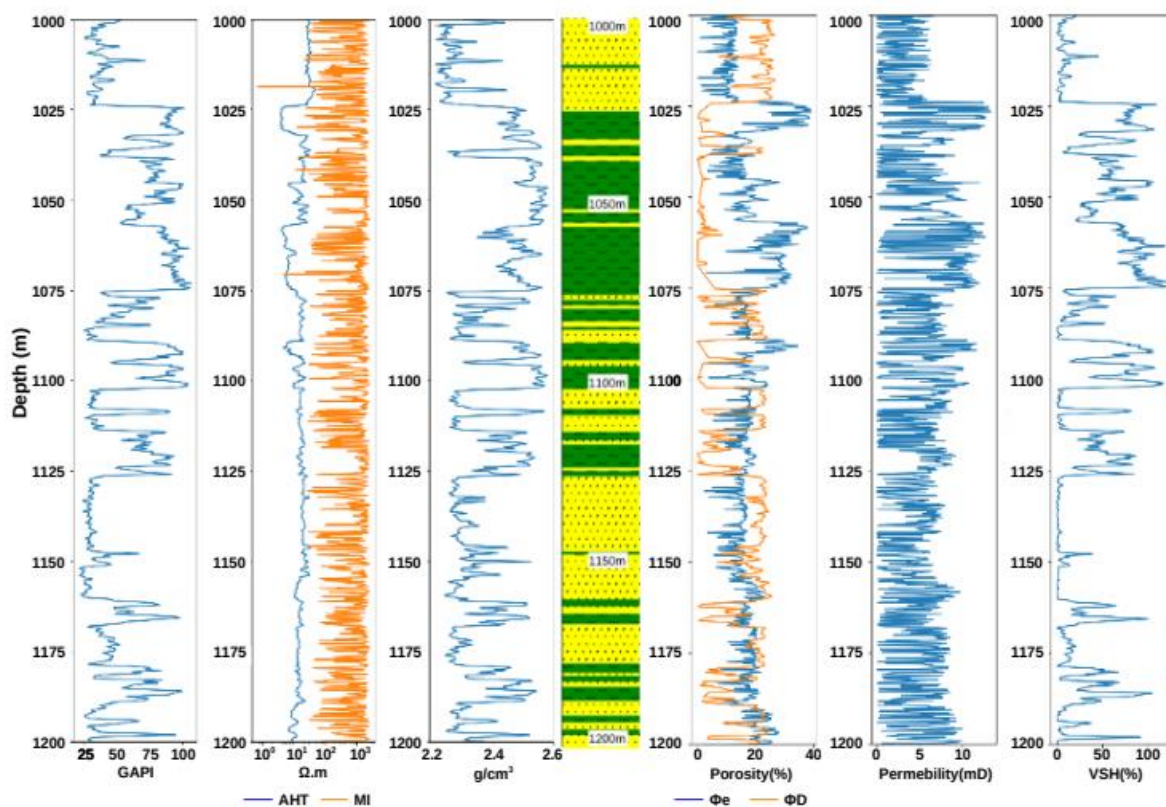


Figure 13 – Presentation of Gamma Ray, electrical and density profiles. To the right of the lithological representation column are the calculated porosity, permeability and clayiness (VSH) values.

5. CONCLUSIONS

The laboratory analysis of 31 sandstone samples gets in the outcrops of the Maracangalha Formation, locality of Loreto and Ponta de Nossa Senhora, reinforcement the heterogeneities associated with the composition of such formation. The values of porosity, permeability and free fluid index obtained for the investigated samples from Loreto locality indicate that such samples tend to constitute reservoirs with greater hydrocarbon storage, transmission and recovery capacity than the samples of Ponta de Nossa Senhora. The low permeability and the lower

effective porosity values of this last group of sandstones can be explained by the more clayey nature of such samples.

The results gets from the analysis of geophysical well logs corroborate with those obtained from the laboratory. Since, despite the effects of weathering and erosion on the outcropping rocks, the porosity and permeability values obtained by NMR are in the range of values calculated from the well logs for most of the sandstones of the Maracangalha Formation.

The joint analysis of the petrophysical properties signaled that the LOR group sandstones present petrofacies similar to those of the Caruaçu Member sandstones and, thus, reinforces the hypothesis that these sandstones are representative of this

member of the Maracangalha Formation. Thus, the results confirm the properties related to transmission and, above all, fluid storage, which attests to the good characteristics of the Caruaçu Member sandstones in terms of hydrocarbon reservoirs.

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