Evaluation of the potential of a Portuguese sandstone to be a reservoir rock through its physical-mechanical characterization

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Abstract

Oil is an essential fossil fuel in today's society. This product is a combination of hydrocarbons that can come in the form of liquid oil or gas. Oil can be found in underground reservoirs. Reservoirs are sedimentary rocks that allow the storage and flow of hydrocarbons. From a commercial point of view, it is important to know the characteristics of a reservoir rock, particularly the physical properties of the rock as well as the mechanical properties. In the present work are presented the main characteristics of the rock necessary to assess its potential as a reservoir rock. Laboratory tests were carried out on rock samples from Praia de Porto Novo belonging to the Lourinhã Formation. The values of effective porosity and absolute permeability were determined in laboratory. Additionally, the plugs were subjected to tests of tensile strength, uniaxial and triaxial compression which allowed the determination of mechanical properties. To complement the characterization of the rock, it was used: the hydrochloric acid test, X-ray diffraction and a colorimeter. The determination of the effective porosity and the absolute permeability reveals mean values of 12.2% and 0.15 mD, respectively. Through the mechanical characterization tests, the following values were obtained: Young's modulus of 4.96 GPa; Poisson's coefficient of 0.24; cohesion of 1.02 MPa; and friction angle of 46.59º. Based on the results obtained, it was possible to relate properties, and it was concluded that the studied sandstone has the potential to be considered a tight reservoir rock.

Keywords: Reservoir Rock, Sandstone, Physical-Mechanical Properties, Mechanical Characterization

1. Introduction

Petroleum is a complex mixture of different substances, including hydrocarbons, nitrogenous, oxygenated and sulfur compounds that can be presented in solid, liquid or gaseous states. Oil is generated in sedimentary basins from accumulated organic matter, together with inorganic sediments, in oxygen-deficient environments. The sedimentary basin, in which the accumulation of organic matter took place, is gradually subjected to higher temperatures and pressures and occurs the transformation of kerogen into oil. Reservoir rocks are typically sandstones and carbonates with high porosity and permeability. These features allow the storage and flow of large amounts of fluids.

The geological study of the basins is essential to determine if there are conditions necessary for the formation of hydrocarbon accumulations, with a size and location that allow their exploration in an economic way. In the case of reservoir rock, porosity and permeability are important characteristics as the rock formation must have the capacity to store hydrocarbons and enable the transmission of fluids. These properties, together with others such as Young's modulus, Poisson's coefficient, cohesion and friction angle help to determine the potential of a rock as a reservoir rock, which is the main scope of this work.

2. Literature Review

A reservoir rock is a rock that has porosity and permeability values sufficient to allow for the storage and flow of hydrocarbons (Magoon, 2004) (Lapedes, 1978). According to Archer (1986), the different sediment deposition processes can influence the porosity and permeability of a reservoir rock. Reservoir rocks formed by sandstones have grains that have undergone sedimentation, compaction and cementation. Approximately 60% of hydrocarbons exist in reservoir rocks of a clastic nature and 40% in carbonates (Ganat, 2019). In a commercially interesting reservoir there are two properties with great relevance: porosity and permeability. These two features guarantee the storage capacity and fluid flow, respectively.

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2.1. Porosity

Porosity is the measure of the void spaces of the rock, that is, it is the property that relates the volume of voids to the total volume of a rock, represented by ϕ (Ganat, 2019). As sediments were deposited and rocks were formed, some voids that developed became isolated due to excessive cementation. Therefore, many empty spaces are interconnected while other empty spaces are isolated. This phenomenon allows us to define two types of porosity: total porosity and effective porosity (cited in Ahmed, 2001). The total porosity (ϕ_a) defines the relationship between the total pore space and the total volume of the rock, not considering whether the void spaces are interconnected or not. According to Bear (1988), only pores that are interconnected are of interest because it is related to fluid flow. Through this theory comes the concept of effective porosity (also known as open porosity), which is defined by the ratio between the interconnected pore volume and the total volume of the porous medium. The Figure 1 represents the effective porosity.

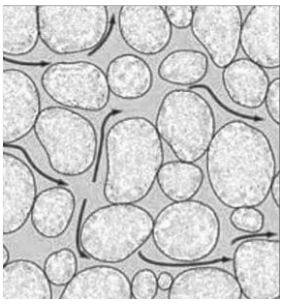

Figure 1 – Scheme illustrating the effective porosity (Ganat, 2019).

However, the effective porosity can be influenced by the presence of cement and/or minerals in the pore space of the reservoir rocks. According to Archer (1986), the porosity of reservoir rocks represents between 5% to 30% of the total rock volume.

2.2. Permeability

In addition to porosity, one of the fundamental properties that a reservoir rock must have is the ability to allow the circulation of fluids through its interconnected pores. This fluid circulation capacity is determined by permeability (Ganat, 2019). This property can be defined through the application of Darcy's law. The following equation represents Darcy's law:

$$\boldsymbol{Q = K.\frac{A}{\mu}.\frac{dp}{dl}} \qquad \text{(Eq. 1)}$$

Where: Q represents the volume of fluid passing through the sample in unit of time [cm^3/s]; K represents the absolute permeability [D]; A represents the cross-sectional area of the sample [cm^2]; μ represents the fluid viscosity [cP]; and $\frac{dp}{dl}$ represents the pressure gradient along the flow line [atm/cm].

Permeability can be classified as: absolute, effective and relative. Absolute permeability is an intrinsic characteristic of the porous medium of a given rock formation, while in the relative permeability, in addition to the influence of the porous medium, the influence of the other phases present in the flow is also accounted for. The effective permeability of a rock is the ability of a fluid phase to flow in the presence of other phases. This type of permeability is not equal to the absolute permeability of the rock, as the absolute permeability assumes that the rock is 100% saturated by a single fluid (Satter et al., 2016) (Monicard, 1980). Relative permeability is the ability of an isolated fluid to flow in the presence of two or more fluid phases in the rock. This type of permeability is given by the ratio between the effective permeability and the absolute permeability of the rock (McPhee et al., 2015).

Permeability can be obtained through the non-stationary method (unsteady-state) or the stationary method (steady-state). Permeability tests in non-steady state consist of simulating the injection of an immiscible fluid (gas or water) into the plug. The determination of relative permeability is based on the observation of the displaced volume, effluent flow and pressure differential (McPhee et al., 2015).

2.3. Relationship between porosity and permeability

Permeability depends on the porous spaces of a rock, however there is no linear relationship between permeability and porosity (Ma et al., 1996). Although this relationship is not linear, in the case of sandstones it is possible to conclude that the permeability value increases with porosity (Schön, 2011). This conclusion cannot apply to all types of rocks. A low porosity implies a low permeability as there is no space for fluids, however a rock with high porosity does not necessarily mean having a high permeability. Despite their porous spaces, rocks may contain other sediments and fluids that hinder permeability, such as clays (Karmann, 2000). The following figure represents the relationship between porosity and permeability.

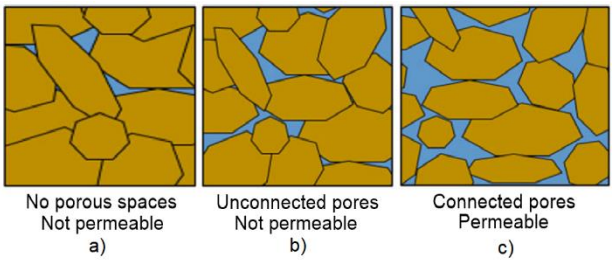

Figure 2 – Relationship between porosity and permeability of a rock where a) represents a rock with reduced porosity and not permeable; b) represents a rock with non-connected and non-permeable porosity; and c) represents a rock with connected and permeable porosity. (Ganat, 2019).

In the case of sandstones, permeability is controlled by porosity (Ganat, 2019). These variations in porosity and permeability values influence the flow capacity and, in turn, the oil productivity. Tests carried out with sandstones (Han et al., 2015) determined that clay also influences these characteristics.

2.4. Mechanical properties

The mechanical properties of reservoir rocks are essential for rock characterization. These properties are determined through laboratory tests on previously prepared rock samples where tensile and compressive stresses (uniaxial and triaxial) are applied to obtain the strength and deformability characteristics.

2.4.1. Elasticity parameters

According to Vallejo et al. (2002), deformability is the property that has the ability to change the shape of the rock when subjected to the actions of forces. Rock deformation can be elastic or permanent depending on the intensity of the applied force or the mechanical characteristics of the rock. The most important elastic parameters in the characterization of a rock are: modulus of elasticity, or also called Young's modulus (E) and Poisson's coefficient (v). Based on values from several authors, Vallejo et al. (2002) defined the range of values of modulus of elasticity and Young's coefficient for sandstones.

$$2{,}94 \text{ GPa} < E < 59{,}82 \text{ GPa}$$

$$0{,}1 < v < 0{,}4$$

Young's modulus and Poisson's coefficient are obtained through the uniaxial compressive strength test.

2.4.2. Resistance parameters

The deformation that a rock undergoes when subjected to a certain stress is called strength. When a force is applied to the rock, it breaks exceeding its peak strength. The determination of the simple compressive strength is important in the mechanical characterization of the rock and is obtained through laboratory testing of simple compression (Vallejo et al., 2002). According to the values obtained in the laboratory test, it is possible to classify the rock according to its strength as described in Table 1.

Table 1 –Typical values of uniaxial compressive strength of rocks based on macroscopic rock description (Barton, 1978).

Grade	Term	Uniaxial comp. strength [MPa]
R0	Extremely weak rock	0,25 – 1,0
R1	Very weak rock	1,0 – 5,0
R2	Weak rock	5,0 – 25
R3	Medium strong rock	25 – 50
R4	Strong rock	50 – 100
R5	Very strong rock	100 - 250
R6	Extremely strong rock	> 250

According to Vallejo et al. (2002), the uniaxial compressive strength and tensile strength values for sandstones are:

- Uniaxial compressive strength:
  29,4 MPa – 230,5 MPa
- Tensile strength:
  4,9 MPa – 19,6 MPa

2.4.3. Seismic wave velocity

Acoustic waves are also known as seismic or ultrasonic waves. These waves are characterized as being elastic propagation waves. Within the scope of this project, the waves of greatest interest are the primary longitudinal seismic waves, also called P waves. According to Vallejo et al. (2002), the speed of P waves depends on the density, elastic properties of the rock as well as properties such as porosity. Lama et al. (1978) and Bourbie et al. (1987) concluded that sample saturation leads to an increase in P wave velocities. The authors also studied the influence of porosity and concluded that the P wave velocity in more porous saturated rocks is lower than in less porous rocks.

2.4.4. Mohr-Coulomb Rupture Criteria

In the Mohr-Coulomb theory, the determination of cohesion (c) and the internal friction angle (φ) is highlighted. The triaxial compression test can be used to determine the Mohr envelope where the confinement stress will vary. With the variation of the confinement tension it is possible to obtain the variation of cohesion and friction angle. Based on values from several authors, Vallejo et al. (2002) defined the range of cohesion values and friction angle for sandstones.

$$7{,}85 \text{ MPa} < c < 34{,}32 \text{ MPa}$$

$$30^{o} < \varphi < 50^{o}$$

2.4.5. Related work

According to Aminzadeh et al. (2013), to accurately characterize a reservoir, it is essential to analyze the

static and dynamic properties of the rock. Static properties are porosity and permeability. While pressure, fluid saturation and temperature are dynamic properties. Reservoir rocks can be classified as conventional and unconventional reservoir rocks. An unconventional reservoir is characterized as an accumulation of hydrocarbons located in low permeability rocks (Schmoker, 1995). According to standard SY/T 6285 (2011), the effective porosity of a reservoir rock of clastic origin can be classified according to Table 2.

Table 2 - Classification of reservoir rock according to effective porosity (SY/T 6285, 2011).

Classification	Porosity [%]
Very high	> 30
High	25 - 30
Average	15 - 24
Low	10 - 15
Extremely low	5 - 10
Ultra low	< 5

According to Guo (2019), sandstones with absolute porosity values between 5% and 40% are considered reservoir rocks with adequate conditions for the exploration of fluid hydrocarbons. Table 3 presents the classification of the fluid hydrocarbon reservoir rock according to the scale defined by Koesoemadinata (1980), where only the absolute permeability value is considered.

Table 3 – Classification of reservoir rock according to absolute permeability (Koesoemadinata, 1980).

Classification	Permeability [mD]
Tight	< 5
Fair	5 - 10
Good	10 - 100
Very good	100 - 1000

Khanin (1965) presented a classification of reservoir rock according to the values of absolute permeability and effective porosity, as shown in Table 4.

Table 4 – Classification of reservoir rock according to absolute permeability and effective porosity (Khanin, 1965);

Reservoir Quality	Permeability [mD]	Porosity [%]
Very high	≥ 1000	≥ 20
High	500 - 1000	18 – 20
Average	100 - 500	14 – 18
Reduced	10 - 100	8 – 14
Low	1 - 10	2 – 8
Very low	< 1	< 2

Tight reservoirs are generally sandstones with low effective porosity and low permeability. The reduced permeability prevents gas from migrating from the reservoir rock. To counteract this behavior, this type of reservoir needs to be fractured in order to obtain an economically profitable gas flow (Bahadori, 2014). Table 5 presents the typical values of effective porosity and absolute permeability measured perpendicularly and parallel to the stratification for tight reservoir rocks.

Table 5 - Typical values of absolute porosity, permeability measured perpendicularly and parallel to tight reservoir rocks (adapted from Enab et al., 2014).

Properties	Typical values
Effective porosity	6 – 25 %
Absolute permeability measured ⊥	0,0001 - 0,1 mD
Absolute permeability measured ‖	0,001 – 1 mD

3. Materials and methods

The Lusitanian Basin is a mostly onshore basin, located on the Iberian West Bank. The geological evolution of the basin occurred in the Mesozoic, having developed as a result of crustal stretching, followed by several rift episodes, associated with the opening of the North Atlantic. The Lusitanian Basin is a non-volcanic rift-type basin (Kullberg et al., 2006). The basin extends for about 200 km in the NNE-SSW direction and for about 100 km in the perpendicular direction. The basin is bounded: to the east by the Hesperic massif, to the west by the horsts of Berlengas, to the south by the Arrábida fault and to the north by the contact with the Porto basin; is translated according to Alves et al. (2003), by the Aveiro fault (Kullberg et al., 2006).

The samples for laboratory tests will be taken from the Porto Novo beach, which belongs to the Lourinhã formation. The formation to be studied is from the Upper Jurassic, and corresponds to the Praia da Amoreira-Porto Novo unit (J^{3AP} - Sandstone, marl and sandstone from Praia da Amoreira-Porto Novo), a member of the Lourinhã formation. The terminus of Praia da Amoreira is essentially composed of continental sediments consisting of coarse kaolinitic sandstones and claystones with intercalated limestone soils. This alternating sedimentation indicates flood currents, which carry large volumes of sediment. Sedimentation was rapid and sedimentary structures indicate that turbulent-type transport dominated. The Porto Novo member is composed of sandstones and clays (Manuppella et al., 1999).

3.1. Sample preparation

Two blocks of sandstone rock were collected at the top of the slope in the northern part of Porto Novo Beach. The choice of blocks considered discontinuities, stratification and possible fractures in the existing blocks. The two blocks collected showed variation in color: one had a grayish coloration, while in the other block a variable color was observed between the shades of yellow to red. The preparation of specimens considering ISRM standards. After collecting the blocks, they were transported to the Instituto Superior Técnico's laboratory, which resulted in 29 plugs. Of the 29 prepared specimens, 5 AP_N CT specimens were cut perpendicularly to the stratification and the rest were cut in the direction of the stratification. The prepared plugs have a cylindrical shape with the following dimensions:

Table 6 – Name and dimensions of plug prepared for physical-mechanical test.

Name	Average length [mm]	Average diameter [mm]
AP_N RCU	132,47	52,96
AP_N CT	85,67	41,69
AP_N Br	28,13	53,15

3.2. Mineral-chemical characterization

The characterization of geological material has a high importance in the characterization of a rock because allows knowing some physical and mineralogical parameters. This characterization consisted of: (i) the description of the geological material, using a stereomicroscope for better discrimination of the constituents and with the support of a colorimeter to characterize the color of this geological material; (ii) carrying out mineralogical analysis using the laboratory technique of X-ray diffraction; and (iii) determination of the percentage of carbonated fraction. It was used an Insize stereomicroscope, model ISM-PM200S. X-ray diffraction allows a mineralogical analysis of rock samples. For this analysis, it was used an X-ray diafractometer (Panalytical X'Pert PRO, with Cu-Kα radiation (40 kV, 35 mA). To quantify the carbonate fraction, small samples of the lithological material (previously dried) were used. An acid attack was carried out with 20% concentrated HCl in distilled water, until completion of the chemical reaction and drying of the residue. The residue from this chemical attack was subsequently washed to remove any excess acid and oven dried to constant mass. The measurement of the dry residue left by a plug, after treatment with hydrochloric acid, will correspond to the non-carbonated fraction.

3.3. Physical characterization

The effective porosity was determined using the traditional method that relates the masses of dry and saturated specimens. To determine the absolute permeability, a method that uses a hydraulic pump to inject confinement pressure was used. To calculate the absolute porosity, the saturation test was started according to the EN 13755-2008 standard, where each group of plugs was placed in water up to half its length. Upon reaching the saturation of the plugs, the effective porosity was calculated through a mathematical expression that uses the differences in masses. Effective porosity (ϕ) is possible to calculate when plugs reach saturation. The equation 2 allows to calculate the porosity where: m_s represents the mass of the saturated specimen [g]; m_d represents the mass of dry specimen [g]; V_t represents the total volume of the specimen; and ρ_o represents the water density.

$$\phi = \frac{\frac{m_s - m_d}{\rho_o}}{V_t} \times 100 \qquad \text{(Eq. 2)}$$

For the absolute permeability test, the following instruments were used: a Hoek cell where the samples were placed; a pressurization equipment (0,5 MPa); a hydraulic pump that injects the confinement pressure (the confinement pressure used was 2 MPa); and a 50 ml burette. Every 10 min after the start of the test, the flow rate and pressure gradient values were measured, which allowed the calculation of the permeability absolute. Absolute permeability was calculated based on the equation 1 (Eq. *1*).

P-wave velocities are measured using ultrasound tests and successive calculations. Ultrasonic testing is performed using a Steinkamp Model BP-7 Ultrasonic Tester. This procedure consists of measuring the speed at which the ultrasonic waves propagate through the plug, and for this it is necessary to take several readings along the plug. Based on relationships already determined by several authors, it is possible to determine the mechanical properties through the velocity of propagation of the P waves. This test can also be used to determine the anisotropy of the geological material under study. In the present work, this test was used to determine correlations with mechanical properties as well as to determine the anisotropy coefficient.

3.4. Mechanical characterization

The mechanical properties of a rock are determined through laboratory tests. The tests allow us to know several parameters such as: uniaxial and triaxial compressive strength; tensile strength; and the deformability parameters (Young's modulus and Poisson's coefficient). To determine these parameters, Brazilian tests (tensile strength), uniaxial and triaxial compression were performed.

The Brazilian test uses a press and a support for the samples, and with the aid of a computer it was possible to read the maximum load supported by the

plug (represented by the Figure 3. Tensile strength was determined by the method of the Brazilian test, using the equation 4 that allows the calculation of the plug's tensile strength, according to the ISRM standard: Suggested Methods for Determining Tensile Strength of Rock Material (1978).

$$\sigma_t = \frac{0{,}636 \times P}{D \times T} \qquad \text{(Eq. 3)}$$

Where: P represents the load [N]; D represents the plug diameter [mm]; T represents the plug thickness [mm]; σ_t represents the tensile strength [MPa].

Figure 3 – Sample placed in the press during the tensile strength test (Brazilian method).

The uniaxial compression test aims to obtain the compressive strength and deformability parameters (Young's modulus and Poisson's coefficient). To carry out this test, strain gauges and an ELE press are used. The test was carried out according to the Portuguese Standard EN 1926-2008. After the plugs are completely saturated, 4 strain gauges are placed in each one: 2 vertically and the other 2 horizontally (Figure 4). These components are intended to measure the deformations of the plug caused by the load. During the test, 3 cycles of loading and unloading were applied. The load application speed is 0.5 MPa/s with a maximum load of 3 MPa and a minimum load of 0.5 MPa at 15 second intervals. The load is applied until the plug breaks.

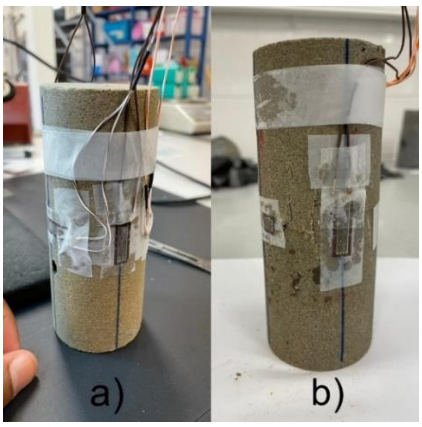

Figure 4 – Sample AP_N RCU with strain gauges placed vertically and horizontally.a) and b) represents the sample before and after the uniaxial compression test.

The triaxial assay was performed on the AP_N CT samples in a total of 13 plugs. In order to perform the triaxial test it is necessary to use the Hoek cell, where the sample is placed on a latex membrane containing oil. The plug is subjected to a hydrostatic stress state, in which the applied stress acts in all directions, in accordance with the standard: Suggest Methods for Determining the Strength of Rock Materials in Triaxial Compression. Various confinement voltages were applied, specifically 2 MPa, 4 MPa and 6 MPa. These stresses are applied through the hydraulic pump. Tension (axial) is applied by an ELE press under the pistons that are placed at the ends of the Hoek cell. In Figure 5 you can see the sample placed in the Hoek cell and in the press.

Figure 5 – Hoek cell and press used during the triaxial compressive strength test.

4. Results

The macroscopic characterization of rocks is based on the observation of their visible characteristics such as color and homogeneity. The sample has a grayish color where uniform grains can be seen. Based on this analysis, it is concluded that the sample is heterogeneous. Afterwards, a stereomicroscope was used, which allows a magnified view of the fragments under observation. These fragments result from acid attack on the samples. The identification of minerals was carried out based on the physical and mechanical properties where it was possible to identify the quartz due to the vitreous to greasy shine. Muscovite was identified by pearlescent shine and feldspar due to its perfect cleavage. Calcite was identified because it has a reaction when it comes into contact with hydrochloric acid. Based on Figure 6, it can be seen that most grains low sphericity and very angular. The grains are smaller than 4 mm in size.

Figure 6 - Fragments of samples observed under stereomicroscopic where it is possible to visualize the constituent minerals of the rock.

To the naked eye, a group of samples has a more cream-grey hue and which in colorimetric terms are characterized by average values of luminosity (L*), green-red component (a*) and yellow- blue (b*): L*= 54.09 ± 1.30; a* = 0.98 ± 0.14; b* = 7.13 ± 0.35. The second group of samples differs from the previous one by presenting a more yellowish tone and that, in chromatic/colorimetric terms, it has chromatic coordinates L* = 52.64 ± 1.67; a* = 3.85 ± 0.51; b* = 16.97 ± 1.90. The X-Ray Diffraction analysis confirmed the macroscopic observation made. The sandstone studied is composed of a detrital fraction composed of quartz, feldspar (albite and microcline), mica and clay minerals (clinochlor). Through the hydrochloric acid test it was found that the percentage of carbonate fraction in the rock is 21,90% ± 2,23. The percentage of carbonated cement present in the samples can have a negative impact on the rock's physical properties (Zhixue et al., 2010). Some authors have suggested that carbonated cement together with compaction are the main factors that control the quality of a reservoir (Anjos et al., 2000).

According to the classification suggested by the SY/T 6285 (2011) standard, the porosity value (12.21%) obtained is considered low. One of the factors influencing this property is the amount of carbonated cement in the rock sample. The distribution of carbonated cement in the sample will fill the voids causing a reduction in porosity, and consequently reduce permeability as the cement forms barriers that impede the flow of fluids (Zhixue et al., 2010). Since the sphericity of the grains is low, it can result in a reservoir rock with a reduced porosity (Tissot et al., 1984). However, most grains have a similar size (≈ 2 mm) which may indicate a reasonable porosity value, unlike a rock that has grains of different sizes (Ganat, 2019). Absolute permeability was measured only in plugs named AP_N CT. Permeability was measured in two directions of orientation: parallel to the flow direction and perpendicular to the flow direction. The permeability values obtained in the test in the different plugs show values below 0.40 mD. The mean value of permeability parallel to the direction of flow (0,24 mD) is higher than the value obtained for permeability perpendicular to the direction of flow (0,06 mD), as expected according to Ganat (2019). The difference in permeability measured parallel and vertically to the stratification plane is a consequence of the origin of the sediments, as the grains were deposited in horizontal planes (Hu et al., 2017). The anisotropy coefficient was calculated through the ratio between the mean values of permeability measured perpendicularly and parallel to the stratification (kv/kh). The anisotropy coefficient of absolute permeability is 0.25, which according to the classification proposed by Ismael et al. (2017) is a value that indicates that sandstone has anisotropy. Permeability measured parallel to (0.24 mD) and perpendicularly (0.06 mD) to the stratification obtained in laboratory tests are values considered low according to the classification proposed by Koesoemadinata (1980) presented in Table 4. However, according to Enab et al. (2014) and Rajput et al. (2016), the values obtained in this test may indicate that sandstone may have potential for tight reservoir rock. A tight reservoir is generally defined as having values of permeability measured in parallel between 0.001 mD and 1 mD, and permeability measured perpendicularly to 0.1 mD. Considering the average values of effective porosity and absolute permeability, based on the values presented in Table 4 by Khanin (1965), it is possible to conclude that the studied sandstone presents a conventional reservoir quality reduced to very low. However, the values obtained for effective porosity and absolute permeability fit the typical values presented by Enab et al. (2014) for a tight reservoir rock. This type of reservoir rock is characterized by its very low permeability.

The P-wave velocity test was carried out at different stages of the experimental work. The propagation velocities of the P waves were measured: in dry samples with and without salt, and saturated. In this test, the stratification of the samples was considered. It was concluded that in the measurements carried out in different states, the P wave velocities measured in parallel with the stratification present higher values than the velocities measured perpendicularly with the stratification. This situation is due to the fact that stratification acts as a barrier to the propagation of P waves. Based on the maximum value, minimum value and intermediate value of the P wave velocities, it was possible to calculate the Birch coefficient, which indicates the anisotropy of the geological material
In the AP_N RCU and AP_N CT samples, an average Birch coefficient of 10.10% was determined. According to the anisotropy classification, according to the P wave velocities, proposed by Tsidzi (1997) a

coefficient between 6% to 20% indicates that the rock has a moderate anisotropy.
Through the analysis of the results it is verified that the propagation speeds of the waves P are smaller for the saturated samples than for the dry ones. This behavior does not agree with the expected result, as according to Kassab et al. (2015) P waves propagate faster in saturated samples than in dry samples. The speed of P waves can be influenced by several factors including: porosity, temperature and depth. However, the presence of clay in the pores can reduce the speed at which P waves propagate. Based on the results obtained in X-ray diffraction, it appears that the amount of clay is considered insignificant. However, Mello (2011) states that even a low percentage of clay in the rock can significantly reduce P wave velocities. Although the clay grains are quite small, this mineral has a large surface area which causes a reduction in contact stress between the grains of the matrix.

The Brazilian tests were carried out on a total of 11 samples called AP_N Br. The Brazilian test allows determining the tensile strength of rock samples. It is verified that the average value of the tensile strength is 0.69 MPa. During this test, the load was applied in the stratification direction. The tensile strength values obtained are mostly below 1 MPa. According to the literature review, the values obtained in the test are below the range of values associated with sandstones.

The uniaxial compressive strength test was performed on a total of 5 plugs called AP_N UCS. The uniaxial compressive strength test allows determining the uniaxial compressive strength and the elastic parameters: Poisson's coefficient and the modulus of elasticity. During the test, the load was applied parallel to the stratification. The average value obtained for uniaxial compressive strength is 13,74 MPa. According to the classification in Table 1, the plugs analyzed in the uniaxial compression test belong to a rock that can be considered weak. The average value is considered low for a sandstone rock according to classification of Vallejo et al. (2002).

According to the laboratory results, it can be concluded that the greater the effective porosity, the lower the uniaxial compressive strength (σ_1=-3,3811ϕ+49,251). Several authors (Vernik et al. (1993), Li et al. (2003), Kahraman et al. (2005)) describe this relationship between properties as being linear. Regarding the relationship between uniaxial compressive strength and tensile strength, it was found to be a non-linear relationship. In this study, it is verified that there is a tendency to increase the uniaxial compressive strength with the increase in the propagation velocity of the P waves, which presents a correlation given by σ_1=0,0121v_p-12,3860.

The mean value of Young's modulus is 4.96 GPa and 0.24 of Poisson's coefficient. The values of the elasticity parameters are within the expected for a sandstone according to literature review.

The triaxial compressive strength test was performed on a total of 13 plugs called AP_N CT. Three different loads were applied: 2 MPa, 4 MPa and 6 MPa. In the analysis of the triaxial compressive strength values with different confinement stresses, it is verified that the maximum principal stress increases with the increase of the confinement stress. Through the analysis of results it is verified that the maximum principal stresses when the load is applied perpendicularly to the stratification are lower than the stresses with load applied in parallel, however considering the standard deviations, this difference is not considerable. The mechanical characterization tests allowed the determination of the strength envelope according to the Mohr criterion. Figure 7 shows the envelope and Mohr circles according to the Mohr-Coulomb criterion calculated using RocScience's RocData program.

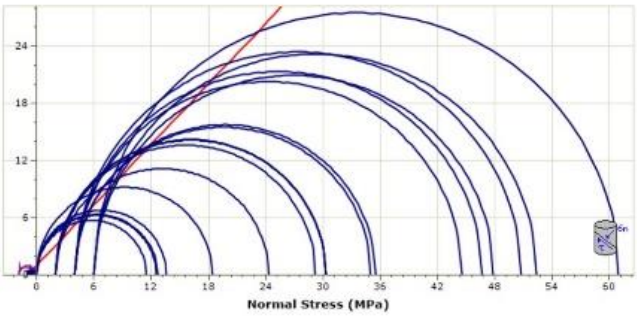

Figure 7 – Mohr's envelope and circles determined for the target samples of study.

According to the Mohr Coulomb failure criterion, it was possible to obtain the value of cohesion (c) and friction angle (φ). An average cohesion value of 1,02 MPa and an angle of friction of 46,59º were obtained. According to the values presented in literature review, the obtained friction angle value is within the expected range for a sandstone, however the cohesion is slightly lower than the expected value.

5. Conclusion

The work carried out allowed to determine some physical and mechanical properties of a sandstone from the Lusitanian Basin in order to assess whether the rock has potential for a reservoir rock. The properties that were studied in this work were: effective porosity, absolute permeability, propagation speed of elastic waves P, tensile strength, uniaxial compressive strength, Young's modulus, Poisson's coefficient and triaxial compressive strength. The macroscopic characterization of this sandstone was also carried out.

An average effective porosity value of 12,21% was obtained, which is an expected value considering a sandstone rock. Regarding permeability, the mean value of absolute permeability measured in parallel is 0,24 mD and measured in perpendicularly is 0,06 mD. Although the effective porosity is considered reasonable, the absolute permeability is considered to be quite low. This relationship between the two properties demonstrates that this sandstone does not have the potential to be a reservoir rock for liquid hydrocarbons. Generally, liquid hydrocarbon reservoirs require permeability values in the order of hundreds of milidarcy (Khanin, 1965). The low permeability hinders the flow of fluids in the reservoir, and its exploitation is not considered economically viable. However, the studied sandstone can be considered a tight reservoir. Typically, tight reservoirs have permeability values of around 0,1 mD and porosity in the order of 10% (Rajput et al. 2016).

As with permeability, the velocity of P waves is different if measured in parallel or perpendicular to the stratification, the latter having higher values. Sandstone is then considered to have anisotropy. It was also found that the propagation speed of P waves is higher in dry samples than in saturated samples, which can be explained by the presence by the presence of clays, albeit in small quantities (Mello, 2011). It was possible to relate the effective porosity with the velocity of the P waves, where it is verified that the greater the porosity, the lower the velocity of the P waves. Through the uniaxial compressive strength test, it is verified that the studied sandstone is considered a soft rock. This feature is usually associated with reservoir rocks. Based on the uniaxial compression test, it was also possible to determine the modulus of elasticity and the Poisson's coefficient, which were found to be within the range of expected values. With the uniaxial compressive strength values obtained, it was possible to relate it to the effective porosity, and the greater the porosity, the lower the uniaxial compressive strength. It is concluded that there is a tendency to increase the uniaxial compressive strength with the increase in the speed of propagation of the P waves. Unlike what happens in the tests to determine absolute permeability and speed of P waves, the stratification of the samples did not influence the results obtained in the triaxial compression test.

Bringing together all the analyzed parameters, it is concluded that the sandstone from the Lourinhã Formation in the Porto Novo Beach region has potential as a tight reservoir.
In order to improve and complement the study carried out in this work, some future developments are suggested. One of the important developments would be to carry out mechanical characterization tests with samples saturated in different fluids in order to verify their influence on the rocks. It would be equally important to carry out a more complete study of the degree of selection and shape of the grains as it may influence the values of the rock's intrinsic properties.

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