Analysis of Fluid Substitution in Barreiras/Pirabas Formation Mixed Carbonate Rocks in the Brazilian State of Pará

Karolina A. Correia[1], José J.S. de Figueiredo[1]

Graduate Program in Geophysics, Federal University of Pará[1]

Abstract

The research focuses on the integration of laboratory data and the analysis of fluid substitution in mixed siliciclastic-carbonate rocks of the Barreiras/Pirabas Formation on the Equatorial Margin of Brazil. The correlations found between the properties provide insights into how the complexity of these rocks directly influence the porosity and permeability of carbonate rocks. The study also aims to improves the understanding of fluid replacement in mixed carbonate-siliciclastic rocks. By comparing the Gassmann and Biot models, the results indicate that the Gassmann model offers a superior fit for the Pirabas/Barreiras Formation.

Introduction

Carbonate rock reservoirs account for around 60% of the world's total oil reserves today (Zhao et al., 2013). Therefore, it has been of great importance to characterize this type of reservoir rock since it differs greatly from sandstone rocks, especially with regard to its formation, diagenetic processes, elastic and petrophysical properties.

The basins located in northern Brazil have played a significant part in the deposition of large mixed carbonate-siliciclastic platforms, distributed in various offshore and onshore portions of the continental shelf since the Paleocene (Figueiredo et al., 2009; Cruz et al., 2019). The Barreiras/Pirabas formation, on the equatorial margin, represents a combination of carbonate and siliciclastic rocks and is found in several basins along the North and Northeast regions of Brazil (de Fátima Rossetti, 2001; Nogueira et al., 2021).

Rock physics models are used to predict the behavior of petrophysical properties in order to understand and characterize reservoir rocks (Mavko et al., 2020). A critical point in this process is the understanding and modeling of fluid substitution in carbonate rocks, a challenging task given the high complexity associated with their geological formation (Misaghi et al., 2010).

In this work, we will use fluid substitution theories to analyze rocks of mixed carbonate-siliciclastic formation in the region of the equatorial margin of Brazil. The methodology is based on an integration of experimental data analysis together with the study of Gassmann-Biot theories. The main objective is to provide new knowledge and developments in fluid substitution analysis, especially in the unique geological setting of the Pirabas/Barreiras Formation.

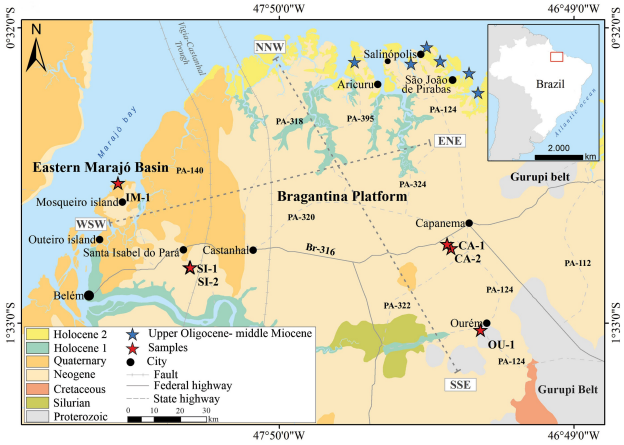

Figure 1 – Location map of sedimentary basins and platforms in the northern region of Brazil with exposures of Miocene deposits. Adapted from (Baía et al., 2023)

Methodology

We collected samples from the Barreiras/Pirabas Formation in the municipality of São João de Pirabas, located in the northeast of Pará, within the Bragantina Platform (Nogueira et al., 2021) (Figure 1).

The study involves selecting samples from the Barreiras/Pirabas Formation, followed by ultrasonic and petrophysical measurements, including porosity and permeability. After this, the samples go through the process of total saturation in an automatic saturator and the density and velocity of S-wave and P-wave are measured again. Based on this information, a fluid substitution model is developed using the Gassmann-Biot theory. Figure 6 illustrates the methodology used in this work.

A total of 11 samples were collected from the Pirabas/Barreiras Formation, with a diameter of 37 mm and a length of between 30 mm and 120 mm. After, they were dried in a vacuum oven at 50℃ for around 24 hours and stored at space temperature. For the ultrasonic measurements, the 1Mhz transducer pair was used to

obtain the axial and radial measurements of the sample, in which case the P and S wave velocities were estimated by recording the time of arrival using the ultrasonic equipment. Porosity and permeability were measured using a porosimeter and gas permeameter, respectively. Three measurements were taken for each sample, and the final porosity and permeability values are the averages of the three measurements.

For Gassmann's theory, which is widely used in fluid substitution, the elastic moduli of rocks are related to the matrix fractions and the properties of the main constituent minerals, in addition to the properties of the fluids. This is expressed using the equation,

$$k_{sat} = k_{dry} + \frac{\left(1 - \frac{k_{dry}}{k_m}\right)^2}{\frac{\phi}{k_{fl}} + \frac{(1-\phi)}{k_m} + \frac{k_{dry}}{k_m^2}}, \quad (1)$$

where k_{sat} is the saturated bulk modulus, k_{dry} is the bulk modulus of rock frame, k_m the bulk modulus of minerals of the rock matrix, k_{fl} bulks modulus of the pore fluids, and ϕ is porosity.

In Mavko et al. (2020); Wang (2001), some fundamental assumptions for Gassmann's theory are presented. From these assumptions, the S and P wave velocity equations are derived.

$$V_p = \sqrt{\frac{k_{sat} + \frac{4}{3}\mu}{\rho_B}} \quad (2)$$

$$V_s = \sqrt{\frac{\mu}{\rho_B}} \quad (3)$$

where, μ is the shear modulus and ρ_B is the bulk density.

In Biot (1956) formulas are provided to predict the velocities in saturated rocks in terms of the properties of the dry rock and the interaction mechanisms between the pore fluid and the mineral matrix of the rock. The velocities are described as:

$$V_p = \left\{ \frac{\Delta \pm \left[\Delta^2 - 4(\rho_{11}\rho_{22} - \rho_{12}^2)(PQ - Q^2)\right]^{1/2}}{2(\rho_{11}\rho_{22} - \rho_{12}^2)} \right\}^{1/2} \quad (4)$$

$$V_s = \left(\frac{\mu_{fr}}{\rho - \phi\rho_{fl}\alpha^{-1}} \right)^{1/2} \quad (5)$$

where,

$$\Delta = P\rho_{22}R\rho_{11} - -2Q\rho_{12}$$

$$P = \frac{(1-\phi)AK_0 + \phi K_0 K_{fr}/K_{fl}}{A + \phi K_0/K_{fl}} + \frac{4}{3}\mu_{fr}$$

$$Q = \frac{A\phi K_0}{A + \phi K_0/K_{fl}}$$

$$R = \frac{\phi^2 K_0}{A + \phi K_0/K_{fl}}$$

$$A = 1 - \phi - K_{fr}/K_0$$

$$\rho_{11} = (1-\phi)\rho_0 - (1-\alpha)\phi\rho_{fl}$$

$$\rho_{22} = \alpha\phi\rho_{fl}$$

$$\rho_{12} = (1-\alpha)\phi\rho_{fl}$$

$$\rho = \rho_0(1-\phi) + \phi\rho_{fl}$$

Results

Correlation of petrophysical properties

The results will be presented in crossplots and comparative graphs between the elastic and petrophysical properties, elucidating the relationship between these parameters. The graph (Figure 2) shows the correlation between porosity, P-wave velocity (V_p) and density in rock samples. There is a strong downward correlation between porosity and V_p ($R^2 = 0.96$), indicating that Vp decreases with increasing porosity, consistent with rock physics, where pores reduce density and rigidity, impacting the propagation of elastic waves. The color bar highlights this relationship, showing that more porous areas have lower V_p and density.

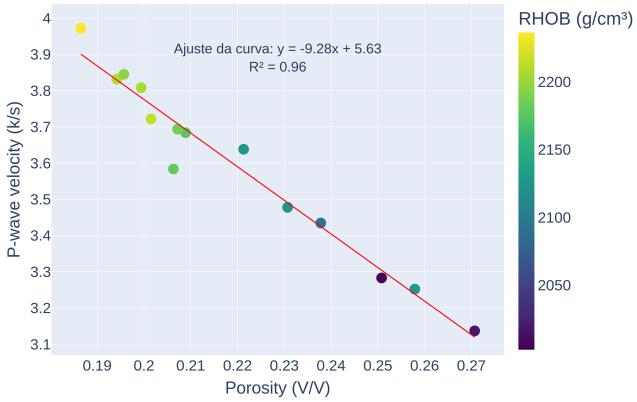

Figure 2 – Relationship between porosity, P-wave velocity (V_p) and density for rock core samples. There is a clear linear trend with an $R^2 = 0.96$

In Figure 3 there are two groups of carbonate rocks from the same mixed-siliclastic-carbonate outcrop, differentiated by their petrophysical properties. Group 1 has high porosity and permeability, while Group 2 has less. These distinctions are based on the correlation between porosity, permeability and density. This suggests that, although from the same outcrop, the rocks have unique properties. There is a positive relationship between porosity and permeability, with Group 1 being more permeable for the same porosity. Porosity is correlated adversely with density, and Group 1 generally has greater permeability for the same density.

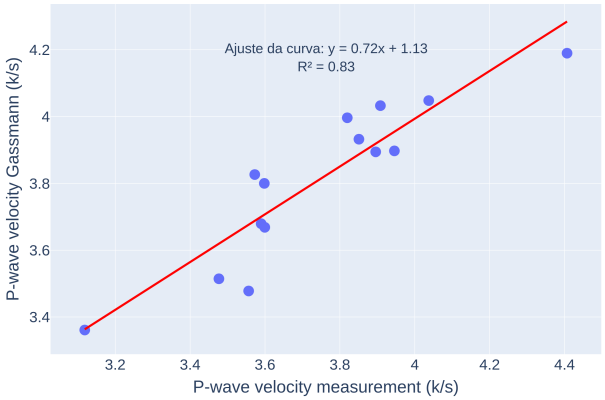

Figure 4 – Correlation between the P-wave velocity measured in the laboratory and that estimated by the Gassmann equation for water-saturated rocks ($R = 0.88$)

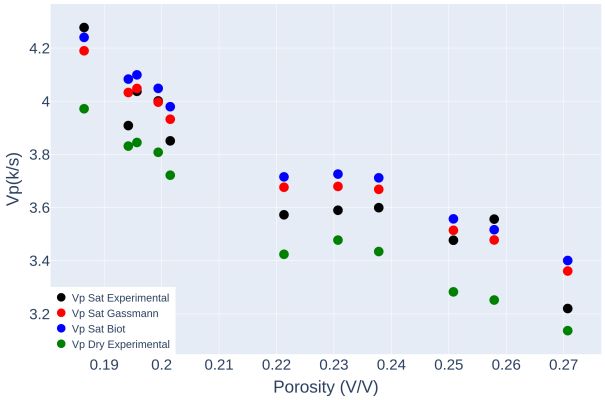

Figure 5 – Comparison between Gassmann-Biot models and measurement results for dry and totally saturated samples.

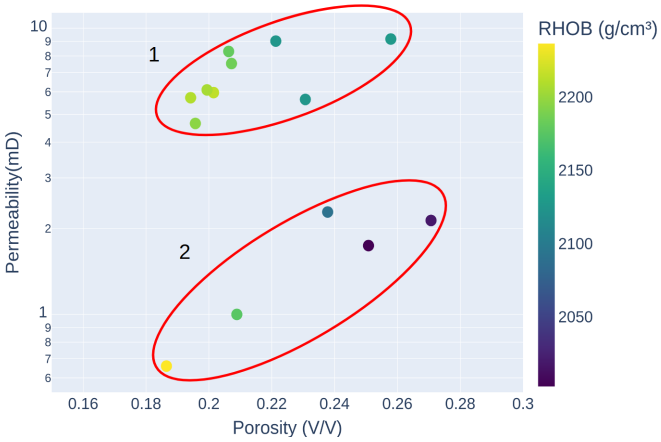

Figure 3 – Relation between porosity, permeability and density, revealing the presence of two distinct groups of data.

Gassmann-Biot fluid substitution analysis

The graph in Figure 4 highlights a strong correlation ($R = 0.88$) between the P-wave velocity measured in the laboratory and that estimated by the Gassmann equation for water-saturated rocks. Discrepancies between measured and predicted Vp are attributed to experimental factors, such as sample saturation and measurement errors, as well as rock heterogeneity, including variations in mineralogy and texture. Despite its limitations, the Gassmann equation is still a useful tool for estimating Vp based on petrophysical properties, according to the correlation obtained between the laboratory measurement and that generated by the model.

The results of the Gassmann-Biot models are shown in the graph in Figure 5, compared with experimental measurements in dry and saturated conditions. We can see that the measurements of the saturated samples show higher values for the P-wave velocity (V_p), influenced by the density of the water, which increases the modulus (K) and therefore the V_p. The model curves are similar to the experimental measurements of totally saturated rock. However, for both Gassmann and Biot, the precision is better at high P-wave velocities and low porosity, while at low velocity values and high porosity, the fit faces challenges, although it is still acceptable.

Table 1 – Error metrics evaluation between laboratory measurements and model predictions for samples

Metric	Gassmann Model	Gassmann-Biot Model
MSE	0.007350	0.013339
MAPE	2.063229	2.849075

Different metrics are used to assess the adequacy of models in relation to real data. In this context, we point out the Mean Absolute Percentage Error (MAPE), which represents the average of the absolute percentage differences between the model's predictions and the actual values, and the Mean Squared Error (MSE), which corresponds to the average of the squared differences between the model's predictions and the actual values. Basically, both metrics provide valuable information for assessing the degree of fit of the model in relation to the actual measurements, the values of which are described in Table 1.

Table 1 complements the information presented in the graph in Figure 5, providing a detailed analysis of the accuracy of the models. According to both metrics used, the Gassmann Model shows a better approximation in relation to outcrop samples of mixed carbonate-siliclastic rocks, compared to the Biot model.

Conclusions

The research focused on the analysis of experimental data from dry and saturated rocks, as well as the application of fluid substitution models to predict the behavior of petrophysical properties in mixed siliciclastic-carbonate rocks. A strong linear correlation was observed between P-wave velocity and porosity.

In addition, when investigating the relationship between porosity and permeability, it was found that although the rocks come from the same outcrop, they can be grouped into two distinct types based on these parameters. When evaluating the approximations provided by the models used by means of the analysis of the graphs and error calculations, it was verified that the Gassmann model presents the best fit for mixed rock formation.

Acknowledgements

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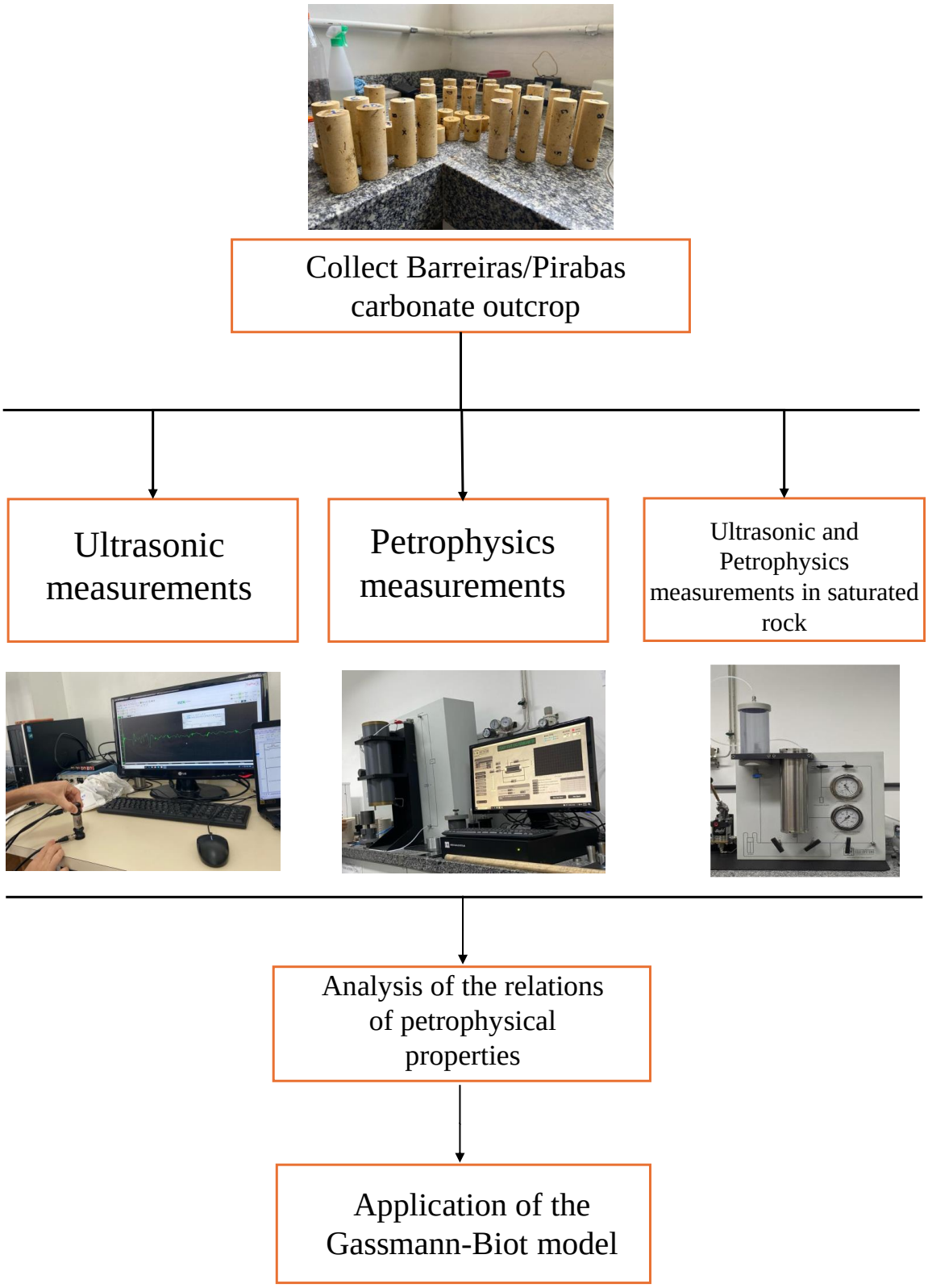

Figure 6 – This flowchart shows the structure of the methodology applied, including a description of the experimental stages, the analyses carried out and the implications of these data for the application stage of the fluid substitution model.