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# Integration of Micro-CT Image Analysis and Effective Medium Models for Elastic Characterization of Pre-Salt Carbonates

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# Integration of Micro-CT Image Analysis and Effective Medium Models for Elastic Characterization of Pre-Salt Carbonates

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## Abstract Summary

This study aims to evaluate the applicability of effective rock physics models for predicting the petrophysical and elastic behavior of carbonate rocks and in the extraction of properties from micro-CT images from the Barra Velha Formation in the Santos Basin. We integrated laboratory and well data to observe how geometry and pore type can give us different answers. With the information from the images, we were able to obtain the porosity and aspect ratio, so that we could compare it with the information from the KT and DEM models. The results of the images show that there is heterogeneity in the pores, and the DEM model was capable of better capturing the shape of the pores as porosity increased, showing zones with mixed porosity between pores with aspect ratios of 0.15 to 0.8 proportionally, reinforcing its importance for predicting the behavior of carbonate reservoir rocks and aiding the seismic interpretation of pre-salt rocks.

## Introduction

Hydrocarbon exploration and production has become more common in carbonate reservoir rocks, where the pore system is more complex than in sandstone rocks in general. Given this and the heterogeneity of these rocks, it is interesting to analyze how these geological parameters influence petrophysical and elastic behavior (Skalinski and Kenter, 2015).The Santos Basin is one of the most active exploration regions in Brazil and is characterised by extensive pre-salt carbonate systems. The Barra Velha Formation, a notable reservoir unit within these systems, is characterised by high porosity, diverse pore types and a heterogeneous spatial distribution of elastic properties (Wood et al., 2025).

Given this context, in Mavko et al. (2020) gives us effective medium models and and their applicability, such as those proposed by the KT and DEM models, have become essential tools for estimating elastic properties from parameters like porosity, matrix and fluid moduli, and pore aspect ratio. One way to calibrate the models is by extracting information from the rock using micro-CT image analysis. These analyses allow the sensitivity of the models to be assessed and provide parameters that help to understand the behavior of reservoir rocks in greater detail (Sharifi, 2022).

The purpose of this work is to apply effective rock physics models, to carbonate rocks from the Barra Velha Formation by integrating laboratory measurements, well log data and extract information from Micro-CT image. The main focus is to evaluate how pore geometry, particularly aspect ratio and pore type distribution obtained, influences the elastic response predicted by the models. The results contribute to a better understanding of how pore geometry influences elastic responses and support more accurate seismic interpretation in carbonate reservoir settings.

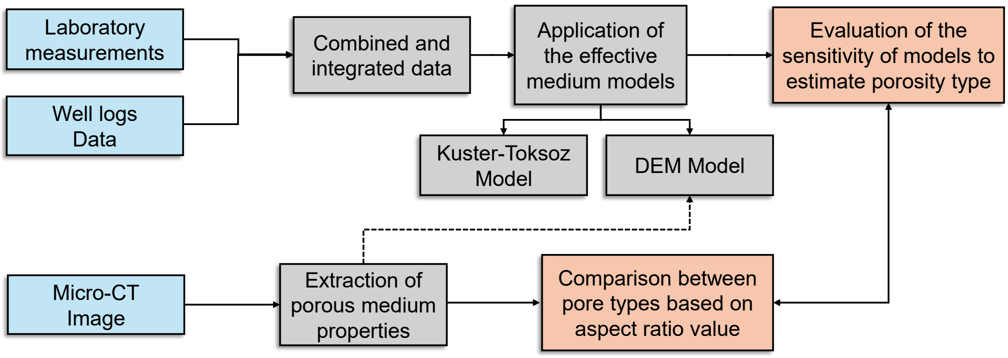


Figure 1: Flowchart showing the structure of the methodology implemented in this study, including the experimental steps, extraction of properties through image analysis and the implementation of the effective models and the evaluation of the models for the data.

## Method and Theory

This study is based on well and laboratory data from the Santos Basin, located offshore on the Brazilian Eastern Margin. The target is the pre-salt Barra Velha Formation, deposited during the Aptian in a restricted lacustrine environment with high salinity, prior to the marine ingression that formed the Ariri Formation (Carvalho et al., 2022).

The data used in this study include petrophysical measurements of porosity and ultrasonic measurements of P-S wave velocity, which are integrated with information from well data and micro-CT image analysis in the Barra Velha formation interval. High-resolution micro-CT images were used to investigate the internal pore structure of the samples. Image segmentation was performed using the SNOW algorithm (Gostick, 2017), allowing for the quantification of total porosity and estimation of pore aspect ratios. Based on pore geometry, three categories were defined: crack-type ($\alpha \approx 0.01$), reference ($\alpha \approx 0.15$), and stiff-type pores ( $\alpha \approx 0.8$) (Xu and Payne, 2009).

The next step is to apply the effective models to estimate the elastic behavior based on the parameters of the rock's petrophysics, to evaluate the sensitivity of the models and identify different porosity zones based on the pore aspect ratio. The flowchart in Figure 1 shows the steps taken during this study.

The KT and DEM models follow different approaches to estimate the elastic behavior of porous rocks. The KT model works with predefined pore shapes, like spherical, needle or penny-shaped, considering them as isolated inclusions in a solid matrix. On the other hand, the DEM model adds porosity gradually, taking into account how the interaction between pores and matrix evolves. In this work, both models were applied using a calcite matrix, and different aspect ratios were tested to represent the pore systems found in carbonate rocks. The full mathematical formulation is described in (Mavko et al., 2020).

## Results

Figure 2C shows the distribution of the aspect ratio with values concentrated between $\alpha = 0.5$ and $\alpha = 0.8$ with an average of $\alpha_m = 0.62$. However, the graph shows a bimodal behavior reflecting the heterogeneity of the pores in the sample.This variability is important for distinguishing between different pore types, such as crack and stiff, and for assigning representative input parameters in

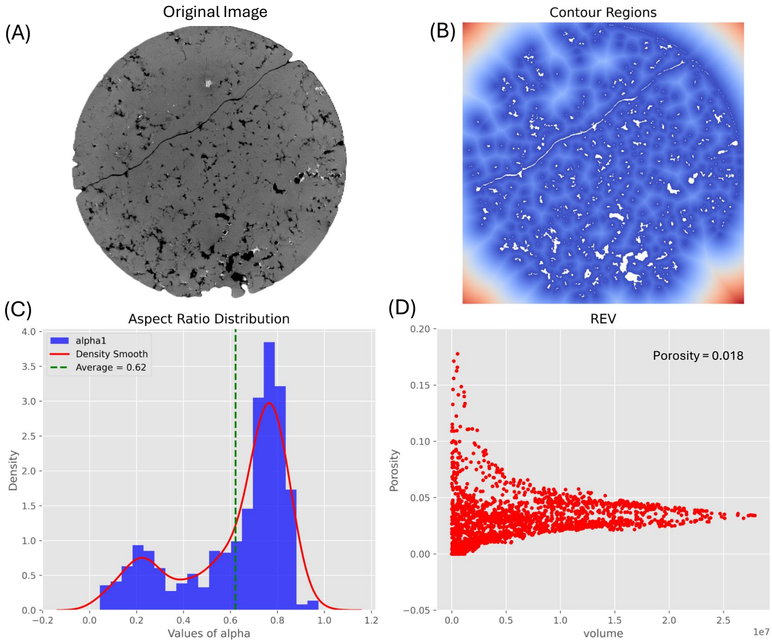


Figure 2: Results from digital image analyses for pore characterization (A) Original image of the sample (B) Contour extraction and geometric analysis separate matrix(1) and pore space(0) (C) Histogram with the distribution of pore aspect ratio, the trend line in red, and the average $\alpha$ values of 0.62 (D) Analysis of REV and its volume stability for estimated porosity of 0.018.

effective medium models.

The porosity estimated from image analysis was approximately 0.018, considerably lower than the values obtained in the laboratory, which range between 0.1 and 0.3. This difference may be related to several factors, including the resolution limitation of micro-CT and the fact that the analysis was based on a single 2D slice, which does not represent the full 3D complexity of the porous system. In the case of the REV (Representative Elementary Volume) analysis in Figure 2D, we observed this quantification of porosity based on the ratio between the pixels associated with the porous region and the total pixels in the image, such that the subvolumes were evaluated progressively until the porosity stabilized, indicating a representative volume of the porous structure.

For both the KT and DEM models, the matrix was considered to be composed of calcite, and the visualization was done by means of a crossplot between the porosity and bulk modulus together with the bulk density for the well data and the samples, and the curves generated by the models are a function of the aspect ratio parameter of the pores in the rock (Figure 3AB). For the KT model, we observed that most of the well data aligns with the curve associated with the penny-shaped type, suggesting the predominance of fissure-type pores in the formation interval shows in Figure 3A.

In the DEM model shows in Figure 3B, inclusions are introduced gradually, considering different proportions for particular aspect ratio values. Curves with a greater contribution from pores with very small $\alpha$ ($\alpha \approx 0.01$) result in lower moduli and show better agreement with the well data. However, it can be seen that the data trends towards the curves representing a more homogeneous distribution of pores, with $\alpha = 0.15$ and $\alpha = 0.8$ suggesting the mixed presence of crack and stiff pores.

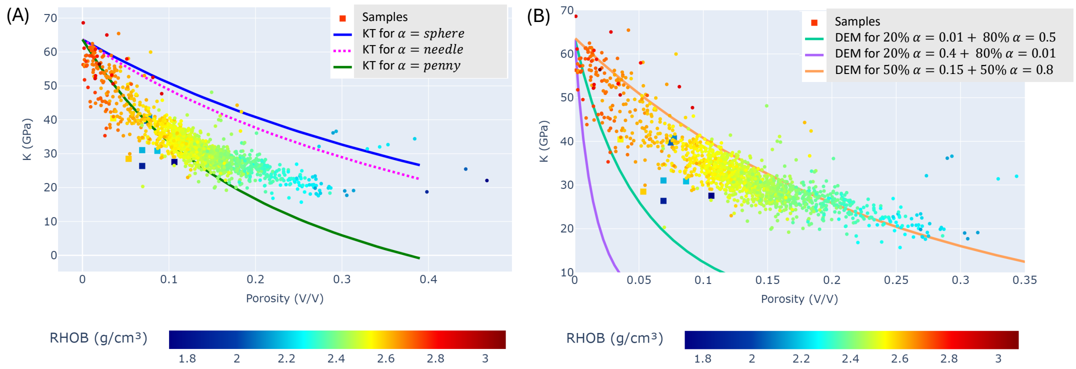


Figure 3: (A) Bulk modulus (K) estimated by the Kuster-Toksoz (A) and DEM (B) models, compared to real data. The curves reflect different pore geometries and proportions, indicating a predominance of fissure-type pores in the more porous areas.

## Conclusions

The parameters extracted from the image analysis (porosity and aspect ratio) show us that the porous system is heterogeneous with considerable variation in aspect ratio values, and these results will be included in future KT and DEM models. The KT model, which assumes static pore geometries, pointed to a predominance of fissure-type pores, as the data aligned with penny-shaped inclusion curves. Differently, the DEM model, which incorporates porosity incrementally, was able to represent more complex pore structures.It showed better agreement with zones containing mixed pore types. The aspect ratio distribution obtained from image analysis was used to configure pore geometry scenarios in the DEM model, and the resulting elastic trends showed good agreement with zones containing mixed pore types, reinforcing the model's ability to represent the heterogeneity observed in the micro-CT image.

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