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Optimizing Elastic Property Estimation with Limited Seismic Data: An Elastic Geostatistical Approach

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Abstract

Structurally complex fields, such as Brazilian pre-salt reservoirs, present significant challenges in reservoir characterization, particularly in accurately delineating and predicting facies using seismic data. Standard elastic properties including compressional and shear impedance, and Vp/Vs ratio are often inadequate for distinguishing carbonate facies due to overlapping petrophysical responses and geological heterogeneity. These limitations call for advanced inversion techniques capable of overcoming structural and faciological complexities in such challenging settings. This study introduces a elastic geostatistical seismic inversion (GSI) technique tailored to Brazilian pre-salt Tupi field, aiming to enhance reservoir characterization in geologically intricate environments. Leveraging the Historic Genetic Algorithm (HGA) framework, this method integrates stratigraphic and structural modeling with geostatistical simulation (SGS) and rock physics principles. Using a single seismic dataset, elastic properties including Bulk Modulus, Shear Modulus, Density, and Compressional Impedance were successfully obtained through inversion procedures, addressing limitations of conventional deterministic approaches. The innovative methodology combines geological modeling with geophysical workflows, ensuring refined simulated properties and enhanced geological consistency. Improving access to key elastic properties, this approach improved property resolution, reduced overlap in facies classification, and allowed better delineation of porous reservoirs and non-productive zones in the Tupi field, characterized by its carbonate reservoirs buried beneath a thick salt layer in addition to minimizing the computational costs.

Introduction

The Brazilian pre-salt carbonate fields, known for their unique depositional characteristics, are among the most challenging geological formations of the world for reservoir exploration and management. Thick salt sequences challenge seismic signal propagation and reduce in property estimation, yielding to a pursuit of seismic inversion techniques to properties beyond the standard ones. The Tupi field, situated within the Santos Basin, is emblematic of these challenges (Cruz et al., 2025).

Traditional seismic inversion approaches often utilize deterministic models reliant on Zoeppritz equations or their approximations to extract subsurface properties such as compressional impedance (Tarantola, 2005). However, these models struggle in pre-salt carbonates, limiting lithology separation due to overlapping petrophysical characteristics. Stochastic inversion methods, particularly geostatistical approaches integrated with genetic algorithms, offer promising solutions by improving property predictability, minimizing uncertainties, and enabling sensitivity analysis.

This study applies a novel geostatistical inversion methodology using full-stack seismic data combined with an HGA optimization framework (Nascimento et al., 2025) to characterize pre-salt carbonate reservoirs efficiently. Elastic properties—including bulk modulus, shear modulus, density, and compressional Impedance (P-impedance)—are directly obtained using minimal data inputs while retaining high geological consistency and resolution.

Method and Dataset

The HGA workflow combines geological modeling and seismic inversion into an iterative process, improving accuracy and consistency. It begins with a stratigraphic and structural framework to capture spatial correlations, followed by Sequential Gaussian Simulation (SGS) with co-kriging to generate P-impedance realizations mapped to a grid aligned with seismic data. Synthetic seismic data are created using reflectivity coefficients and wavelets, with correlations assessed through a trace-by-trace sliding window. High-correlation samples are added to subsequent iterations as new input data, enhancing geological integrity. Velocity models initially guide simulations but are replaced by correlations from accumulated data in the subsequent iterations, ensuring alignment between geological models and seismic results.

After deriving elastic properties such as bulk modulus, density, shear modulus, and P-impedance, a viability analysis is conducted to identify the optimal relationships among these properties for facies classification. The most effective relationship is applied to generate facies probabilities using a Bayesian approach. Once the classification was completed, an additional analysis is performed to establish the best correlation between effective porosity and elastic properties, producing a porosity volume. This comprehensive workflow aims to improve the reservoir characterization, delivering key outputs such as facies probabilities, porosity models, and elastic property distributions—all obtained using a single seismic dataset. A schematic representation of the HGA workflow and reservoir seismic characterization is illustrated in Figure 1.

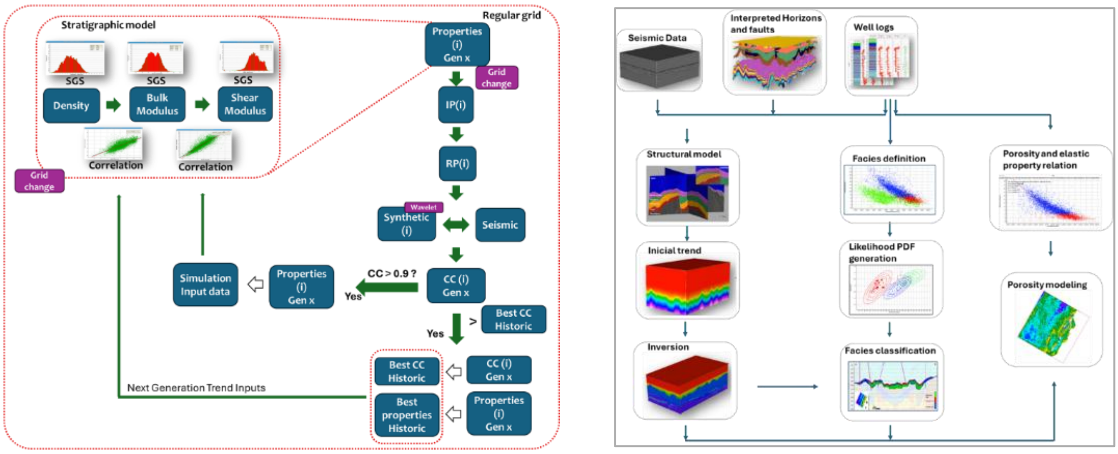

Figure 1: On the left, HGA workflow for geostatistical seismic inversion. On the right, simplified workflow for seismic inversion and reservoir characterization, encompassing seismic inversion, bayesian facies classification, and the generation of the porosity model.

This study explores the carbonate Tupi field, located in the Santos Basin, Brazil. The analysis relied on the post-stack seismic image, processed using reverse time migration (RTM) and least square migration (LSMi) techniques. Additionally, well logs were integrated, offering detailed information on rock and fluid properties essential for accurate reservoir characterization.

Results

In Figure 2, the progress of the iterations can be observed. The top images show the evolution of the input seismic data throughout the iterations, with an increasing number of data points exceeding the 0.9 threshold. In the middle, the improvement in correlation is displayed, and at the bottom, the adjustments in P-impedance are shown. With just five iterations, the correlation in the reservoir predominantly reaches values greater than 0.9.

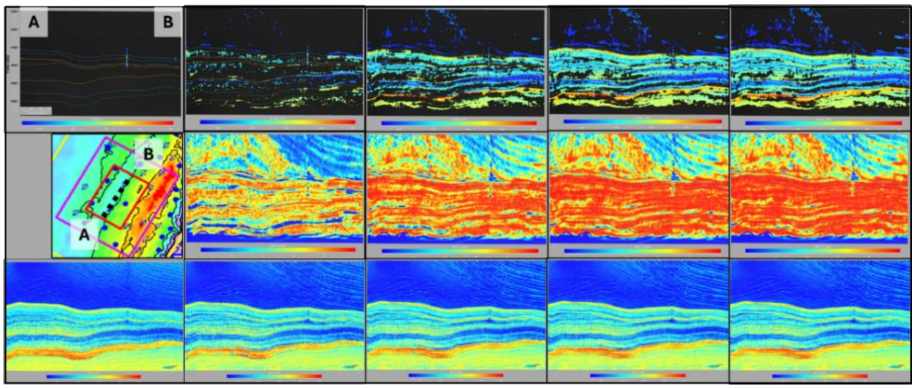

Figure 2: Progress of the HGA workflow from the first to the fifth iteration shown through columns: At the top row, simulation input data; in the middle, best correlations; at the bottom, P-impedances. There is an evolution of the new data classified as simulation input data when the correlation is above 0.9. The P-impedance progressively converges to a more geologically accurate result.

Using density and shear modulus cross-plots, the Bayesian classification framework achieved promising results in separating facies types as showed in Figure 3. The non-reservoir magnesian clay facies demonstrated negligible overlaps with tight and porous reservoir facies. Probability density functions (PDFs) applied in the BVE zone effectively delineated reservoir zones into upper, middle, and lower partitions. Porous facies were predominantly located in the upper zones, while magnesian clays were more abundant in the middle and lower regions.

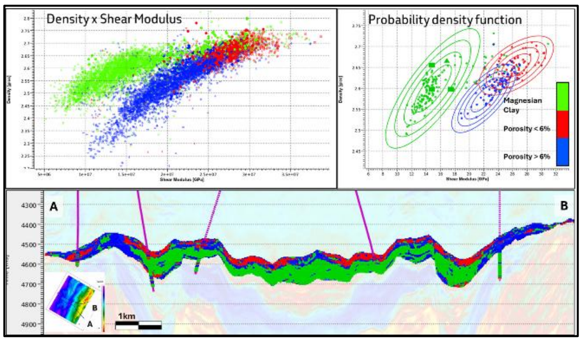

Figure 3: Top: Bayesian facies classification utilizing shear modulus and density relationships alongside probability density functions for each facies. Bottom: Most probable facies determined through Bayesian classification.

Effective porosity volumes were generated by correlating shear modulus with porosity, as illustrated in Figure 4, while incorporating the probability of magnesian clay occurrences. Porosity distribution maps confirmed structural highs within the BVE zone as areas of enhanced porosity.

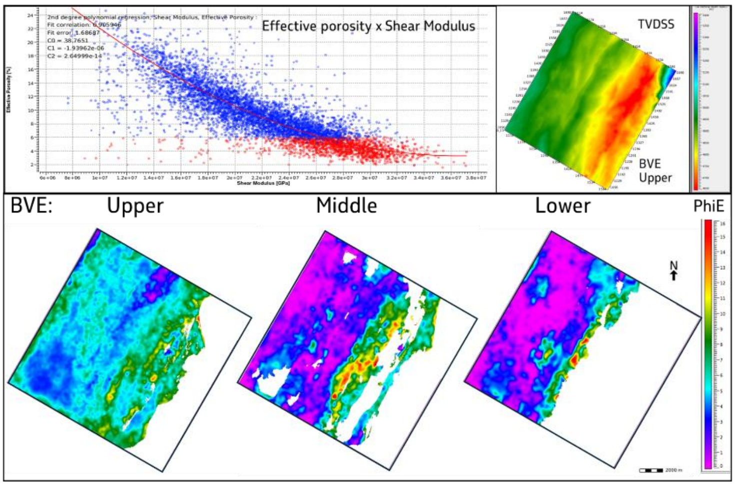

Figure 4: Top: Relationship between effective porosity and shear modulus, along with the structural features from the reservoir's top. Bottom: Effective porosity distribution within the internal zones of the BVE, highlighting the highest porosity values concentrated in the structural highs.

Conclusions

This study demonstrates the effectiveness of achieving accurate reservoir characterization in pre-salt carbonate formations using a novel elastic GSI approach with limited seismic datasets. By integrating geostatistical inversion techniques, Historic Genetic Algorithms (HGA), and Bayesian classification, the methodology provides a powerful alternative to deterministic inversion methods, enhancing lithological separation and fluid sensitivity analyses.

Elastic property estimates—including bulk modulus, shear modulus, density, and P-impedance—exhibited strong correlations with well-log data, demonstrating alignment and reliability. The HGA methodology also significantly improved seismic characterization, enabling the accurate delineation of geological features such as faults and structural displacements.

Bayesian frameworks effectively distinguished reservoir facies, including tight and porous zones, from non-reservoir magnesian clay facies, offering detailed mapping capabilities. Furthermore, the elastic HGA method reduced reliance on extensive seismic datasets, proving both cost-efficient and scalable for large-scale reservoir exploration while maintaining high accuracy in characterization results.

References

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