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Decoding the Iara Cluster Reservoirs Architecture: Insights into Multi-Scale Compartmentalization in Pre-Salt Carbonates

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Abstract Summary.

Accurately identifying reservoir compartmentalization during the early stages of field development remains a major challenge in pre-salt carbonate systems, where geological complexity introduces significant uncertainty in reserve estimations. Deepening the understanding of this phenomenon, the present analysis focuses on the Iara Complex in Brazil's Santos Basin, where pre-salt reservoirs exhibit pronounced lateral and vertical heterogeneities. By integrating formation evaluation analysis of mainly of pre-prodution static pressure data, fluid characterization and well logs with seismic interpretation, the study reveals multiple oil and water contacts, contrasting pressure gradients, and fluid property variations that strongly support the existence of multi-scale hydraulic compartmentalization. Regional segmentation is identified across the Barra Velha reservoirs in the Berbigão, Sururu, and Atapu fields, while localized barriers impact the Itapema Formation in Atapu. The Jiquiá Shale plays a key role as a vertical flow barrier, critically influencing reservoir connectivity. These findings underscore the value of early, multidisciplinary compartmentalization assessments to reduce subsurface uncertainty and enhance reserve prediction in complex pre-salt environments.

Introduction

The oil and gas sector in Brazil has experienced significant growth, driven by the continuous increase in production from pre-salt reservoirs in the Santos and Campos Basins, which have become the country's main source of hydrocarbons since 2017, accounting for around 79% of total output in 2025 (ANP, 2025). However, projections by EPE (2025) indicate a potential decline in crude oil production over the next decade, underscoring the urgent need for reserve replacement to ensure long-term supply sustainability. This can be achieved through new exploratory discoveries, revitalization of mature fields, or optimized management of existing reservoirs.

In this context, the characterization of reservoir compartmentalization becomes crucial, as this phenomenon directly influences the volume of moveable hydrocarbons that can be drained by individual wells (Jolley et al., 2010), and significantly impacts the accuracy of reserve estimations. However, owing to the absence of dynamic production data, identifying reservoir compartmentalization during early field history is challenging, requiring multi-disciplinary analysis to maximize the synergy of available static subsurface data.

Pre-salt carbonate reservoirs are characterized by a high degree of facies, depositional, diagenetic, and structural complexity, resulting in significant lateral and vertical heterogeneities. This geological setting is conducive to the development of both static and/or dynamic intraformational seals, which may act as flow barriers within the reservoir, promoting the compartmentalization and segregation of hydrocarbon accumulations. Consequently, several studies have documented the presence of multiple free water levels within these reservoirs across key oil fields in the Santos Basin (Mello et al., 2021; Petersohn et al., 2021; Vital et al., 2023).

Therefore, this study aims to characterize the multiple oil-water contacts observed throughout the Iara complex in light of the reservoir compartmentalization concept, as well as to propose hypotheses regarding the static behavior of its reservoir aquifer systems.

Method and/or Theory

To address the objectives of this study, we used data from 17 wells across the Iara Complex, 11 of which tested the reservoir under virgin conditions. The dataset included well logs, rock and fluid sample reports, and, when available, basic petrophysical data reports. Furthermore, we used a public post-stack depth-migrated seismic data named R0258_3D_IARA_RTM_PSDM.

We applied a multidisciplinary methodology focused on integrating pre-production data analysis and seismic interpretation to identify the static phenomena affecting the reservoirs under study. The workflow began with the interpretation of oil and water gradients derived from static reservoir pressure data, which was subsequently integrated with well log interpretation to define oil-water contacts. To support the pressure analysis, the excess-pressure plot technique was employed to highlight contrasts between the analyzed gradients, as illustrated in **Figure *1***.

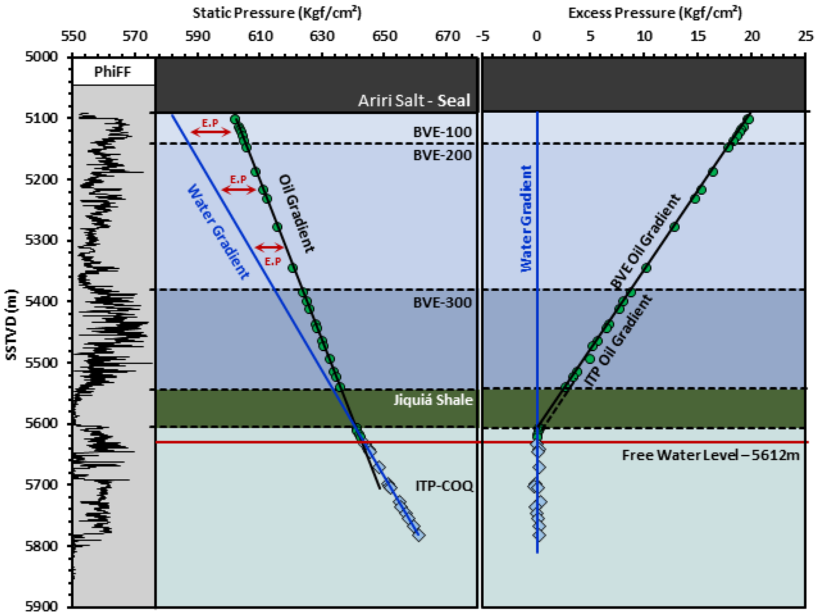

Figure 1: Static pressure analysis of 3-BRSA-1172-RJS well in Atapu field in order to identify the free-water level. The first represents a traditional static pressure x sstvd plot, whilst the second one is characterized by the excess pressure plot which highlight the fluid gradient contrasts.

Following, PVT properties and hydrocarbon composition data were examined to assess similarities or dissimilarities among the well samples. Finally, all analyses were integrated with seismic interpretation aimed at mapping the reservoir extent, allowing us to formulate hypotheses regarding the observed phenomena.

Results

Reservoir pressure analysis under virgin conditions enabled the identification of four distinct oil gradients: two in the Berbigão Field (0.0809 and 0.0989 kgf/cm²), one in the Sururu Field (0.0785 kgf/cm²), and one in the Atapu Field (0.0777 kgf/cm²). Although the oil gradients in the main producing zones of the Berbigão, Sururu, and Atapu fields are relatively similar, hydraulic compartmentalization among these reservoirs is considered almost certain. This conclusion is supported by fluid analysis, which revealed a high degree of dissimilarity in fluid properties across the different fields.

Furthermore, the evaluation conducted in this study showed that out of the 11 pre-production exploratory wells analyzed, 6 reached the water zone, and several irregular oil-water contacts (OWCs) were identified. The maximum OWC variation was approximately 150 meters, observed between well 9-BRSA-1284-RJS in Atapu and well 9-BRSA-1212-RJS in Sururu. Even when considering only the hydraulically connected wells within the Atapu Field, a significant OWC variation of about 40 meters was observed.

Given the peculiar scenario observed in the Atapu Field (Figure 2), it was necessary to reduce the scale of investigation, conducting a detailed, integrated analysis. Based on static pressure data, a single oil gradient was identified across all wells, along with at least three distinct water gradients. Three wells in the study area exhibited oil–water contacts within the Itapema Formation reservoirs, while the remaining contacts were observed in the Barra Velha Formation reservoirs. The contacts identified within the BVE Formation showed minimal variation, whereas those in the Itapema Formation displayed greater variability. This contrast highlights a significant distinction in the hydrodynamic behavior between the two reservoir intervals.

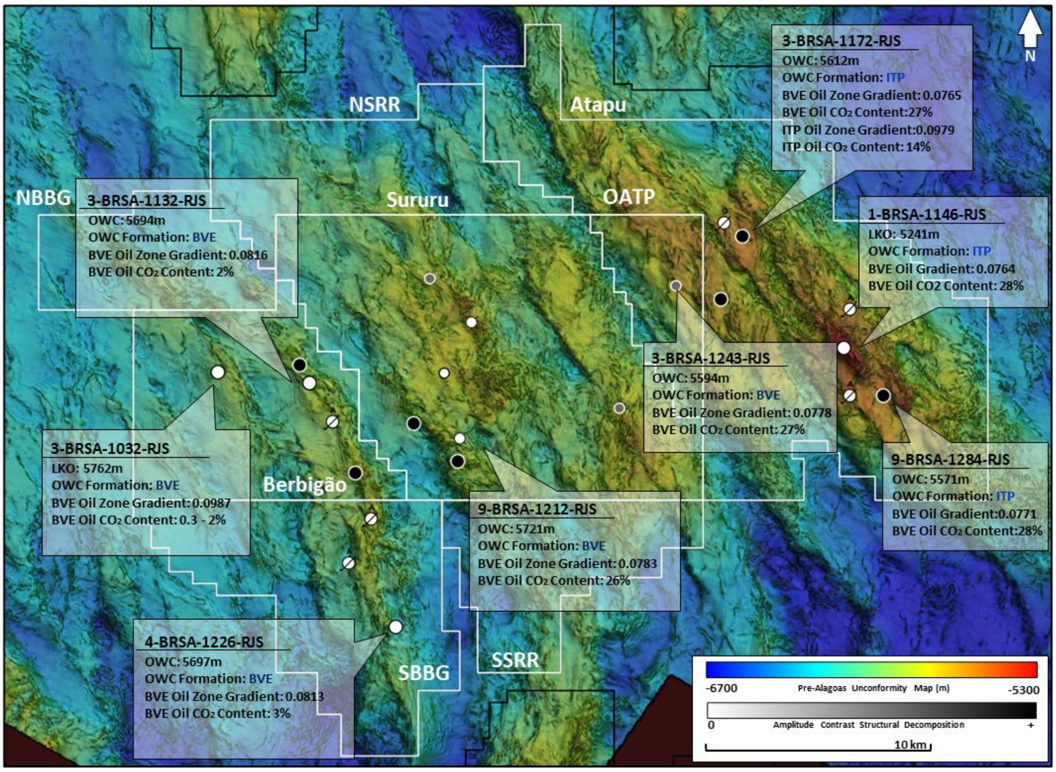

Figure 2: Corended map of Pre-Alagoas Unconformity and Structural Decomposition with the distribution of important static reservoir pressure information and CO2 accumulation content.

The transition between the Barra Velha and Itapema Formation reservoirs is marked by a significant regional drowning cycle, represented by a laminite/shale interval informally referred to as the "Jiquiá Shale." This unit constitutes a major vertical discontinuity in reservoir properties. This characteristic, combined with the structurally complex setting of the area—characterized by a high density of faults as identified in this study through seismic interpretation and the use of structural attributes such as curvature and semblance—creates a favorable scenario for hydraulic compartmentalization at this reservoir level.

To support this hypothesis, well 3-BRSA-1172-RJS encountered the deepest oil–water contact (OWC) identified in the Atapu Field, associated with a hydrocarbon accumulation of 8 meters in the Itapema Formation. This accumulation exhibits anomalous fluid characteristics compared to other samples from the field, including significantly lower values of CO_2 content, solution gas–oil ratio, saturation pressure, and C1–C4 content. In contrast, the southeastern area of the Atapu Field—explored by wells 1-BRSA-1146-RJS and 9-BRSA-1284-RJS—also revealed hydrocarbon accumulations in both the Barra Velha and Itapema Formations. In this region, the two reservoirs are separated by a thinner Jiquiá interval. The similarity in oil pressure gradients and fluid compositions between the two formations suggests the possibility of hydraulic communication across this boundary.The central-western region of the field, as tested by well 3-BRSA-1234-RJS, differs from the others in that it exhibits hydrocarbon accumulation exclusively within the Barra Velha Formation.

Conclusions

The integration of static pressure data, fluid characterization, and seismic interpretation enabled a comprehensive assessment of reservoir compartmentalization within the Iara Complex. The identification of multiple oil–water contacts, distinct fluid properties, and divergent pressure gradients provides strong evidence for multi-scale hydraulic compartmentalization, ranging from regional lateral segmentation of the Barra Velha reservoirs across the Berbigão, Sururu, and Atapu fields to more localized compartmentalization within the Itapema Formation in the Atapu Field. In this last case, the vertical barrier associated with the Jiquiá Shale, combined with a structurally complex fault framework, plays a fundamental role in governing reservoir connectivity and internal flow barriers. These results highlight the critical importance of early compartmentalization diagnosis in pre-salt carbonates and reinforce the value of integrated, multidisciplinary workflows for reducing subsurface uncertainty and enhancing reserve estimations. Moreover, this study reinforces the critical role of the Jiquiá Shale within the petroleum system of the Santos Basin, once act as an effective seal.

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