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Analysis of analogous microbialite reservoirs and their associated petroleum systems in rift and passive margin basins: South Atlantic (Brazil) vs. North Atlantic (Portugal)

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This study compares the efficiency of petroleum systems in the Santos Basin (Brazil) and the Lusitanian Basin (Portugal), focusing of the geological controls on hydrocarbon accumulation in two analogous microbialite reservoirs. We present a methodology integrating the static elements (source and reservoir rocks, seal, and trap) and dynamic elements (migration and accumulation, tectonic processes, thermal history, diagenesis) of petroleum systems with multiscale characterization from the basin to pore scale. Interpretive diagrams based on geological data analysis and a comparative table of static and dynamic elements were used to evaluate the analogous reservoirs and comprehensively analyze their potential. Salt tectonics played a critical role in the success of the Barra Velha Formation microbialite reservoirs in the Santos Basin, with the evaporite domes providing a highly effective seal for hydrocarbon trapping. In contrast, the Cabaços Formation microbialites in the Lusitanian Basin exhibit poor porosity due to pervasive diagenetic alteration (calcite recrystallization and mechanical compaction) observed at the petrographic scale. However, significant variations in lateral facies within these microbialites, observed at the outcrop scale, suggest potential for less diagenetically altered zones with improved reservoir properties and, consequently, better chances for hydrocarbon storage.

KEYWORDS

sedimentary basins, petroleum systems, static elements, dynamic elements, microbialite reservoirs

1 Introduction

The oil industry utilizes analogous outcrops as a crucial tool to understand subsurface hydrocarbon reservoirs, aiming to construct more robust predictive geological models and reduce exploration uncertainties (Garcia et al., 2003; Kenter et al., 2010; Garcia et al., 2020; Garcia et al., 2021). While subsurface data are obtained indirectly through the physical properties of rocks (reflection seismic), information from direct sources is obtained from good quality outcrop samples with large lateral and vertical extensions, exploratory drilling cores, geochemical analyses and petrographic analyses. The integration of data obtained directly and indirectly in oil and gas prospecting allows the characterization of the distribution of petrophysical and compositional properties, resulting in a multiscale sampling of data, from the grain-pore scale to the sequence stratigraphy scale. Integrating data across different observation scales allows for multiscale characterization of petroleum system elements, optimizing the understanding of reservoir geometry, variations, and internal structures (Garcia et al., 2014; 2015; Dragos, 2018).

Carbonate rocks are very important reservoir rocks for hydrocarbon storage around the world (Worden et al., 2018; Nabawy et al., 2019). Carbonate sedimentation is normally associated with the rift and SAG phases of basins in environments of intense organic activity, mainly in marine or lacustrine conditions, with little water circulation and/or high carbonate concentration, caused by high evaporation rates. Particularly, carbonate sedimentation associated with marine evaporite environments combines different situations that favor the lateral and vertical coexistence of sedimentary facies that can behave as source rocks or reservoirs, depending on their evolution over time, post-burial. In this context, developed petroleum systems can present two of their main static elements, source rocks and reservoir rocks, very close together, favoring voluminous accumulations, in the presence of good sealing rocks (evaporites, shales and other sealing layers). It is crucial to highlight the importance of understanding surface geology to predict subsurface petroleum elements in such geological settings.

Microbialites and coquinas have gained prominence since the 2006 discovery of oil in the Santos Basins Pre-Salt play, at Brazil. This discovery has prompted a more detailed study of global analogues, including the Cabaços Formation microbialites in the Lusitanian Basin, Portugal. In these analogue studies, two approaches are of fundamental importance: the geochemical approach (TOC and kerogen analysis) and the facies detailing of carbonate lithologies, both being part of the same sampling methodology, based on the multiscale characterization adopted in this work.

Over the last 10 years, different genetic models have been proposed and published for the carbonate reservoirs of the Santos Basin Pre-Salt, where the Barra Velha Formation is located. Within these models, some authors advocate their microbial origin (Muniz and Bosence, 2015; Saller et al., 2016; Brelaz et al., 2019), while other authors began to propose an abiotic origin for the laminated carbonates of the Barra Velha Formation, based on petrographic and geochemical analyses of highly alkaline lacustrine environments, influenced by hydrothermal fluids, with high concentrations of silica and magnesium and evaporitic conditions that favored the control of the development of these facies (Wright and Barnett, 2015; Wright and Tosca, 2016; Herlinger et al., 2017; Wright and Barnett, 2017; Lima and De Ros, 2019; Gomes et al., 2020; Carramal et al., 2022). However, due to the various uncertainties that still persist regarding the depositional processes that originated these laminated carbonates, the discussion about their genesis remains open for several authors in the literature (Farias et al., 2019; Rebelo et al., 2023).

The recognition of these two genetic typologies (biotic and abiotic) for carbonates with laminar structure in the Barra Velha Formation makes this debate important, since for each reservoir interval the correct characterization must be recognized so that the application of analogous models can be developed. The intervals of laminated microbial carbonates of the Barra Velha Formation recognized as being of biogenic origin are those indicated in this article as potentially analogous to the microbiolites of the Vale Verde Formation (chronoequivalent of the Cabaços Formation) in the Lusitanian Basin, studied in outcrop at Pedrogão Beach.

Regarding the association of volcanogenic and biotic processes in the geological record, this has been recognized in the literature, such as the article by Wang et al. (2020), which reports sedimentary characteristics of microbiolites influenced by volcanic activity, observed in the Shipu Group of the Lower Cretaceous, eastern China. The Shipu Section is presented with nine assemblages of laminated microbiolites intercalated with pulses of volcanic rocks, represented by breccias and volcanic agglomerates, tuffites and tuffaceous sandstones and siltstones. The authors conclude that the moderate supply of volcanic ash favored the development of microbial carbonates.

Thus, this article is limited to addressing as potential analogues only the intervals recognized as being of biogenic origin in the Barra Velha Formation, in the Campos Basin, and the carbonates recognized as being of microbial origin in the Cabaços Formation, in the Lusitanica Basin. In the comparative case study presented the authors compare the two analogous laminated carbonate reservoirs, seeking to reevaluate data from internal reports, published articles, theses and dissertations, as well as unpublished data from the ANP database (BDEP) referring to the analyzed brazilian basin, as well as the data used from the Lusitanian Basin. All these data were used to analyze their respective petroleum systems' static and dynamic elements. The first reservoir comprises the Aptian Barra Velha Formation microbialites (post-rift section) in the Lapa Field, central Santos Basin, Brazil. The second is the Oxfordian (Upper Jurassic) Cabaços Formation in the Lusitanian Basin, consisting of microbial laminated carbonates, tested in exploratory wells in the central part of that basin.

According to Magoon and Dow (1994), a functioning petroleum system requires a suite of geological processes and elements, such as hydrocarbon generation, migration, and preservation. Essential elements include source, reservoir, seal and overburden rocks. Generation-migration-accumulation and trap formation are the included processes. The spatio temporal interaction of these processes is crucial for hydrocarbon accumulation and preservation, defining a basin's petroleum potential. A petroleum system describes the relationship between the hydrocarbon formation area and its accumulation site. Oil shows or gas flows in reservoir rocks can indicate an active petroleum system.

The definitions of petroleum system elements have been revisited since Magoon and Dow's (1994) seminal work. Regarding static elements, the present article follows the approach that these are mappable features related to tectonic and sedimentary processes, including source rocks, reservoir rocks, seal rocks, and traps (Barbosa et al., 2022; 2023). The trap, the fourth static element, is mappable seismically and is crucial for containing hydrocarbons within the reservoir rock's pore system (Garcia et al., 2014; 2015).

The dynamic elements of petroleum systems are those amenable to modeling. They are linked to post-depositional basin dynamics and include tectonics (subsidence history, uplift and subsidence rates), heating (thermal flow), and basin structuring (Al-Hajeri et al., 2009). These dynamic elements can influence the petrophysical attributes and pore characteristics of reservoir rocks, impacting their hydrocarbon accumulation potential (Perrodon and Masse, 1984).

This work presents a comparative case study of the Barra Velha Formation microbialite play of the Lapa Field (Santos Basin, Brazil) and its analogous, potentially prospective Cabaços Formation microbial carbonates of the Lusitanian Basin (Portugal). This comparative analysis of petroleum systems and analogous reservoirs between the Brazilian and Lusitanian basins represents a novel contribution (Barbosa et al., 2022; 2023).

The overall objective of this research is to analyze the efficiency of petroleum systems in the South Atlantic (Brazil) and Lusitanian (Portugal) basins, focusing on the geological factors influencing hydrocarbon accumulation in the analogous reservoirs. The specific objectives are to characterize, using a multiscale approach, each basin`s static and dynamic elements, comparing source rock, reservoir, and seal characteristics. A multiscale study encompassing static and dynamic elements requires, among other aspects, understanding the property distribution of analogous lithostratigraphic units, from the basin scale to the pore scale (Garcia et al., 2003; 2014; 2015).

This study examines the burial history of each reservoir and its analogue, diagenetic progression related to organic matter evolution, and hydrocarbon migration pathways from source to reservoir to determine the success or failure of these reservoirs as hydrocarbons accumulators, considering the geodynamics of both basins.

2 Geological settings

This section presents the location maps (Figure 1) of the Santos Basin and Lusitanian Basin, as well as the main geographic aspects of the two studied basins. The geological characteristics of their origins, as well as the aspects of their tectonostratigraphic evolutions. The last paragraph describes the depositional environments of the two analogous reservois analyzed.

The Santos Basin is located in the southeastern region of Brazil and covers the coastal strip of the states of Rio de Janeiro, São Paulo, Paraná and Santa Catarina. Its area is approximately 350,000.0 km^2, up to a bathymetric elevation of 3,000 m (Macedo, 1989). It is a passive margin basin generated during the Neocomian, corresponding to the rupture of the Gondwana Supercontinent and the opening of the Atlantic Ocean. The thickness of its sedimentary section can reach 15 km, covering the rift sequence, having been deposited on a thinned crust (Mio et al., 2005). The tectonostratigraphic evolution of the Santos Basin can be divided into three main supersequences: Rift, Post-Rift and Drift, with the crystalline basement of the basin represented by Precambrian rocks of the Ribeira Belt (Moreira et al., 2007). The accommodation space for sedimentation was generated from subsidence related to the extensional efforts that resulted in the rifting of the Gondwana Supercontinent.

The Lusitanian Basin is located on the western margin of the Iberian Plate, located onshore and in the shallow portuguese offshore. It has a maximum sediment thickness of approximately 5 km and extends onshore for approximately 320 km in the north-south direction and 180 km east-west, with a considerable offshore extension to the west and north (Pimentel et al., 2011). It corresponds to a distensive basin, its formation being related to the rupture of Pangea, as well as the formation of the Tethys Sea and the North Atlantic. Its rifting began in the Triassic, and its oceanic crust had its effective formation from the Upper Jurassic (Palain, 1976; Soares et al., 2012). The basin sediments belong from the Upper Triassic to the Upper Cretaceous, with Paleogene coverage, with the largest sedimentary volume being of Jurassic age (Azerêdo et al., 2003). The evolution of the Upper Jurassic, where the Cabaços Formation is located, includes 3 major tectono-sedimentary stages, well recorded in the central region of Portugal: 1) Installation of the rift, responsible for a generalized flooding of the basin with a predominance of carbonate sedimentation, 2) creation of intensely subsiding sub-basins with a significant siliciclastic influx and 3) late drift interpreted as a period of thermal subsidence, associated with eustatic variations with significant filling of the basin (Kullberg et al., 2006).

Regarding the depositional environments of the two analogous reservoirs investigated in this work, the limestone rocks outcrop at Pedrogão Beach in the Lusitanian Basin belong to the Vale Verde Formation (chronoequivalent to the Cabaços Formation) and suggest deposition in coastal lakes and lagoons fed by predominantly calm marine waters, sufficiently oxygenated to support non-marine benthic fauna. Fossiliferous limestones and bioturbated marly limestones occur, with some intercalations of marly levels and levels with prominent microbial lamination (Pena dos Reis et al., 2007). The depositional environment of the Barra Velha Fm. Has been the subject of numerous debates since the 2000s, with Dias (2005a) attributing a marine depositional environment for the deposition of carbonates from the Macabu Fm. (Winter et al., 2007), Campos Basin, correlatable to the Barra Velha Fm. Other authors (Moreira et al., 2007; Carminatti et al., 2008; Formigli et al., 2009) suggested a transitional depositional environment, under marine influence, for the carbonates of the Barra Velha Fm. However, the marine influence on the deposits of this formation was contested by Wright and Barnett (2015), Muniz and Bosence (2015) and Pietzsch et al. (2018). Despite uncertainty about the exact chemical conditions that produced the sediments of the Barra Velha Formation, it can be inferred that the lakes of the formation were hyper-alkaline and prone to evaporation (Wright and Barnett, 2015). Based on a vast collection of data, Wright and Barnett (2015), Wright and Barnett (2017) present a model of the depositional environment of a shallow, extensive, hyper-alkaline evaporite lake draining basic igneous terrains (Castro, 2019).

3 Petroleum systems

The Petroleum Systems study contain the stratigraphic diagrams (Figures 2, 4), and event charts (Figures 3, 5) for the analyzed and proven petroleum systems, represented by the symbol (!), in the Santos and Lusitanian basins, respectively: Picarras/Itapema-Barra Velha/Itapema (!) and Cabaços-Cabaços (!)

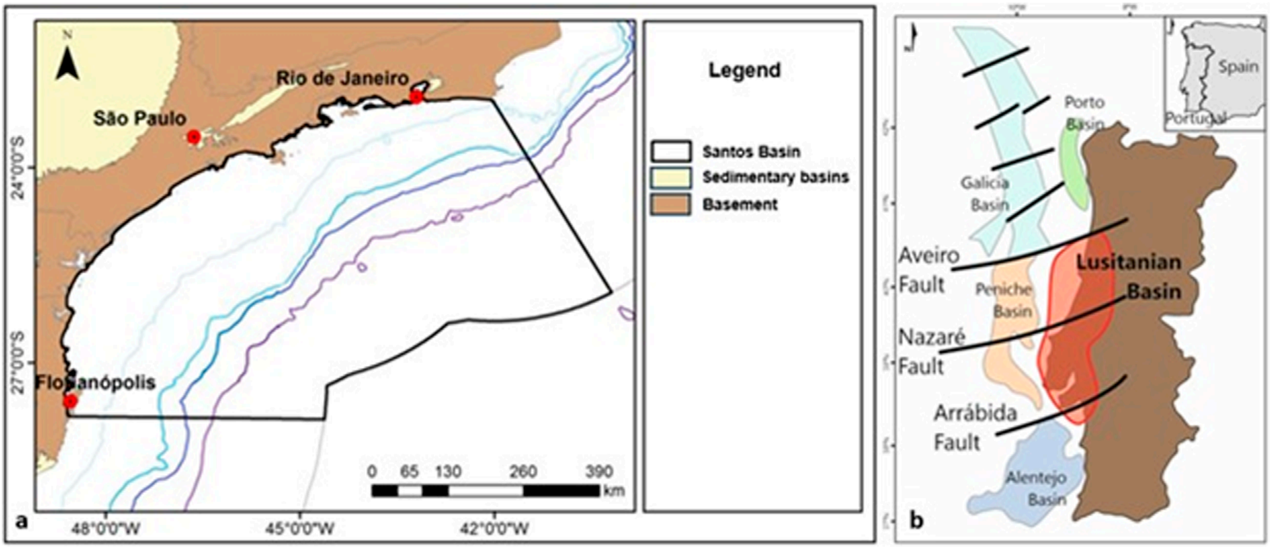

FIGURE 1
Location Maps of the Santos Basin (a), in Brazil, modified from Sumário Geológico (2017) and the Lusitanian Basin (b), in Portugal, modified from Pena dos Reis and Pimentel (2013).

3.1 Santos Basin

The Itapema/Piçarras-Barra Velha/Itapema petroleum system operates within the pre-salt section of the Santos Basin. Hydrocarbons are generated in the lacustrine shales of the Itapema and Piçarras formations and accumulate in the coquina and microbialite carbonate reservoirs of the Itapema and Barra Velha formations (Aptian) (Figure 2).

This system involves petroleum generation from the Barremian Itapema Formation shales and the Barremian-Aptian Piçarras Formation shales (Garcia et al., 2019), with the latter being the focus of this study. The average total organic carbon (TOC) content of the Piçarras Formation shales ranges from 1% to 3.5% (Sanabria, 2022). The Ariri Formation evaporites serve as the primary seal. Figure 3 presents the event chart, illustrating the elements and processes (Magoon and Dow, 1994) of the Itapema/Piçarras-Barra Velha/Itapema petroleum system (Papaterra et al., 2010). This study focuses specifically on the Barra Velha Formation microbialite reservoirs.

3.2 Lusitanian Basin

The studied petroleum system Cabaços-Cabaços of the Lusitanian Basin involves the generation of petroleum by the marly limestones of the Cabaços Formation (Figure 4), with average TOC values varying from 1.2% to 2.8% (up to 28.6%, locally), with types I, II and III kerogens (Spigolon et al., 2011). This petroleum system involves hydrocarbon generation from the Cabaços Formation marly limestones (Figure 4). These source rocks have average TOC values ranging from 1.2% to 2.8%, with local values up to 28.6%, and contain Type I, II, and III kerogens (Spigolon et al., 2011).

Onshore exploratory wells such as Benfeito-1, Freixial-1, and Campelos-1, drilled in the central Lusitanian Basin, have tested this potential reservoir. Hydrocarbons generated in the Late Jurassic Cabaços Formation marly limestones migrated directly into the microbialite layers within the same formation. Potential seals include anhydrite layers within the Cabaços Formation and the Late Triassic/Early Jurassic Dagorda Formation evaporites. The Figure 5 illustrates the simplified petroleum systems of the Lusitanian Basin, with the Cabaços-Cabaços system highlighted within the light blue dotted line.

Simplified Petroleum Systems of the Lusitanian Basin, modified from Barbosa et al. (2023). The Cabaços-Cabaços petroleum system is highlighted within the light blue dotted line. Oil generated from the Cabaços Formation shales migrates to microbialite layers within the same formation. Potential seals include anhydrite layers within the Cabaços Formation and evaporites of the Dagorda Formation (Late Triassic/Early Jurassic).

4 Materials and methods

4.1 Materials

This section describes the data used in the multiscale analysis of the studied petroleum systems. Integrated seismic, well, geochemical, petrographic, and outcrop data enabled the characterization of static and dynamic elements, evaluation of synchronism, and estimation of the probability of geological success (Pg).

4.1.1 Barra Velha Formation - Santos Basin

The Figure 6A shows the location of the Lapa Field in the Santos Basin, while Figure 6B shows the location of well 3-BRSA-861-SPS and the 2D seismic line VB99-186, presented in the results (Section 4). This investigation uses data from two exploratory wells in the Lapa Field (Figure 6B): 3-BRSA-861-SPS and 3-BRSA-1101-SPS. Both well's composite profiles and

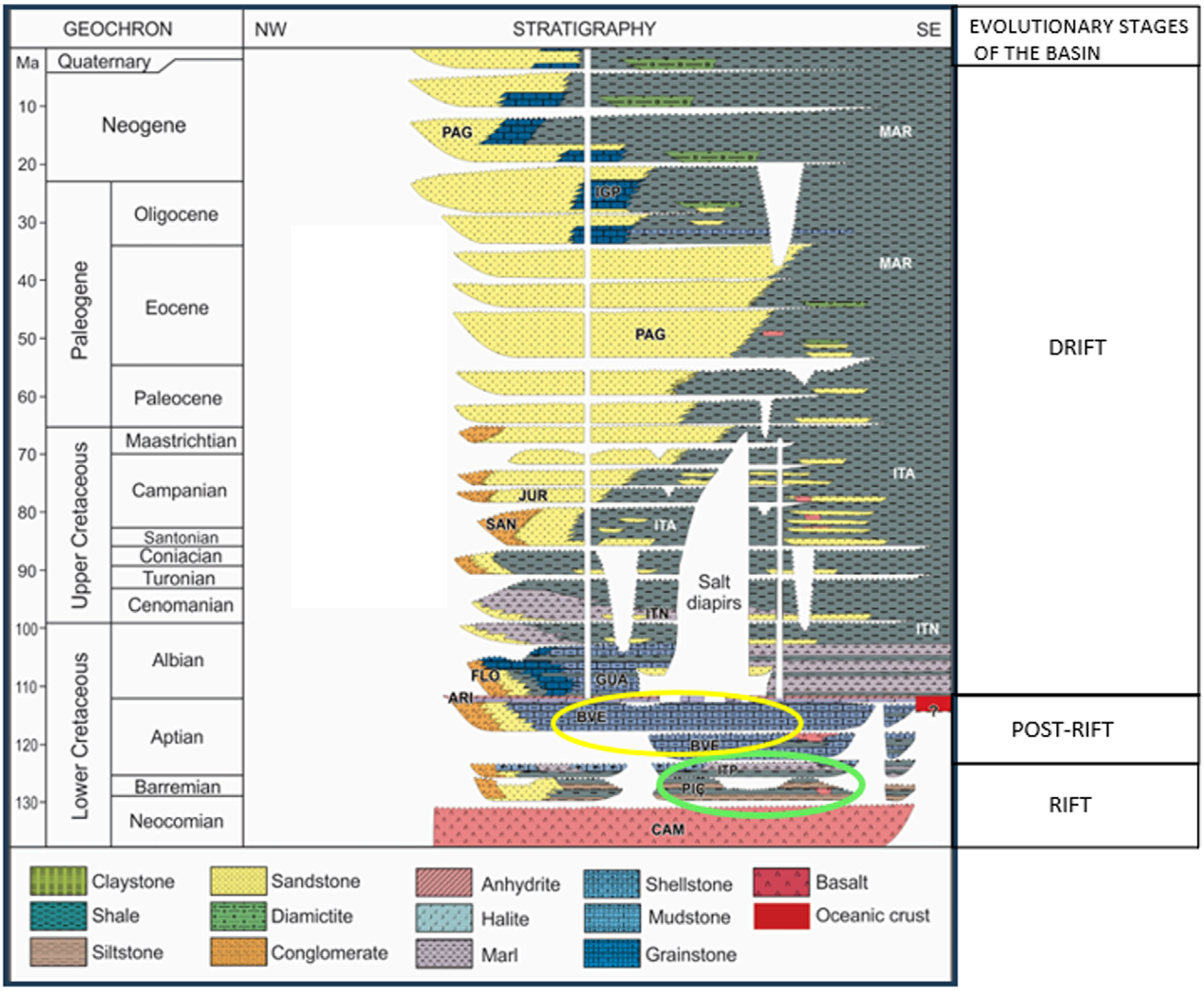

FIGURE 2
Stratigraphic Diagram of the Santos Basin, modified from Garcia et al. (2019). Key for lithostratigraphic names: CAM (Camboriú), PIÇ (Piçarras), ITP (Itapema), BVE (Barra Velha), ARI (Ariri), FLO (Florianópolis), GUA (Guarujá), ITN (Itanhaém), ITA (Itajaí-Açu), SAN (Santos), JUR (Jureia), PAG (Ponta Aguda), MAR (Marambaia), IGP (Iguape). The Itapema/Piçarras-Barra Velha/Itapema petroleum system is shown, with the light green circle indicating the Itapema/Piçarras Formation source rocks and the yellow circle indicating the Barra Velha Formation microbialite reservoirs.

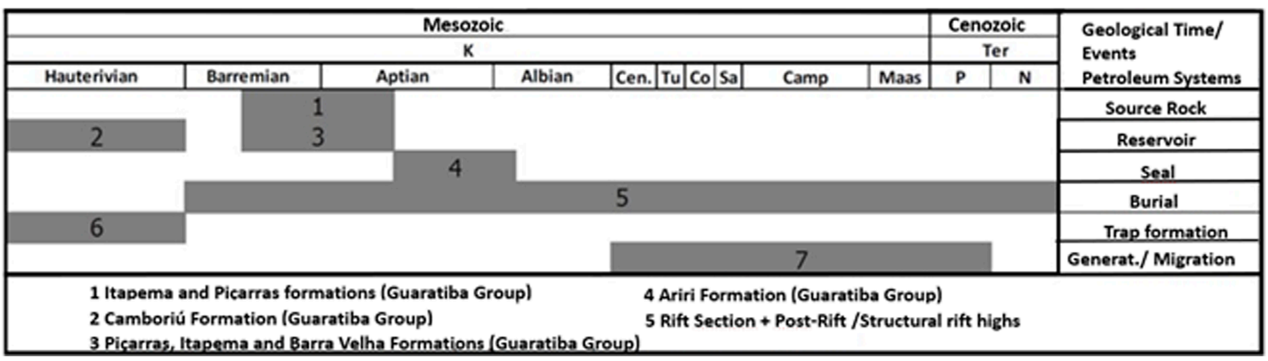

FIGURE 3
Events chart of the Picarras/Itapema-Barra Velha pre-salt petroleum system, Santos Basin, modified from Papaterra et al. (2010): source rocks of the Itapema and Piçarras formations–Guaratiba Group (1), microbialite reservoir rocks of the Barra Velha Formation–Guaratiba Group (3) and seal rocks of the Ariri Formation–Guaratiba Group (4).

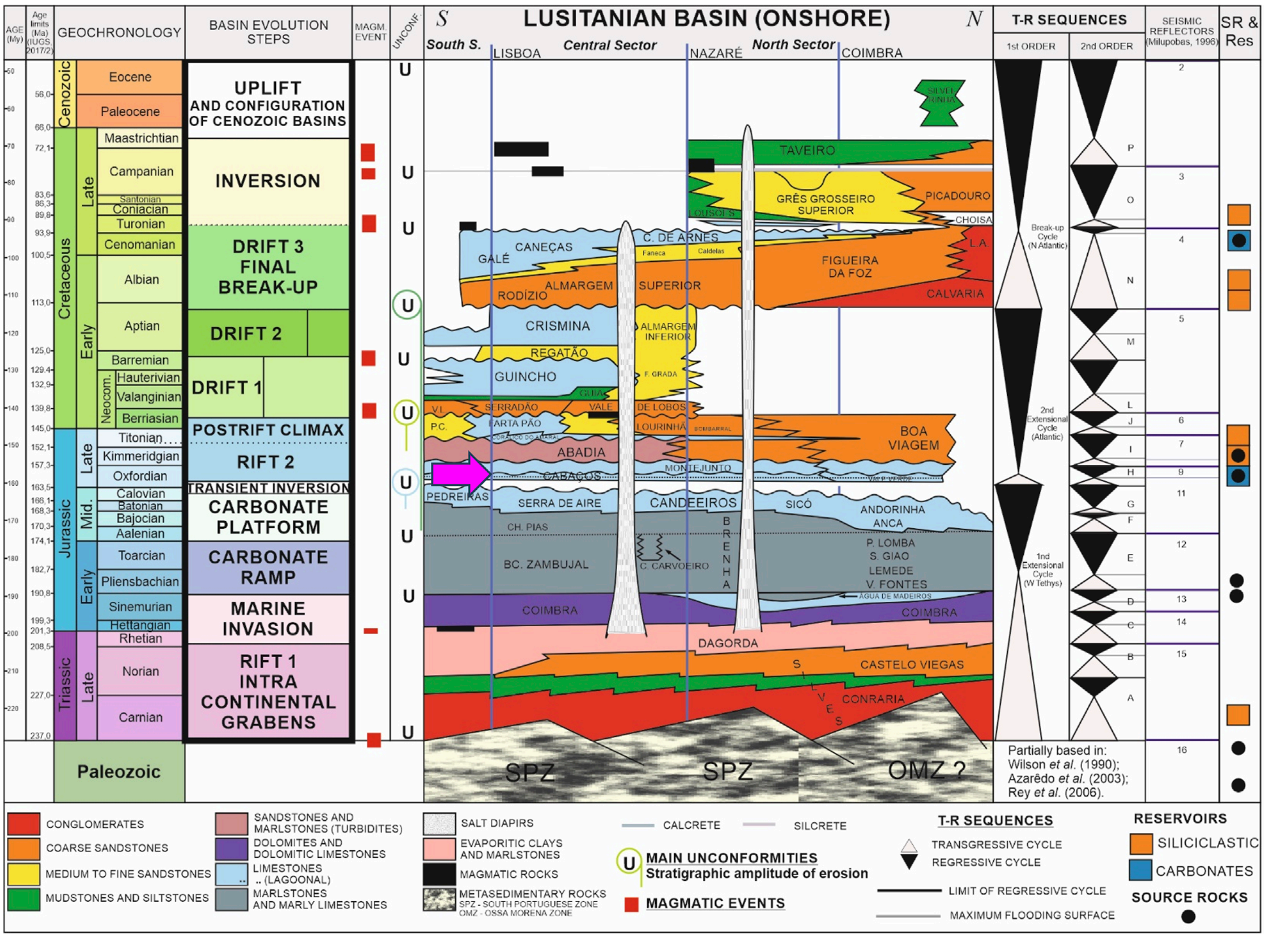

FIGURE 4
Cronolitostratigraphic Diagram of the Lusitanian Basin, modified from Pena dos Reis and Pimentel (2013). The position of the Cabaços Formation of Cabaços-Cabaços studied petroleum system is indicated by the pink arrow.

well folders were downloaded from the ANP Exploration and Production Database (BDEP). However, only the composite profile of well 3-BRSA-861-SPS (indicated by the pink arrow in Figure 6B) is presented in the results, as this well penetrated 378 m of the Barra Velha Formation and reached the Piçarras Formation source rocks.

Geochemical analyses of the Piçarras and Itapema formation source rocks, including Rock-Eval pyrolysis and TOC data, are used to assess their generative potential. The geochemical results are presented as diagrams of generative potential (S2) versus TOC and hydrogen index (HI) versus TOC (Sanabria, 2022). The results present photomicrographs of Barra Velha Formation carbonate thin sections, including descriptions and observed diagenetic features (Sartorato et al., 2020).

4.1.2 Cabaços or Vale Verde Formation–Lusitanian Basin

Figure 7 displays the central Lusitanian Basin, showing the location of the interpreted 2D seismic line AR9-80 (Rasmussen et al., 1998) used in this research and the positions of the analyzed exploratory wells Benfeito-1 (Bf-1) and Freixial-1 (Fx-1). The seismic line AR9-80 is presented in the Multiscale Characterization (Section 4.2), showing the interpreted horizons penetrated by wells Bf-1 and Fx-1, which traversed the entire Cabaços Formation, reaching Lower and Middle Jurassic layers, respectively. The results present the composite profile of the Freixial-1 (Fx-1) exploratory well, which penetrated 299 m of Cabaços Formation carbonates (from 1885m to 2184 m), highlighting the potential microbialite reservoir.

Geochemical analyses of TOC and kerogen type from the Vale Verde Formation (Cabo Mondego outcrop) and Cabaços Formation (Vale das Flores outcrop) (Spigolon et al., 2011) are presented in Section 4.2, demonstrating the generative potential of organic-rich portions of these formations. Six petrographic analyses of Upper Jurassic Vale Verde Formation carbonates from the Pedrogão Beach outcrop, conducted by the Atlantis Project (Federal University of Sergipe), are presented in Section 4.2.

4.2 Methods

The Multiscale Reservoir Characterization (CAMURES) method (Garcia et al., 2014) forms the basis for the multiscale characterization presented in Section 4. This characterization,

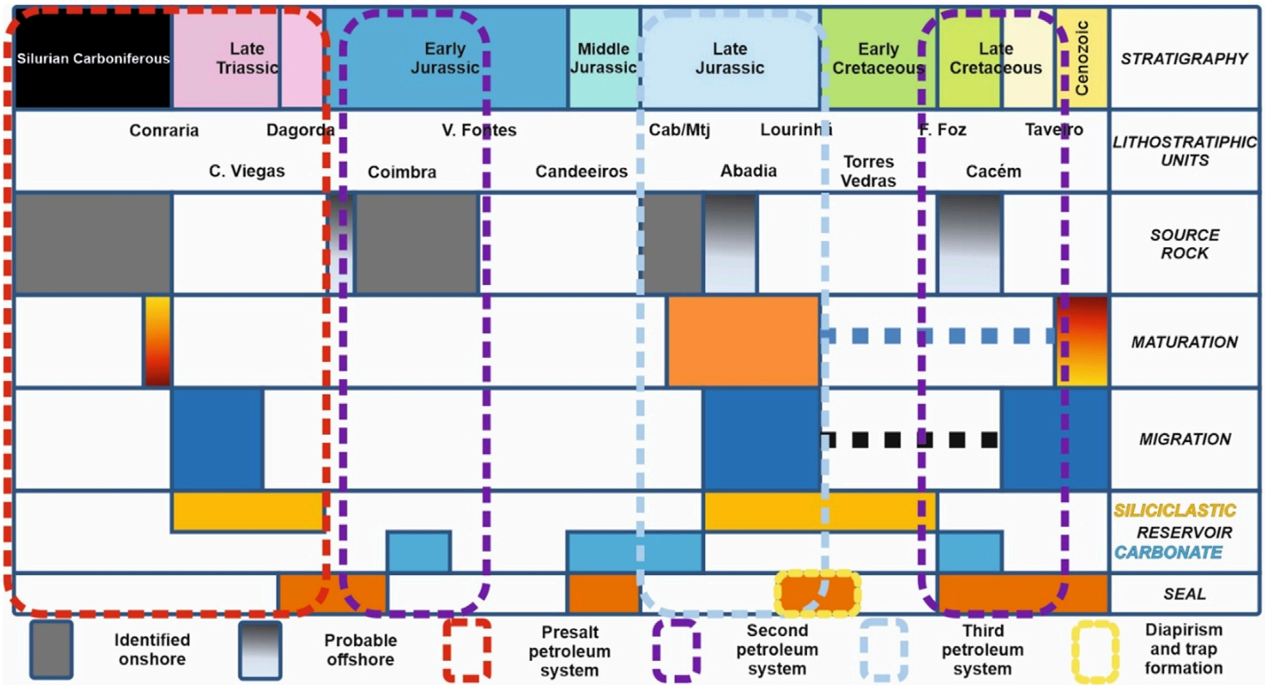

FIGURE 5
Simplified Petroleum Systems of the Lusitanian Basin. The Cabaços-Cabaços petroleum system is shown within the light blue dotted line, referring to the third petroleum system, modified from Barbosa et al. (2023). The oil is generated from the shales of the Cabaços Formation and migrate to the microbialite layer reservoirs of the own Cabaços Formation of the Late Jurassic. The potential seals are the anhydrite layers of the own Cabaços Formation and the evaporites of the Dagorda Formation (Late Triassic/Early Jurassic).

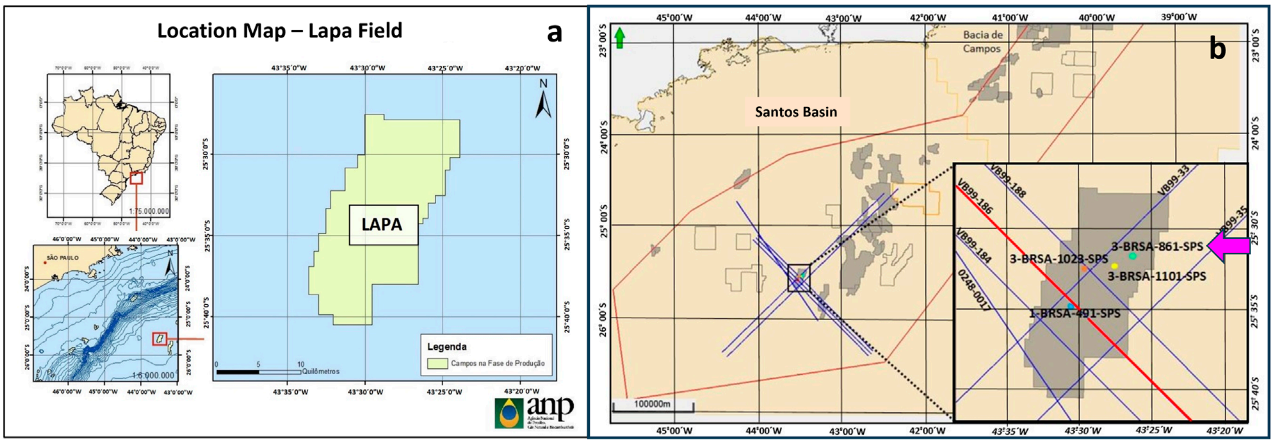

FIGURE 6
(a) Lapa Field location map in the Santos Basin, São Paulo State, Brazil, adapted from Agência Nacional do Petróleo–ANP (2017); **(b)** Detailed map showing the locations of the two exploratory wells, with emphasis on well 3-BRSA-861-SPS (pink arrow) (Silva and Pereira, 2017), which is presented in the results. The 2D seismic line VB99-186 (highlighted in red) is presented in Section 4.1.

used as the first stage of the investigative methodology, aims to demonstrate active petroleum systems in each basin. It incorporates schematic geological sections/event charts, interpreted 2D seismic reflection lines, well data, outcrop data (where available), geochemical analyses of source rocks, and petrographic analyses with diagenetic descriptions. This stage also includes the evaluation of Pg for each reservoir.

The Pg for each petroleum system was calculated using the play concept method (Otis and Schneidermann, 1997), assigning values from 0.0 to 1.0 to each of the four play factors (source rock, reservoir rock, trap, and dynamism). The resulting Pg represents a scenario of probable hydrocarbon occurrence and is calculated by multiplying the probabilities (P) of the four factors: Psr, Pr, Pt, and Pd. Pg depends on the quantity and quality of available geological data and

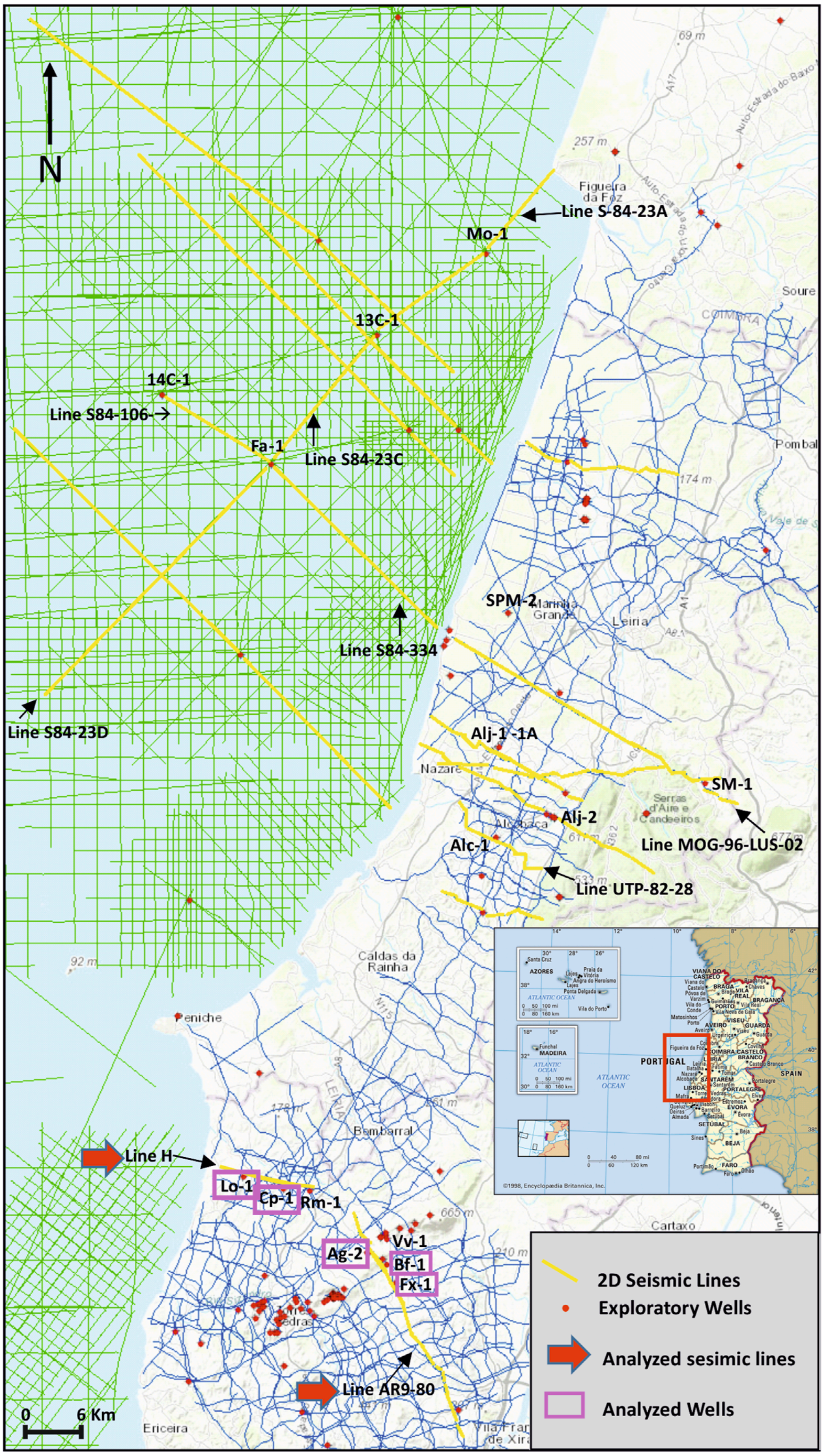

FIGURE 7
Location map of the 2D seismic line AR9-80 and wells Aldeia Grande-2 (Ag-2), Freixial-1 (FX-1), and Benfeito-1 (Bf-1); line H with wells Lourinhã-1 (Lo-1) and Campelos-1 (Cp-1); and outcrops of the Cabaços Formation and its chrono-equivalent Vale Verde Formation (Cabo Mondego, Praia do Pedrogão, and Vale das Rosas). Seismic lines, wells, and outcrops used in this study are indicated by red arrows (adapted from DGEG Direção Geral De Energia E Geologia, 2021).

the explorer's interpretation. Geological risk is classified as very high (0.0–0.05), high (0.05–0.15), moderate (0.15–0.25), low (0.25–0.5), and very low (0.5–1.0) (Otis and Schneidermann, 1997; Lucena and Lustosa, 2007; Rose, 2001).

The second stage of the methodology (Section 5 – Petroleum Systems Analysis with Results and Discussion) analyzes the petroleum system elements through 1) a comparative table of static and dynamic elements, synchronism, and economic aspects (Table 1 and 2) an illustrative interpretative scheme of the static and dynamic elements of each petroleum system (Figure 8).

Table 1 addresses the four static elements (source rock, reservoir rock, seal rock, and trap), dynamic elements (basin deployment tectonism, sedimentary column, geothermal gradient, generation-migration, migration routes, active tectonism during generation-migration, diagenesis, and accumulation), synchronism, and economic aspects (Pg and commerciality).

Figure 8 illustrates the interrelationship between the compared petroleum system` static elements (SE1–SE4) and dynamic elements (DE1-DE3), including influencing factors and processes. Synchronism across these elements is also analyzed. The scheme is divided into color-coded sections: gray for source rock (SE1), blue for reservoir (SE2) and trap (SE4), and green for seal rock (SE3) and trap (SE4). Dynamic elements (DE1-DE3) are distributed along these sections, with red arrows indicating the flow of synchronism.

5 Multiscalar characterization

This section presents the data used for the multiscale characterization of the petroleum systems and analogous reservoirs in each basin. Integrating seismic, well, geochemical, petrographic, and outcrop data allows for characterizing static and dynamic elements, evaluating synchronism, and estimating the probability of geological success (Pg). This analysis is crucial for comparing analogous reservoirs and understanding the factors controlling hydrocarbon accumulation. The data discussed here form the basis for the results presented in Section 5.1.

5.1 Santos Basin (Brazil) – Barra Velha Formation

The analysis of the Santos Basin petroleum system's static elements includes the following: interpreted 2D seismic line VB99-186 (across the Lapa Field), composite profile of well 3-BRSA-861-SPS, geochemical profile of the Piçarras Formation source rocks, and petrographic analyses of the Barra Velha Formation, including descriptions of active diagenetic processes. Figure 9 shows a portion of the interpreted pre-stack time migration (PSTM) 2D seismic line VB99-186 (Silva and Pereira, 2017), located near the Lapa Field. The primary hydrocarbon migration pathway from the Piçarras Formation at the base of the rift is evident. Hydrocarbons migrate along major faults (Figure 9) that transect the rift and post-rift sequences, reaching the base of the salt (Ariri Formation) or the top of the Barra Velha Formation, charging the carbonate reservoirs. These rift-phase faults are crucial in directing hydrocarbon flow, compartmentalizing sedimentation and focusing migration toward structural highs. This allows hydrocarbons generated in the Piçarras Formation to reach the Itapema Formation coquinas and Barra Velha Formation microbialites, trapped by the Ariri Formation evaporites.

The composite profile of well 3-BRSA-861-SPS in the Lapa Field (Figure 10) reveals the presence of the three key static elements: source rock, reservoir rock, and seal rock, confirming an active petroleum system. This well was selected due to its significant penetration of the Barra Velha Formation microbialites. Analysis of the well log (Figure 10) reveals 2,285 m of Ariri Formation sealing evaporites (2,878–5,163m depth), 378 m of Barra Velha Formation reservoir rock (5,163–5,541m depth), and 185 m of Itapema Formation coquinas (5,541–5,726m depth, end of well). The well also reached the Piçarras Formation source shales.

In the Santos Basin pre-salt, the organic-rich rift-phase Itapema Formation shales are the primary source rock. The Piçarras Formation is also a potential source rock. Three intervals with TOC values above 2% stand out (Figure 11): unit A of the Piçarras Formation and units C1-B and C3 of the Itapema Formation (Sanabria, 2022). The Piçarras Formation radioactive shales (unit A) have TOC values above 1% (up to 3.5%), S2 values between 5–20 mg HC/g rock, and HI values above 400 mg HC/g TOC, indicating good to very good oil generation potential (Figure 11). The Itapema Formation shales (units C1-B and C3) correlate with TOC and S2 positively, indicating that higher organic carbon content correlates with more significant generative potential (Figure 11). TOC in the Itapema Formation ranges from 2% to 4.5% (Sanabria, 2022).

Sedimentological analysis of a 50-m Barra Velha Formation carbonate core from the upper portion of the formation, located south of the basin (Farias, 2018), identified the following facies: arborescent calcite, magnesian claystone with spherulitic interstitial calcite, laminite, and calcarenite/calcirudite. The Barra Velha Formation carbonates are affected by silicification and dissolution, which can impact reservoir quality. Thin section analysis reveals calcite and dolomite as the dominant minerals. Fibrous calcite aggregates occur as calcite shrubs (Figure 12A) and spherulites (Figure 12B). Diagenetic calcite is a minor late (mesogenetic) phase, after mechanical compaction in reworked facies (Figure 12D). Dolomite is the primary early diagenetic mineral, occurring in various textures and shapes representing different phases, including rhombohedral dolomite (Figure 12C) (Sartorato et al., 2020). Silica minerals are observed in four diagenetic phases: 1) cryptocrystalline silica, 2) microquartz, 3) fibrous microquartz, and 4) megaquartz. Microquartz is the most common, occurring intensely in structural highs (Figures 12E, F). Megaquartz occurs as cement (Figures 12G, H), filling vugs and fractures, and has the greatest impact on reservoir quality (Sartorato et al., 2020).

The integrated geological data (2D seismic, well, geochemistry, and petrography) confirms a successful Piçarras/Itapema-Itapema/Barra Velha petroleum system, with all static and dynamic elements active. Therefore, Pg values were assigned based on those data from the Lapa Field:

- Probability of source rock–the source shales of the Piçarras and Itapema Formations received a 0.8 probability of generation, due to the average TOC from 2% to 6% (high to excellent), having entered the oil generation window;

TABLE 1 Analysis of the efficiency of the static and dynamic elements, timing/synchronism and economic aspects of proven petroleum systems.

	Petroleum System	Piçarras-Itapema/Barra Velha-Itapema (!)	Cabaços-Cabaços (!)
Static elements	Main Source Rock	Shales of the Piçarras and Itapema	Marly limestones of the Cabaços Formation
	Medium TOC	2%–6%: high to excellent	2%–5% (up to 28.6%): high to excellent
	Medium Depth	5270 m (Itapema Formation)	1906m
	Medium thickness	100–300 m	200 m (up to 385m)
	Kerogen	Type I (oil)	Types I, II and III (oil and gas)
	Hydrogen Index	>900 mg HC/g TOC	Up to 664 mg HC/g TOC
	Vitrinite reflectance (Ro%)	0.6% (oil window)	0.57 a 1.37% (oil and wet gas windows)
	Reservoir Rock	Microbial carbonates of the Barra Velha Formation	Laminated microbial carbonates of the Cabaços/Vale Verde Formation
	Medium Porosity	12% (up to <25%) – from reasonable to very good	2.00% up to 05% (insignificant)
	Permeability - K (mD)	50mD up to 1 Darcy (good to a very goog)	N/D (No data)
	Medium depth	5193m	1500m
	Maximum thickness	378m	385 m (Well Cp-1)
	Presence of oil or gas	Confirmed (oil and gas)	Confirmed (gas)
	Sealing Rock	Evaporites of the Ariri Formation	Evaporites of the Dagorda Formation, marls of the Tojeira Formation (base of the Abadia Formation) and layers with anhydrite of the Cabaços Formation
	Medium thickness	2378 m	641 m (Dagorda Formation)
	Traps	Traps associated with structural highs, also classified as stratigraphic traps	Stratigraphic and Strucutural
Dynamic elements	Tectonism – 1st phase	Responsable for implementing the basin	Responsable for implamentating the basin
	Sedimentary column (maximum thickness)	3200m, up to the top of the reservoir	1399m, up to the top of the reservoir (Well Bf-1)
	Geothermal gradient	Based on geochemical analysis, the geothermal gradient reached the oil generation window	Based on the geochemical analysis, the geothermal gradient reached the oil and gas generation windows
	Generation-Migration	Cenomanian-Oligicene	Upper Jurassic
	Main migration routes	Fault System (connecting the Formação Itapema a Formação Barra Velha)	Direct contact and diapir walls
	Tectonism most active in the generation-migration	Responsable for the fault system of the rift and post-rift or transitional phases of the basin	Responsable for the diapirism of the evaporites of the Dagorda Formation and associated fault system
	Diagenesis	Silicification and dissolution, mechanical and chemical compaction, silica cementation, fibrous microquartz and megaquartz	Matrix replacement and recristalization by drusiform and mosaic calcite, and mechanical compaction
	Accumulation	Confirmed (oil and gas)	Small quantities of gas
SYNCHRONICITY/TIMING		Present	Not present

(Continued on the following page)

TABLE 1 (*Continued*) Analysis of the efficiency of the static and dynamic elements, timing/synchronism and economic aspects of proven petroleum systems.

	Petroleum System	Piçarras-Itapema/Barra Velha-Itapema (!)	Cabaços-Cabaços (!)
Economics	Probability of geological sucess (Pg)	0.5184 (very low risk)	0.042 (high to very high risk)
	Commerciality of accumulation	Confirmed (oil and gas)	Not confirmed

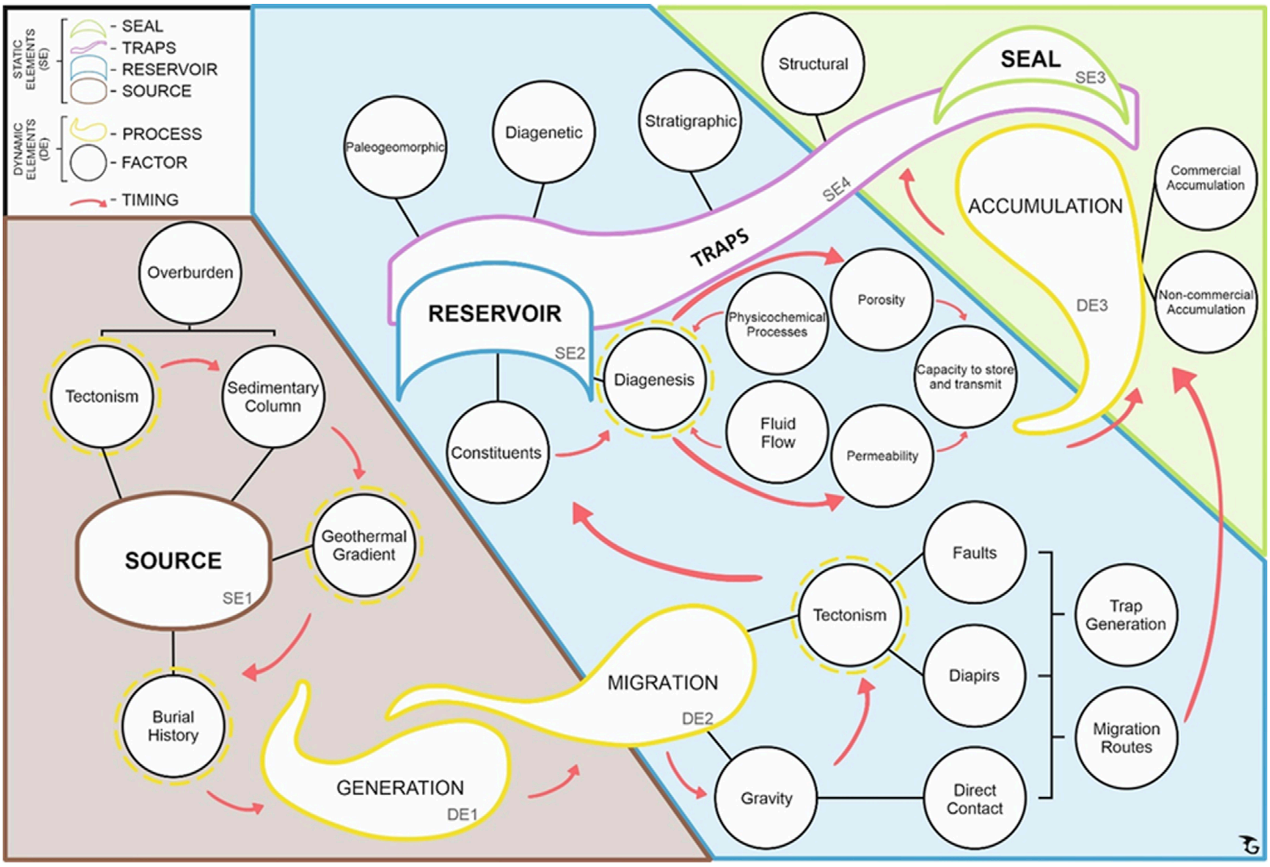

FIGURE 8
Interpretative Illustrative Scheme shows the interrelationship between the petroleum system's static and dynamic elements (Barbosa et al., 2022; Barbosa et al., 2023).

- Probability of reservoir rock–the microbialites of the Barra Velha Formation received a probability of 0.9 due to their excellent petrophysical characteristics, with porosities reaching up to 25% (very good) and good to very good permeability, despite the diagenetic processes observed in petrographic thin sections;
- Trap probability–the salt tectonics observed in the evaporites of the Ariri Formation allowed the formation of an excellent sealing layer for the carbonates of the Barra Velha Formation, supporting the score of 0.9 for the trap probability in this petroleum system; and
- Dynamic probability (synchronism and migration) – the structural compartmen-talization of the rift phase of the Santos Basin, combined with salt tectonics, led to the formation of efficient migration routes, so that the hydrocarbons generated in the Piçarras and Itapema Formations could reach the microbialites of the Barra Velha Formation, as can be seen in the seismic line presented (Figure 9). These factors justified the probability of 0.8 for this topic.

Then, the probability of geological success (Pg) for this reservoir can be calculated as Pg = 0.8 × 0.9 × 0.9 × 0.8 = 0.5184. The

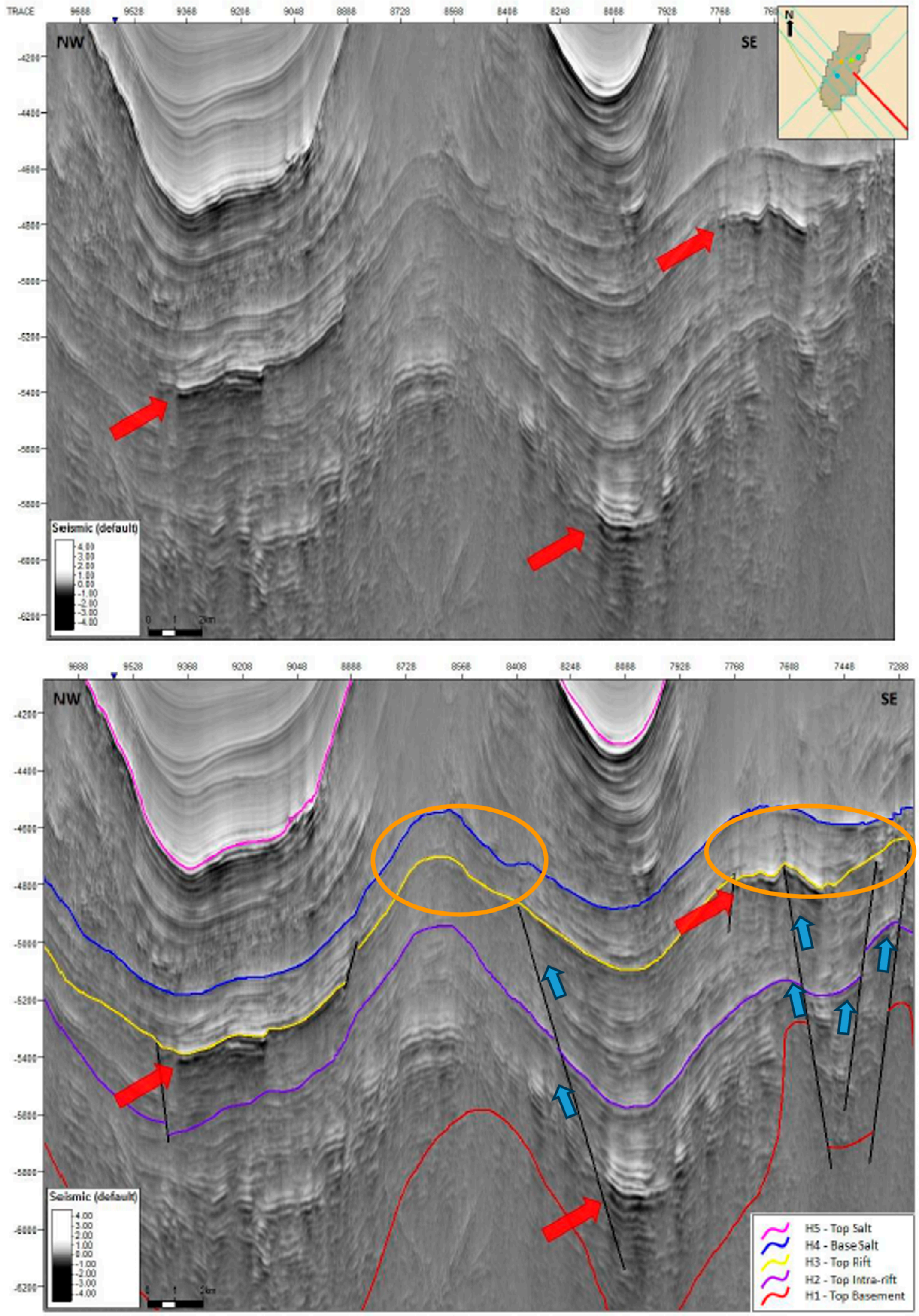

FIGURE 9
Interpretation of part of the PSTM 2D seismic reflection line VB99-188 with the main horizons: salt top/Ariri Formation top (in pink), salt base/Barra Velha Formation top (in blue), rift top/Itapema Formation top (in yellow), intra-rift/Piçarras Formation top (in purple) and basement top (in red). The large faults that compartmentalize the rift phase of the basin reach the top rift's reflector (in yellow) and consequently, the Barra Velha Formation, overlying. The points indicated by red arrows indicate carbonates saucer-shaped bodies, highlighted with TecVA attribute. The blue arrows indicate the migration routes for hydrocarbons generated in the rift phase formations. The orange circles shows the potential areas to storage hydrocarbons on the Barra Velha Formation microbialites. Modified from Silva and Pereira (2017).

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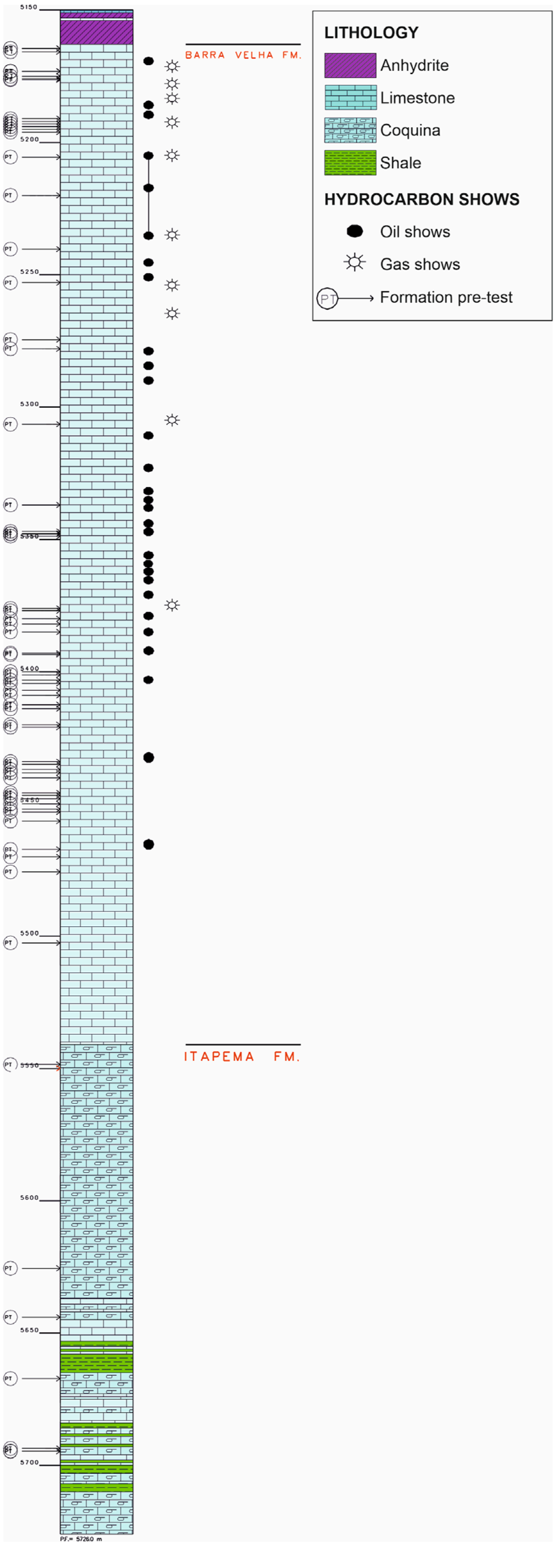

FIGURE 10
576m interval of the composite log of exploratory well 3-BRSA-861-SPS, from a depth of 5150m–5726m (end of the well). The Barra Velha Formation (indicated by the pink parenthesis) has a total thickness of 378m (from 5163m to 5541m depth). Above the Barra Velha Formation occur the evaporites (halite and anhydrite) of the Ariri Formation (seal rock), with a total thickness of 2285m throughout the well (from 2878m to 5163m depth). The well reached the source shales of the Itapema Formation (inside the blue parenthesis).

interpretation of the geological risk for this achieved grade is framed as very low risk for this petroleum system.

5.2 Lusitanian Basin–Cabaços/Vale Verde Formation

The analysis of the Cabaços-Cabaços petroleum system includes interpreting the 2D seismic line AR9-80, a composite log of well Freixial-1 (Fx-1), a geochemical profile of the Cabaços and Vale Verde Formation source rocks, petrographic analyses of the carbonates, and descriptions of diagenetic processes. The calculation of Pg is also presented.

The interpreted 2D seismic reflection line AR9-80 (Rasmussen et al., 1998) executed in the central part of the Lusitanian Basin, more precisely on the Arruda sub-basin, is presented in Figure 13. The exploration wells Benfeito-1 (Bf-1) and Freixial-1, drilled in the central portion of seismic line AR9-80, completely cut the microbialites of the Cabaços Formation, cutting, respectively, 186.5m and 299m of thickness of this formation. The presence of diapirism in the evaporites of the Dagorda Formation, which resulted in the listric faults observed in the NW portion of the seismic section (Figure 13), enabled the development of migration routes for the hydrocarbons generated in the marly levels of the Cabaços Formation, to the porous carbonate levels of this formation itself, as well as, to the carbonates of the Montejunto Formation and the turbidite sandstones of the Abadia Formation.

Benfeito-1 encountered oil and gas shows in the Abadia, Montejunto, and Cabaços formations, as well as in the Middle and Lower Jurassic formations. A gas show at 1,475m depth in the Cabaços Formation confirms the active Cabaços-Cabaços petroleum system. Freixial-1 also encountered oil and gas shows in the Abadia, Montejunto, and Cabaços formations.

Freixial-1 penetrated 299m of Cabaços Formation carbonates (1885–2184m depth) (Figure 14). The interval comprises: laminated and hardened black marls intercalated with black clayey limestones (1885–1919m), microcrystalline white anhydrite intercalated with black limestones (1919–2067m), and dark gray to black micritic, compact limestones with recrystallized fractures and lignite (2067–2184m). Regarding the profiling performed in the Freixial-1 well in the interval shown in Figure 14 (from 1865m to 2200m depth), the profile to the left of the lithological column is the Gamma Ray (GR) profile, indicating the carbonates of the Cabaços Formation in the peaks on the left, with intercalations of clayey limestone or calcareous marl, clayey levels and massive anhydrite. The Sonic profile (DT), shown in the curve on the far right, presents slight peaks on the left, indicating more porous levels; however, in most of the profile, the carbonates of the Cabaços Formation are massive and with very low porosity (2%–5%).

The Pedrogão Beach outcrop (Figures 15A–F) provides excellent exposure of the Vale Verde Formation limestones, chronoequivalent to the Cabaços Formation. These ostracod- and charophyte-rich limestones, with rare restricted marine fauna, overlie Upper Callovian marl-calcareous sediments with ammonites. The Vale Verde Formation suggests deposition in coastal lakes and lagoons fed by marine waters (Wright and Wilson, 1985). Above the basal discontinuity, intercalation of marls, marly limestones (sometimes lignitic), and fossiliferous/bioclastic limestones,

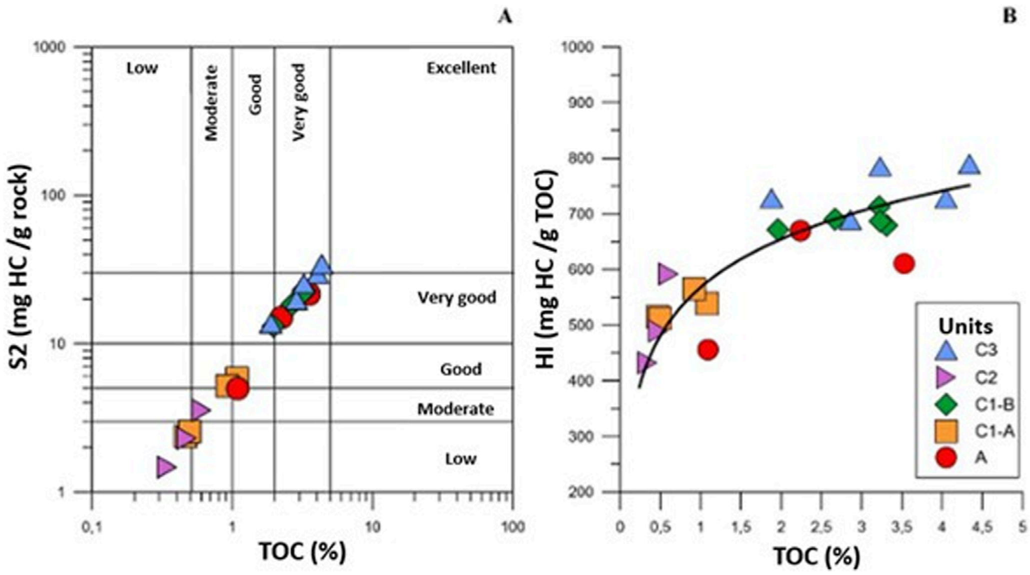

FIGURE 11
Evaluation of the generating potential from Rock-Eval and TOC pyrolysis data for samples from the Piçarras and Itapema formations. Caption: **(A)** Diagram of evaluation of the generating po-tential (S2) and total organic carbon (TOC); **(B)** hydrogen index (HI) versus TOC ratio. Modified from Sanabria (2022).

occasionally bounded by desiccation surfaces, indicates subaerial exposure (Figure 15F). The upper succession comprises fossiliferous calcarenites and limestones increasingly intercalated with microbial laminites (potential reservoir) (Pimentel and Pena dos Reis, 2016) and less frequent marly limestones. The Pedrogão Beach outcrop showcases the potential reservoir characteristics of the microbialite limestones of the Vale Verde or Cabaços formations (in the south of the basin), confirmed by hydrocarbon occurrences in Benfeito-1 and Freixial-1 (Figure 14). The average Cabaços Formation thickness in these wells is 242m, reaching a maximum of 385 m in the Campelos-1 well.

In the northern Lusitanian Basin, continental to transitional facies predominate, represented by the Vale Verde Formation calcilutites, carbonaceous marls, and lignites. In the south, anoxic marine facies with bacterial organic matter, represented by the Cabaços Formation calcilutites, predominate (Spigolon et al., 2011). Figure 16 presents geochemical analyses (TOC, HI, kerogen type) for samples from the Cabaços Formation (Vale das Rosas outcrop) and the equivalent Vale Verde Formation (Cabo Mondego outcrop).

The highest TOC values occur in the Cabaços Formation outcrops within the Runa, Turcifal, Arruda, and Bombarral sub-basins and the Serra de Montejunto (BEICIP-FRANLAB, 1996; Dias, 2005b) (Figure 17A). Vitrinite reflectance (Ro%) values from the Cabo Mondego outcrop (Figueira da Foz region) range from 0.25% to 1.37% (Figure 17B), with the highest values (reaching oil window maturity) mainly in the Lourinhã region. The highest Ro values (0.57%–1.37%) occur in the Bombarral region (BEICIP-FRANLAB, 1996).

The Figure 18 shows four petrographic analyses (Figures 18–a–18–d) performed on samples of limestone rocks from the Pedrogão Beach outcrop, from the Upper Jurassic Vale Verde Formation, carried out by the Atlantis Project (Federal University of Sergipe).

The carbonate lithologies in the Pedrogão Beach outcrop (Vale Verde Formation) are varied, according to the field samples and petrographic thin sections described in the Atlantis Project (Federal University of Sergipe). According to Folk's classification (Folk, 1959), calcilutite, calcarenite and biolithite occur, with a predominance of micritic/spathic calcarenites. According to Dunham's classification (Dunham, 1962), they correspond to mudstones, wackestones, packstones and boundstones, with the wackestone and packstone facies being the most common and the most likely to become reservoirs, due to their low to moderate depositional subenvironmental energies (Figures 18A–D). Regarding mechanical compaction, the packing pattern is open with punctual contacts between the constituents present. Most bioclasts are"floating" in the micritic matrix, with the rock supported by the matrix. They do not present macroporosity. Wackestones generally present a moderate selection with a modal size of medium sand, with a granulometric variation from silt to granules. The coarse fraction is due to large mollusk bioclasts. The structures present are irregular stratifications and bioaccumulations of ostracods. In terms of mechanical compaction, the packing pattern is normal with straight and concave-convex contacts between the constituents present. The average porosity in this lithology in sheet is 0.97% and a maximum of 2%, rock supported by grains and mud. The packstone lithologies present a moderate selection with a modal size of fine sand, with a granulometric variation from silt to very coarse sand, the coarse fraction is due to large mollusk bioclasts. The structures present are irregular stratifications, stylolites and fractures. The average porosity observed in the packstones is 0.83% and a maximum of 1.67%.

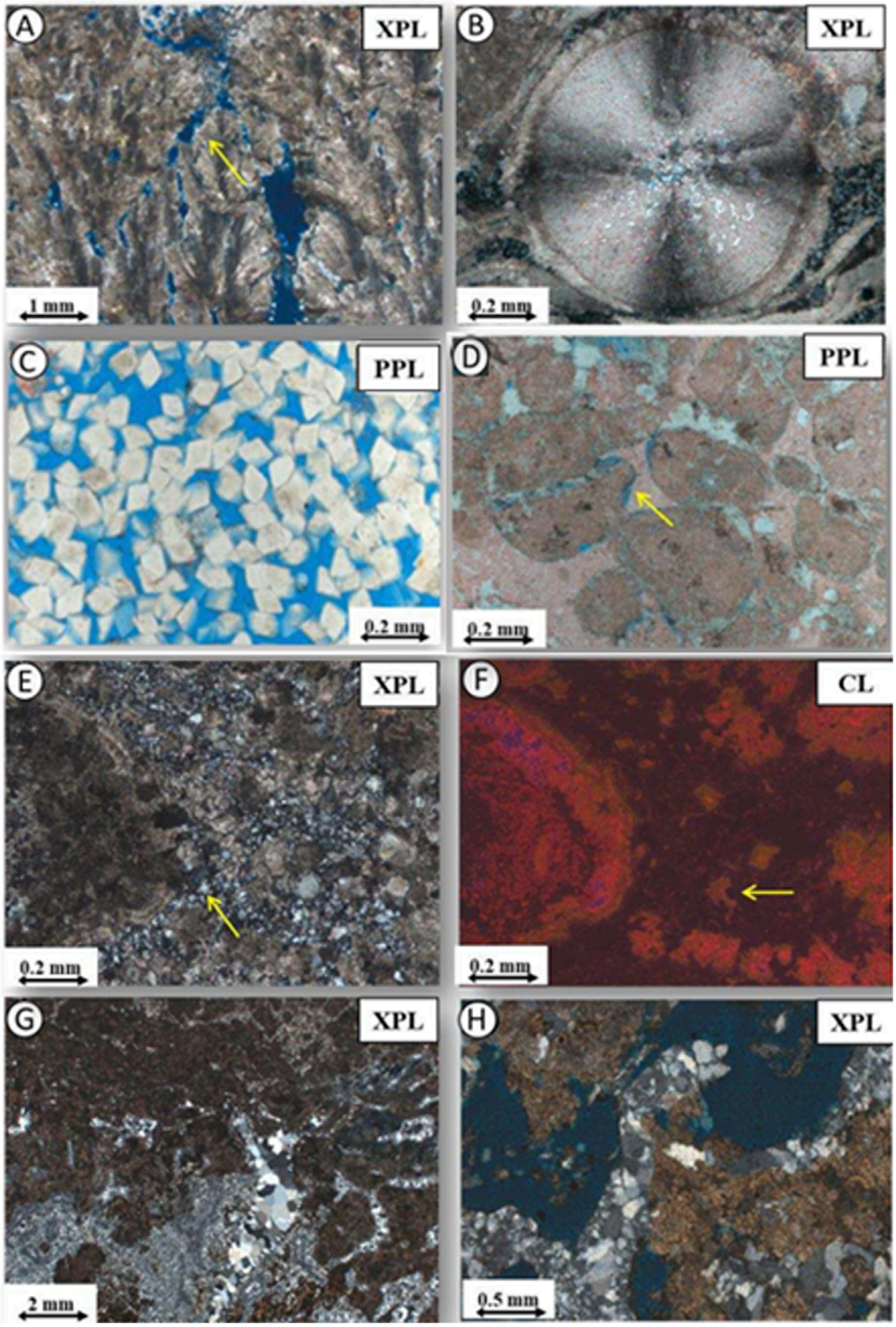

FIGURE 12
Photomicrographs illustrating the calcitic and siliceous diagenetic phases observed in the carbonates of the Barra Velha Formation. **(A)** thin section under cross-polarized light (XPL) showing calcite shrubs; **(B)** thin section under cross-polarized light (XPL) presenting calcite sherulites; **(C)** thin section under plane polarized light (PPL) showing rhombohedral dolomite; **(D)** thin section under plane polarized light (PPL) presenting late blocky calcite cement (yellow arrow); **(E)** thin section under cross-polarized light (XPL) showing microquartz cement swalling rhombohedral dolomite crystals; **(F)** same thin section showed in the **(E)** under cathodoluminescence (CL): note that the non-luminescent microquartz crystals seems to corrode the dolomite crystals; **(G)** thin section under cross-polarized light (XPL) showing megaquartz cement associated with microquartz; and **(H)** thin section under cross-polarized light (XPL) presenting megaquartz cement filling fractures and partially replacing the carbonate framework.
Modified from Sartorato et al. (2020).

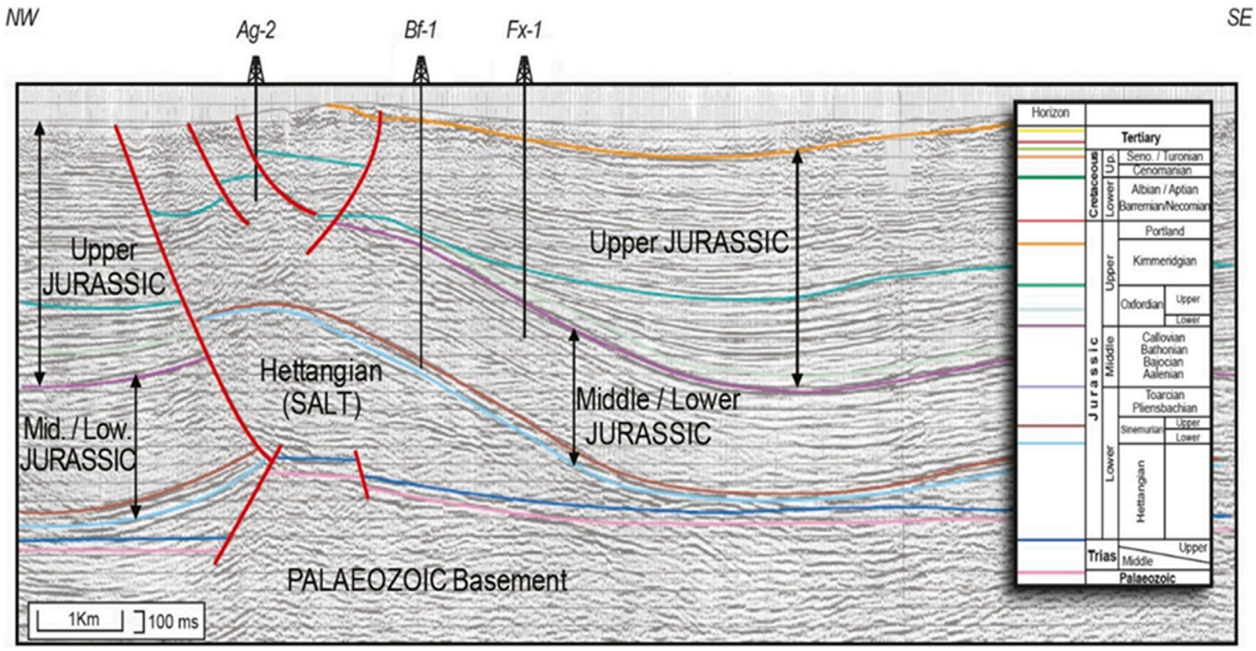

FIGURE 13
2D reflection seismic line AR9-80 interpertated. The exploratory wells Benfeito-1 (Bf-1) and Freixial-1 (Fx-1) drilled 186.5m and 299m of the thickness of the Cabaços or Vale Verde Formation. Modified from Rasmussen et al. (1998). The diapirism of the Dagorda Formation and its resulting listric faults, observed in the NW portion of the seismic section, allowed the development of migration routes of the hydrocarbons generated in the marly levels of the Cabaços Formation, to the porous carbonate levels of this formation itself.

Diagenetic compaction is strong, with replacement and recrystallization of the peloidal matrix by calcite mosaics, particularly in wackestones. Originally porous lithologies, excluding the microporous mudstones, experienced significant porosity reduction due to drusiform and mosaic calcite cementation in intraparticle/moldic pores, vugs, and fractures, exacerbated by mechanical compaction in packstones. Porosity reduction is estimated at 15.5%.

All geological data (interpreted 2D seismic line, exploratory wells, geochemistry of source rocks and description of petrographic thin sections) were analyzed to confirm that the Cabaços-Cabaços petroleum system is effective and, consequently, proving that all static and dynamic elements are active. The effectiveness of this petroleum system was proven by the occurrence of a gas show detected in the Benfeito-1 (Bf-1) well at a depth of 1475m in the limestones of the Cabaços Formation, despite the low porosity levels detected, between 2% and 5%, according to the final report of the Benfeito-1 well. The composite profiles of these two wells were downloaded from the General Directorate of Energy and Geology–DGEG.

The scores given to the probability of geological success (Pg) ranges were based on analyses of well information, interpreted seismic lines and geochemical data, and from an exploratory point of view can be justified as follows.

- Probability of source rock–the source rocks of the Cabaços Formation received a probability of 0.7, as they have an average thickness of 200 m, an average TOC of 2%–5% (up to 28.6%, locally) and have entered the oil and gas generation windows;
- Probability of reservoir rock–the microbialites of the Cabaços Formation, or its chrono-equivalent Vale Verde Formation, received a probability of 0.3 due to having insignificant average porosity (from 2% to 5%) and probable low permeability, resulting from the diagenetic processes of mechanical compaction and carbonate cementation (calcite), observed in the descriptions of the investigated petrographic thin sections;
- Trap probability–received a probability of 0.5 because no traps were observed in the interpreted seismic lines presented on the carbonates of the Cabaços Formation. However, they may be trapped by the evaporites of the Dagorda Formation, in the walls of the diapirs, which occur in the central and northern portions of the basin. Another possible form of trapping of these is the anhydrite levels observed in these carbonates in the outcrop of Pedrógão Beach and in the composite profile of the Benfeito-1 well; and
- Dynamic probability (synchronism and migration) – received a probability of 0.4 due to only one gas show detected in the Benfeito-1 well in the potential reservoirs of the Cabaços Formation.

The potential microbialite reservoirs of the Cabaços Formation and its chronoequivalent Vale Verde Formation had the following calculation of their probability of geological success (Pg): Pg = 0.7 × 0.3 × 0.5 × 0.4 = 0.042. This Pg note classifies the geological risk as high to very high risk for this petroleum system.

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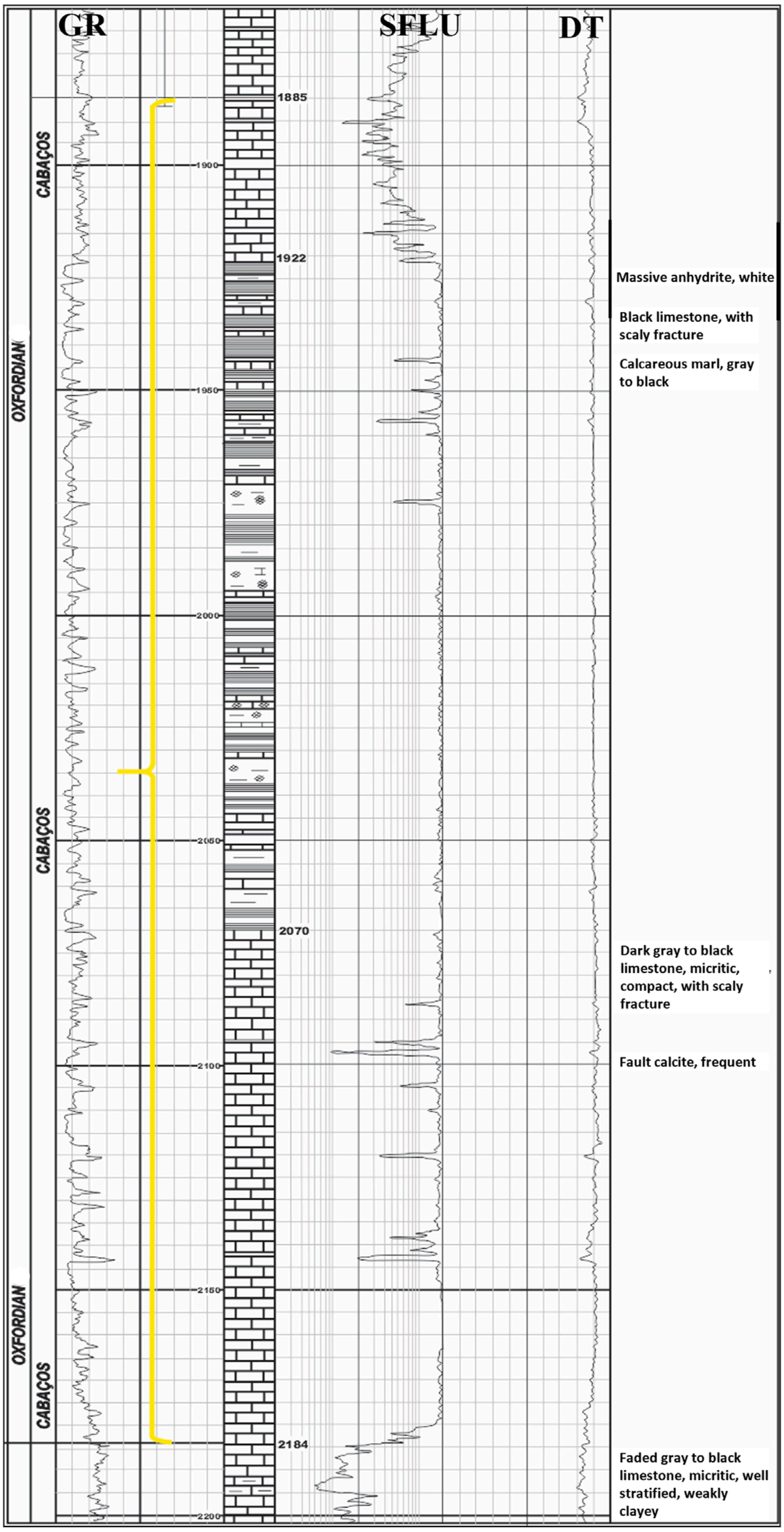

FIGURE 14
335m interval (from 1865m to 2200m depth) of the composite log (Well Completion Log) of the Freixial-1 (Fx-1) exploratory well, showing the 299m thickness (from 1885m to 2184m) of the limestones of the Cabaços Formation (inside the yellow bracket). GR = Gamma Ray Log. SFLU = Spherically Focused Log. DT = Sonic Log.

FIGURE 15
(A) - Partial view of the type outcrop of the limestones of the Vale Verde Formation at Pedrogão Beach (Pimentel and Pena dos Reis, 2016). **(B)** - Side view of the Pedrogão Beach outcrop, showing alternating portions of massive calcarenites with limestones with microbial lamination. **(C)** - Microbial lamination observed in the limestones of the Pedrogão Beach outcrop. **(D)** - Pedrogão Beach outcrop showing in detail the lamination of microbial mats. **(E)** - Detail of the carbonates with microbiaal mats texture from the Pedrogão Beach outcrop. Fractures filled by calcite microveins can be seen cutting the rock matrix at an angle of 55°–60°. **(F)** - Desiccation surfaces that limit intercalations of marly levels and levels with microbial lamination, evidencing episodes of sub-aerial exposure in the limestone rocks of the Pedrogão Beach outcrop.

6 Petroleum systems analysis - results and discussion

This section compares the efficiency of the petroleum system elements (static and dynamic), synchronicity, and economic aspects (Table 1), contrasting the two studied systems. Figures 19, 20 illustrate the interpretative schemes of the static and dynamic elements, which underpin the detailed petroleum system and reservoir analysis presented below. This analysis encompasses the tectonic-structural setting of each basin and its relationship with migration, source rock characteristics, reservoir thickness and petrophysical properties, and the influence of diagenesis based on petrographic analysis.

The concepts of static and dynamic petroleum system elements used here are consistent with those presented in previous publications by Barbosa et al. (2022) and Barbosa et al. (2023). This research also considers other works on analogous petroleum systems regarding definitions and fundamental principles. It is important to

PERIOD	AGE	FORMATION	TOC	HI	KEROGEN TYPE
UPPER JURASSIC	OXFORDIAN	VALE VERDE	1.2	483.3	II
			28.6	338.5	III
		CABAÇOS	2.8	563.9	I-II

FIGURE 16
Results of geochemical analyses of total organic carbon (TOC), hydrogen index (HI) and kerogen type for samples from the Cabaços Formation (Vale das Rosas outcrop), in the central sector of the Lusitanian Basin, and its equivalent Vale Verde Formation, on the north of the basin. Modified from Spigolon et al. (2011). Remarks: Kerogen types: I (oil), types II (oil) and III (gas).

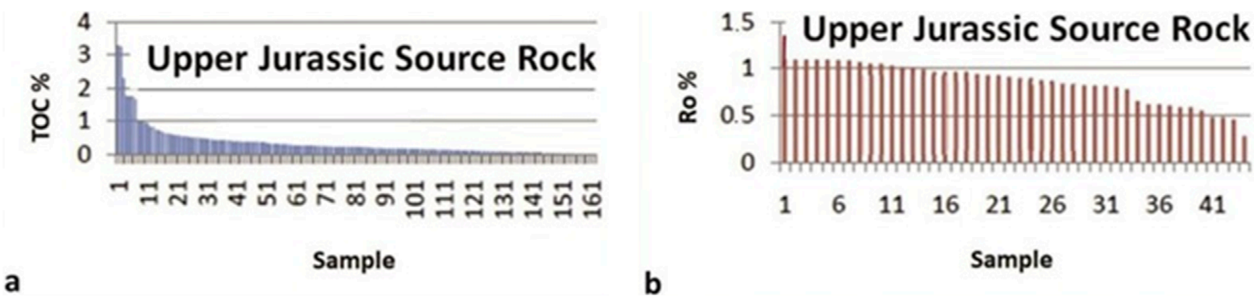

FIGURE 17
Total Organic Carbon (TOC) **(a)** and vitrinite reflectance (Ro%) **(b)** data of the source rocks of the Cabaços or Vale Verde Formations. Modified from BEICIP-FRANLAB (1996), Dias (2005b).

note that the most prospective elements of an exploratory play may contribute from generation to trap formation (Huvaz, 2009). Many tools can be used to infer petroleum systems' key processes and elements, particularly 3D approaches integrating geophysical, geochemical, and geological data (Dickson et al., 2005), as adopted in this study.

6.1 Results

6.1.1 Petroleum systems analysis and the potential of the microbialite reservoirs - Barra Velha Formation–Santos Basin (Brazil)

The Piçarras and Itapema formation source rocks (SE1; Figure 19) exhibit significant thicknesses (100–300m) and occur at an average depth of 5,270m (Table 1). Geochemical analyses indicate Type I kerogen (oil), high average TOC (2%–6%), and vitrinite reflectance (Ro) of 0.6% (Figure 11), confirming maturity within the oil window. The geothermal gradient, sedimentary overburden, and burial history are the primary factors contributing to the positive source rock characteristics.

Normal faults, which compartmentalized the rift-stage formations into horsts and grabens, connect the source rocks (Piçarras and Itapema formations) with the reservoirs (Barra Velha Formation), providing effective migration pathways (Figure 9). Direct contact between the Itapema Formation source rocks and the Barra Velha Formation microbialites also contributes to migration. These observations confirm the effectiveness of the generation (DE1) and migration (DE2) dynamic elements (Figure 19) in the Lapa Field. Salt tectonics related to the Ariri Formation diapirs did not significantly influence the pre-salt structural compartmentalization and faulting (Caldas and Zalán, 2009).

The Barra Velha Formation microbialites exhibit reasonable to very good porosities (12% to >25%) and good to very good permeabilities (50 mD to 1 Darcy) (Pereira et al., 2013), demonstrating the effectiveness of the reservoir static element (SE2; Figure 19). Silicification and dissolution are the primary diagenetic factors, potentially enhancing or reducing reservoir quality. Observed silicification processes include cementation by silica, fibrous microquartz, and megaquartz (Figure 12), with megaquartz filling pores and fractures. Mechanical and chemical compaction are also observed. The good porosity at the average depth of 5,193m (Table 1) is notable and may be attributed to geothermal convection diagenesis (Jones and Xiao, 2013), which can increase porosity by up to 10% and permeability by an order of magnitude.

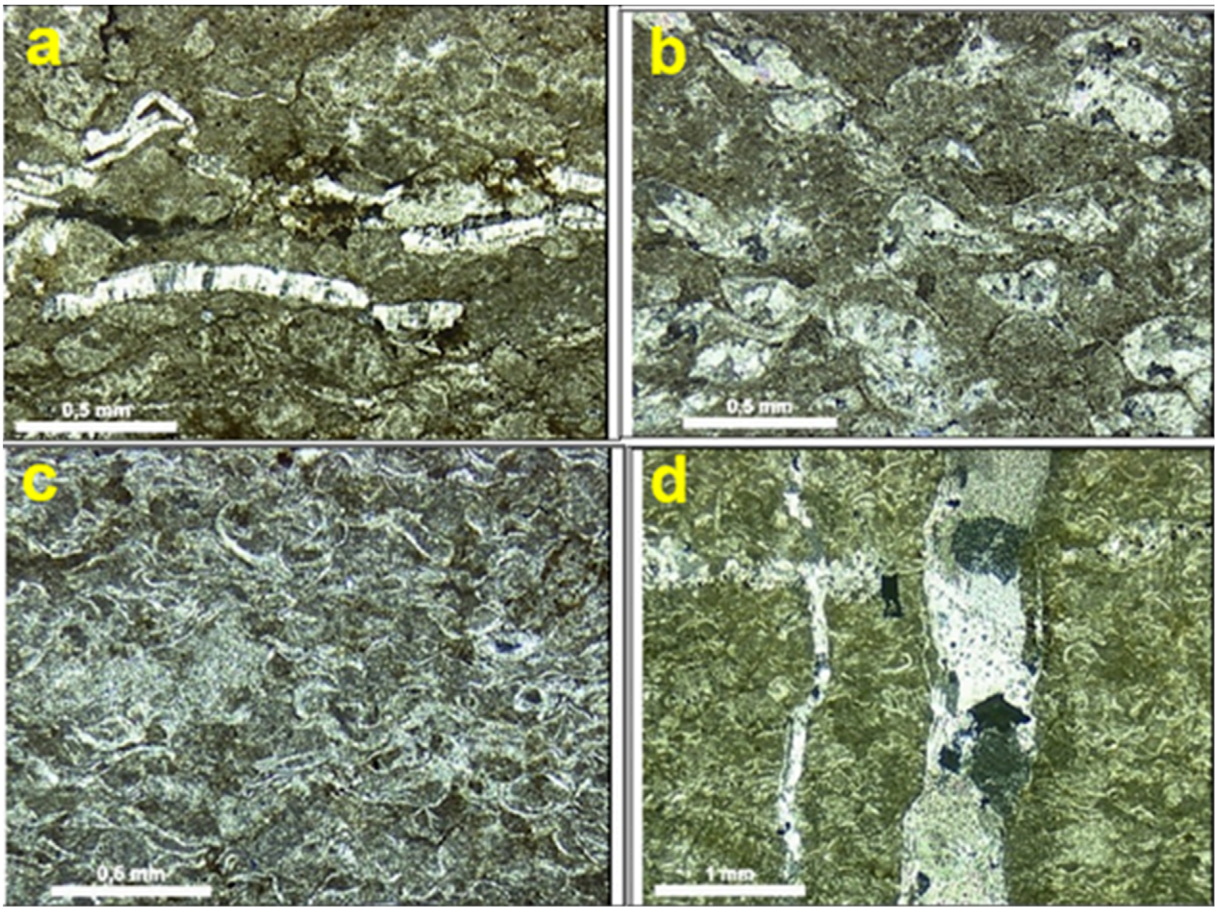

FIGURE 18
Petrographic analyses performed on samples of limestone rocks from the Pedrogão Beach outcrop **(A)** - Photomicrograph of well-compacted packstone with bioclasts of recrystallized and fractured pelecypods and mollusks. Mechanical compaction was one of the observed diagenetic processes responsible for reducing the original porosity of these carbonates. **(B)** - Photomicrograph of wackestone showing several bioclasts with intraparticle porosity filled with drusiform calcite. This diagenetic process drastically reduced the original porosity of the rock. **(C)** - Photomicrograph of compacted packstone with bioaccumulation of ostracods, with recrystallized areas. **(D)** - Photomicrograph of packstone with several veins filled with mosaic calcite.

Traps (SE4; Figure 19) are primarily structural, associated with highs where hydrocarbons migrate along faults connecting the carbonate reservoirs to the underlying source rocks. Stratigraphic traps, resulting from direct contact between the Itapema Formation source rocks and the Barra Velha Formation microbialites, may also occur. The Ariri Formation evaporites (SE3), with an average thickness of 2,378m in the studied wells (Table 1), provide excellent sealing capacity due to their low permeability. The synchronism of these processes and factors facilitated the development of commercially viable hydrocarbon accumulations in the Lapa area.

6.1.2 Petroleum systems analysis and the potential of the microbialite reservoir of the Cabaços or Vale Verde Formation - Lusitanian Basin (Portugal)

The Cabaços Formation source rock (SE1; Figure 20) has an average thickness of 200 m (up to 385 m in well Campelos-1) and occurs at an average depth of 1,906m (Table 1). Geochemical analyses indicate Type I, II, and III kerogens (oil and gas) (Figure 16), Ro values of 0.57%–1.37% (catagenesis to metagenesis) (Figure 17), and maturity within the wet oil and gas windows. Average TOC is 2%–3.5% (Figures 16, 17). Burial history and the geothermal gradient are the most influential dynamic factors controlling source rock characteristics.

Gas shows and traces of hydrocarbons in the Cabaços Formation carbonates in wells Freixial-1 (Figure 14) and Benfeito-1 confirm that generation (DE1) and migration (DE2) occurred (Figure 20), although not effectively enough to create substantial accumulations. Seismic line AR9-80 (Figure 13) clearly shows migration pathways along faults associated with Dagorda Formation evaporite domes in the Serra do Monte Junto area. Hydrocarbons likely originated from organic-rich marls within the Cabaços Formation and migrated upwards into more porous microbialite layers within the same formation.

The Cabaços Formation carbonates (SE2; Figure 20) are compact with low porosities (2%–5%), as reported for well Benfeito-1 Final Report. Petrographic analysis (Atlantis Project; Figure 18) indicates that diagenetic processes, including replacement and recrystallization of the matrix by drusiform and mosaic calcite in

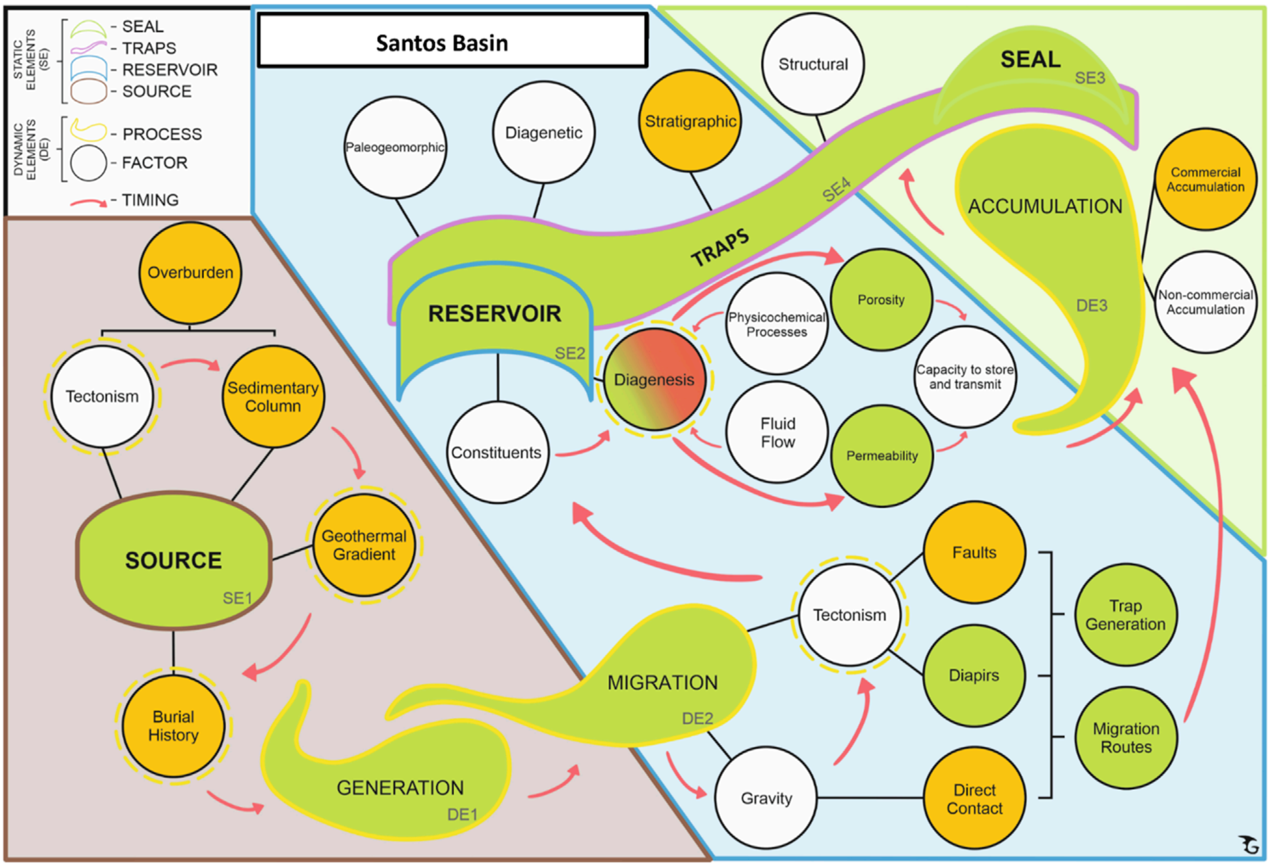

FIGURE 19
Interpretative illustrative scheme of the analysis of the static and dynamic elements in the study of the Barra Velha Formation's reservoir in the Santos Basin, in Brazil. Legend: Elements, factors and processes that were successful, in green; factors and processes that were not successful, in red; factors and processes with 50% chance of success, in green and red; factors and processes that were relevant in the formation of the petroleum system, in orange; and factors and processes that were not relevant in the formation of the petroleum system, in blank.

wackestones and packstones, along with mechanical compaction, drastically reduced original porosity.

Traps (SE4) in the Lusitanian Basin can be structural (associated with closed structures) or stratigraphic (associated with facies variations). Stratigraphic traps appear dominant in the Cabaços Formation carbonates, with anhydrite layers within the formation acting as seals (SE3) for the more porous microbialite intervals. These anhydrite layers are observed in outcrop and in the Benfeito-1 well log.

The plastic behavior of Dagorda Formation evaporites may also form structural and/or stratigraphic traps, potentially sealing the Cabaços Formation carbonates. Additionally, the Tojeira Member marls at the base of the Abadia Formation (Figure 4) may form stratigraphic traps, retaining hydrocarbons in the underlying Montejunto and Cabaços formation carbonates.

6.2 Discussion

The lacustrine carbonate reservoirs of the giant pre-salt fields in the Santos Basin differ significantly from classic lacustrine deposits (Gomes et al., 2020). Previous studies have highlighted their distinct depositional characteristics, early diagenesis, and reservoir quality. The geological understanding of carbonate facies, particularly the role of biological and diagenetic processes, has improved considerably in recent decades. Several authors have contributed to the study of analogous lacustrine microbial carbonate reservoirs in the Atlantic and Middle Eastern margins (Saller et al., 2016; Erthal et al., 2017; Rogerson et al., 2017; Perri et al., 2018). Studies of modern microbialite analogues are also crucial for understanding their deposition and biogeochemical processes (Laval et al., 2000; Pereira et al., 2015).

The stratigraphy, sedimentology, and petroleum system evolution of the West Iberian basins have been correlated with those of the East European basins (Dragos, 2018), particularly in formations affected by salt tectonics. These studies utilize field observations, published literature, and technical reports, considering Paleozoic and Mesozoic source rocks, siliciclastic and carbonate reservoirs, and Mesozoic and Tertiary seals.

At the basin and seismic scales, the Barra Velha Formation microbialite reservoirs are located within the Aptian pre-salt section (Lower Cretaceous) of the Santos Basin (Figure 2). The seismic line (Figure 9) reveals a fault system connecting the Piçarras and Itapema formation source rocks to the overlying carbonate reservoirs. The potential Cabaços Formation microbialite reservoir is Oxfordian (Upper Jurassic). It is located within the Rift two evolutionary stage

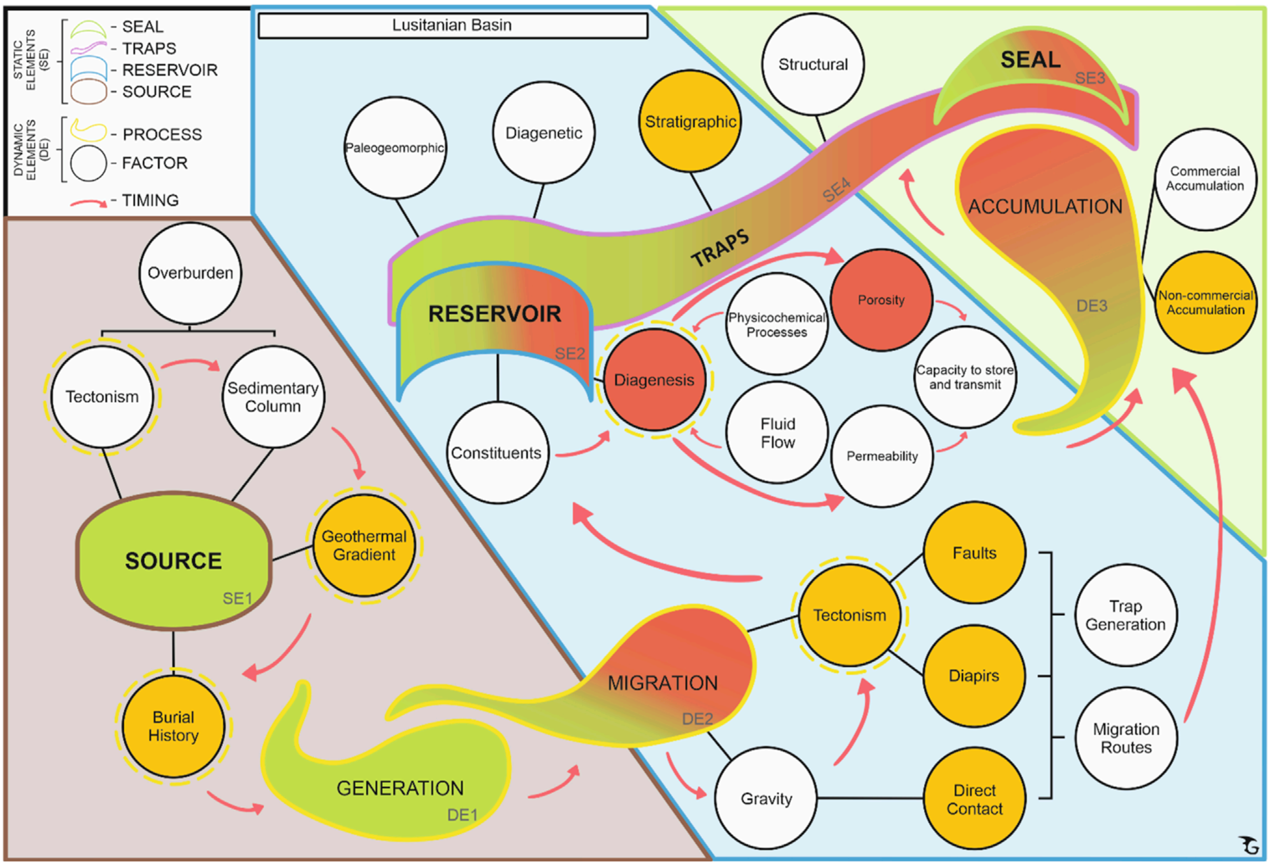

FIGURE 20
Interpretative illustrative scheme of the analysis of the static and dynamic elements in the study of the Castelo Viegas Formation's reservoir of the Grés de Silves Group, in the Lusitanian Basin, Portugal. Legend: Elements, factors and processes that were successful, in green; elements, factors and processes that have not been successful, in red; factors and processes with 50% chance of success, in green and red; factors and processes that were relevant in the formation of the petroleum system, in orange; and factors and processes that were not relevant in the formation of the petroleum system, in blank.

of the Lusitanian Basin (Figure 4), with the marly carbonates of the same formation acting as the primary source rock in this study. The seismic line AR9-80 (Figure 13) shows wells that penetrate the Cabaços Formation. Well Benfeito-1 encountered a gas show at 1,475m depth within the 238m of Cabaços Formation penetrated. Well Freixial-1 drilled 299m of the Cabaços Formation (Figure 14), and well Campelos-1 penetrated 396m. In the Santos Basin, well 3-BRSA-861-SPS (Figure 10) encountered Itapema Formation source shales and 378m of Barra Velha Formation microbialites. Well 3-BRSA-1101-SPS penetrated 359m of the same reservoir. The average thickness of the Cabaços Formation microbialites in the three Lusitanian wells is 311m, compared to 368m for the Barra Velha Formation in the two Santos Basin wells, suggesting comparable depositional thicknesses.

At the petrographic scale (Figure 18), the Cabaços Formation microbialite samples from the Pedrogão Beach outcrop exhibit extensive calcite cementation, significantly reducing porosity (Table 1). Petrographic analysis of the Barra Velha Formation microbialites (Figure 12) reveals silicification and dissolution, which can influence reservoir quality. These microbialites exhibit an average porosity of 12% and good to very good permeability (Table 1).

Geochemical analyses in both basins demonstrate that the Piçarras, Itapema (Figure 11), and Cabaços (Figures 16, 17) formation source rocks have sufficient TOC and Ro values to generate hydrocarbons (Table 1). The Santos Basin source rocks are mature within the oil window, while the Cabaços Formation source rocks reached maturity within both the oil and gas windows.

In the Santos Basin, the Barra Velha Formation carbonates are trapped structurally (associated with highs) and stratigraphically, sealed by the thick (>2,300 m average; Table 1), low-permeability Ariri Formation evaporites.

Regarding the traps occurring in the Lusitanian Basin, it was observed that in addition to structural traps, associated with deformation and creation of closed structures, stratigraphic traps may occur, associated with facies variations and creation of differentiated volumes within the units (Pena dos Reis and Pimentel, 2012). The main forms of traps (SE4) for the potential reservoirs of the Cabaços Formation are stratigraphic, with the anhydrite layers of this formation, observed in the outcrop profile and in the Benfeito-1 exploratory well, functioning as seals (SE3) for the more porous layers of the microbialites. Another situation of potential traps is the seals of the evaporites of the Dagorda Formation, which, due to their plasticity, can generate stratigraphic and structural traps overall potential reservoirs of the basin, including over the carbonates of the Cabaços Formation. Another potential sealant is the marls of the Tojeira Member (Figure 4), at the base of the Abadia Formation, which can form stratigraphic traps, retaining hydrocarbons from the reservoirs of the underlying Montejunto and Cabaços Formations.

The probable causes of why profitable hydrocarbon fields have not yet been discovered in the drilled prospects that intersected the Cabaços Formation are the following.

- The observed lithologies of the Cabaços Formation, mainly wackestones and packstones, as already mentioned, had rigorous diagenetic factors acting, such as replacement and recrystallization of the matrix by drusiform and mosaic calcite, and mechanical compaction, which strongly decreased their porosities;
- The 2D seismic line AR9-80 presented in Figure 13, shows the faults related to the diapiric structures of the evaporites of the Dagorda Formation. Hydrocarbon migration may have occurred along these faults, or through their walls; and
- The Alpine Inversion (Late Cretaceous) may have developed compressive properties, like thrust systems and anticlines. These associated with modern fractures may be the originators of damage to the traps, permitting the leakage of these preserved hydrocarbons in the direction of upper units and the surface, resulting in oil seeps.

7 Conclusion

This research presents a novel methodology for analyzing petroleum system elements (static and dynamic), focusing on analogous microbialite reservoirs in Brazil and Portugal. The main conclusions from the detailed reservoir analysis are outlined below.

In the Santos Basin case study, salt tectonics played a crucial role in the success of the Barra Velha Formation microbialite reservoirs. The evaporite domes provide an effective seal, enabling the retention of substantial hydrocarbon volumes sourced from the Itapema and Piçarras formations. Despite the observed diagenetic processes (silicification and dissolution), favorable petrophysical properties (porosity and permeability) contribute to the reservoir's effectiveness. Analysis and quantification of the petroleum system elements classify this reservoir as low risk (Pg = 0.5184).

Although gas shows have been encountered in wells penetrating the Cabaços Formation microbialites in the central Lusitanian Basin, the overall hydrocarbon potential remains low. Significant diagenetic alteration, including replacement and recrystallization of the matrix by drusiform and mosaic calcite, and mechanical compaction, resulted in poor porosity. However, the strong lateral facies variations within the microbialites suggest that zones with less diagenetic impact and better porosity may exist elsewhere in the basin, potentially enhancing gas storage potential. Furthermore, the substantial thickness of the microbialites (up to 385m), observed in both wells and outcrops, remains a positive factor. The calculated geological risk for these microbialites is high to very high (Pg = 0.042).

The methodology employed in this study facilitated a comprehensive analysis of the static and dynamic elements of the compared petroleum systems in the two basins, providing insights into the processes and factors controlling their effectiveness. Based on these elements and observed synchronism, the probability of geological success (Pg) and the geological risk for each reservoir was determined.

Pimentel and Pena dos Reis (2020) highlight the potential of the Lusitanian Basin to generate hydrocarbons and accumulate gas in the deepest and most preserved structural levels of the basin, mainlly in its central and offshore portions. The authors emphasize the basin's enormous potential as a "natural laboratory" to study the characteristics and geological evolution of an Atlantic margin basin, as an analogue of other oil basins targeted for research and exploration around the world. Good and easy access to excellent outcrops in its onshore portion, combined with the abundance of geological and geophysical research data, reinforce this potential and the importance of preserving and valuing the knowledge accumulated over decades in this basin.

Data availability statement

The raw data supporting the conclusions of this article will be made available by the authors, without undue reservation.

Author contributions

GuB: Writing–original draft. GG: Writing–original draft. GaB: Writing–review and editing. RP: Writing–review and editing. AG: Writing–review and editing.

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Conflict of interest

The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

Generative AI statement

The author(s) declare that no Generative AI was used in the creation of this manuscript.

Publisher's note

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