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RESEARCH PAPER

Petroleum exploration and production in Brazil: From onshore to ultra-deepwaters

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Abstract: The Santos Basin in Brazil has witnessed significant oil and gas discoveries in deepwater pre-salt since the 21st century. Currently, the waters in eastern Brazil stand out as a hot area of deepwater exploration and production worldwide. Based on a review of the petroleum exploration and production history in Brazil, the challenges, researches and practices, strategic transformation, significant breakthroughs, and key theories and technologies for exploration from onshore to offshore and from shallow waters to deep–ultra-deep waters and then to pre-salt strata are systematically elaborated. Within 15 years since its establishment in 1953, Petrobras explored onshore Paleozoic cratonic and marginal rift basins, and obtained some small to medium petroleum discoveries in fault-block traps. In the 1970s, Petrobras developed seismic exploration technologies and several hydrocarbon accumulation models, for example, turbidite sandstones, allowing important discoveries in shallow waters, e.g. the Namorado Field and Enchova fields. Guided by these models/technologies, significant discoveries, e.g. the Marlim and Roncador fields, were made in deepwater post-salt in the Campos Basin. In the early 21st century, the advancements in theories and technologies for pre-salt petroleum system, carbonate reservoirs, hydrocarbon accumulation and nuclear magnetic resonance (NMR) logging stimulated a succession of valuable discoveries in the Lower Cretaceous lacustrine carbonates in the Santos Basin, including the world-class ultra-deepwater super giant fields such as Tupi (Lula), Mero and Buzios. Petroleum development in complex deep water environments is extremely challenging. By establishing the Technological Capacitation Program in Deep Waters (PROCAP), Petrobras developed and implemented key technologies including managed pressure drilling (MPD) with narrow pressure window, pressurized mud cap drilling (PMCD), multi-stage intelligent completion, development with Floating Production Storage and Offloading units (FPSO), and flow assurance, which remarkably improved the drilling, completion, field development and transportation efficiency and safety. Additionally, under the limited FPSO capacity, Petrobras promoted the world-largest CCUS-EOR project, which contributed effectively to the reduction of greenhouse gas emissions and the enhancement of oil recovery. Development and application of these technologies provide valuable reference for deep and ultra-deepwater petroleum exploration and production worldwide. The petroleum exploration in Brazil will consistently focus on ultra-deep water pre-salt carbonates and post-salt turbidites, and seek new opportunities in Paleozoic gas. Technical innovation and strategic cooperation will be held to promote the sustainable development of Brazil's oil and gas industry.

Key words: Brazil; deepwater pre-salt exploration; Campos Basin; Santos Basin; turbidite sandstone; lacustrine carbonate; deepwater development; flow assurance

Introduction

Global deepwater oil and gas resources are extremely abundant, with immense potential for exploration and development, making them a focal point for global oil and gas exploration and a crucial area for increasing reserves and production. The eastern coast of Brazil, the Gulf of Mexico in the United States, and the Gulf of Guinea in West Africa are collectively known as the "Golden Triangle" of global deepwater oil and gas exploration, with recoverable oil and gas resources accounting for 40% to 50% of the total recoverable deepwater resources worldwide.

In 1953, the state-owned Brazilian Petroleum Company (Petrobras) was created. The company moved to offshore just 15 years after initiated exploration onshore, drilled the first well in 1968 and in the same year reached the first discovery, Guaricema field, in the Sergipe-Alagoas Basin, NE Brazil, in water depth of 15 m. In 1974 the first discovery in Campos Basin, the Garoupa field followed by

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the Namorado Field in 1975, the first giant field offshore in in Albian/Cenomanian sandstone turbidites at 166 m water depth. The Marimbá Field, discovered in 1984 at a water depth of 383 m, marked a significant step in deepwater production. The introduction of Remote Operated Vehicles (ROVs) was a groundbreaking development, as this depth exceeded the range that divers could safely operate in. In 1985 the Marlim Field was discovered, in water depths ranging from 660 m to 1 100 m.

To address the technological challenges faced in deepwater exploration and development, the technological progression at Petrobras for managing deep-water production development was marked by the establishment of Technological Capacitation Program in Deep Waters (PROCAP) in 1986, which overcome development technologies from operational water depths of 1 000 m to 3 000 m. In 2006, the giant ultra-deepwater oilfield Tupi was discovered in the Pre-salt Santos Basin, followed by a series of world-class oilfields. It was Petrobras's advancements in deep and ultradeep waters that truly propelled it to global leadership in the oil and gas industry.

Summarizing and reviewing Brazil's exploration and development journey from onshore, shallow water, deepwater, ultra-deepwater to the pre-salt, as well as its successful practices and theoretical and technological advancements, holds significant reference value for global deepwater petroleum exploration and development.

1. Exploration from onshore to offshore basins

1.1. Exploration transition from onshore craton basins to rift basins

Brazil presents a large diversity of sedimentary basins both onshore and offshore (Fig. 1), encompassing sedimentary rocks from the Pre-Cambrian to the Recent. The onshore basins cover an area of almost 500×10^4 km^2, primarily corresponding to the extensive Paleozoic basins (such as Amazonas, Pamaiba, Paraná basins) and smaller rift basins along the eastern coast (such as Recôncavo, Tucano basins).

In South America, there were very few exploration initiatives during the 19th century, leaving the region largely absent from the oil map at that time. In Brazil, only one well was drilled in the Paleozoic Basin of Paraná in 1897, which turned out to be dry [1]. At the beginning of the 20th century, however, a notable surge in exploration activity was observed in South America, primarily led by foreign oil companies, many petroleum provinces in South America had already been discovered by 1921 except for Brazil [2]. International corporations showed little interest in Brazil, and a few private and government Brazilian initiatives were the sole entities exploring in the country, yielding no economic results. During the same period up to 1938, exploration activity in Brazil, although open to foreign capital, was limited to drilling a few dozen wells by domestic companies, with no commercial success.

In 1938, the National Petroleum Council (CNP) was established, and exploration activity in Brazil gained momentum, becoming more systematic. In 1941, the first commercial oil accumulation in Brazil was discovered by CNP: the Candeias field, with area of 108.53 km^2 and reserve reaching 152 million barrels (1 bbl=0.159 m^3), in the Recôncavo Basin, a rift basin located in northeastern Brazil [1, 3]. Other discoveries were made in this basin.

The culmination of these efforts resulted in the establishment in October 1953 of Petrobras, a company that would operate as the state monopoly of the sector. Petrobras's objective would be to promote research, mining, refining, trading, and transportation of oil and its derivatives, with the aim of achieving Brazil's self-sufficiency in petroleum. In the postwar era (after 1945), growing domestic consumption had already reached 137 000 barrels per day, and a daily oil production of 2 700 barrels indicating a strong dependence on foreign petroleum.

The primary exploratory strategy of the American geologist Walter K. Link in Brazil was the search for in the extensive Paleozoic basins [4]. Under his leadership, Petrobras Exploration organized laboratory facilities, field geologists and interpretation teams. However, despite extensive exploration efforts, no commercial discovery was made, leading to frustration with only a few discoveries stemmed from the Cretaceous Recôncavo Basin. The Cretaceous rift Recôncavo Basin served as a significant training ground for Petroleum Geology in Brazil, imparting concepts that proved invaluable for exploration in other regions. Depositional systems, biostratigraphy zonation, fault block tectonics, and many other areas of knowledge found the Recôncavo Basin to be a fertile natural laboratory for studying and educating numerous generations of Petrobras explorers.

The discovery of the Carmópolis Field in 1963, with reserves reaching 460 million barrels in Sergipe-Alagoas Basin, marked a significant milestone for Brazil's oil industry. This giant onshore field underscored the potential of marginal basins and raised hopes for achieving petroleum self-sufficiency in Brazil. Coupled with other discoveries in the Recôncavo Basin, Carmópolis contributed to the growing optimism surrounding Brazil's oil reserves. By 1965, the volume of oil in-place discovered in Brazil had reached approximately 5 billion barrels. Despite these promising figures, domestic production remained relatively modest, at around 90 000 barrels per day. This production level was still insufficient to meet the country's gradually increasing consumption demands. By the end of 2023, more than 500 oil and gas fields had been discovered onshore in Brazil, and the scale of oil and gas fields is generally small.

1.2. Moving to offshore shallow water in passive continental margin basins and discovery of salt domes

While the onshore discoveries, including Carmópolis,

Fig. 1. Distribution map of sedimentary basins in Brazil and its surrounding areas.

were of immense importance, Petrobras Exploration recognized that they alone would not be able to satisfy Brazil's petroleum needs and considered imperative to venture offshore Sergipe-Alagoas Basin [5].

In assessing offshore sedimentary basins for exploration potential, two primary criteria were considered: Firstly, the continuity from producing onshore to offshore basins was evaluated. For example, the discovery of the giant Carmópolis field onshore suggested the presence of similar petroleum prospects offshore [6-7]. Secondly, the analogy of depositional situations like those observed in producing basins abroad was examined. This criterion involved comparing geological formations in Brazil, such as river deltas, to those in other regions known for significant oil reserves, like the Niger delta.

Geophysical surveys along the East Coast from Alagoas to Rio de Janeiro in 1968 paved the way for identifying favorable areas for wildcat wells on the continental shelf. Following the footsteps of exploration, biostratigraphic concepts were launched for all sedimentary basins in Brazil, based on foraminifera, calcareous nannofossils, non-marine ostracods and palynomorphs [8-9]. The year 1968 marked a pivotal technological leap in Brazil's exploration efforts with the establishment of Petrobras' first Center for Processing of Digital Seismic data, enhancing seismic expertise and facilitating software development.

In 1968, Brazil embarked on its offshore exploration journey with the drilling of the first offshore well in the

Espirito Santo Basin revealing salt domes, which ignited enthusiasm of exploration teams: “basin with salt is basin with oil.” Around the same time, the discovery of the Guaricema oil Field in the offshore Sergipe-Alagoas Basin, marked a significant milestone for Brazil's petroleum industry. Situated at a shallow water depth of 15 m, this discovery pointed to the country's offshore potential. Production tests conducted in Guaricema revealed promising oil flows, with rates reaching 2 000 bbl/d of high-quality light oil (relative density of 0.81) [10].

By the beginning of 1971, 53 offshore wells had already been drilled, providing valuable insights of the sedimentary basins on the Brazilian continental platform [6-7]. The economic results, however, did not respond to the enormous exploration effort of Petrobras. Only one significant discovery was made on the continental platform, the Ubarana Field with reserves of 240 million barrels, discovered in 1973 in the Potiguar Basin on the Equatorial Margin.

2. Significant breakthroughs in the post-salt of the Campos Basin

2.1. Breakthroughs in the post-salt based on turbidite geological model

The 1970s decade witnessed significant breakthroughs of Petrobras. The 1973 oil shock, marked by a dramatic surge in oil prices, intensified Brazil's quest for oil self-sufficiency, emphasized the urgency of domestic exploration efforts amidst escalating consumption.

In 1974, the discovery of the Garoupa Field marked the beginning of Petrobras's deep dive into the Campos Basin [7]. This field, located at a water depth of 120 m, was found in Albian porous carbonate rocks, boasting an oil column around 100 m thick with estimated reserves up to 230 million barrels. Oil flows of 3 000 bbl/d of light oil (relative density of 0.87) were measured.

In 1975, another significant milestone was achieved with the discovery of the Namorado Field in Albian/Cenomanian sandstone turbidites, at almost 200 m water depth, that became the first offshore giant field in Brazil. To date, the field has produced nearly 500 million barrels of oil equivalent. With the discovery of Enchova Field in 1976 in Eocene turbidites, followed by other discoveries, the Campos Basin became a hub for turbidite knowledge within Petrobras.

The early 1980s since the first discoveries, a huge collection of geological and geophysical data had already been accumulated from the Campos Basin, this data collection effort resulted in the consolidation of an integrated geological model that played a crucial role in supporting successful exploratory processes in the Basin. The post-salt petroleum systems in the Campos Basin consist of lacustrine shales of the Lagoa Feia Formation as the source rocks, and the oil migration through salt windows, facilitating the movement of hydrocarbons from the source rocks to the post-salt porous sandstones and carbonates [11].

At the end of 1984, Brazil’s cumulative recoverable reserves reached 4.3 billion barrels of oil equivalent, and oil production rate approached nearly 50×10^4 bbl/d, which could make up 50% of domestic consumption. Nonetheless, oil self-sufficiency was not secured; thus, there is an urgent need for new exploration breakthroughs.

2.2. New advances in geological theory of deepwater gravity flow and seismic technology

After the mid-1980s, a series of major discoveries were made in the deep waters of the Campos Basin, mainly owing to the breakthroughs in two aspects: deepwater gravity flow depositional model, and 3D seismic acquisition, processing, and interpretation technology.

2.2.1. Establishment of deepwater gravity flow depositional model

The innovative insights on deepwater depositional models provided a powerful tool to deepwater exploration in the Campos Basin. Biostratigraphy zonation studies, along with paleo-bathymetric maps, helped delineate potential reservoirs and guide exploration activities [12-13]. Deepwater sedimentation geological models and salt tectonics were key factors to understand the migration pathway through salt windows to the post-salt turbidite reservoirs in deepwater settings [11]. The perception that a depositional feature could be "visible" in a seismic section guided the construction of integrated depositional model, which is crucial for exploration. Thus, a geological model of turbidite deposits in bathyal environment was delineated through subaqueous gravitational mechanisms, including slides, debris flow, granular flow, and turbidity currents [12-14]. The model incorporates fluvial, coastal, and continental shelf/slope deposits, including channels and turbidite fan (Fig. 2). Therefore, the search for paleo basin-lows in a structural favorable position led

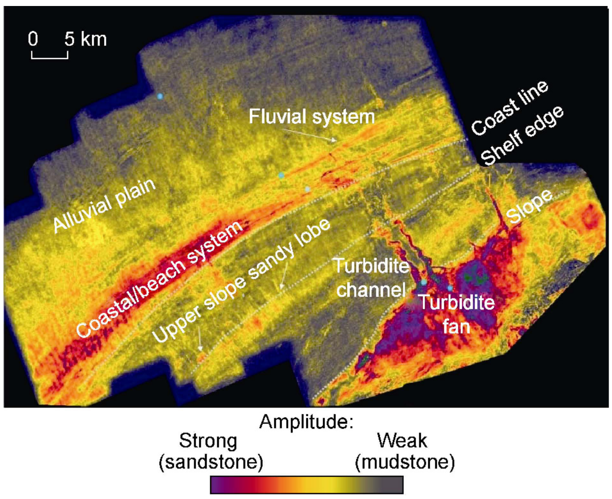

Fig. 2. Distribution of seismic facies in the Campos Basin [15].

to successful responses in the search for oil in turbidites.

2.2.2. 3D seismic acquisition, processing, and interpretation technology

The geophysical data acquisition, processing, and interpretation technology directly drives the deployment of exploration wells and the discovery of large accumulations in deep waters. Already in the early 1980s, seismic surveys in deep waters of the Campos Basin made it possible to detect and predict hydrocarbons, marking the big dive into deep waters and later into ultra-deep waters. In the late 1980s, a new phase was characterized by the extensive use of 3D seismic to direct exploratory activity, notably in the Campos Basin.

The high-quality 3D seismic data collected in deep waters spurred Petrobras to develop techniques for seismic processing, leveraging 3D seismic as a reservoir characterization tool to optimize well placement. Seismic data led to the development of more robust reservoir simulation models.

Starting from the mid-1990s, exploration routinely employed techniques like amplitude variation with offset (AVO) and direct hydrocarbon indicators (DHI), integrated with rock physics laboratory data from Petrobras Research Center (CENPES), providing quantitative data for seismic interpretation. The Rock Physics modeling, known as "Petroseismic," provided the foundation for utilizing elastic attributes in both 3D and 4D seismic interpretations.

A notable amplitude anomaly in the seismic profile (Fig. 3a) led to the discovery of the Marlim Field in the Oligocene turbidites with high porosity and high permeability. It has more than 6 billion barrels of oil in-place and recoverable reserves of more than 2.5 billion barrels, in water depths ranging from 660 m to 1 100 m. The oil with relative density of 0.92 was accumulated in friable reservoirs with permeability as high as 2 μm^2 (Fig. 3b). In 1992, Petrobras won its first Offshore Technology Conference awards (OTC) for the deepwater production system in the Marlim field.

In this scenario, Petrobras drilled a world record-breaking wildcat well at a water depth of 1 853 m (1-RJS-436A), in the northern part of Campos Basin, discovering the Roncador Field. The net pay is 153 m in Maastrichtian turbidites. The field's oil in place volume was estimated at 9 billion barrels of oil equivalent, with reserves of 26×10^8 bbl of oil equivalent. By 2000, Roncador field was already producing at the deepest water depth earning Petrobras the second OTC award for Petrobras. Development achievements in Campos Basin laid a fundamental foundation for future pre-salt production. In 2006 Brazil became self-sufficient in petroleum with almost 90% of production coming from turbidite reservoirs and mainly from Campos Basin deepwater (Fig. 4).

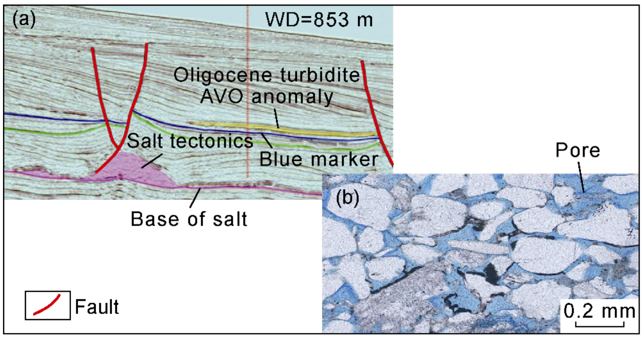

Fig. 3. Seismic profile of giant Marlim Oil Field (a) and typical thin section picture of Oligocene turbidite reservoir (b).

Petrobras made a notable discovery in the northern portion of the Campos Basin with the Jubarte oil Field. This discovery, located in Upper Cretaceous turbidite reservoirs, confirmed the presence of a flat spot seismic anomaly. This was crucial for optimizing exploration not only in the Jubarte field area but for future discoveries in Sergipe-Alagoas and Espírito Santo Basins deep waters, as well as throughout the pre-salt exploration and development process [16].

3. Santos Basin: a world-class deepwater province

3.1. The presence of petroleum system in the Pre-salt

The exploration of the Santos Basin experimented a boom after the early 2000's when significant discoveries in ultra-deepwater transformed the region into a major petroleum province. In 2000, many international companies and Petrobras acquired blocks in the basin. Petrobras acquired concessions in the so called "Cluster Blocks" in the ultradeep waters, ranging from 1 900 m to 2 400 m in water depth. The entire area was then covered by the largest 3D seismic program in the world, covering more than 20 000 km^2 providing detailed geological insights of the Outer High, a prominent geological feature in Santos Basin.

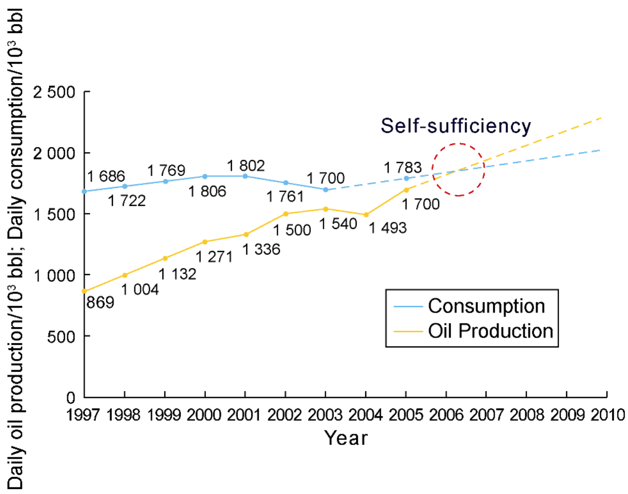

Fig. 4. Oil production and consumption in Brazil before self-sufficiency.

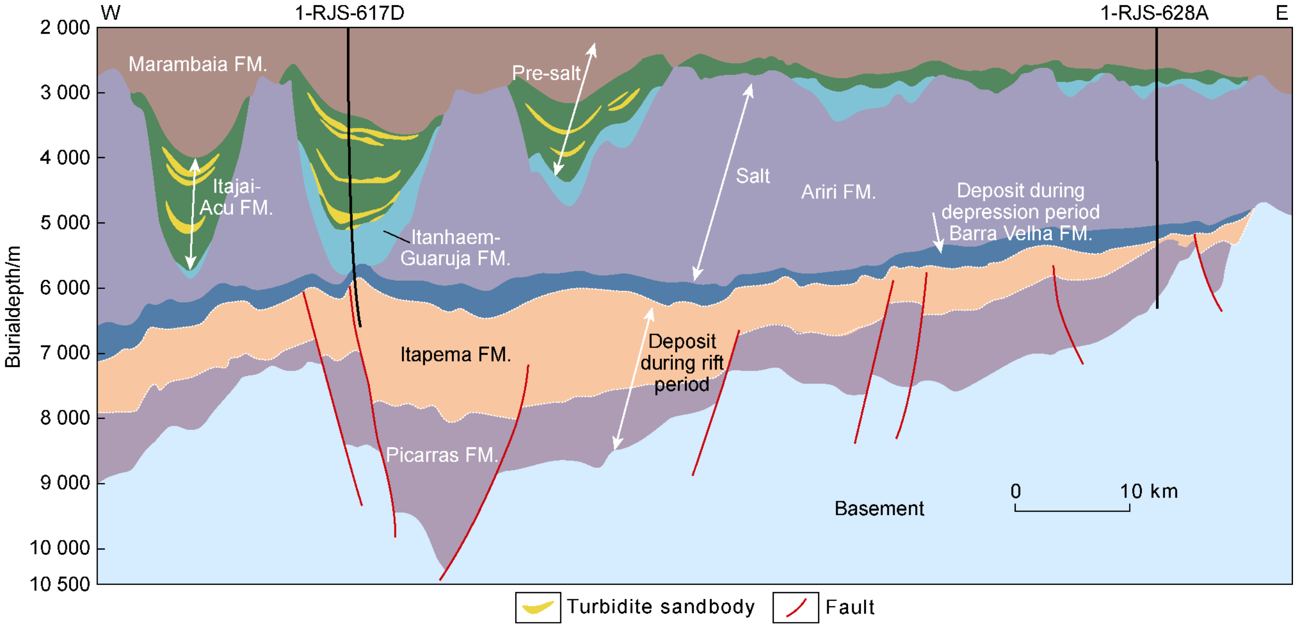

Fig. 5. Geological section interpreted from seismic data in the Santos Basin.

The first well (1-RJS-617D) deployed by Petrobras in the Parati lead in 2005 aimed to penetrate deep salt layer to explore multiple target layers in post-salt and pre-salt. This well is located in an area with a thin salt layer to avoid drilling problems (Fig. 5). Despite numerous challenges and a drilling period exceeding a year, the well with a depth of 7 600 m provided crucial insights into the area. Although not commercially viable, the Parati well confirmed the presence of an active petroleum system in the Pre-salt section and the presence of carbonate rocks, albeit with low permeability and porosity. The petroleum system confirmed in the Parati area encouraged further exploration efforts in the pre-salt.

In August 2006, a wildcat well (1-RJS-628A) was drilled at the water depth of 2 126 m in the Tupi area, and it faced complex situations when drilling the Ariri Formation evaporite section of 2 000 m thick above the reservoirs (Fig. 5). Well 1-RJS-628A confirmed the presence of good-quality carbonate facies represented by shrubby biolithite, grainstones/rudstones and some dolomites of the Lower Cretaceous Barra Velha Formation below the pre-salt. In Tupi, the depositional morphology was much more favorable for the development of carbonate facies with better permo-porosity conditions than those observed in Parati well.

Well 1-RJS-628A unveiled a substantial carbonate oil reservoir. The well test showed light oil with relative density of 0.89, gas-oil ratio (GOR) of 240 m^3/m^3, and up to 12% of CO_2 in the dissolved gas [17]. The second well drilled 10 km apart in the structure found similar oil reservoir, confirming the presence of giant Tupi Oilfield.

It was confirmed a superb play, consisting of Barremian-Aptian lacustrine shale source rocks feeding carbonate reservoirs, capped by a gigantic continuous stratified salt layer, a perfect seal (Fig. 6). The figure shows the difference in morphology of discontinuous salt

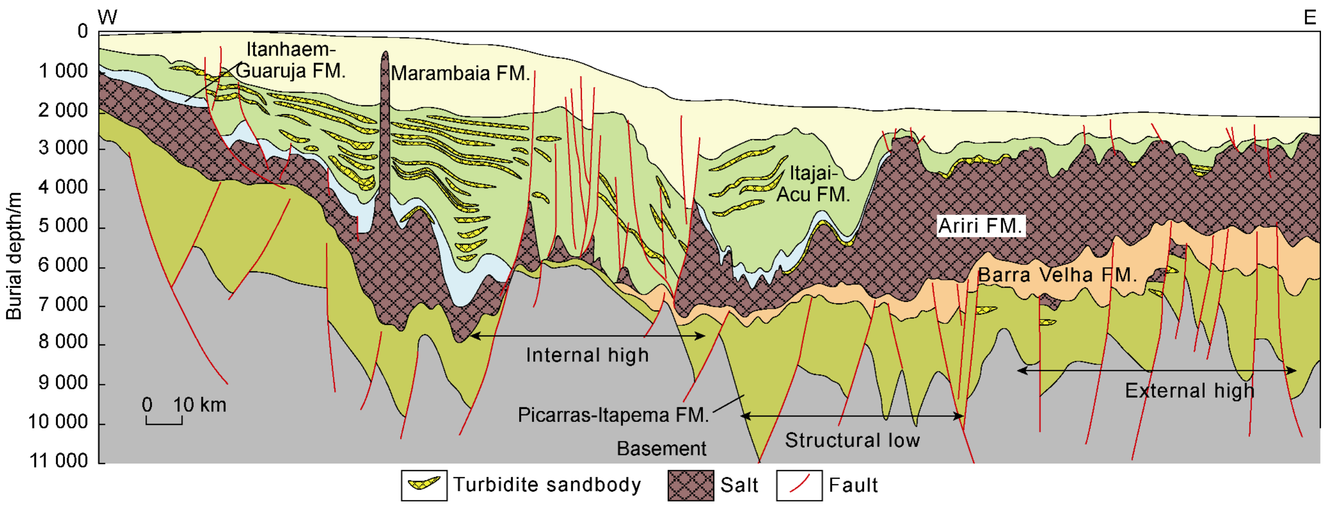

Fig. 6. Sketch of EW geological section in the Santos Basin.

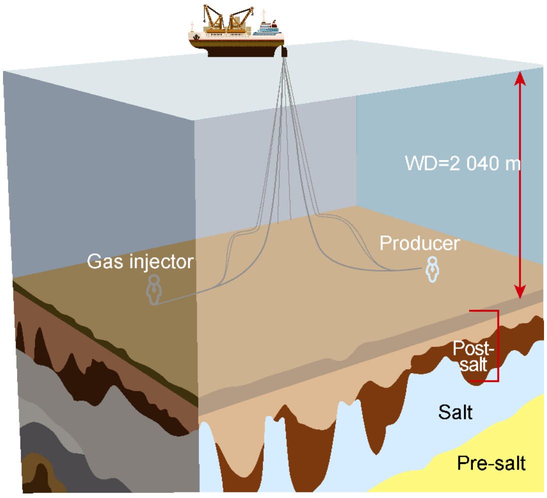

Fig. 7. Sketch of pre-salt reservoir, salt layer, post-salt layer, and water depth.

in shallow waters, and it transitions to form a large continuous wall in ultra-deep waters, forming the perfect seal of the pre-salt.

The pre-salt carbonate reservoirs are as thick as 400 m and are overlain by 2 000 m of salt, 2 000 m of post-salt rocks and 2 000 m of sea water, a completely different scenario to explore and produce (Fig. 7).

The discoveries in the pre-salt of the Santos Basin promoted the comparative study between the Santos Basin and the Campos Basin, which showed that similar carbonate reservoirs were also present in the deep and ultra deep waters of the Campos Basin. It was in the Jubarte Oilfield in the northern portion of the Campos Basin that the pre-salt section was encountered with oil and gas shows. With the existing production facilities for the post-salt, well test was carried out in the pre-salt carbonate reservoir in the year 2008, which obtained oil flow from the pre-salt of the Campos Basin for the first time.

With these established geological models, years of exploration in the pre-salt of the Santos Basin and the Campos Basin resulted in numerous discoveries. These oilfields produce from the Aptian Barra Velha Formation microbial carbonate rocks and the Aptian/Barremian Itapema Formation coquinas [15, 18–20].

3.2. Reservoir prediction using lacustrine carbonate geological model

Reservoirs were the first and critical uncertainties in pre-salt. Questions were raised related to quality, continuity and even the genesis of this complex reservoir. Efforts to understand the pre-salt carbonate reservoirs involved extensive laboratory research, outcrop studies and a continuous rock-log-seismic calibration.

Two types of carbonate reservoirs are mainly developed in the pre-salt: the Barremian–Aptian coquina and its overlying Aptian microbial carbonate rock. Non-reservoir magnesian-clays occur widespread in the basin, normally associated with in-situ carbonate rocks (Figs. 8 and 9).

The first type of important reservoir rock is the Barremian–Aptian coquinas, which are composed of bivalves, forming grainstones, rudstones and floatstones, deposited on highs formed during rift-interval extensional faulting. They are laterally surrounded by fine-grained rocks (marls and shales), organic-rich facies that accumulated in the depositional lows.

The high energy facies present different degrees of shell preservation. Dissolution and cementation by calcite and less frequently by silica, are very common processes

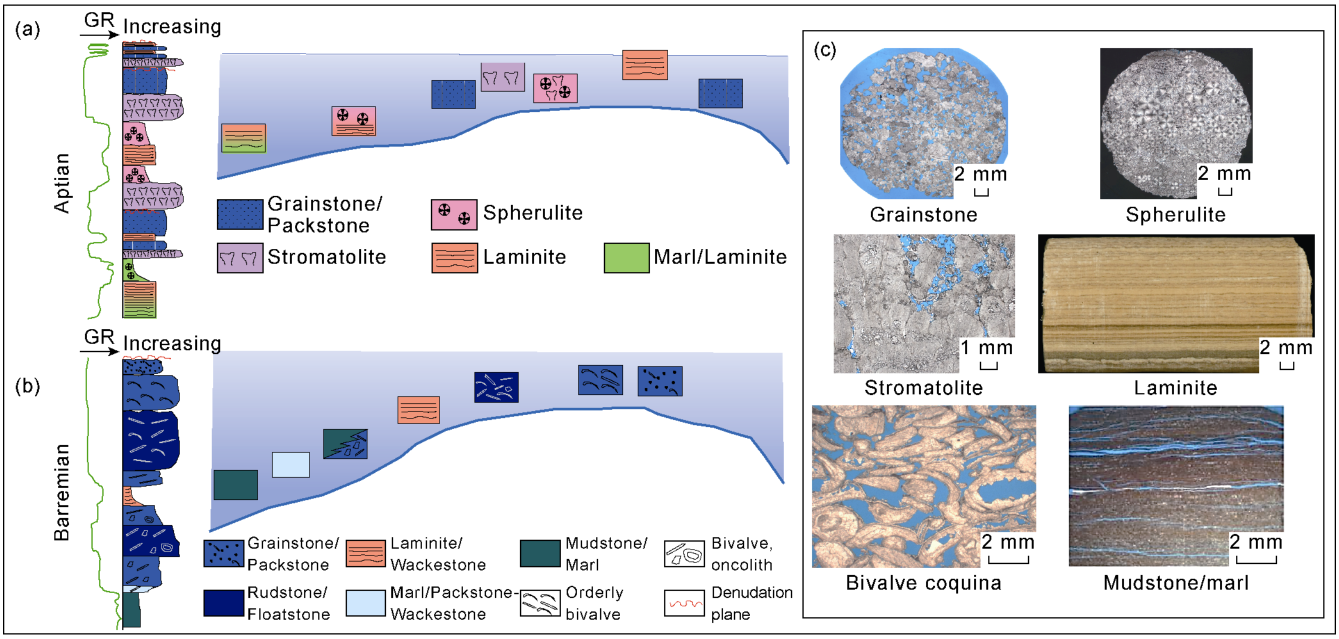

Fig. 8. Schematic lithologic profile of Aptian (a) and Barremian (b) and typical thin section pictures of cores (c) (GR: gamma ray).

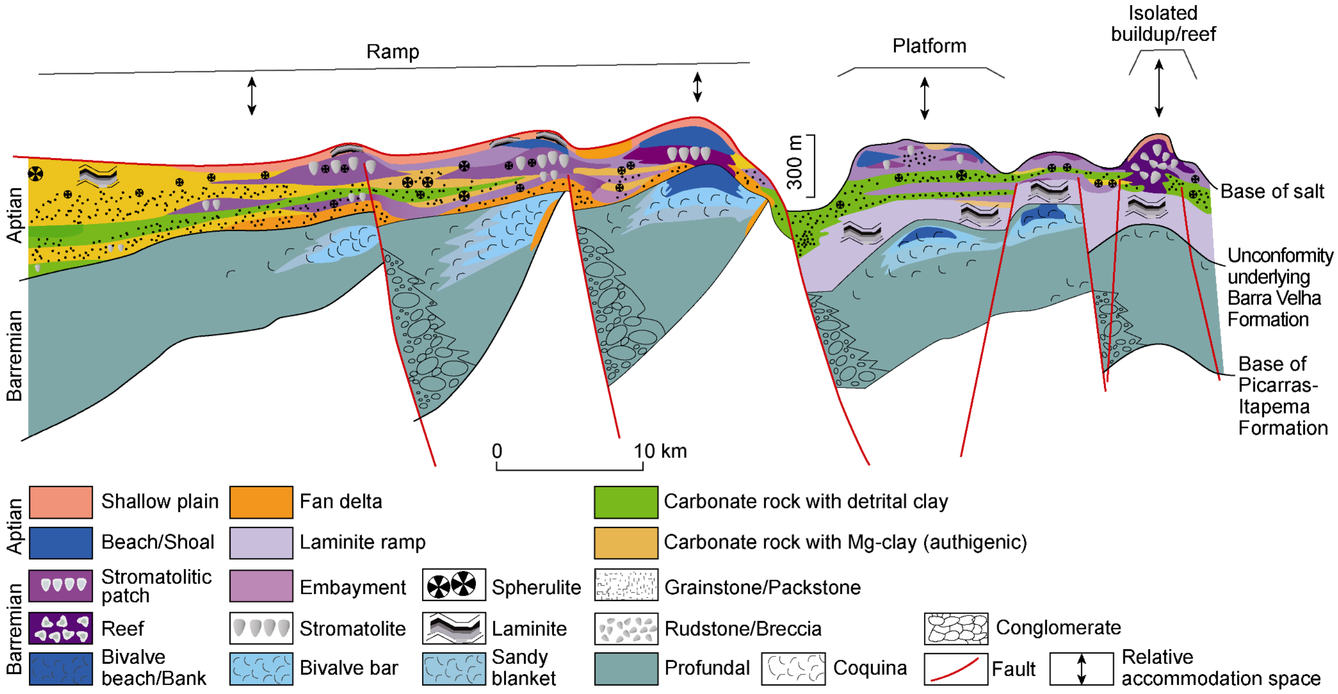

Fig. 9. Schematic sedimentary facies model of pre-salt carbonates in the Santos Basin.

in these facies; so moldic porosity is frequently observed as well as vugs. Intergranular porosity is less common, but usually associated with high permeabilities. The coquinas show a large range of porosity and permeability reflecting the texture and the diagenetic process; the best reservoirs can reach porosity values of 20% and permeabilities up to 3–4 μm^2. The coquinas are important reservoirs in the giant Búzios and Mero fields [21].

The understanding of reservoir models for the coquinas in the Campos Basin began with the discoveries of the Badejo, Linguado, and Trilha fields in the 1970s. In the early of 21st century, new coquina reservoirs were found in the Baleia Azul, Baleia Franca, and Baleia Anã fields, also in the Campos Basin. These discoveries greatly contributed to the comprehension of the pre-salt coquinas in the Santos Basin.

The second type of important reservoir is the Aptian carbonate rock, which is also the most important reservoir in the pre-salt oil and gas fields. They comprise both in-situ and reworked lithofacies. The in-situ lithofacies encompass a wide variety of arrangements and sedimentary structural patterns, including stromatolites, spherulitites, and microbial laminites. It is inferred from the fossilized, extracellular, polymeric substances in the micritic nuclei that the sedimentation process is not an exclusively abiotic process, but influenced by microbe. Aadditionally, the conclusion on the basis of isotopic data supports the organic, biogenic origin [22].

The stromatolites, in general, are characterized by the presence of bush-like calcite elements (shrubs), typically exhibiting well-defined lamination due to the presence of millimeter-scale laminae in spherulites. The bush-like elements vary in size and shape, and they also show variations in arrangement, which can range from more to less dense, significantly influencing the poroperm characteristics. Dolomite is frequently observed among the shrub-like forms, generally in small percentages, so that the stromatolites present framework porosity. Sometimes dissolution is observed, which can lead to some vugs.

The spherulitites are formed by spherical grains (spherulites), typically coarse to very coarse sand-sized, with their characteristic extinction cross. Spherulitites are usually laminated, with a dolomitic matrix. They usually present low permo-porosities.

Grainstones and rudstones are primarily formed by intraclasts, mainly including clasts of stromatolites, and to a lesser extent, clasts of laminites and spherulitites. Peloids and spherulites are other observed components. They constitute a significant part of the Aptian reservoirs. Usually, they exhibit physical-chemical compaction features, an important factor in the loss of part of the depositional porosity. Calcite cementation occurs disseminated in these lithofacies, locally completely filling the intergranular space. Grain dissolution is another diagenetic process observed.

Intergranular porosity is the dominant type, with moldic porosity also occurring along with some vuggy porosity. Due to grain size, physical-chemical compaction, and cementation, they exhibit a wide range of permo-porosity characteristics, reaching porosity values of up to 20% and permeabilities in the range of hundreds of millidarcies.

Dolomites are relatively common, typically associated with in-situ facies, preferably spherulites, and less commonly with stromatolites. In the former, they can form quite dense mosaics. Locally, unassociated dolomites are observed, sometimes characterizing saddle dolomites, with some intracrystalline porosity. Breccias, typically partially silicified, are important lithofacies, especially in buildups. These facies usually exhibit vuggy porosity, often with excellent permeabilities.

The laminites include smooth and crenulated forms, with varied textures ranging from micritic to micro-peloidal. They exhibit large variations in porosity, ranging from very low to values of up to 30%. Due to their fine texture, they typically have low permeability, around 1×10^{-3} μm². Packstones are of limited occurrence, as are wackestones.

The interpreted depositional architecture and paleogeography comprise ramps, platforms, and buildups, measuring tens of meters in thickness and several kilometers laterally but with marked variations in reservoir facies. Reworked facies predominate on ramps, whereas buildups, located in areas with high rates of accommodation bordering the carbonate platform, are mostly stromatolites intercalated with reworked facies. The facies distribution characterized by shrubby stromatolites, packstones/grainstones, and dolomites, sometimes associated with Mg-Si clays and spherulites can be seen schematically (Fig. 9).

3.3. Reservoir evaluation through nuclear magnetic resonance (NMR) logging

Another important success factor for the Pre-salt was the formation evaluation using nuclear magnetic resonance (NMR) logging. The NMR logging profiles have the significant advantage of measuring porosity in complex lithologies, independently of interpretation parameters, resulting in more accurate reservoir volumetrics. NMR profiles have also enabled the identification of layers of highly viscous oil or tar sands, which could act as permeability barriers and have a significant impact on water injection projects. Some of these layers may prevent vertical aquifer action, requiring the repositioning of water injection wells to the oil zone if the tar mat is precisely situated at the oil/water contact.

Furthermore, when NMR logging began to be used in wells drilled with oil-based drilling fluid and used for bottom hole fluid sampling, such as Modular Formation Dynamics Tester (MDT), there was indeed a significant revolution in the evaluation of carbonate rocks in the pre-salt. It differentiates the oil from water signal allowing for much easier quantification of oil presence and porous formation thicknesses in the pre-salt. This greatly increased the calculation accuracy of water saturation and oil saturation and the calculation confidence of pre-salt formation volume.

Synthetic drilling fluid played an important role in the discovery and development of the pre-salt, enabling the drilling through the thick salt layer and facilitating advancements in reservoir evaluation through nuclear magnetic resonance (NMR) logging [23].

3.4. Significant discoveries in the deepwater pre-salt

The discovery of the Tupi Field, the first supergiant oil field in Brazil, with reserves of $(50–80)\times10^{8}$ bbl, represented a significant advancement in Brazil's petroleum industry. Subsequently, intensive exploration activities in the pre-salt discovered numerous oil and gas fields, including the Búzios, Mero, Sepia, Berbigao, Sururu, Atapu, Sapinhoa, Itapu, and Lapa oil field. These discoveries further confirm the huge potential of oil and gas resources in the Pre-salt.

At present, the Santos Basin has become one of the hotspots for global oil and gas exploration and development. There are nine oilfields in production, and more than 20 blocks that have been discovered without production in the pre-salt. Among them, there are more than 15 oilfields/blocks with oil in place exceeding 1 billion barrels. These major discoveries have had a profound impact on the global oil and gas energy sector. They not only consolidate Brazil's position in global energy supply, but also provide important references for the strategy and technological development of deepwater oil and gas exploration.

4. Key technologies and achievements of deepwater oil and gas development in Brazil

4.1. PROCAP

The PROCAP promoted the overall improvement of deepwater operation ability in Brazil. In the mid-1980s, with the successive discoveries of large deepwater oilfields such as Marimbá, Albacora, and Marlim in the Campos Basin, how to convert deepwater exploration discoveries into development production became a key bottleneck. Petrobras launched the PROCAP (1986–1991) with the aim of enabling Petrobras and contractors to jointly develop new technologies applicable to large deepwater oilfields [24–26]. This research and development plan include over 100 projects, covering areas ranging from geotechnical engineering, marine meteorology to various issues related to deepwater development, such as mooring, risers, underwater equipment, and floating production units. By using the Campos Basin as a deepwater new technology research and development laboratory on a mining scale, Petrobras has fully involved its technical personnel, senior consultants, and management team in evaluating and approving various research plans, and prioritizing the inclusion of the most promising technologies in field tests. The implementation of the PROCAP has enabled Petrobras to have a basic operational capability at a water depth of 1 000 m. Subsequently, Petrobras further promoted the implementation of the PROCAP 2000 (1993–1999) and the PROCAP 3000

(2000–2010). The goal of PROCAP 2000 is to expand the operation water depth to 2 000 m, especially by achieving breakthroughs in underwater pressurization systems and successfully applying electric submersible pumps to deepwater oil wells for the first time. In 1998, Petrobras successfully implemented the completion of open hole gravel pack (OHGP) in horizontal wells, which made it possible to prioritize the use of horizontal wells for development in sand prone formations in the Campos Basin, significantly improving economic benefits [24]. The PROCAP 3000 program was initiated in 2000, mainly aimed at solving the development problems of Marlim South and Roncador oilfields, enabling the company to operate at a water depth of 3 000 m, and reducing the cost of deepwater oil and gas development. It consists of 88 sub projects of 17 system projects, mainly including well control, intelligent oilfields, drilling and completion equipment, ultra-deep water drilling and completion fluids, pre-salt drilling, ultra-deep water oil well integrity, artificial lifting, steel suspension risers, flexible risers, 3 000 m underwater equipment, unconventional production systems, ultra-deep water cementing, floating oil production, storage and offloading systems (FPSO), single column platform new ship design, deep resistivity imaging logging, etc. [27–29].

4.2. Managed pressure drilling (MPD) and pressurized mud cap drilling (PMCD) in deep waters with narrow pressure window

In deepwater operations, the overlying formation, which is almost a thousand of or even thousands of meters thick, are replaced by seawater, resulting in a significant reduction in overburden pressure compared with onshore or shallow-water wells. This leads to a narrower window between the formation fracture pressure and the formation pore pressure, making it easier for pressure control to be improper, leading to leakage or overflow. The extremely thick salt layer in the pre-salt of the Santos Basin is prone to hole shrinkage, collapse, and pipe sticking, posing many challenges to deepwater drilling [30]. Managed Pressure Drilling (MPD) technology aims to solve complex drilling problems in narrow pressure windows by actively managing the wellbore annular pressure. Through research and development, a series of specialized equipment has been developed to meet technical and safety operation requirements, and the adaptability and qualification of drilling rigs and equipment have been certified. Self-elevating drilling rigs and anchored devices have been widely used for MPD operations in Brazil and other waters, confirming the benefits of this technology. In the Santos Basin, the pre-salt carbonate reservoirs are subject to karstification, resulting in the development of dissolved pores and high-angle fractures in some layers. During drilling, severe losses can occur, making it difficult to achieve normal circulation of drilling fluid even with MPD. Therefore, further research and development of the Pressurized Mud Cap Drilling (PMCD) technology are needed. The drilling fluid system is designed to be underbalanced, and when severe losses occur, the goal is not to plug the leaks. Instead, working fluid is continuously injected into the drill pipe and annulus to quickly drill through the thief zone, switching from MPD mode to PMCD mode. In April 2014, the MPD technique was applied in the Tupi Oilfield of the Santos Basin for the first time, then switched to PMCD when a severe loss interval was encountered and ultimately reached the target layer smoothly. The completion of this well represented a technological milestone, as it was the deepest well drilled using the PMCD technique at the time, with a dynamic positioning rig.

4.3. Multi-stage intelligent completion in the pre-salt thick reservoirs

Once the oil and water wells are put into production in deepwater environments, subsequent testing and operations still require the rental of expensive drilling vessels, making it difficult to implement many operations that can be carried out at onshore and shallow water jacket platforms in deepwater reservoir. Especially for the thick carbonate reservoirs in the pre-salt of the Santos Basin, multi-stage intelligent completion technology is crucial to deal with reservoir heterogeneity and potential water and gas channeling. By dividing the thick reservoir into two to three sets of development layers, the use of 2–3 levels of intelligent completion can achieve layered development in a well pattern. Once water or gas channeling occurs in a certain layer, the flow control valve (ICV) of oil producer or injector in that layer can be closed to efficiently and cost-effectively solve the channeling problem, improving the sweep volume and recovery rate of oil reservoir development [31].

Currently, Petrobras carries out multi-stage intelligent completion in over 100 wells in the pre-salt of the Santos Basin. For the large-scale application of intelligent completion in ultra-deepwater oil wells of the Tupi Oilfield for the first time, Petrobras won the third OTC Award in Houston in 2015 [32–34]. The "all-electric" intelligent well completion technology under development is expected to bring higher operational efficiency and improve crude oil recovery in the pre-salt area of the Santos Basin.

4.4. Development mode of FPSO and underwater production system

The sudden surge in oil prices during the 1973 crisis had a significant impact on oil sales, leading to underutilization of many cargo ships due to reduced demand. Capitalizing on this surplus of hulls in the market, Petrobras seized the opportunity to purchase and convert them into production platforms, known as Floating Storage and Offloading Production Units (FPSOs). These FPSOs were equipped with large storage capacities and integrated facilities for Gas/Oil and Oil/Water separation, as well as chemical treatment at the topside.

The adoption of FPSOs favored the use of wet Christmas tree completion in the Campos Basin. Production development followed a three phases approach: a long-term test, followed by a pilot production unit, and culminating in the definitive production unit. This approach allowed for the acquisition of dynamic reservoir data and the anticipation of revenue, thereby making projects economically viable. This revenue anticipation proved particularly beneficial during a critical period in the Brazilian economy characterized by high prices of imported oil.

4.5. Flow assurance in deepwater complex operation settings

In deepwater operations, the seabed is a high-pressure, low-temperature environment (about 4 °C). Large-diameter marine pipes and risers are required for long-distance transportation from the subsea wellhead to the FPSO, making it easy for wax precipitation, asphaltene deposition and natural gas hydrate formation to occur during the transportation of well fluids. In severe cases, these deposits may block the pipeline. The fluid components may contain acidic media such as H_2S and CO_2, as well as solid impurities such as sand and gravel, which can easily cause serious problems such as pipe wall corrosion and scaling. Ensuring the safe flow of fluids and reducing production losses during the development of deepwater oil fields is crucial. Petrobras first proposed the term "flow assurance" (GARESC) in the industry, which has become widely known around the world. "Flow assurance" includes but is not limited to measures to prevent and mitigate various precipitates, such as calcium carbonate, strontium carbonate, strontium sulfate, barium sulfate, hydrate, and asphaltene. These processes can occur throughout the production string, from the intelligent completion valve to the flow line, and even in the oil-water separator [35–36]. Understanding the stability parameters of these substances under different temperature conditions, selecting and injecting appropriate chemical inhibitors to prevent precipitation during operation, and removing the formed scale are crucial for ensuring stable production in deepwater oil and gas fields. An important lesson in flow assurance came from the early production test in the pre-salt of the Campos Basin in 2008. The ESS-103 well initially produced at a rate of around 20 000 barrels per day but quickly ceased production due to calcium carbonate precipitation in topside facilities. This was attributed to inadequate scavengers used to neutrally remove H_2S. Then, the problem was solved by replacing the scavenger. This occurrence provides valuable experience for solving the problem of downhole scale in the pre-salt of the Santos Basin like Búzios Oilfield. In addition, the pre-salt oil reservoirs in the Santos Basin generally have high carbon dioxide content [20, 37–38], forcing equipment to use high-grade anti-corrosion materials to ensure the integrity of the wellbore, tubing, riser, and FPSO upper facilities. Despite these measures, carbon dioxide corrosion cracks still occur on the flexible risers. The solutions to mitigate future risks include the use of rigid pipelines and other protective measures [39] to enhance the durability and reliability of the infrastructure deployed in the pre-salt oilfields and ensure the continuous success of production operations.

4.6. Globally largest CCUS-EOR project

Most of the oil reservoirs in the Santos Basin have high-GOR light crude oil, and the gas generally contains CO_2 (0–78%). Petrobras, in fulfilling its environmental, social and governance (ESG) responsibilities, chooses not to directly discharge high CO_2-content gas into the atmosphere, but installs compact membrane separation systems on FPSOs to purify the produced gas and re-inject CO_2 or high CO_2-containing produced gas back into the reservoir. In addition to environmental benefits, high CO_2-containing gas can achieve miscible flooding in the reservoir to enhance oil recovery, but it increases the complexity of the design, construction, and operation of FPSOs, and limits the maximum production capacity of each FPSO to a certain extent.

According to statistics, by the end of 2023, the cumulative injection of CO_2 in the pre-salt area of the Santos Basin in Brazil had exceeded 40 million tons, with an annual injection scale of 10 million tons.

5. Conclusions

Since the first deepwater petroleum discovery in Brazil in the mid-1980s, Petrobras has overcome various challenges to exploration and development in deep waters, and has achieved a series of significant discoveries in the post-salt turbidites of the Campos Basin and in the pre-salt carbonate rocks of the Santos Basin. Through the PROCAP, the comprehensive improvement of deepwater operation capabilities has been promoted. Successful exploration and development has been achieved successively in Marlim, Roncador, Tupi, Mero and Buzios. A series of major petroleum discoveries and development engineering achievements have been recognized internationally. Petrobras has won 7 OTC awards.

The focus of exploratory activities in Brazil is the ultra-deepwater. The lacustrine carbonate reservoirs of the Pre-salt continue to be a main target of exploration in Santos and Campos Basins, while turbidite reservoirs are the objectives in Campos, Espírito Santo, and Sergipe-Alagoas basins on the Eastern Margin and in the basins of the Brazilian Equatorial Margin. The Pelotas Basin, located at the southernmost tip of Brazil, has been the subject of geological and geophysical studies, and dozens of blocks were acquired in the last ANP auction in December 2023 to be the target of exploratory wells soon. Recent discoveries in Namibia in turbidite reservoirs increased the expectation of success. To cope with the more complex operating environment in ultra deep water, the groundbreaking technology HISEP will further support the sustainable development of Brazil's oil and gas industry. It is expected that the pre-salt peak production reach peak production around 2030.

Onshore, mostly led by Brazilian companies, exploratory activities are primarily concentrated in the Paleozoic Parnaíba Basin, with a focus on gas, and in the mature Cretaceous basins of the Recôncavo, Potiguar, and Sergipe-Alagoas, in northeastern Brazil. Exploratory projects in the Paraná Basin, a vast Paleozoic basin in southern/south Brazil, are expected to return in the coming years, especially for gas discovery. The proximity to major consumer centers increases the attractiveness of this basin, despite the difficulties of seismic imaging due to the presence of thick basalt layers.

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