Geochemical Characteristics and Distribution of the Subsalt Source Rocks in the Santos Basin, Brazil

Guoping Zuo, Hongping Wang, Guozhang Fan, Jiazhen Zhang, Yonggang Zhang, Chaofeng Wang, Liu Yang, Liangbo Ding, Xu Pang, and Yinhui Zuo*

ABSTRACT: The Santos Basin in Brazil is a hot area of oil and gas exploration in recent years, and its subsalt lacustrine mudstones are the main source rock of the basin. However, there is a lack of studies on the source rocks of the subsalt Picarras and Itapema formations, which is not conducive to the accurate evaluation of the source rock characteristics. Based on logging data of 51 wells and geochemical data of 16 wells, this paper makes detailed evaluations of the organic matter abundance, type, maturity, and distribution characteristics of source rocks of the subsalt Picarras Formation and Itapema Formation in the Santos Basin. The results show that the characteristics of source rocks of the Itapema and Picarras formations are similar, both of which have a high abundance of organic matter. The types of organic matter are mainly type I and II, and the maturities are in the low-maturity to the high-maturity stage, which meets the standard of good source rocks. The total organic carbon content of the source rocks of the Picarras Formation ranges from 0.4 to 4.0%, much lower than that of the source rocks of the Itapema Formation, 0.8–5.6%. In addition, the hydrogen index average value of the source rocks of the Itapema Formation is 712.8 mg/g TOC, higher than that of the Picarras Formation, 697.5 mg/g TOC, both revealing a great hydrocarbon potential. The quality of source rocks of the Itapema Formation is better than that of the Picarras Formation. The two sets of source rocks have great hydrocarbon generation potential and are mainly developed in the eastern and western sags of the central depression. Therefore, the surrounding uplift areas will be the target for further oil and gas exploration.

1. INTRODUCTION

Since Tissot et al. proposed the theory of late oil generation of kerogen thermal degradation in the 20th century, research on source rocks has been a significant work for geologists to analyze the oil and gas exploration prospects in basins and zones. Oil and gas are generated and discharged from source rocks, and after migration and accumulation, the oil and gas can become valuable resources for human development and utilization. The source rocks play an important role during the oil and gas exploration. Especially with the improvement of oil and gas exploration, it is increasingly difficult to increase the reserves and production. Therefore, the characteristics and evaluation of source rocks have become the top priority of oil and gas exploration. The geochemical characteristics of source rocks mainly focus on the abundance, type, and maturity of organic matters. Macroscopically, it is also necessary to evaluate the thickness distribution of source rocks.

Global and gas exploration has experienced a development stage from shallow to deep and from land to sea. In the present day, the world has entered a new stage of oil and gas exploration and development in deep water. In recent 10 years, the proportion of newly discovered passive continental margin basins has reached 65% in global oil and gas exploration, with emphasis on the Gulf of Mexico, Santos, Kwanza, Senegal, and Arab basins. The Santos Basin is a typical passive continental margin petroleum-bearing basin in Southeast Brazil, with excellent petroleum geological conditions and numerous oil and gas discoveries. By the end of 2016, 38 oil and gas fields have been discovered in the subsalt strata of the basin, with a total proved recoverable reserves of about 30 billion barrels, accounting for 94% of the Santos Basin. Since 2006, several giant oil and gas fields such as Lula, Jupiter, Sapinhoa, Franco, and Libra have been continuously discovered in the field of lacustrine carbonates of the subsalt strata in the deep-water area of the Santos Basin, revealing that the subsalt strata of the basin have rich oil and gas resources and great exploration potential.

Predecessors have made some understandings of the research of source rocks. Scholars generally believe that there are two sets of source rocks in the Santos Basin. One is the lacustrine source rocks of the Early Cretaceous Barremian–Aptian Stage Guaratiba Group in the subsalt rift period, and the other is the marine source rocks of the Late Cretaceous Cenomanian–
Turonian Stage Itajai-Acu Formation in the postsalt drift period. It is confirmed that the Guaratiba Group lacustrine mudstones, including the Picarras Formation and Itapema Formation deposited in the subsalt rift period, are the main source rocks of the basin. The lacustrine source rocks of the Guaratiba Group in the subsalt strata are characterized by high organic matter abundance, good types, and great hydrocarbon generation potential, in which the total organic carbon content (TOC) is between 1.0 and 15.9%, and the average value is 5.12%. The hydrogen index (HI) ranges from 500 to 1084 mg/g, with an average of 755 mg/g. The average value of hydrocarbon generation potential \( S_1 + S_2 \) is 42 mg/g, the kerogen type is type I, and the source rocks are widely distributed throughout the basin.

Previous geochemical evaluations of the presalt source rocks in the Santos Basin were mostly concentrated in the Guaratiba Group. However, there are two set of dark mudstones developed in this group that show differences in the scale and quality due to the different depositional environments, have not been carefully investigated. These are Picarras and Itapema Formations, respectively. These differences cannot be reflected by the overall evaluation of the Guaratiba Group, which restricts the evaluations of petroleum potential and favorable zones. In addition, there is a lack of geochemical data in the previous research. Some studies use the geochemical data of source rocks in the rift period of the adjacent Campos Basin for analogy research, and other studies use the data of only one well for the whole basin research, leading to great controversy on the research results. Therefore, based on the logging data of 51 wells and the geochemical data of 16 wells, combined with the seismic data and sedimentary facies, this paper systematically studies the organic matter abundance, type, maturity, and distribution of the source rocks of the subsalt Picarras Formation and Itapema Formation in the Santos Basin and reveals the characteristics and center of the source rocks. The research results are of great significance to the further evaluation and exploration of oil and gas resources in the Santos Basin.

2. GEOLOGICAL SETTINGS

The Santos Basin is a typical passive continental margin basin located in the southeast sea area of Brazil, adjacent to the Campos Basin in the north and the Pelotas Basin in the south. It covers an area of about 32.7 \( \times \) 10^4 km^2 and a water depth of 0–3200 m (Figure 1). The presalt lacustrine carbonate in the Santos Basin is rich in oil and gas resources and is considered a hotspot of exploration in the world. The subsalt structure of the basin is generally NE–SW trending. From west to east, the Santos Basin is composed of the western uplift belt, the central depression belt, the eastern uplift belt, and the continent–ocean transition belt.

The tectonic evolution of the Santos Basin is related to the disintegration of the Gondwana continent and the expansion of the Atlantic Ocean since the Mesozoic. It experienced three stages of tectonic evolution as follows. (a) The rift period from the deposits of the Picarras Formation to the Barra Velha Formation; (b) the transition period from the deposits of the Ariri Formation; and (c) the drift period from the deposits of the Guaruja Formation to the present day. Correspondingly, three
sets of giant thick sedimentary sequences were developed, namely the continental giant sequences of the Guaratiba Group in the rift period, the evaporative salt giant sequences of the Ariri Formation in the transition period, and the marine giant sequences of the passive continental margin carbonates, deep-sea mudstones, and deep-sea turbidite sandstones in the drift period (Figure 2). From the bottom to the top, the basin mainly develops four sets of reservoirs: the lacustrine limestone of the Cretaceous Guaratiba Group, the shallow-sea sandstone, carbonate of the Florianopolis Group, the turbidite sandstones of Santos Group, and the turbidite sandstones of the Paleogene–Neogene Marambala Group. Oil and gas are mainly enriched in the limestone reservoir of the subsalt Guaratiba Group. Two sets of source rocks are mainly developed in the basin, one is the lacustrine source rocks of the Lower Cretaceous Barremian–Aptian Stage Guaratiba Group in the subsalt rift period, and the other is the marine source rocks of the Upper Cretaceous Cenomanian–Turonian Stage Itajai-Acu Formation in the postsalt drift period. In recent years, the discoveries of a large amount of oil and gas have confirmed that the lacustrine mudstones of the Guaratiba Group deposited in the subsalt rift period are the main source rock of the basin.

3. METHODOLOGY

For the first time, based on a large collection of geochemical parameters, logging data of 51 wells and the geochemical data of 16 wells, the geochemical characteristics of source rocks of different strata of wells were evaluated from three aspects: organic matter abundance, type, and maturity. Then, based on the logging data, the thicknesses of dark mudstones of 40 wells in the Itapema Formation and 12 wells in the Picarras Formation, the ratio of the dark mudstone thickness to the formation thickness were counted. Next, combined with the seismic interpretation results and sedimentary facies, the thicknesses were analyzed according to the law of dark mudstones developed in deep and semideep lacustrine facies. Then, based on the TOC of 15 wells in the Itapema Formation and 5 wells in the Picarras Formation, combined with the lithofacies paleogeography characteristics and the thickness of the dark mudstones, the horizontal distribution diagrams of TOC of the two formations of the subsalt source rocks were compiled. Taking TOC ≥0.40% as the standard of effective source rock in logging data, the horizontal distribution diagrams of the thickness of the two formations of the subsalt source rocks were drawn. Finally, the hydrocarbon generation potential and favorable areas for development in the Santos Basin were clarified.

4. RESULTS

4.1. Organic Matter Abundance. Organic matter abundance is commonly used to represent the relative content of organic matter in source rocks, which is an important basis for measuring and evaluating the hydrocarbon generation potential of source rocks. In this paper, the organic matter abundance of the subsalt Itapema Formation and Picarras Formation source rocks in the Santos Basin were evaluated by the industry standard for the evaluation of organic matter abundance in continental source rocks issued by the China National Petroleum Corporation in 1995. The evaluation indexes mainly include the TOC, chloroform bitumen “A”
content, total hydrocarbon content (HC), and hydrocarbon generation potential ($S_1 + S_2$) (Table 1).

The TOC of the Itapema Formation source rocks ranges from 0.40 to 7.32%, with an average of 1.38%; the chloroform bitumen “A” content varies from 0.38 to 0.69%, with an average of 0.52%; the HC ranges from 139.3 to 1791.4 μg/g, with an average of 677.4 μg/g; the $S_1 + S_2$ is between 1.09 and 50.20 mg/g, with an average of 12.50 mg/g, which meets the standard of good source rock (Table 2).

The TOC of the Picarras Formation source rocks ranges from 0.71 to 4.76%, with an average of 2.14%; the chloroform bitumen “A” content is 0.24 to 0.28%, with an average of 0.26%; the HC ranges from 235.0 to 895.5 μg/g, with an average of 565.2 μg/g; the $S_1 + S_2$ varies from 2.70 to 66.30 mg/g, with an average of 19.00 mg/g, reaching the standard of good source rock (Table 2).

Comparing the organic matter abundance of the two formations of source rocks, the source rocks of the Itapema Formation and Picarras Formation all meet the good source rock standard, which is consistent with the previous research results that regard them as a whole. However, the organic matter abundance characteristics of the two formations of source rocks also have certain differences. The organic matter abundance of the Itapema Formation shows a higher heterogeneity than that of the Picarras Formation, which has a greater impact on the interval. Moreover, the HI can also reveal the hydrocarbon potential. The HI of the source rocks of the Itapema Formation is 38.55, mainly type I and type II (Figure 5). Besides, the indicators of chloroform bitumen “A” and its family compositions and rock pyrolysis parameters show that the saturated hydrocarbon content of the Itapema Formation source rock is 38.55% and nonhydrocarbon + asphaltene content, rock pyrolysis parameters (HI, $S_1 + S_2$, HI–$T_{max}$ and HI–OI diagram), and kerogen carbon isotope value ($\delta^{13}C$) are used to evaluate the organic matter types of the subsalt source rocks (Table 3).

From the HI–$T_{max}$ and HI–OI diagrams, it can be seen that the organic matter type of the Itapema Formation source rock is mainly type I, followed by type II (Figures 3 and 4). In addition, the kerogen carbon isotope has become the most effective parameter to determine the organic matter type due to little change in the thermal evolution process (generally 1–2‰, with the maximum value not exceeding 3‰). The $\delta^{13}C$ of the Itapema Formation source rock varies from −32.87 to −22.72‰, mainly with light carbon isotope characteristics, indicating that the organic matter type is mainly type I, followed by type II (Figure 5).

4.2. Organic Matter Type. The organic matter type is an important indicator to measure the quality of organic matter in source rocks. It determines the hydrocarbon generation potential of organic matter in source rocks and the nature of generated hydrocarbons (oil or gas) and directly affects the petroleum perspective of a sedimentary basin. In this paper, chloroform bitumen “A” and the family compositions (saturated hydrocarbon content, saturated hydrocarbon/aromatics value, and nonhydrocarbon + asphaltene content), rock pyrolysis parameters (HI, $S_1 + S_2$, HI–$T_{max}$ and HI–OI diagram), and kerogen carbon isotope value ($\delta^{13}C$) are used to evaluate the organic matter types of the subsalt source rocks (Table 3).

Table 1. Evaluation Indexes of the Organic Matter Abundance of the Continental Source Rocks (SY/T 5735-1995)\(^a\)

| Source rocks grade | poor | medium | good | best |
|--------------------|------|--------|------|------|
| TOC (%)            | 0.4–0.6 | 0.6–1.0 | 1.0–2.0 | >2.0 |
| chloroform bitumen “A” (%) | 0.2–0.4 | 0.4–0.6 | 0.6–0.8 | >0.8 |

\(^a\)TOC—total organic carbon content; HC—hydrocarbon content; $S_1 + S_2$—hydrocarbon generation potential.

Table 2. Evaluation Indexes of the Organic Matter Abundance of the Subsalt Source Rocks in the Santos Basin

| horizon        | TOC (%) | chloroform bitumen “A” (%) | HC (μg/g) | $S_1 + S_2$ (mg/g) | HI (mg/g TOC) | evaluation |
|----------------|---------|---------------------------|-----------|-------------------|--------------|------------|
| Itapema Formation | 0.4–7.32/1.38(71) | 0.38–0.69/0.52(3) | 139.3–1791.4/677.4(14) | 1.09–50.2/12.5(61) | 405.9–994.0/712.8(23) | good source rock |
| Picarras Formation | 0.71–4.76/2.14(19) | 0.24–0.28/0.26(2) | 235.0–895.5/565.2(2) | 2.7–66.3/19.0(24) | 292.1–986.0/697.5(13) | good source rock |

Table 3. Evaluation Indexes of the Organic Matter Type of the Continental Source Rocks (SY/T 5735-1995)\(^a\)

| evaluation indexes | I | II | III |
|--------------------|---|----|-----|
| chloroform bitumen “A” and the family compositions | saturated hydrocarbon content (%) | 40–60 | 30–40 | 20–30 | <20 |
|                    | saturated hydrocarbon/aromatics value | >3.0 | 1.6–3.0 | 1.0–1.6 | <1.0 |
|                    | nonhydrocarbon + asphaltene content (%) | 20–40 | 40–60 | 60–70 | 70–80 |
| rock pyrolysis parameters | HI (mg/g) | >700 | 350–700 | 150–350 | <150 |
|                    | $S_1 + S_2$ (mg/g) | >20 | 6–20 | 2–6 | <2 |
| $\delta^{13}C$ (%) | <−28.0 | −28.0 to −26.5 | −26.5 to −25.0 | >−25.0 |

\(^a\)HI—hydrogen index; $\delta^{13}C$—kerogen carbon isotope.
The diagrams of HI$-T_{\text{max}}$ and HI$-\text{OI}$ show that the organic matter type of the Picarras Formation source rock is mainly type I (Figures 3 and 4). The $\delta^{13}$C of the Picarras Formation source rock ranges from $-31.7$ to $-18.5$‰, and the distribution range is wider than that of the Itapema Formation, indicating that the organic matter type is mainly type I and type II$_I$ (Figure 5). In addition, the data of chloroform bitumen "A" and its family compositions in the Picarras Formation source rock are relatively lacking and have only one sample data from one well. The saturated hydrocarbon content is 43.02%, the saturated hydrocarbon/aromatics value is 4.0, and the non-hydrocarbon + asphaltene content is 46.23%. Moreover, the rock pyrolysis parameter HI ranges from 292.1 to 927.0 mg/g, and $S_1 + S_2$ varies from 2.7 to 66.3 mg/g (Figure 5). It is comprehensively determined that the organic matter type of the Picarras Formation source rock is mainly type I and type II$_I$, followed by type II$_{II}$.

Compared with the organic matter types of the two formations of source rocks, the organic matter types of the Itapema Formation and Picarras Formation are mainly type I and type II$_I$, which is consistent with the previous research results taking them as a whole.13,19,21

4.3. Organic Matter Maturity. The maturity of source rocks represents the thermal evolution degree of the transformation of organic matter to oil and gas, which determines the quantity and resource potential of oil and gas generated by organic matter.9,37 In this paper, the vitrinite reflectance ($R_o$), TAI value, rock pyrolysis peak temperature ($T_{\text{max}}$), and biomarker C$_{29}$-sterane the 20S/(20S + 20R) value are mainly used to determine the organic matter maturity of the subsalt source rocks (Table 4).

The deposition time of the Itapema Formation is earlier than that of the Barra Velha Formation, and there is no excessive tectonic movement during this period.13,27,38 Therefore, it can be inferred that the $R_o$ of the Itapema Formation source rock should be higher than that of the Barra Velha Formation. The average value of $R_o$ of the Barra Velha Formation is 0.60%, and the TAI is between 2.6 and 2.7, indicating that it is in the low-mature stage (Table 5). Thus, it is speculated that the thermal evolution of the Itapema Formation should not be lower than the low-mature stage. In addition, the $T_{\text{max}}$ of the Itapema Formation source rock ranges from 471.0 to 466.0 °C, and the C$_{29}$-sterane 20S/(20S + 20R) is between 0.21 and 0.59. It is comprehensively determined that the Itapema Formation source rock is in the low-mature to the high-mature stage.

The average value of $R_o$ of the Picarras Formation is 1.05% (Table 5), the $T_{\text{max}}$ ranges from 425.0 to 438.0 °C, and the C$_{29}$-sterane 20S/(20S + 20R) varies from 0.25 to 0.56, indicating...
that the Picarras Formation source rock is in the low-mature to the high-mature stage.

The maturities of source rocks of the Itapema Formation and Picarras Formation are in the low-mature to the high-mature stage, and the maturity evolution spans are large. In addition, the samples are mainly from the uplift area in the Santos Basin. The burial depth in the depression area where the source rocks are developed is significantly larger than that in the uplift area, and the maturity of the source rocks in the depression area should be higher.

### 4.4. Horizontal Distribution Characteristics of Dark Mudstones.

The dark mudstones of the two formations are mainly distributed in the western and eastern sags of the central depression belt, but the thicknesses are different. The thickness of the dark mudstones of the Itapema Formation is larger than that of the Picarras Formation (Figures 6 and 7). The dark mudstones of the Picarras Formation were deposited in the early rift period and mainly developed in the semideep lacustrine environment. The scale of the lacustrine basin was relatively small, and the thickness of the dark mudstones ranged from 60 to 300 m. The maximum thickness of the dark mudstones reached 200 m in the western sag and 300 m in the eastern sag (Figure 6). With the continuous continental rifting, the scale of the lacustrine basin was further expanded. The dark mudstones of the Itapema Formation were mainly developed in the semideep and deep lacustrine environment.

| Table 4. Evaluation Indexes of the Organic Matter Maturity of the Continental Source Rocks (SY/T 5735-1995)\(^a\) |
|---|---|---|---|---|---|
| evaluation indexes | immature stage | low-mature stage | medium-mature stage | high-mature stage | overmature stage |
| | | | | | wet gas generation stage | dry gas generation stage |
| \(R_o\) (%) | <0.5 | 0.5–0.7 | 0.7–1.0 | 1.0–1.3 | 1.3–2.0 | >2.0 |
| TAI | <2.6 | 2.6–2.7 | 2.7–2.9 | 2.9–3.3 | >3.3 | 510 |
| \(T_{max}\) (°C) | <435 | 435–445 | 445–480 | 480–510 | >510 |
| \(C_{29}\text{sterane} \ 20S/(20S + 20R)\) | <0.2 | 0.2–0.4 | 0.4–0.6 | >0.6 |

\(^a\)\(R_o\)—vitrinite reflectance; \(T_{max}\)—rock pyrolysis peak temperature.

| Table 5. Evaluation of the Organic Matter Maturity of the Subsalt Source Rocks in the Santos Basin |
|---|---|---|---|---|
| well | stratum | top depth (m) | bottom depth (m) | \(R_o\) (%) | TAI | evaluation |
| W-1 | Barra Velha Formation | | | | |
| | | 5052 | 5055 | 0.60 | 2.6–2.7 | low-mature stage |
| | | 5109 | 5112 | 0.60 | 2.6–2.7 |
| | | 5226 | 5229 | 0.64 | 2.6–2.7 |
| W-2 | Picarras Formation | | | | |
| | | 5576.6 | | 1.05 | 2.6–2.7 | high-mature stage |

Figure 6. Dark mudstone thickness of the Picarras Formation in the Santos Basin.
Figure 7. Dark mudstone thickness of the Itapema Formation in the Santos Basin.

Figure 8. TOC of the Picarras Formation in the Santos Basin. TOC—total organic carbon content.
Figure 9. TOC of the Itapema Formation in the Santos Basin. TOC—total organic carbon content.

Figure 10. Source rock thickness of the Picarras Formation in the Santos Basin.
thickness of the dark mudstones varied from 90 to 390 m, and the maximum thickness of the dark mudstones reached 360 m in the western sag and 390 m in the eastern sag (Figure 7).

4.5. Horizontal Distribution Characteristics of Source Rocks. The TOC of the Picarras Formation source rock ranges from 0.4 to 4.0%, and the maximum content reaches 3.6% in the western sag and 4.0% in the eastern sag of the central depression belt (Figure 8). Also, the TOC of the Itapema Formation source rock varies from 0.8 to 5.6%, and the maximum content reaches 4.4% in the western sag and 5.6% in the eastern sag of the central depression belt (Figure 9).

The thickness of the Picarras Formation source rock ranges from 30 to 220 m, the thickest is in the eastern sag of the central depression belt, with a maximum of 220 m, and the thickness in the western sag reaches 160 m (Figure 10). The thickness of the Itapema Formation source rock varies from 30 to 270 m, the thickest is in the eastern sag of the central depression belt, with a maximum of 270 m, and the thickness in the western sag reaches 210 m (Figure 11).

5. DISCUSSION

The Santos Basin, Campos Basin, and Espirito Santo Basin are located on the southeastern coast of the Brazil and the western bank of the South Atlantic. These three sedimentary basins can be called the Great Campos Basin, which belongs to the passive continental margin basin on the eastern coast of Brazil. They have similar tectonic sedimentary backgrounds. The main source rocks are the lacustrine mudstones of the Lower Cretaceous in the subsalt rift period. Among them, the lacustrine mudstones of the Lower Cretaceous Lagoa Feia Group in the Campos Basin have high organic matter abundance, with TOC ranging from 0.7 to 8.0%, with an average of 2.4%. The $S_1 + S_2$ varies from 3.1 to 90.0 mg/g, with an average of 20.6 mg/g, which meets the best source rock standard and is better than the subsalt source rocks in the Santos Basin. The organic matter types are mainly type I and type II, which have the same characteristics as the subsalt source rocks in the Santos Basin. The maturity is in the immature to the low-mature stage, which is lower than that of the Santos Basin. The thickness of source rocks ranges from 200 to 300 m, which is thicker than the subsalt source rocks in Santos Basin. However, affected by the scale and structural pattern of the rift basin, the distribution area of source rocks is much smaller than that in Santos Basin.

Moreover, the lacustrine mudstones of the Lower Cretaceous in the Espirito Santo Basin also have high organic matter abundance, where the TOC is higher than 4.0%, and the HI is generally higher than 400 mg/g. The organic matter types are mainly type I and type II. The $R_o$ ranges from 0.6 to 1.4%, indicating that the maturity is in the low-mature to the high-mature stage. The distribution area of source rocks is smaller than that of the Santos Basin and Campos Basin.

On the whole, the subsalt source rocks of the Itapema Formation and Picarras Formation in the Santos Basin have a good quality, large thickness, and wide distribution area, indicating that the source rocks have great hydrocarbon generation potential, which is superior to the subsalt source rocks in the Campos Basin and Espirito Santo Basin.

In addition, the subsalt source rocks in the Santos Basin are most developed in the eastern and western sags of the central depression belt. The maximum TOC in the eastern sag reaches 4.0% in the Picarras Formation, 5.6% in the Itapema Formation, and the maximum thickness of the source rocks reaches 220 m in the Picarras Formation and 270 m in the Itapema Formation. The maximum TOC in the western sag reaches 3.6% in the
Picarras Formation and 4.4% in the Itapema Formation, and the maximum thickness of the source rocks reaches 160 m in the Picarras Formation and 210 m in the Itapema Formation. The eastern sag and western sag of the central depression belt become the high-quality hydrocarbon generation centers. Furthermore, the source control theory emphasizes that the distribution of oil and gas fields is around the hydrocarbon generation centers and is strictly controlled by them. This theory is an important theory to guide petroleum exploration in continental petroliferous basins. Therefore, the uplift areas around the eastern sag and the western sag of the central depression belt of the Santos basin are favorable areas for further oil and gas exploration.

6. CONCLUSIONS

(1) The characteristics of source rocks of the subsalt Itapema Formation and Picarras Formation in the Santos Basin are similar while characterized by a high organic matter abundance. Also, the organic matter types are mainly type I and II. The maturities are in the low-mature to the high-mature stage. The source rocks are widely developed on the plane and have a large thickness. The source rocks meet the standard of good source rocks. The TOC of the source rocks of the Picarras Formation ranges from 0.4 to 4.0%, much lower than that of the source rocks of the Itapema Formation, 0.8–5.6%. Moreover, the HI average value of the source rocks of the Itapema Formation is 712.8 mg/g TOC, higher than that of the Picarras Formation, 697.5 mg/g TOC, both revealing a great hydrocarbon potential. The quality of source rocks of the Itapema Formation is better than that of the Picarras Formation.

(2) The subsalt source rocks in the Santos Basin have a good quality, large thickness, and wide distribution area and have a great hydrocarbon generation potential, which is superior to the subsalt source rocks in the similar Campos Basin and Espirito Santo Basin. The eastern sag and western sag of the central depression belt are the high-quality hydrocarbon generation centers, which have the material basis for the formation of large and medium-sized oil and gas fields. The surrounding uplift areas are favorable areas for further oil and gas exploration.

AUTHOR INFORMATION

Corresponding Author
Yinhui Zuo — State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Chengdu University of Technology, Chengdu 610059, China; orcid.org/0000-0003-1272-0219; Phone: +86-18280398276; Email: zuoyinhui@tom.com

Authors
Guoping Zuo — PetroChina Hangzhou Research Institute of Geology, Hangzhou 310023, China
Hongqing Wang — PetroChina Hangzhou Research Institute of Geology, Hangzhou 310023, China
Guozhang Fan — PetroChina Hangzhou Research Institute of Geology, Hangzhou 310023, China
Jiazhen Zhang — State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Chengdu University of Technology, Chengdu 610059, China

Yanggang Zhang — PetroChina Hangzhou Research Institute of Geology, Hangzhou 310023, China
Chaolong Wang — PetroChina Hangzhou Research Institute of Geology, Hangzhou 310023, China
Liu Yang — PetroChina Hangzhou Research Institute of Geology, Hangzhou 310023, China
Liangbo Ding — PetroChina Hangzhou Research Institute of Geology, Hangzhou 310023, China
Xu Pang — PetroChina Hangzhou Research Institute of Geology, Hangzhou 310023, China

Complete contact information is available at: https://pubs.acs.org/10.1021/acsomega.2c03018

Notes
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