Acta Oceanol. Sin., 2021, Vol. 40, No. 2, P. 1–12
https://doi.org/10.1007/s13131-021-1754-x
http://www.hyxb.org.cn
E-mail: hyxbe@263.net

The geological characteristics of the large- and medium-sized gas fields in the South China Sea

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Received 23 March 2020; accepted 17 July 2020

Abstract

By the end of 2019, more than 220 gas fields had been discovered in the South China Sea. In order to accurately determine the geological characteristics of the large- and medium-sized gas fields in the South China Sea, this study conducted a comprehensive examination of the gas fields. Based on the abundant available geologic and geochemical data, the distribution and key controlling factors of the hydrocarbon accumulation in the South China Sea were analyzed. The geological and geochemical features of the gas fields were as follows: (1) the gas fields were distributed similar to beads in the shape of a "C" along the northern, western, and southern continental margins; (2) the natural gas in the region was determined to be composed of higher amounts of alkane gas and less CO_2; (3) the majority of the alkane gas was observed to be coal-type gas; (4) the gas reservoir types included structural reservoirs, lithologic reservoirs, and stratigraphic reservoirs, respectively; (5) the reservoir ages were mainly Oligocene, Miocene, and Pliocene, while the lithology was mainly organic reef, with some sandstone deposits; and (6) the main hydrocarbon accumulation period for the region was determined to be the late Pliocene-Quaternary Period. In addition, the main controlling factors of the gas reservoirs were confirmed to have been the development of coal measures, sufficient thermal evolution, and favorable migration and accumulation conditions.

Key words: coal-type gas, coal measures, thermal evolution, hydrocarbon traps, organic reefs, South China Sea

Citation: Zhang Gongcheng, Wang Dongdong, Lan Lei, Liu Shixiang, Su Long, Wang Long, Tang Wu, Guo Jia, Sun Rui. 2021. The geological characteristics of the large- and medium-sized gas fields in the South China Sea. Acta Oceanologica Sinica, 40(2): 1–12, doi: 10.1007/s13131-021-1754-x

1 Introduction

The South China Sea, the largest marginal sea in the northwestern part of the Pacific Ocean, has an overall area of approximately 350×10^4 km^2. It is surrounded by continents and islands. Its north is bordered by China's Guangdong, Guangxi, Hainan, and Taiwan Provinces. The south is bordered by Belitung, Kalimantan, and Palawan, with the east bordered by the Luzon, and west bordered by the Indo-China Peninsula. The South China Sea resembles a diamond shape, measuring approximately 3 000 km in length and 1 600 km in width. It extends NE to SW along the long axis. An abyssal plain with continental margins is located in the middle region, with an average water depth over 1 000 m. The continental shelf (or island shelf) is relatively flat and the continental slope (or island slope) is rugged.

There are 14 large basins in the South China Sea, which are mainly situated on the continental shelf and slope (Fig. 1). These include the Southwest Taiwan Basin, Zhujiang River Mouth Basin, Beibu Gulf Basin, and Qiongdongnan Basin on the northern continental margin (Zhang et al., 2013b); Yinggehai Basin, Zhongjiannan Basin, Wan'an Basin, and Mekong Basin on the western continental margin; and the Zengmu Basin, Brunei-Sabah Basin, Palawan Basin, Nanweixi Basin, Beikang Basin, and Liyue Basin on the southern continental margin. These basins are known to be filled with Cenozoic sediment and local residual Mesozoic sediment.

The history of the onshore oil and gas explorations around the South China Sea can be traced back 100 years, since the beginning of the 20th century. Large-scale exploration activities commenced during the mid-1960s in the shallow-water areas and expanded to the deep-water areas in the 1980s (Gong, 1997). The explorations for gas in the South China Sea began later than the oil exploration activities. By the end of 2019, more than 220 gas fields had been discovered in the region, and the cumulative proven gas in place was estimated at up to 6 000 billion m^3 (conventional hydrocarbon gas only) in the South China Sea. The gas fields in the South China Sea are distributed in groups, and

Foundation item: The National Petroleum Major Projects under contract Nos 2016ZX05026, 2011ZX05025 and 2008ZX05025; the National Natural Science Foundation Major Research Program of China under contract No. 91528303; the National Program on Key Basic Research Project of China (973 Program) under contract No. 2009CB219400; the Key Laboratory Project of Gansu Province under contract No. 1309RTSA041; the National Natural Science Foundation of China under contract No. 41872172; the SDUST Research Found under contract No. 2018TDJH101.

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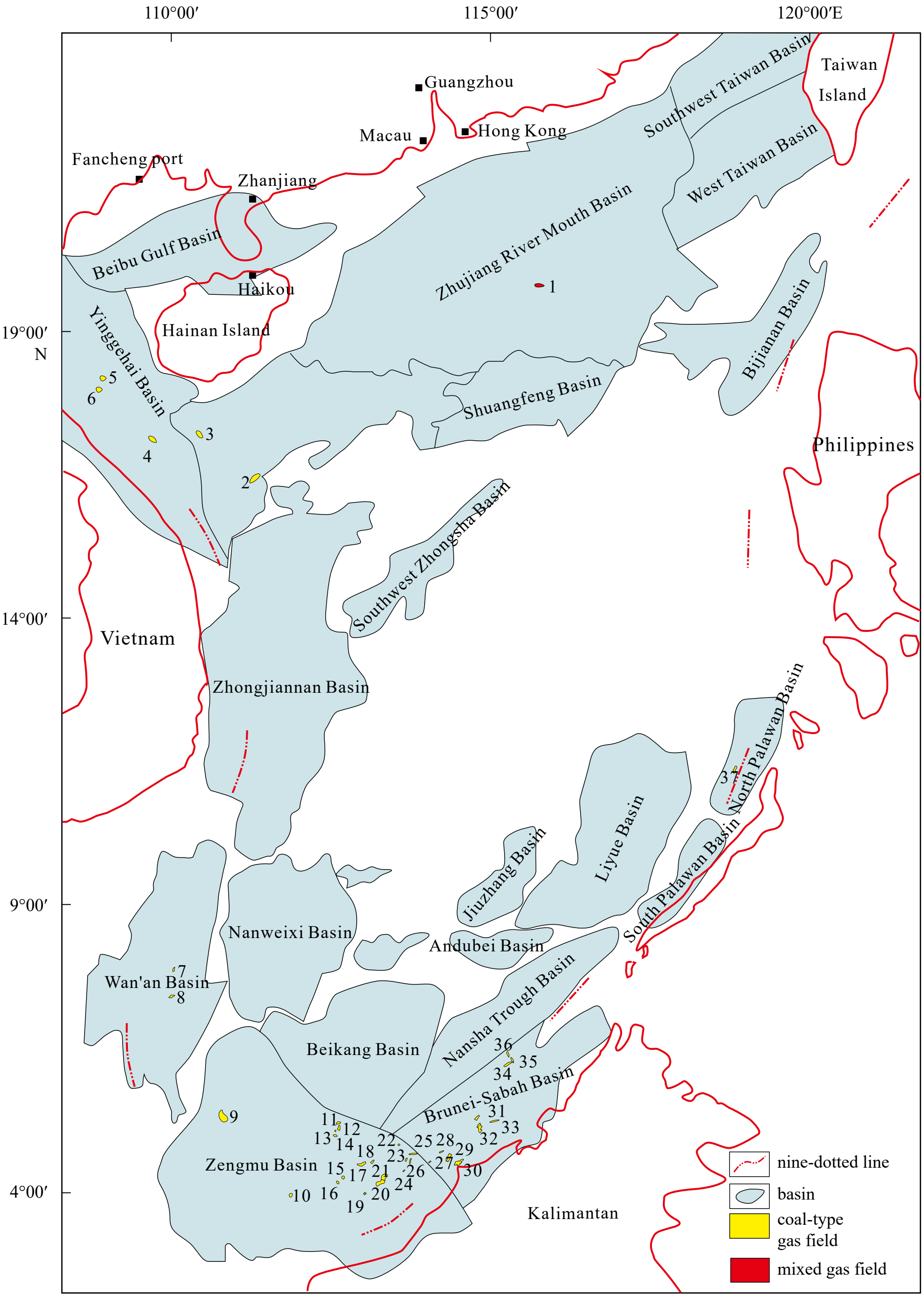


Fig. 1. Distribution map of giant gas fields in the South China Sea. Six gas fields at the continental margin of the northern South China Sea: 1. Liwan 3-1; 2. Lingshui 17-2; 3. Yacheng 13-1; 4. Ledong 22-1; 5. Dongfang 1-1; and 6. Dongfang 13-2; two gas fields at the continental margin of the western South China Sea: 7. Hai Thach; and 8. Lan Tay; twenty-nine gas fields at the continental margin of southern South China Sea: 9. Natuna D-Alpha; 10. K05-1; 11. M1; 12. F23; 13. Serai; 14. M3; 15. Kanowit; 16. Anjung1; 17. F6; 18. Kasawari 1; 19. E8; 20. E11; 21. F13; 22. Jintan; 23. B11; 24. PC4-1; 25. Helang; 26. B12; 27. Baronia; 28. Fairley; 29. Ampa SW; 30. Seria; 31. Kinabalu; 32. Champion; 33. Maharaja Lela-Jamalulalam; 34. Kinarut; 35. Kebabangan; 36. Kamunsu East; and 37. Malampaya-Camago.

mainly located in the northern, western, and southern continental margins (Table 1). The gas field group formations resemble beads in the shape of a “C”, as illustrated in Fig. 1. Therefore, the South China Sea has become one of the largest gas resource areas at the present time.

Previously, due to complex political factors and information blockages, the discussions regarding the South China Sea had focused mainly on the gas geology of individual gas fields or basins (Shi et al., 2008; Pang et al., 2007; Xie et al., 2016; Xie, 2015; Liu and Jin, 1996), rather than the overall geological features of the entire South China Sea. This study presented a systematic analysis of the overall gas distribution, composition, source rock types, and reservoirs in the South China Sea. Unless otherwise specified in this study, the term “gas” refers to hydrocarbon gas.

2 Characteristics of the natural gas

2.1 *Distribution of the gas fields*

The gas fields in the South China Sea are distributed in groups, and mainly located on the northern, western and southern continental margins, as shown in Table 1. The gas field groups resemble a C-shaped bead formation as illustrated in Fig. 1.

The northern gas fields are mainly within the slope zone and extend in an E-W direction. These fields include the Liwan 3-1, Panyu 30-1, Panyu 34-1, and Liuhua 28-2 gas fields, and the Liuhua 4-1, Huizhou 20-1, and Wenchang 9-2 oil and gas fields in the Zhujiang River Mouth Basin; as well as the Yacheng 13-1, Lingshui 17-2, Lingshui 22-1 gas fields in the Qiongdongnan Basin, and the Weizhou 6-1 oil and gas field in the Beibu Gulf Basin (Shi et al., 2008; Pang et al., 2007; Xie et al., 2016; Xie, 2015; Gao et al., 2014; Deng and Chen, 1992).

The western gas fields are mainly located in the shelf-slope area and extend in a N-S direction. The Dongfang and Ledong gas fields in the Yinggehai Basin; Daxiong, Aquamarine, and Xilanhua gas fields in the Wan'an Basin; Jinyin 22, Huayang 10 and 34, Bisheng 16, Danwan 04 and 22, Yinqingxi 18 oil and gas fields in the Zhongjiannan Basin, respectively, are included in the western gas fields of the South China Sea (Liu and Jin, 1996; Zhao et al., 2016; Yang et al., 2015).

The southern gas fields are mainly situated in the shelf zone (Yang et al., 2015) and extend in a NE-SW direction. These fields include the Luconia F and L gas fields in the Zengmu Basin; Champion and Malampaya gas fields; West Linapacan A and West Linapacan B Camago oil fields; Octon and Culanuit oil and gas fields in the Brunei-Sabah Basin; and the Malampaya gas

Table 1. Giant gas fields summary in the South China Sea

Continental margin	Basin	Representative gas field	Discovery time	Gas type	Gas origin	Source		Reservoir	
						Age	Lithology	Age	Lithology
Northern	Zhujiang River Mouth Basin	Liwan 3-1	2006	wet	coal	E_3	mudstone	N_1^1	sandstone
	Qiongdongnan Basin	Lingshui 17-2	2014	wet	coal	E_3	mudstone	N_1^3	sandstone
		Yacheng 13-1	1983	wet dry	coal	E_3	coal-measure	E_3, N_1^2	sandstone
Western	Yinggehai Basin	Ledong 22-1	1995	dry	coal	N_1^{1-2}	mudstone	N_2	sandstone
		Dongfang 1-1	1995	dry	coal	N_1^{1-2}	mudstone	N_2	sandstone
		Dongfang 13-2	2014	dry	coal	N_1^{1-2}	mudstone		sandstone
	Wan'an Basin	Hai Thach	1995		coal	N_1^1	coal	N_1^{1-2}	sandstone
		Lan Tay	1993	wet	coal	N_1^1	carbonaceous mudstone	N_1^3	carbonate
Southern	Zengmu Basin	Natuna D-Alpha	1973	dry	coal	E_3-N_1^3	mudstone	N_1^{2-3}	carbonate
		E11	1971	dry	coal	N_1^1	coal	N_1^{2-3}	carbonate
		K05-1	1997	dry	coal	E_3-N_1^1	coal	N_1^{2-3}	carbonate
		F6	1969	wet	coal	N_1^1	coal	N_1^{2-3}	carbonate
		M1	1972	wet	coal	N_1^1	coal	N_1^{2-3}	carbonate
		F23	1973	wet	coal	N_1^1	coal	N_1^{2-3}	carbonate
		Jintan	1992	wet	coal	N_1^1	coal	N_1^{2-3}	carbonate
		Kasawari 1	2011	dry	coal	N_1^1	coal	N_1^2	carbonate
		Serai	1993	wet	coal	Nk_1^1	coal	N_1^{2-3}	carbonate
		E8	1970	wet	coal	N_1^1	coal	N_1^{2-3}	carbonate
		F13	1969	dry	coal	N_1^1	mudstone	N_1^{2-3}	carbonate
		M3	1970	wet	coal	N_1^1	coal	N_1^{2-3}	carbonate
		B11	1971	dry	coal	N_1^1	coal	N_1^{2-3}	carbonate
		B12	1971	dry	coal	N_1^1	coal	N_1^{2-3}	carbonate
		PC4-1	2006	dry	coal	N_1^1	coal	N_1^{2-3}	carbonate
		Kanowit	2005	wet	coal	N_1^1	mudstone	N_1^2	carbonate
		Anjung1	2008	wet	coal	N_1^1	coal	N_1^2	carbonate
	Brunei-Sabah Basin	Ampa SW	1963		coal	N_1^{2-3}	mudstone	N_1^{2-3}	sandstone
		Seria	1929		coal	N_1^{2-3}	mudstone	N_1^{2-3}	sandstone
		Champion	1970	dry	coal	N_1^{2-3}	mudstone	N_1^{2-3}	sandstone
		Kinabalu	1989		coal	N_1^3	mudstone	N_1^3	sandstone
		Baronia	1967	dry	coal	N_1^3-N_2	mudstone	N_1^3	sandstone
		Fairley	1969	dry	coal	N_1^3-N_2	mudstone	N_2	sandstone
		Kebabangan	1994	wet	coal	N_1^2	carbonaceous mudstone	N_1^3	sandstone
		Kamunsu East	1998	wet	coal	N_1^2	carbonaceous mudstone	N_1^3	sandstone
		Helang	1990	wet	coal	N_1^3	mudstone	N_1^3	sandstone
		Maharaja Lela-Jamalulalam	1990	wet	coal	N_1^{2-3}	mudstone	N_1^3	sandstone
		Kinarut	1972		coal	N_1^2	mudstone	N_1^3	sandstone
	Palawan Basin	Malampaya-Camago	1989		coal	E_2^3-E_3^1	Marlstone	N_1^1	carbonate

field in the Palawan Basin.

2.2 *Composition of the gas*

Natural gas includes hydrocarbon gas and non-hydrocarbon gas, depending on the chemical composition. Hydrocarbon gas refers to methane and C_{2-4} heavy hydrocarbon gases. Meanwhile, non-hydrocarbon gas includes CO_2, N_2, H_2, and H_2S. It has been determined that, based on the obtained statistical data of the gas compositions in all the large gas fields (with geological reserves of over 30 billion m^3) which have been discovered in the northern continental margin (Table 2), the majority of the gas fields in the region produce hydrocarbon gas. The hydrocarbon gas makes up 83% of the total, and the non-hydrocarbon gas accounts for much less, excluding the gas within the Dongfang 1-1 and Ledong 22-1 gas fields. In the Dongfang 1-1 gas field, the hydrocarbon gas accounts for between 6.19% and 92.6% of the total, with an average of 61.2%. The non-hydrocarbon gas has been observed to be dominated by CO_2, which ranges between 0.9% to 71.3% (average: 21.32%), and also N_2, which ranges from 0% to 38.8% (average: 14.4%) (Wang, 2018). In the Ledong 22-1 gas field, hydrocarbon gas makes up 6.03% to 96.02% of the total (average: 58.5%). The non-hydrocarbon gas mainly consists of CO_2 (0% to 93.2%; average: 27.6%), along with N_2 (0.95% to 33.18%; and average: 12.3%). In terms of the drying degrees, the natural gas produced in the Dongfang 1-1, Dongfang 13-2, Ledong 22-1, and Yacheng 13-1 gas fields (Liu and Chen, 2011) has been categorized as dry gas, with a dry coefficient greater than 0.95. The gas produced in the Lingshui 17-2 includes both dry gas and wet gas, with a dry coefficient of 0.92 to 0.97 (Huang et al., 2017). The gas produced in the Liwan 3-1 gas field has been categorized as wet gas, with a dry coefficient ranging between 0.88 to 0.92 (Pan et al., 2001).

The gas produced in the southern segment of the western continental margin and the southern margin share similar compositions with the gas from the northern margin. For example, the lateral distribution of CO_2 is regular, with low CO_2 content in the gas fields in the Palawan Basin, Brunei-Sabah Basin, and the southeastern part of the Zengmu Basin. Also, high CO_2 content has been observed in the western slope zone of the Zengmu Basin. It has been determined that the Luconia L is the largest gas field in the region, with gas reserves composed of 1.3 trillion m^3 of hydrocarbon gas, which accounts for 29%, and 4 trillion m^3 of CO_2, accounting for 71%, as detailed in Fig. 2.

2.3 *Types of gas*

The hydrocarbon gas in the northern gas fields has been determined to be predominately thermogenic gas, with a very small portion categorized as biogenic and mixed gases (biogenic and thermogenic gas) (Fig. 3). The biogenic gas and mixed gas are mainly present in the shallow layers of the Dongfang 1-1 and Ledong 22-1 gas fields. In regard to the thermogenic gas, apart from the Liwan 3-1 gas field, it commonly contains ethane carbon isotopes of over −28‰ and relatively heavy methane carbon isotopes. The ethane carbon isotopes generally range from −28.4‰ to −17.8‰, and the methane carbon isotopes range between −40‰ and −31.7‰, which suggest that the thermogenic gas is essentially a coal-type gas. The gas obtained in the Liwan 3-1 gas field contains ethane carbon isotopes ranging from −29.6‰ to −28.6‰ due to high contributions of aquatic organisms to the organic matter in the area, and is lighter than the common coal-type gases. This type of organic matter is categorized as sapropelic and humic and has lighter percentages of carbon isotopes than the common humic organic matter (Zhu et al., 2008). It is also believed that the Oligocene Enping Formation coal measures, along with the Zhuhai Formation terrigenous marine source rock, provided primary sources of natural gas (Cui et al., 2009), although the Eocene Wenchang Formation lacustrine source rock may have also contributed.

The features of the source rock in the northern regions of the South China Sea are considered to be favorable for coal-type gas generation. For example, as primary source rock, the Miocene Meishan and Huangliu Formations in the Yinggehai Basin, and the Oligocene Yacheng Formation in the Qiongdongnan Basin, as well as the Enping Formation in the Zhujiang River Mouth Basin, contain humic organic matter which are mainly composed of Type II_2-III kerogen. This has been found to provide the material basis for generating coal-type gas. Therefore, these regions possess significant potential for gas generation.

The gas in the Zengmu Basin on the southern continental margin is also known to originate from coal measures (Abdullah and Abolins, 2006). In addition, the coal-measure source rock and the terrigenous marine source rock in the Brunei-Sabah and Palawan Basins have been observed to contain sapropelic-humic type and humic type organic matter, which are considered to be unlikely to promote oil-type gas generation. Therefore, it can be concluded that hydrocarbon gas in that area of the South China Sea is also coal-type gas.

2.4 *Gas reservoir types in the South China Sea*

There are a variety of gas reservoir types located in the large-scale gas fields in the South China Sea. In accordance with the findings presented by Dai (Dai et al., 2014), the gas reservoirs were divided into three types based on the origin of the traps in the present study: structural, lithologic, and stratigraphic traps. Each type was then further divided into several sub-types based on the controlling factors on the traps, as detailed in Fig. 4.

2.4.1 *Structural gas reservoirs*

(1) Anticlinal gas reservoirs: anticlinal traps are widely present in the South China Sea. These types of reservoir were almost always dipped and formed by bending strata in response to tectonic movements. Typical examples include the Liwan 3-1 gas field in the Zhujiang River Mouth Basin and the Seria gas field in the Brunei-Sabah Basin.

(2) Fault anticlinal gas reservoirs: these types of reservoir are relatively common and essentially anticlinal traps formed as a

Table 2. Gas composition data of main gas fields in the South China Sea

Gas field	Hydrocarbon gas/%	C_1/C_{1-5}	CO_2/%	N_2/%	$\delta^{13}C_1$/‰	$\delta^{13}C_2$/‰
Lingshui 17-2	98.02–99.52	0.92–0.97	0.18–1.72	0.1–1.3	−40.5 to −37.2	−26.2 to −24.0
Dongfang 1-1	6.19–92.60	>0.95	0.9–71.3	0–38.8	−38.8 to −31.7	−28.6 to −22.8
Yacheng 13-1	83–89	0.91–0.99	6.53–11.50	0–4.65	−40.0 to −35.0	−27.0 to −24.5
Dongfang 13-2	83–92	>0.95	1.48–3.42	7.0–15.5	−38.0 to −36.1	−26.8 to −25.1
Liwan 3-1	⩾96	0.88–0.92	2.37–3.21	0.04–0.15	−38.0 to −36.6	−29.6 to −28.6
Ledong 22-1	6.03–96.02	>0.95	0–93.2	0.95–33.18	−40.2 to −30.8	−26.0 to −24.2

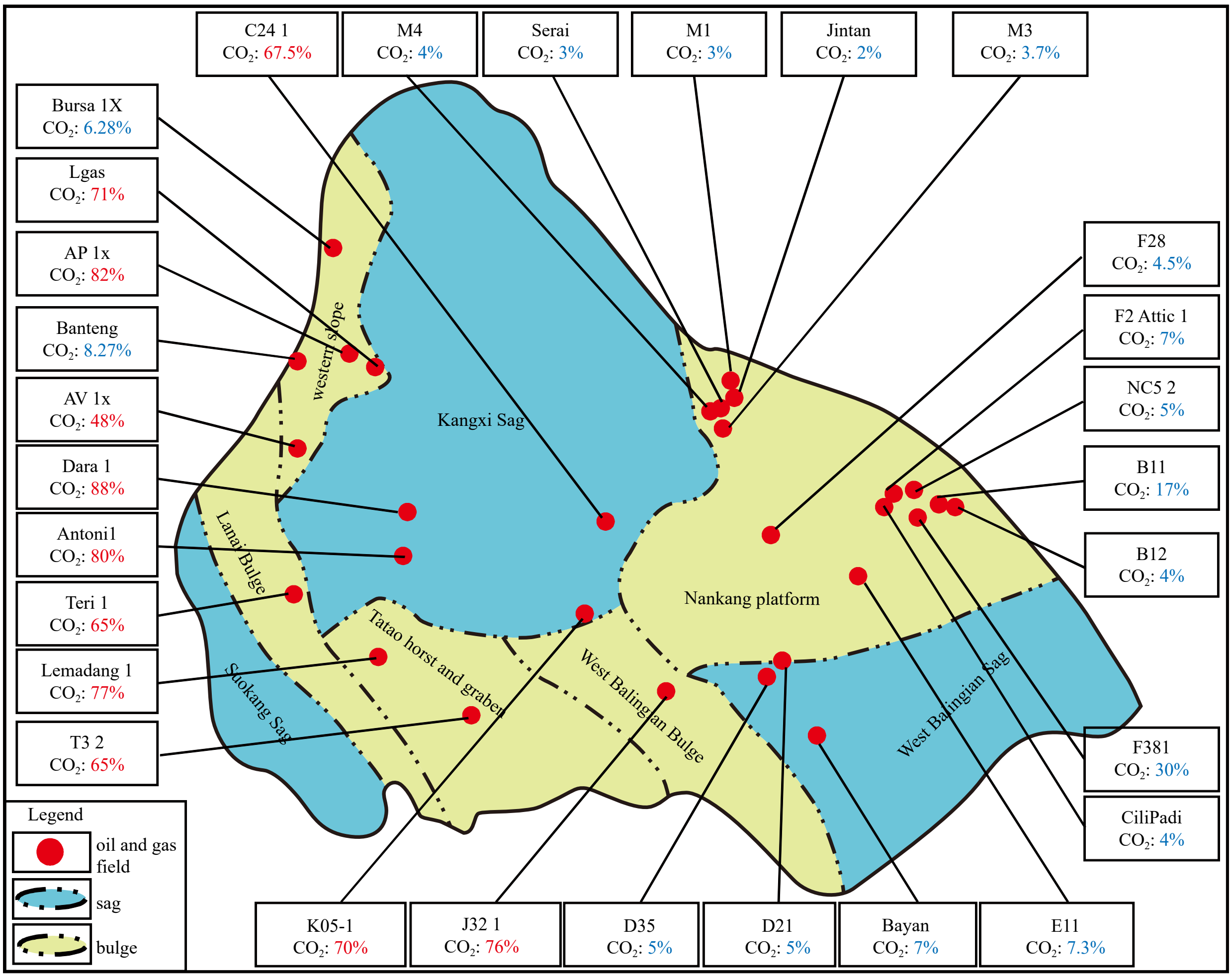


Fig. 2. CO_2 content of main gas fields in the Zengmu Basin in the southern South China Sea.

result of cutting or faulting actions. Typical examples include the Panyu 34-1 gas field in the Zhujiang River Mouth Basin; Yacheng 13-4 gas field in the Qiongdongnan Basin; Aquamarine gas field in the Wan'an Basin (Wang et al., 2017), and the Baram A gas field in the Brunei-Sabah Basin.

(3) Rollover anticlinal gas reservoirs: these types of reservoirs are mainly present in the Brunei-Sabah Basin. They were developed by gas-filled rollover anticlinal traps which had formed in association with the down thrown walls of contemporaneous faults when the deltas propagated towards the sea. Typical examples include the Champion and Ampa SW gas fields.

(4) Fault block gas reservoirs: these types of reservoirs were formed by gas trapped inside fault-screened traps. In the South China Sea, the developed Cenozoic faults had significant control over the hydrocarbon accumulation. Typical examples include the Panyu 30-1 reservoir in the Zhujiang River Mouth Basin, and the Tukau and Fairley reservoirs in the Brunei-Sabah Basin.

(5) Fault nose gas reservoirs: these types of reservoirs were formed by gas trapped inside nose-like structures and blocked by the upward dips of the faults. These reservoir types are broadly presented in the Brunei-Sabah Basin, such as the Magpie and Gannet gas reservoirs.

(6) Uplifted diapir-anticlinal gas reservoirs: these types of reservoirs were formed by the deep natural gas which migrated upward through ductile pathways, and then accumulated in the anticlinal traps which had formed as a result of the deformations of the overlying strata in response to the creeping and uplifting of the plastic strata (for example, the mudstone, salt rock, or gypsum beds) under the conditions of heterogeneous gravity or horizontal stress. Typical examples include the Dongfang 1-1 and Ledong 22-1 gas reservoirs are located in the Yinggehai Basin.

2.4.2 *Lithologic gas reservoirs*

(1) Organic reef gas reservoirs: these types of reservoirs are mainly distributed in the Wan'an, Zengmu and Palawan basins. Typical examples include the Luconia L gas field. These reservoir types are considered to be the most important types of gas reservoirs (Xie et al., 2018) due to the fact that they account for approximately 70% of total gas reserves in the South China Sea.

(2) Lenticular sandstone gas reservoirs: these types of reservoir are composed of lenticular sandstone with a certain porosity and permeability. Significant discoveries have been reported of these gas reservoir types in the canyon water channels extending along the central axis of the Qiongdongnan Basin.

(3) Pinch-out lithologic gas reservoirs: these types of reservoirs are formed by natural gas trapped in reservoirs which had been pinched upward or had decreased in permeability. Typical examples include the Tiga gas field in the Brunei-Sabah Basin and the Dongfang 13-2 gas field in the Yinggehai Basin.

2.4.3 *Stratigraphic gas reservoirs*

These types of gas reservoir are sealed by top and lateral tight

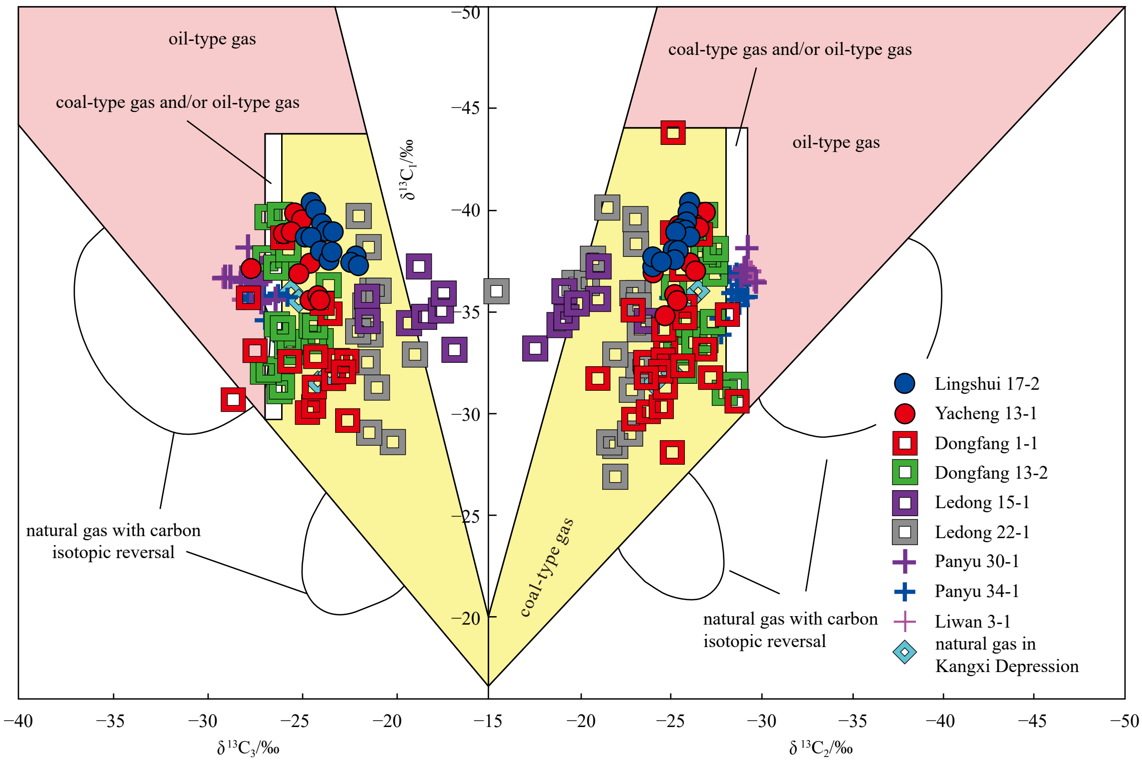


Fig. 3. Identification of major natural gas genetic types in the South China Sea (modified from Dai et al. (2014), Zhao et al. (2005), Huang et al. (1997) and Huang et al. (2017)).

mudstone deposits. A typical example is the Yacheng 13-1 gas field in the Qiongdongnan Basin.

2.5 *Formation period and lithology of the gas reservoirs*

2.5.1 *Formation period*

The gas reservoirs in the South China Sea are considered to be relatively young, having been primarily formed during the Neogene period, and locally during the Paleogene period. The distribution of the Oligocene gas reservoirs is relatively limited. These have been mainly found in the Yacheng 13-1 gas field of the Qiongdongnan Basin, as well as the western section of the Wan'an Basin, and in the Balingian Sag of the southern Zengmu Basin. The Miocene gas reservoirs are the most broadly distributed over the northern, western, and southern continental margins, and specifically in the Zhujiang River Mouth Basin. These include the Lingshui 17-2 gas field in the Qiongdongnan Basin; Dongfang 13-2 gas field in the Yinggehai Basin; central-eastern portions of the gas field group of the Wan'an Basin; west slope gas field group and the Nankang platform gas field group in the Zengmu Basin; Ampa SW and Champion gas fields in the Brunei-Sabah Basin; and Malampaya-Camago gas field in the Palawan Basin. The distribution of the Pliocene gas reservoirs is also limited. These are mainly in the Dongfang 1-1 and Ledong gas fields of the Yinggehai Basin and the Brunei-Sabah Basin. The Eocene strata also may provide potential gas reservoirs, such as those in the Liyue Basin.

2.5.2 *Lithology of the region*

Organic reef and sandstone areas are known to have primary reservoir potential, followed by granite buried hill areas. The organic reef reservoirs are distributed within the Zengmu Basin and the northwest Palawan Basin on the southern continental margin, as well as the Wan'an Basin on the western continental margin. In the Zengmu Basin, organic reef gas reservoirs have mainly developed, such as the Luconia L gas field with 1.3 trillion m^3 of hydrocarbon gas reserves. In addition, in the Wan'an Basin, organic reefs have been found to be mainly distributed in the central uplift. In the northwest section of the Palawan Basin, Nido limestone deposits act as the primary major reservoir areas.

The sandstone reservoirs are mainly distributed within the Zhujiang River Mouth Basin and the Qiongdongnan Basin on the northern continental margin. These types of reservoirs have also been identified in the Yinggehai Basin on the western continental margin, and in the Brunei-Sabah Basin on the southern continental margin. In addition, they may be presented locally in the Eocene strata on the western margin of the Wan'an Basin, along with the southern margin of the Zengmu Basin and the Liyue Basin on the southern continental margin.

2.6 *Accumulation period*

In previous studies, Dai et al. (2003) divided the gas reservoirs of China into five types based on their accumulation stage as follows: (1) super-late hydrocarbon generation and accumulation (Neocene-Quaternary); (2) late hydrocarbon generation and accumulation (Paleogene-Neocene); (3) early hydrocarbon generation and accumulation (predominately Mesozoic); (4) late shape-forming and accumulation (Neocene-Quaternary); and (5) early (predominately Mesozoic) hydrocarbon generation and accumulation.

All of the gas fields discovered in the South China Sea have been found to exhibit the typical features of "super-late hydrocarbon generation and accumulation". The accumulation of gas had mainly occurred during the Pliocene-Quaternary Period. For example, in the Qiongdongnan Basin, the gas accumulation in the Yacheng 13-1 gas field has been determined to have begun occurred at approximately 5.2 Ma, and has continued until the present day.

3 Geochemical characteristics of the source rock

From the perspective of the classic gas geology theories, source control theories, or petroleum system analyses, source rock is considered to be the first element for hydrocarbon accumulation. Global and domestic exploration practices suggest that hydrocarbon gas can be classified into coal-type gas, oil-type gas, and inorganic gas (Dai, 2018), depending on its origin. Coal-type gas includes the gas formed by coal and humic organic matter. In recent years, the unique tectonic paleogeography in the South China Sea confirm that the source rocks of natural gas are mainly

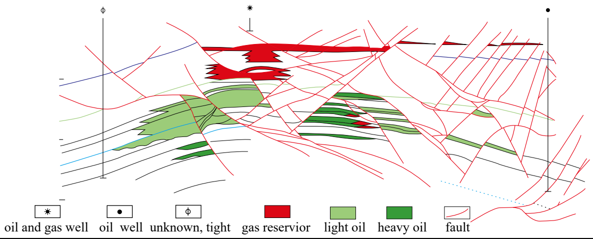
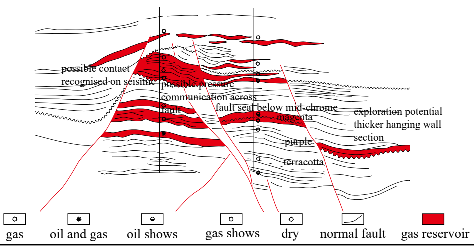
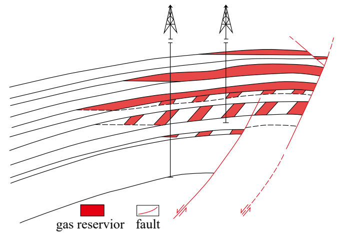
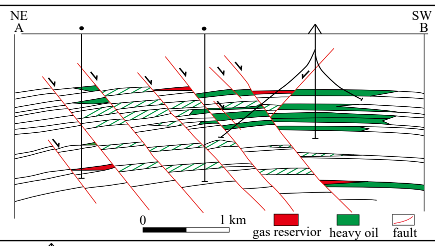
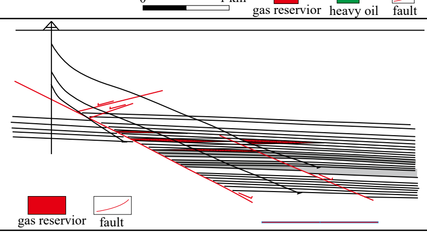
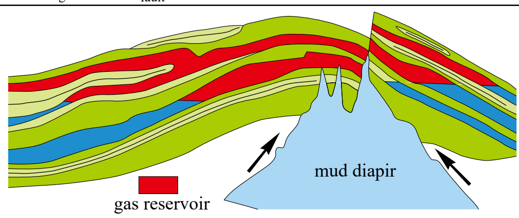
Class	Sub-class	Represetative gas reservoir	Typical cross-section
Structural gas reservoir	anticlinal gas reservoir	Seria	
	fault anticlinal gas reservoir	Baram A Aquamarine	
	rollover anticlinal gas reservoir	Champion Ampa SW	
	fault block gas reservoir	Panyu 30-1 Tukau Fairley	
	fault nose gas reservoir	Magpie Gannet	
	diapir uplifted anticlinal gas reservoir	Dongfang 1-1 Ledong 22-1	

Fig. 4.

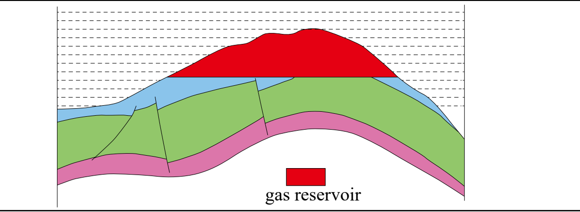
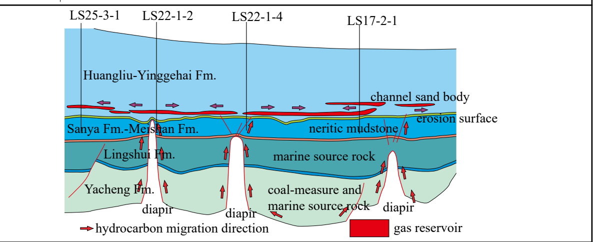
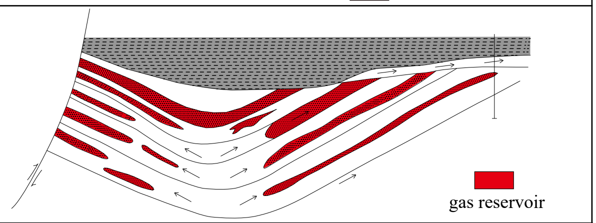
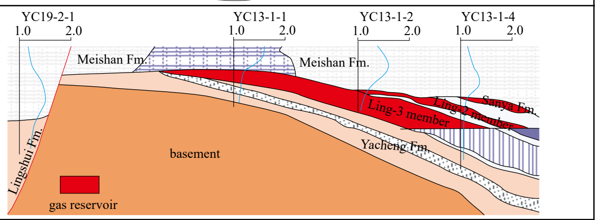
Lithologic gas reservoir	organic reef gas reservoir	L, E11, F6 Malampaya, Lan Tay	
	sand lens gas reservoir	Lingshui 17-2	
	up-dip pinch-out lithologic gas reservoir	Tiga	
Stratigraphic gas reservoir	stratigraphic unconformity screened gas reservoir	Yacheng 13-1	

Fig. 4. Gas reservior classification in the South China Sea.

coal measures (Fig. 5), which may have potentially generated substantial amounts of hydrocarbon gas under adequate thermal evolution conditions (Tang et al., 2013; Zhang, 2012).

The coal measure source rock in the South China Sea mainly include the coal measures in the transitional deltas. The South China Sea was located within a low-latitude zone when the climate was warm and humid during the Cenozoic period, which allowed blooming plants to become abundant. During the Oligocene period, substantial transitional coal-bearing deltas were deposited, with multiple large, moderate, and small rivers flowing into the sea, such as the Zhujiang River, Red River, Mekong River, Rajang River, Baram River and Champion River deltas. In each sedimentary system, source rock were formed in the deltas and near neritic environments. Previous research investigations have revealed that the source rock can be classified into delta coal measures and neritic mudstone, which are known to differ in organic matter content (Zhang et al., 2014). For example, the delta source rock include coal, carbonaceous mudstone, and dark mudstone. These have been found to have high to very high abundance of organic matter, and are characterized by high bicadinane, low oleanane, and high Pr/Ph ratios.

However, the organic matter in neritic mudstone mainly originated from the deltas. In summary, the organic matter can be divided into two types: terrigenous organic matter, which is characterized by high bicadinane, low oleanane, and moderate Pr/Ph ratios; and marine algae organic matter, which is considered to be rare, with no observed bicadinane or oleanane, and low Pr/Ph ratios. Under sufficient thermal evolution conditions, the coal measure source rock in the deltas enter into hydrocarbon generation windows. In addition, the migration and accumulation of natural gas in this area form several gas fields in the delta regions.

3.1 *Northern continental margin*

The coal-bearing deltas were primarily formed during the Oligocene period. The coal measure source rock in the deltas was mainly formed in the early Oligocene and primarily distributed within the delta plain belts. The neritic mudstone source rock was mainly formed in the late Oligocene and distributed in the prodelta-neritic belts, and also further distributed within the slope-sag zones far from the shore areas (Fig. 6).

The delta coal measure source rock was primarily formed during the fault depression period prior to the expansion of the Neo-South China Sea, when an E-W trending was evident, with narrow and long gulfs. At that time, the fault depressions increased as a result of the extensions of the basins on the northern continental margin of the South China Sea. At the same time, the depositional scope had expanded, allowing for the formations of river-fan deltas, delta-tidal flats, and lagoons within a littoral to neritic depositional system. Many of the wells which have been drilled in the northern sections of the South China Sea have encountered multiple coal seams in the lower Oligocene strata (Zhang et al., 2013a, 2007). These coal measures commonly have high abundance of organic matter (Zhang et al., 2016a), over 1.0% TOC, and Types II_2 and III kerogen, as well as over 2 mg/g hydrocarbon-generating potential through pyrolysis.

The neritic mudstone source rock was mainly formed during the late Oligocene period. The continual expansion of the Neo-South China Sea enabled the transition from a fault de-

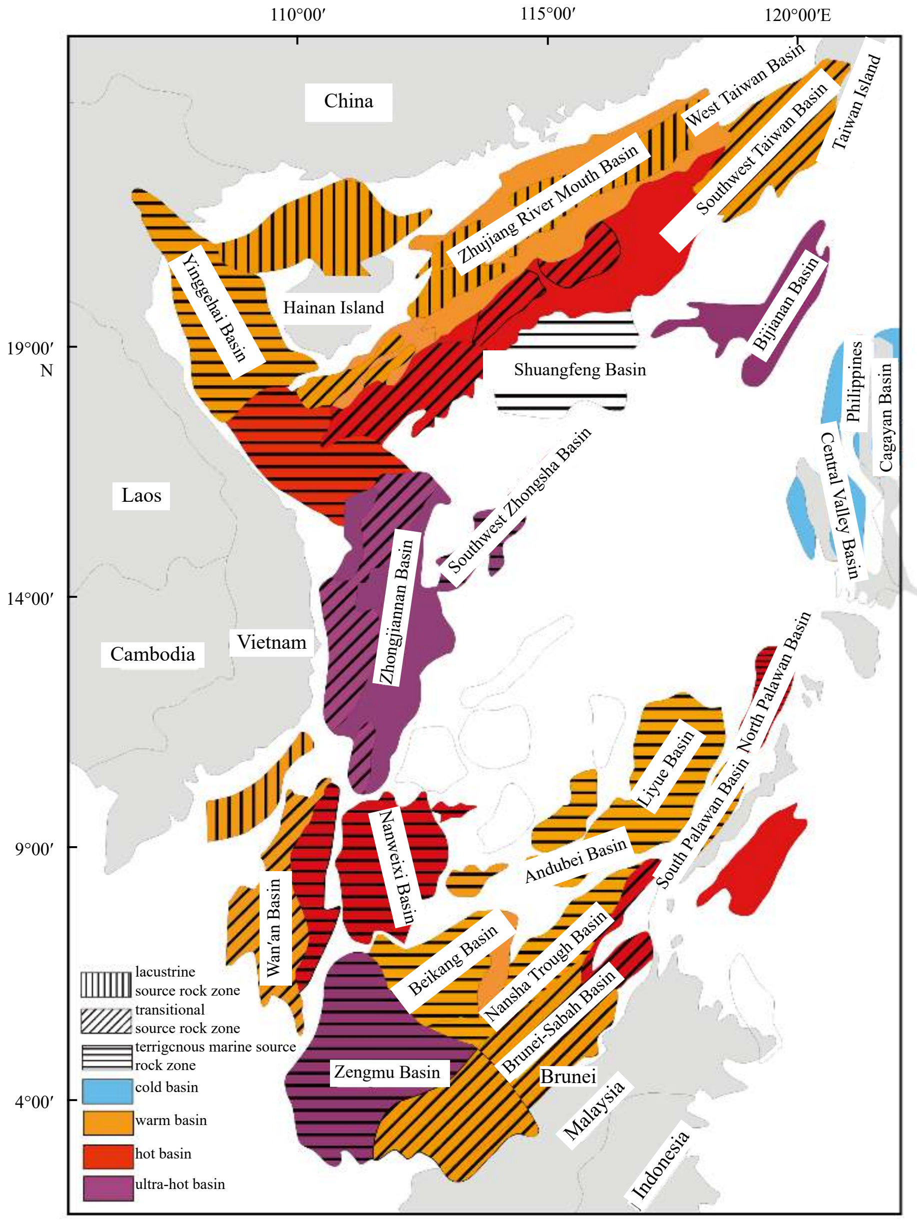


Fig. 5. Source rock distribution and geothermal heat flow map in the South China Sea.

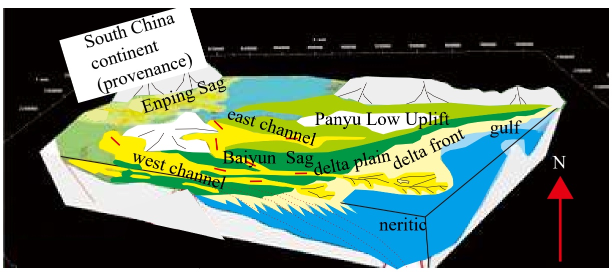


Fig. 6. Binary distribution model of source rock in transitional facies in the South China Sea.

pression stage to a depression stage. As a result, the depositional range further expanded; sea water invaded from the south to the north; the water level rose; and the depositional environment became marine-dominated (Zhang et al., 2009). This had essentially enabled the formation of coastal plains, fan deltas, and deltas within a littoral to neritic bathyal depositional system. The neritic mudstone source rock contained Types II_2 and III kerogen, and had lower organic matter abundance than the coal-measure source rock. The average TOC content of the neritic mudstone source rock has been confirmed to be 1.08% in Zhujiang River Mouth Basin, and 0.71% in the Qiongdongnan Basin. As for the composition of the biomarkers, it is now clear that the neritic source rock contained abundant oleanane, which indicated that the majority of the organic matter originated from terrigenous higher plants, with only small amounts originating from algae (Li et al., 2014).

In the Yacheng 13-1 gas field of the Qiongdongnan Basin, the gas drying coefficient is more than 0.95, and is considered to be a dry gas (Liu and Chen, 2011). The isotopic composition of the gas $\delta^{13}C_1$ ranges between −40.0‰ and −35.0‰ and the $\delta^{13}C_2$ ranges between −27.9‰ and −23.7‰. It has been found that the source rock were mainly the same source rock of the coal measures of the Yacheng Formation. The reservoirs mainly include the sandstone of the Sanya Formation, and the 2nd and 3rd members of the Lingshui Formation (Xie and Tong, 2011). In the Lingshui 17-2 gas field, the gas drying coefficient is between 0.92 and 0.97, indicating that both dry gas and wet gas exist (Huang et al., 2017). In the isotopic composition of the gas, the $\delta^{13}C_1$ ranges between –39.0‰ and –34.0‰, and the $\delta^{13}C_2$ value is between –26.5‰ and –24.4‰ (Huang et al., 2017). The source rock of Yacheng Formation is identified as the main source rock, including coal measures and terrigenous marine mudstone. The reservoirs are mainly composed of the sandstone of the Yinggehai and Huangliu Formations (Zhang et al., 2016b).

In Dongfang 1-1 gas field, which is located in the eastern section of the Yinggehai Basin, has a gas drying coefficient more than 0.95, which falls in the category of a dry gas (Zhao et al., 2005). In the isotopic composition of the gas, the $\delta^{13}C_1$ ranges between –40.45‰ and –35.0‰ and the $\delta^{13}C_2$ ranges between –21.77‰ and –25.7‰ (Zhao et al., 2005; Huang et al., 1997). The source rock mainly include the continental and marine source rock of the Meishan Formation. The reservoirs are mainly composed of the sandstone from the second member of the Yinggehai Formation (Huang et al., 2002).

In the Liwan 3-1 gas field, which is located in the southern section of Zhujiang River Mouth Basin, the drying coefficient has been confirmed to range between 0.88 and 0.92, and is considered to be a wet gas. In the isotopic composition of the gas, the $\delta^{13}C_1$ ranges between –38.0‰ and –36.6‰, and the $\delta^{13}C_2$ ranges between –29.6‰ and –28.6‰. The primary source rock include three sets of source rock: the strata of the Wenchang Formation, Enping Formation, and Zhuhai Formation, respectively. The reservoirs are mainly composed of the sandstone of the Zhujiang and Zhuhai formations (Shi et al., 2010).

3.2 *Western section of the South China Sea*

The coal measure source rock in the western section of the South China Sea was mainly composed of Oligocene-Lower Miocene strata. At that time, the western section was influenced by the northwestward expansion of the sea. The continuous progradation toward southwest caused the basin to be affected by NW extensions, and a delta-littoral neritic depositional system appeared. The coal measures in the Wan’an Basin and the Zhongjiannan Basin have relatively high hydrocarbon-generating potential, in which the S_1+S_2 exceeds 50 mg/g, and the organic matter is mainly of Type II_2 kerogen. In addition, the hydrogen index ranges from 150 to 400 mg/g, even reaching up to 650 mg/g in some samples, which indicates the existence of good source rock. For the mudstone, the TOC content has been found to vary greatly, ranging from 0.1% to 6%, in which the S_1+S_2 ranges from 0.15 to 30 mg/g, and the hydrogen index is lower than 300 mg/g. The organic matter has been found to be mainly Type III kerogen, which reflects medium source rock.

3.3 *Southern section of the South China Sea*

When the Proto-South China Sea died out and the Neo-South China Sea expanded, two types of basin groups appeared in the southern part of the South China Sea (Jin et al., 2004; Zhang et al., 2015, 2018). One type included the foreland basins which had formed in the northern part of Borneo as a result of the subduction of the Proto-South China Sea toward Borneo, such as the Zengmu and Brunei-Sabah Basins. The other type included the Nansha rifted-split basins, which had drifted toward the modern locations from the northern part of the South China Sea with the expansion of the Neo-South China Sea, such as the Liyue and Palawan basins (Xie et al., 2015a; Zhang et al., 2017).

3.3.1 *Foreland basins*

With the subduction of the Proto-South China Sea toward Borneo, a N-S fold thrust belt appeared in the northern part of Borneo, and substantial amounts of sediment were transported northward. Then, during the Oligocene to Miocene periods, a fluvial-delta/ coastal plain littoral to neritic depositional system was formed within the foreland basins.

The Oligocene and early Miocene coal measures, mainly developed in delta environment, and the neritic mudstone were the primary source rock of the Zengmu Basin (Xie et al., 2015b; Liu et al., 2016). The coal measure source rock contained Types II_2 and III kerogen, and the neritic mudstone source rock contained Type III kerogen. The coal measure source rock had a TOC content of over 6%, and a pyrolyzed hydrocarbon content ranging between 8.03 and 291 mg/g. Therefore, it was considered to have had significant hydrocarbon-generating potential. The TOC content of neritic mudstone source rock ranged between 0.3% and 5.5% (average: 1.4%), and a pyrolyzed hydrocarbon content of 10 mg/g or less, with a pyrolyzed hydrocarbon content of less than 2 mg/g in the majority of samples.

The source rock of the Brunei-Sabah Basin was mainly in the Miocene strata. Similarly, the Miocene source rock includes coal measures and neritic mudstone, with the organic matter dominated by Types II_2-III kerogen and a small amounts of Type II_1 kerogen. The mudstone samples exhibit TOC content levels of 0.13% to 5.87% (average: 1.33%). The organic matter is composed of vitrinite and inertinite mainly from higher plants, and small amounts from hydrobiontic algae. The biomarker compounds show relatively high Pr/Ph ratios of 5.8 on average. The abundant oleanane and bicadinane suggest that the organic matter mainly originated from terrestrial higher plants (Zhang et al., 2016c; Liu et al., 2018).

3.3.2 *Rifted-split basins*

The rifted-split basins were filled with marine sediment during the Eocene to Quaternary periods. During the early Oligocene, prior to the formation and expansion of the oceanic crust of the Neo-South China Sea, the Nansha Block was situated on the northern continental margin of the Proto-South China Sea, close to the southern margin of the South China continent. Therefore, it is considered that the South China continent served as a source for the formation of a delta-fan delta/underwater fan littoral to inner neritic to outer neritic depositional system. The Neo-South China Sea began to expand during the late Oligocene to middle Miocene periods. As a result, the Nansha Block was separated from the South China continent and shifted southward to be separated from its source. Subsequently, the supply of terrigenous organic matter became less, and carbonate platforms and organic reef formations developed (Wang et al., 2016). During the depositional processes, the source rock were primarily formed from the Eocene to the early Oligocene, and were dominated by coal measures.

The organic matter in the Eocene and Oligocene marine source rock in the Liyue Basin were mainly composed of Type III kerogen and small amounts of Type II_2 kerogen. The TOC content ranged between 0.14% and 3.53%. The majority of samples were found to have TOC content levels of approximately 0.5%, and some were less than 1.0%. The pyrolyzed hydrocarbon-generating potential was considered to be generally low, at less than 1.0 mg/g in most samples, or over 2.0 mg/g in some samples. The majority of the Eocene samples were defined as poor source rock, with only a few displaying the characteristics of good source rock. In previous investigations, several Oligocene samples were considered to be good source rock, but the majority were poor. The organic matter was dominated by vitrinite and inertinite which had originated from higher pants, with small portions of sapropelic material detected. The distribution patterns of the steranes and terpanes indicated that the C_{27} and C_{29} were higher than the C_{28}. These findings suggested contributions of both terrestrial higher plants and lower aquatic organisms, with greater contribution ratios of terrestrial higher plants.

In summary, the natural gas in the South China Sea can be generally characterized by higher quantities of natural gas in the southern continental margin, and lower abundance of natural gas in the northern continental margin. Meanwhile, greater quantities of natural gas have been discovered in the western continental margin and less natural gas in the eastern continental margin. The controlling factors on the gas reservoirs have been determined to be the joint actions of the multi-stage, large-scale, and skirt-like development of coal-bearing deltas in the continental margins, as well as sufficient thermal evolution, and favorable migration and accumulation conditions. From a macroscopic perspective, the influences of thermal evolution degrees have been found to be obvious. In particular, in the eastern part of the northern continental margin of the South China Sea, the thermal evolution of the source rock has been confirmed to be low, and has not yet entered the stage of abundant gas accumulation. Therefore, those locations mainly contain developed oil fields.

4 Conclusions

The South China Sea has become a proven giant source of natural gas, where the gas fields (groups) resemble beads distributed in the shape of a "C" on the northern, western, and southern continental margins. The major geological and geochemical features of the gas reservoirs can be summarized as follows: (1) the gas composition is dominated by alkane gas. In accordance with the analysis of 131 gas samples, methane accounts for an average of 81.22%; ethane 2.86%; propane 0.96%; and butane 0.45%, respectively. In addition, non-hydrocarbon gases, such as CO_2 and N_2, average 3.67% and 11.23%, respectively, with barely any H_2S detected; (2) the gas types are dominated by coal-type gases; (3) the reservoir types display various characteristics. For example, large gas fields are present in the Oligocene, Miocene, and Pliocene strata, with sandstone and carbonate representing the primary rock types; (4) the main hydrocarbon accumulation period was late, mainly occurring during the Pliocene–Quaternary periods; (5) the gas reservoir types also displayed varying characteristics, which included structural, lithologic, and stratigraphic reservoirs.

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