Discovery and Analysis of Shale Gas in a Carboniferous Reservoir and its Enrichment Characteristics in the Northern Nanpanjiang Depression

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Abstract: Shale gas resources are considered to be extremely abundant in southern China, which has dedicated considerable attention to shale gas exploration in recent years. Exploration of Shale gas has considerably progressed and several breakthroughs have been made in China. However, shale gas explorations are still scarce. Summary and detailed analysis studies on black shale reservoirs are still to be performed for many areas. This lack of information slows the progress of shale gas explorations and results in low quantities of stored black shale. The Carboniferous Dawuba Formation, which is widely distributed and considerably thick, is one of the black shale formations targeted for shale gas exploration in southern China in the recent years. The acquisition and analysis of total organic carbon, vitrinite reflectance, types of organic matter, mineral composition, porosity, and permeability are basic but important processes. In addition, we analyzed the microscopic pores present in the shale. In this study, we also showed the good gas content of the Dawuba Formation, as well as the geological factors affecting its gas content and other characteristics. To understand the prospect of exploration, we compared this with other shale reservoirs which have been already successfully explored for gas. Our comparison showed that those shale reservoirs had similar but not identical geological characteristics.

Keywords: Nanpanjiang Depression; Dawuba Formation; shale gas; organic geochemistry; reservoir; gas content

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1 Introduction

The commercial exploration of shale gas started in the eastern United States in 1621 and developed rapidly up to the 1920s (Curtis, 2002). Currently, five main (Silurian to Cretaceous) basins, rich in shale gas reservoirs and useful for shale gas production, are known in the United States (Hill and Nelson, 2000; Curtis, 2002; Martineau, 2007; GWPC, 2009. Based on the geological conditions of shale gas in the United States, previous authors have formulated a method for shale gas evaluation in China (Wang et al., 2013; Zou et al. 2015; Guo, 2016). Southern China is considered to be rich in shale gas resources (Wang et al., 2013; Guo et al., 2014a; Xi et al., 2017a,b). Previous analyses considered the shale gas enrichment patterns within the complicated tectonic background of southern China (Li and Ou, 2018; Xi et al., 2018). Shale gas research and development have been sporadically carried out in northern China and shale gas exploration has spread all over the country (Liu et al., 2018). Up to present, domestic shale gas exploration has resulted in the discovery of reservoirs in Chongqing (Fuling region), where the gas production of a single well can reach 54.72×10^{4} m^3/d (Guo et al., 2014b). However, shale gas explorations have been scarce in China. Now, driven by increasing energy needs and structural adjustments in the production capacity, shale gas investigation and the relative research work are being intensified. China needs to produce shale gas to fill the natural gas gap. Nevertheless, black shales have been scarcely identified previously, due to the lack of summary studies on the shale gas geological conditions slowing the progress of shale gas exploration in many areas. Investigation demonstrated that the Carboniferous Dawuba Formation includes a thick black shale sequence in the southern Guizhou Province. In correspondence of well CY-1, the gas content of the Dawuba Formation black shales was of 0.88 m^3/ton– 2.84 m^3/ton and the gas was mainly composed of CH_4. In order to understand the shale gas exploration potential and promote further shale gas exploration, we analyzed the sedimentary background, organic geochemistry, reservoir physical properties, gas content, and factors possibly influencing the gas content of the Dawuba Formation black shale. In addition, we compared the geological conditions of the Dawuba Formation shale with other shale gas reservoirs, determined how these conditions can influence the success of shale gas exploration. Our analysis of the shale gas exploration prospect can be used as a reference for future explorations.

2 Geological Background

The Nanpanjiang Depression (Zhao and Ding, 1996), also known as the Dian-Qian-Gui Basin (Mei et al., 2005; Du et al., 2009), is a Devonian continental margin rift basin which includes the southern Guizhou, eastern Yunnan, and northern Guangxi regions (Fig. 1). This basin, which is considered a retro-arc (Li and Li, 2007) or peripheral foreland basin (Qin et al., 1996; Cai and Zhang, 2009), contains multiple cycles of siliceous rocks and mud shales representing shallow water carbonate platform and deep-water basin facies, respectively (BMGRGR, 1985; Zeng et al., 1995; Yang et al., 2012a). Their deposition started during the late Paleozoic–early Triassic and ended in the early Mesozoic (Wang et al., 2009). The Nanpanjiang Depression is bounded by the Shizong-Mile fault to the north-west, the Ziyun-Danchi fault to the north-east, the Pingxiang-Nanning fault to the south-east, and the Babu suture zone to the south-west (Yang et al., 2012b). Its northern part belongs to southern Guizhou, and contains organic-rich shale gas reservoirs of the Lower Carboniferous Dawuba Formation. However, this shale has never been reported before, nor has it been investigated or explored in detail. Only a small number of researchers have described it (Liang et al., 2011). In recent years, it has been discovered that the thick black shales are widely distributed among outcrops of this formation. An investigation well named “CY-1” (Fig. 2) was drilled in southern Guizhou for shale gas exploration. Its study proved that the Lower Carboniferous Dawuba Formation has exploration potential for shale gas with superior geological characteristics. In this paper we describe the characteristics of the organic-rich shale, the organic geochemistry, reservoir properties, and the micropores of the Dawuba Formation based on relevant outcrops and well CY-1. The aim of our study was to summarize the geological characteristics and evaluate the exploration potential for shale gas in this region.

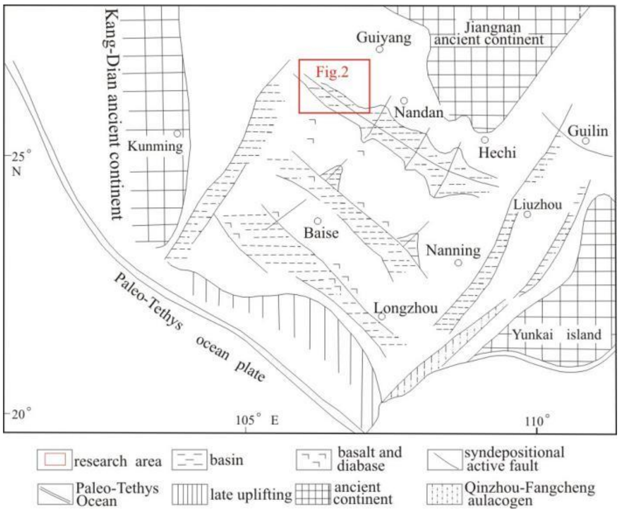

Fig. 1 Sedimentary-tectonic settings (Chen and Zeng,1990; Du et al.,1997)

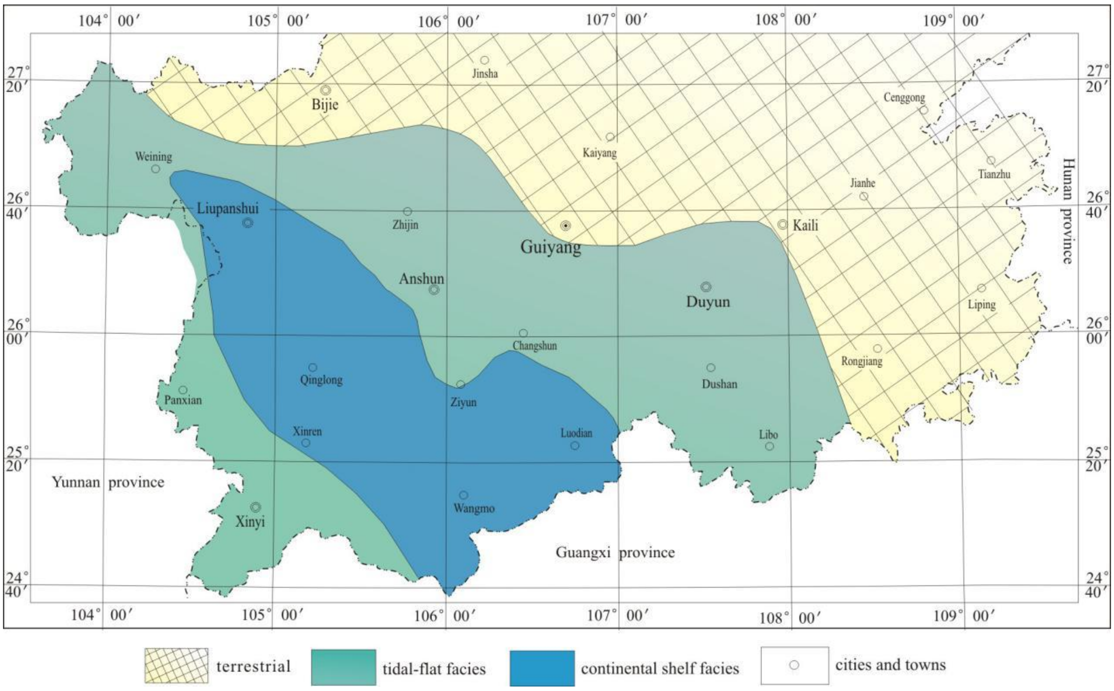

Fig. 2 Sedimentary facies in Lower Carboniferous series in Southern Guizhou

3 Stratigraphic Characteristics

The analysis of samples collected from well CY-1, within the Lower Carboniferous Dawuba Formation (Table 1), showed that the sedimentary water was shallow (S/Ba > 1), while the sedimentary environment was totally anaerobic (V/(V+Ni) > 0.5) and oxygen deficient/oxygen-rich (in 12 samples V/Cr was 4.25–2.00, and in 7 samples it was < 2.00). This formation was constituted by marine deposits (B was generally > 100 ppm except for a small amount). The longitudinal value of B may indicate that many periods of retrogradation and progradation alternated during the deposition of the Dawuba Formation. The sedimentation took place mainly under bathyal and oxygen-deficient conditions and the continental shelf facies of this period has mixed sedimentary characteristics. The formation was generally 209 m thick and mainly a composed of organic-rich shale. Its top and bottom members mainly consisted of siliceous rock and marl, while the middle member was composed of middle-thick mud-crystal limestone and marl (mudstone/stratum ratio generally > 80%). The accumulation thickness of the organic-rich shale was generally > 100 m. The sedimentary environment of this stratum was comprised between the shelf and an inter-platform basin. It was represented by tidal flat facies rocks to the north and basin facies siliceous rocks to the south, accompanied by isolated platforms. The sedimentary water was shallow and characterized by retention conditions, as suggested by the horizontal bedding in the shale and by the laminated-streaky structures in the siltstone.

Table 1 Elements data of well CY-1

Well depth(m)	B	V	Cr	Ni	Sr	Ba	Sr / Ba	V / (V+Ni)	V / Cr
712.48	53	55	27	0.01	603	64	9.42	1.00	2.04
733.28	157	198	108	33	422	92	4.59	0.86	1.83
741.28	101	217	111	33	427	220	1.94	0.87	1.95
749	240	206	78	173	472	139	3.40	0.54	2.64
764.48	115	117	145	65	410	153	2.68	0.64	0.81
805.3	214	197	94	37	390	101	3.86	0.84	2.10

833.85	186	168	73	41	620	99	6.26	0.80	2.30
846.7	41	61	30	10	531	43	12.35	0.86	2.03
860.5	161	170	81	38	298	88	3.39	0.82	2.10
882.21	231	213	114	67	273	129	2.12	0.76	1.87
891.21	182	207	111	41	309	162	1.91	0.83	1.86
933	22	85	22	24	246	61	4.03	0.78	3.86

Note: The unit of the above elements is ppm

In correspondence of well CY-1, the Dawuba Formation was located at a depth of 708 m–933 m, it was 209 m thick, and mainly composed of limestone, with large amounts of mud in the underlying and overlying members. The formation could be divided into five sections from bottom to top, among these, the first, third, and fifth section contained abundant organic-rich shales and had a total accumulated thickness of 153 m. The thickness of the first section was of – 65 m, that of the third section – 40 m, and that of the fifth section – 48 m. Small amounts of siliceous rock were present in the top member of the first section and in the bottom member of the fifth section. The shale of the first section member was the thickest and the most concentrated.

Six outcrop observation points were established on the Dawuba Formation (including well CY-1, see Fig. 2 for the specific locations). Observation points ①–④ were aligned following the shallow to deep water sedimentary transition, while ④–⑥ were aligned parallelly to the sedimentary direction (Fig. 3). At observation point ① there was grey silicarenite, characterized by thin gray-black shale interlayers. this stratum thinning rapidly and had a thickness of only – 40 m. At observation point ② there were fine sands in the upper part, with dark gray-gray thin siltstone-argillaceous siltstone at the top, the rest of the outcrop was composed of 200 m thick black shale. This stratum thickening rapidly, reaching – 250 m. At observation point ④ there was marl in the upper part, with small amounts of shale at the top. a large amount of limestone was present in the middle, while the rest was mainly composed of shale and small amounts of marl. The thickness of the Dawuba Formation was > 245 m, in the same time the thickness of the black shale member was > 180 m. At observation point ⑤, the middle and top members were composed of limestone, the bottom member of arenaceous shale, and the rest of 150 m thick black shale. The thickness of the Dawuba Formation was – 200 m and getted thinner. At observation point ⑥, the formation was – 250 m thick, it contained marl in the middle, while the rest was composed by a thick stratum of black shale (– 200 m).

In general, the black shale of the Dawuba Formation in south Guizhou resulted heterogeneous, it showed a longitudinal lithology change and the characteristics of the lithological assemblage changed laterally.

Below, we describe the organic geochemistry, reservoir characteristics, and gas content reconstructed from the black shale samples collected from well CY-1 (Fig. 4).

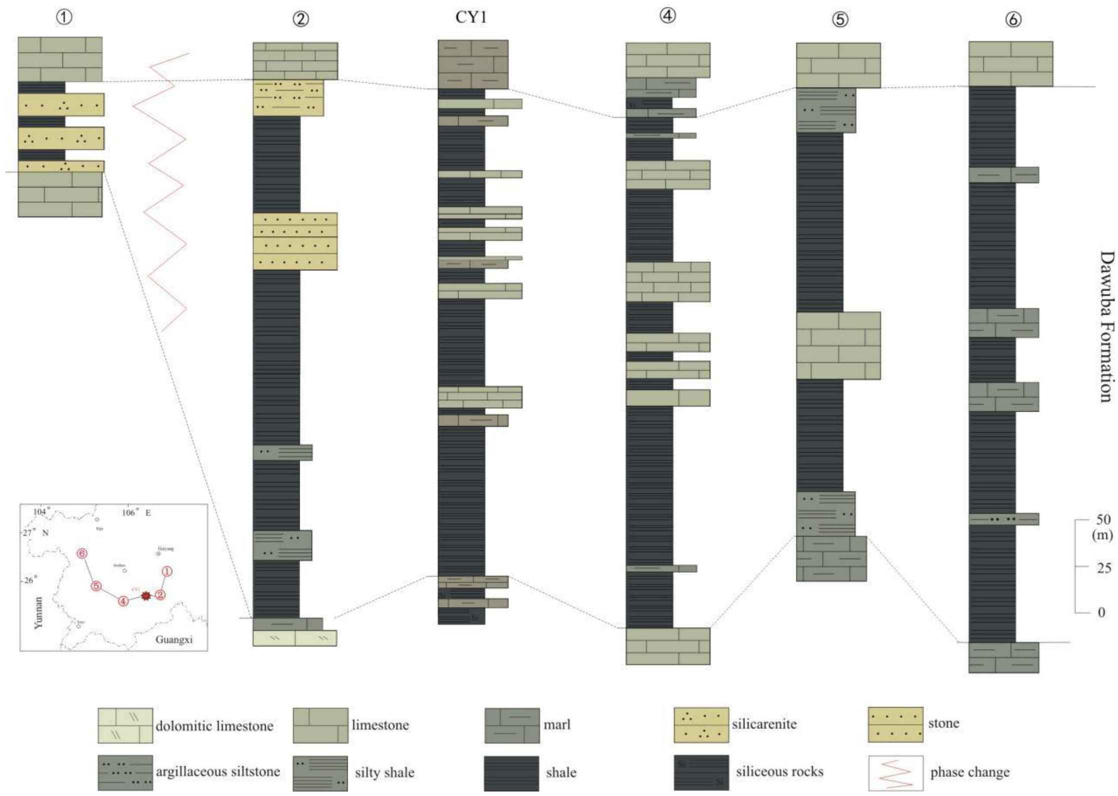

Fig. 3 Stratigraphic correlation of Dawuba Formation in South Guizhou

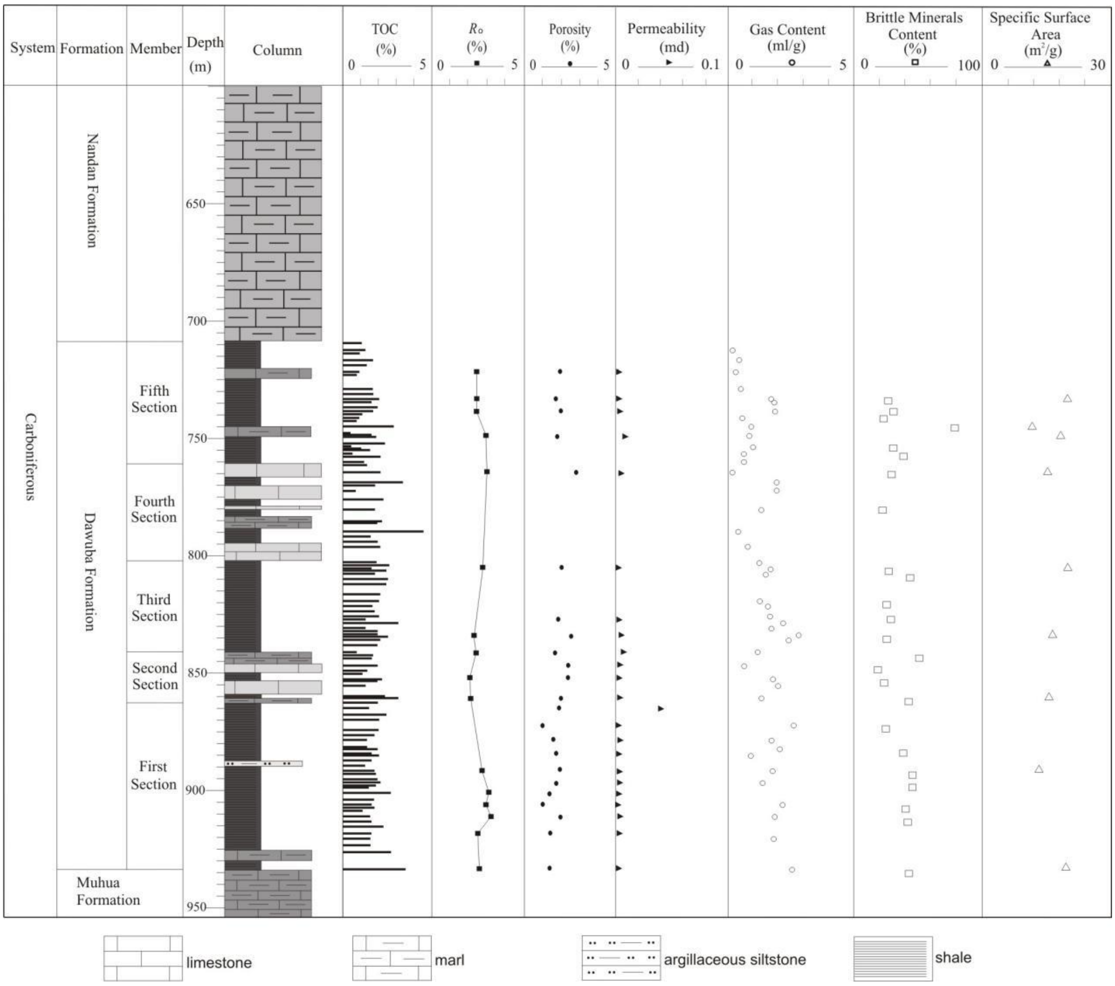

Fig.4 Composite stratigraphic column of Well CY-1

4 Organic Geochemistry Condition

4.1 Organic Matter Abundance

Organic matter abundance is one of the most important basic parameters for the evaluation of source rock and is generally characterized based on its total organic carbon content (TOC). It is believed that an organic carbon content > 0.5% identifies shale gas source rocks (Tissot and Welte, 1978; Welte and Yukler, 1981). The natural gas depends on the decomposition of organic matter in the rocks, a higher organic carbon content is linked to the production of more natural gas. According to the statistics of organic carbon and gas content in the mudstones of the Barnett shale gas reservoir in the United States, there is a clear positive correlation between gas and organic carbon content (Hill et al., 2002; Bowker, 2007; Jarvie et al., 2007). The average value of TOC in this area generally ranged between 1%–5% and greatly increased from north-west to east-south in keeping with sedimentary distribution of this period.

The results obtained from 106 samples collected from well CY-1 demonstrate their high organic carbon content. Overall, TOC was equal to 1%–3%, it lowest value was of 0.21%, the highest 4.51%, and the average 1.81%. Only one sample contained < 0.5% black mudstone with an argillaceous limestone interlayer. Two samples contained 0.5%–0.6% black mudstone with dark gray marl and a calcareous shale interlayer. Five calcareous mudstone samples, limited to the upper member of the first section of the Dawuba Formation, contained 0.6%–1.0%; 98 black shale samples, accounting for 92.45% of the total samples, contained > 1.0%. The TOC increased downward. Overall, this was good source rock with TOC first increasing and then decreasing from the bottom to the top, due to the lithology change. The TOC was distributed evenly, its particularly high values between 802 m and 905 m reveal a higher abundance of organic matter in the third and fifth sections (Fig. 5).

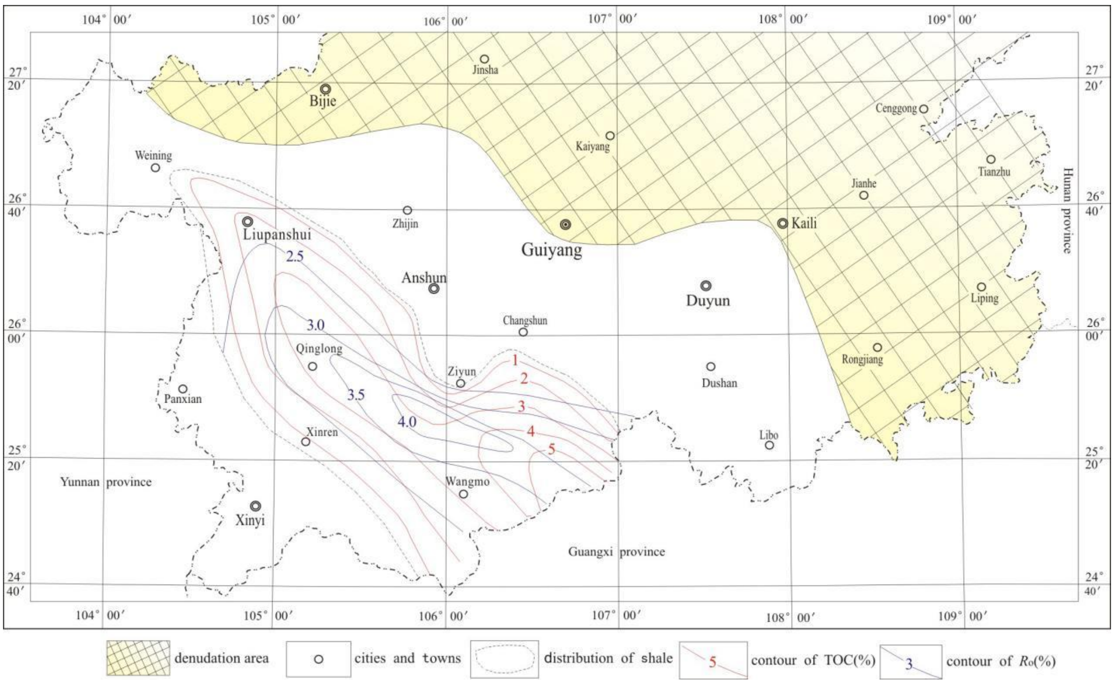

Fig. 5 Contour map of TOC and R_o of the Dawuba Formation in South Guizhou

4.2 Maturity

Although the impact magnitude of maturity on shale gas is not yet clear, it is certain that both a low and high maturity are detrimental for shale gas accumulation. In case of high maturity the reservoir space of the shale gas may decrease, especially during the diagenetic evolution stage (Wang et al., 2013). In this study, we analyzed the maturity of the Carboniferous Dawuba Formation in southern Guizhou by a common method (vitrinite reflectance; R_o, %), moreover, we analyzed the diagenetic evolution stage based on the shale clay mineral composition and on illite crystallinity.

The maturity in this area was generally > 2%, it can also be > 4% when the rift trough core has a rather high maturity. The average value of maturity of the rift trough core was gradually lower towards the two sides, perhaps due to the hydrothermal activity in the rift trough.

The results of 18 samples of organic-rich shale collected in well CY-1 show that this shale is over mature. The minimum value of R_o was 2.13%, the maximum 3.27%, and the average 2.66%. The illite crystallinity and *I/S* composition in the clay minerals did not change significantly in the vertical direction. Illite crystallinity was obviously related to diagenetic evolution and vitrinite reflectance, in terms of illite crystallinity index. Illite crystallinity is negatively correlated to diagenesis, while illite in *I/S* is positively correlated to maturity (Liu et al., 2007). According to the above criteria, we can conclude that the shale in well CY-1 is in the middle stage of diagenesis.

In general, the Carboniferous Dawuba Formation in southern Guizhou is favorable for shale gas accumulation, because the organic-rich shale is over-mature in the middle stage of diagenesis (Fig. 5).

4.3 Types of Organic Matter

The different types of kerogen can affect not only the hydrocarbon-generating capacity of the rock but also the adsorption and diffusion rate of the natural gas. It has been found that the adsorption capacity of different types of organic matter is negatively correlated to the hydrocarbon-generating capacity: type Ⅲ > type Ⅱ > type Ⅰ (Ji et al., 2012). Kerogen maceral is an important classification method for organic matter. In this study, it was used to analyze the type of organic matter corresponding to the phase of high maturity of the Dawuba Formation in well CY-1 (Table 2). This organic matter was mainly composed of exinite and vitrinite, and then sapropelite and inertinite, exinite was mainly represented by a humic amorphogen and few exinite debris, vitrinite by collinite, sapropelite by a sapropelic amorphogen and sapropelic debris, and inertinite by a filament without fluorescence (type index = 21–29). Therefore, the organic matter types contained in the black shale of the Dawuba Formation are mainly type $Ⅱ_2$–Ⅲ (Fig. 4).

Table 2 Kerogen maceral and types from Dawuba Formation in well CY-1

Well depth(m)	Sapropelite(%)	Exinite(%)	Vitrinite(%)	Inertinite(%)	Type index	Type
712.48	1.41	55	34	5	357	$Ⅱ_2$
733.28	2.52	62	30	4	358	$Ⅱ_2$
749	2.13	67	13	19	381	$Ⅱ_2$
764.48	2.06	64	28	4	389	$Ⅱ_2$
805.3	1.82	43	42	13	418	III
833.85	1.28	54	37	8	436	III
860.5	1.34	47	45	8	452	III
905.64	1.99	55	37	7	0	III
911	1.65	71	22	3	0	$Ⅱ_2$
933	2.01	75	19	—	0	$Ⅱ_2$

5 Reservoir Conditions

5.1 Characteristics of Mineral Composition

The analysis of the organic-rich shale of the Dawuba Formation in well CY-1 by X-ray diffraction showed that it was mainly composed of clay minerals and quartz. Clay minerals oscillated between 13%–69%, and constituted on average the 43%. Quartz oscillated between 5%–45%, and constituted on average the 26%. Several samples also had a high content of feldspar, carbonate minerals, and hematite. They constituted the 0%–36%, 1%–70 %, 0%–28%, respectively. Their distribution was extremely uneven. In addition, the shale contained a small amount of pyrite (generally < 5%). Clay minerals were mainly *I/S* and illite-based, and contained a small amount of chlorite. The relative content of *I/S* oscillated between 64%–89%, and its average was 80.4%. Illite constituted 9%–22% of the clay minerals (average = 12%). The relative content of chlorite was 1%–14% (average = 5.3%). Brittle minerals (quartz, feldspar, pyrite and hematite) oscillated between 11%–79% (average = 34.5%), but oscillated mostly between 30% –50%.

Vertically, the mineral content of this stratum was controlled by the lithology and the lithofacies. The stratum had a higher content of carbonate at the top and at the bottom, in parallel with a lower content of other minerals (the vertical characteristics were noticed at the outcrop observation points). The clay minerals showed a decreasing trend from top to bottom. The quartz minerals gradually increased from top to bottom. Among these, the percentage of brittle minerals was generally stable (> 40% in the first section). Brittle minerals are more conducive to the transformation of the reservoir (Fig. 4).

5.2 Porosity and Permeability

The analysis of 25 samples from the Dawuba Formation collected in well CY-1 showed that the porosity oscillated between 1.04%–2.87% (average = 1.90%), but generally ranged between 1.4%–2.5%. The lowest permeability recorded was of 0.001 md and the highest 0.041 md (average = 0.0033 md) (Fig. 4). The porosity and permeability were generally low and vertically decreased with increasing depth (Fig. 6a, 6b), moreover, they were positively correlated (Fig. 7).

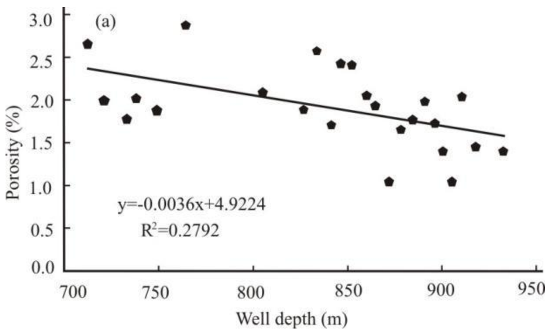

Fig. 6a

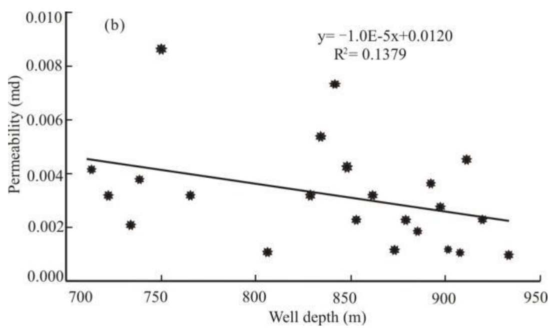

Fig. 6b Relationship between Permeability and Well Depth

Fig. 6 Relationship of well depth, porosity and permeability of the Lower Carboniferous Dawuba Formation in well CY-1

(a), Relationship between Porosity and Well Depth ; (b), Relationship between Permeability and Well Depth.

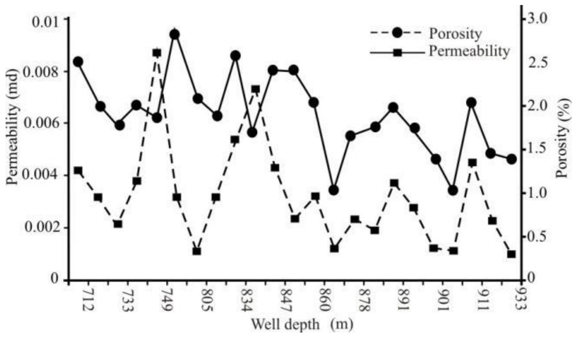

Fig. 7 Relationship between porosity and permeability of the black shale from the Dawuba Formation in well CY-1

5.3 Micro-characteristics of the Reservoir

The analysis by scanning electron microscopy (SEM) revealed that the black shale in well CY-1 presented many types of micropores, irregular fractures, and dissolution fractures in the clay minerals. These fractures were < 2 μm in diameter, and they did not present filling, nor irregular partial illite filling (Fig. 8). Further observations of the microfractures and porosity of the shale by Ar-ion milling and field-emission scanning electron microscopy (FE-SEM) showed that the micro-fractures with diameter < 1 μm were well developed between the matrix and the clay minerals, in the matrix minerals, and in the clay minerals. Some relatively large microfractures were also developed between the organic matter and the matrix minerals, and were connected with intergranular fractures. These fractures are more meshed and better connected. In addition, a few dissolved pores could be observed in the matrix mineral with poor connectivity, relatively isolated. Within a few pyrite particles, we could observe micropores and organic pores with great connectivity (Fig. 9).

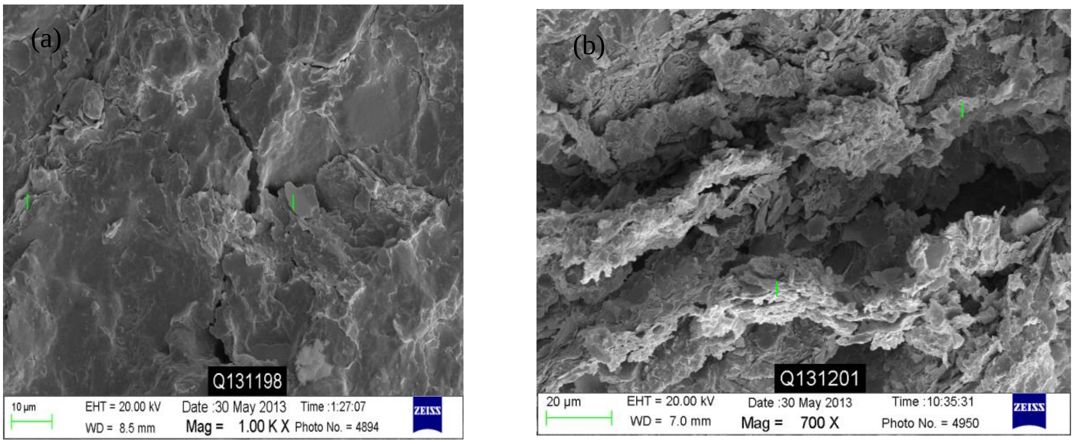

Fig. 8 Micropore characteristics of black shale in well CY-1 by Scanning Electron Microscopy (SEM)

(a), Irregular Fractures in Sheet-like Illite; (b), Filament and Sheet-like Illite Grows and Fills in Dissolution Pores.

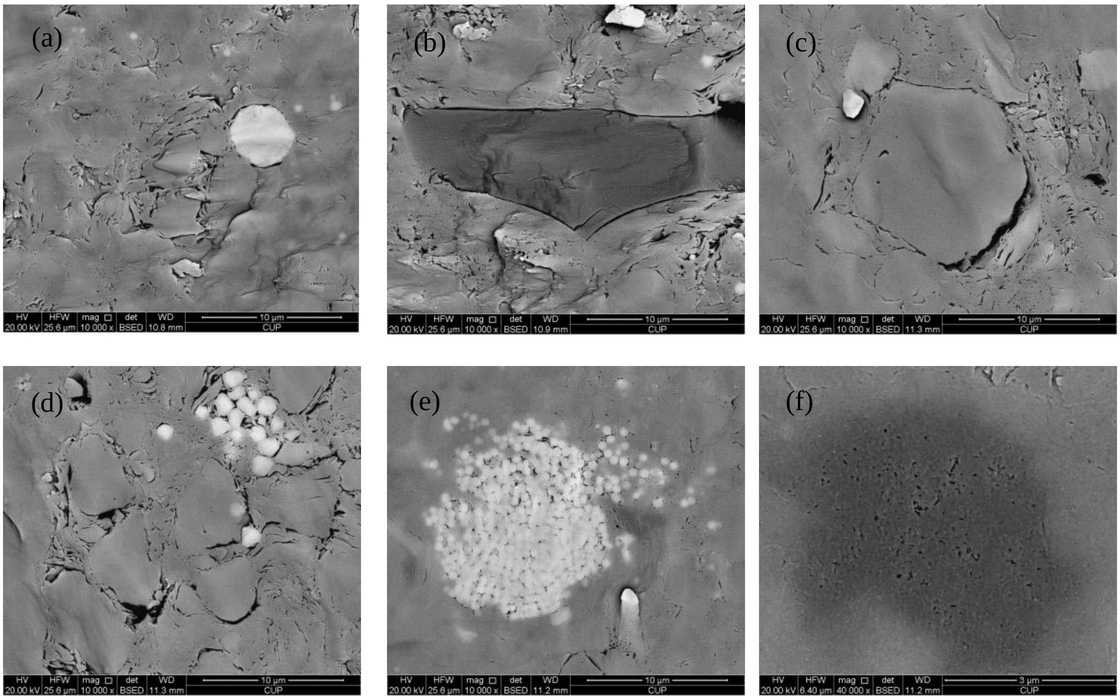

Fig. 9 Micropore characteristics of black shale in well CY-1 by Ar-ion Milling and Field-emission Scanning

Electron Microscopy (FE-SEM）

(a) Microfractures between the clay and matrix minerals; (b) microfractures between the organic matter and the matrix minerals; (c) microfractures and dissolution pores between the clay and the matrix minerals; (d) microfractures in the matrix mineral; (e) pores in the framboid-like pyrite particles; (f) nanopores in the organic matter.

In general, the black shale in well CY-1 contained not only micro-fractures, but also some intergranular and organic pores with great connectivity.

The low temperature nitrogen adsorption method, used to describe micropore characteristics, showed that the pore volume ranged between 0.011 ml/g–0.044 ml/g and the specific surface area oscillated between 7.847 m^2/g–13.419 m^2/g (average = 10.441 m^2/g), with an irregular distribution. The extraction isotherms of the samples indicated that the pore structure was open and complex. A mixture of curve types were observed, but they mainly corresponded to slit-shaped and cylindrical-shaped pores open at both ends, while part of the samples had obvious inkbottle type pores (Fig. 10).

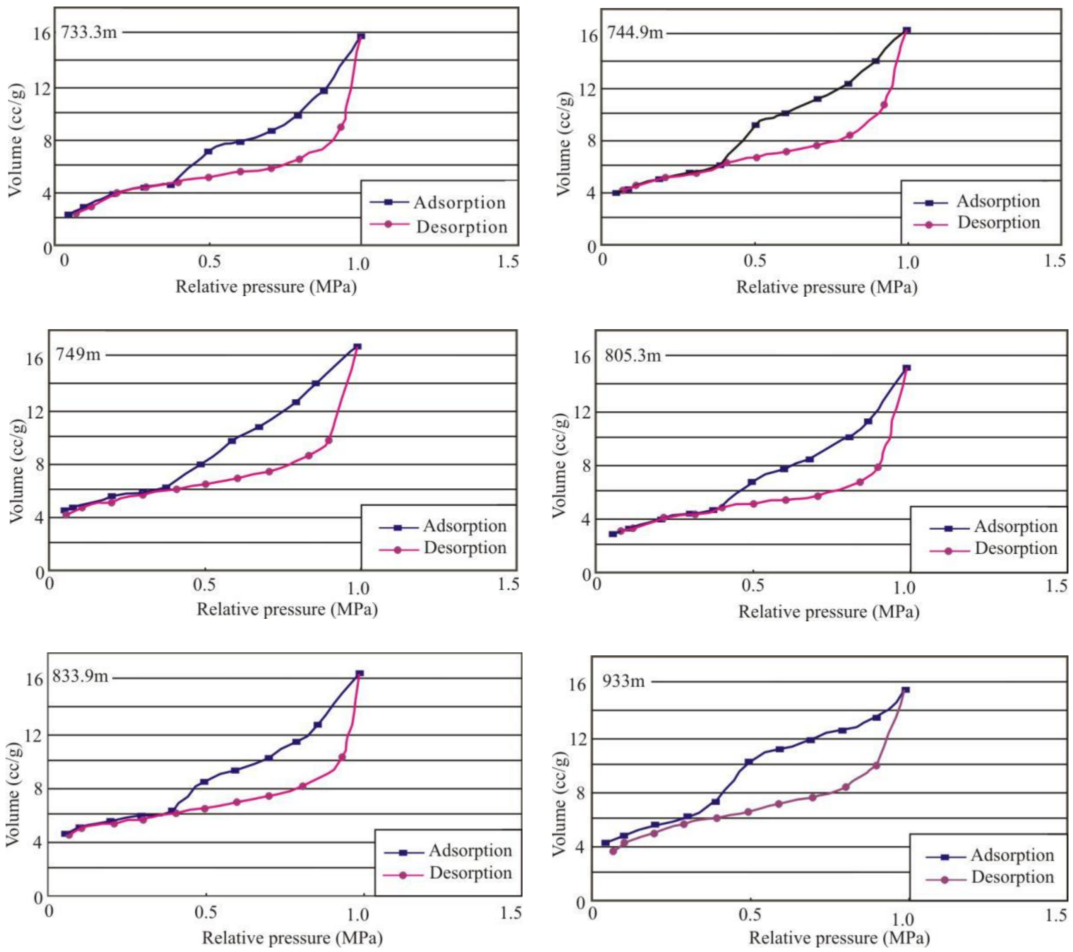

Fig.10 Characteristics of adsorption-desorption isotherms of the Dawuba Formation shale in well CY-1

6 Gas Content

6.1 Analysis of Gas Content in the Field

The shale gas content includes the desorption gas in the field, the lost gas, and the residual gas contents. The desorption gas content in the field is obtained from the cores, the lost gas content is calculated from the gas loss during the drilling and core-taking processes, and the residual gas content corresponds to the residue present in the core, which cannot be completely desorbed in the field (due to time and instrument limitations). The desorption gas in the field was measured using a capillarimeter, designed and manufactured by China University of Geosciences (Beijing). During the measurement process, the fresh core was sealed and the desorbed gas was recorded at 5 min intervals. We obtained the ordinary (20 ℃), ground (combined with the temperature of the specific drilling depth), and high (90 ℃) temperatures for desorption. At the end of the measurements, the gas was released for 2 hours, for a total of < 5 ml.

The desorption experiment was carried out on 44 samples collected in well CY-1, the lost gas content was calculated by linear regression, and the residual gas was obtained by fully crushing and desorbing the core. The gas content of well CY-1 ranged between 0.2 m^3/ton–2.84 m^3/ton (average = 1.39 m^3/ton). Below 768.58 m, the gas content increased from 0.2 m^3/t to 2 m^3/ton. Above 768.58 m, it remained generally oscillated between 1.5 m^3/ton–2.5 m^3/ton. Nevertheless, in two samples between 789 m and 795 m the gas content was < 1 m^3/ton. The lower gas content of this last interval is explained by the presence of a limestone interlayer, of which we sampled the marl.

At shallow burial depths (< 768.58 m), the TOC was slightly lower and the gas content was,gas content in shallow range of 768.58m well depth is generally less than 1 m^3/ton except a very small amount of shale. the gas content was instead relatively stable for depths > 768.58 m. While the limestone sample had a low gas content, the shale samples had high gas contents.

6.2 Enrichment Regularity of Shale Gas

The organic carbon and gas contents of a Lower Carboniferous black shale (Fig. 11a) reported in the present paper are similar to those in previous studies (Hill et al., 2002; Boyer et al., 2006; Bowker, 2007; Jarvie et al., 2007). The gas content increased linearly, in parallel with the organic carbon content. When the organic carbon content was > 2%, the gas content was > 1.6 m^3/ton, additionally, when the TOC was only 0.82%, the gas content was only 1.2 m^3/ton. These data indicate that the organic carbon content was the main factor regulating the adsorption of the shale gas. These relationships also show that that rock still contained a certain amount of gas when the TOC was 0%. We conclude that the organic matter may provide only part of the shale gas storage space, other minerals, fractures, and pores should provide additional storage space, inducing shale gas enrichment.

The relation diagram (Fig. 11b) indicates that there was a weak correlation between the brittle mineral and the gas content. The correlation between quartz and gas content (Fig. 11c) indicates that the gas content increased significantly in parallel with quartz. A study of shale reservoirs in the Lower Paleozoic Longma Formation, in the southeastern Sichuan Basin (Nie et al., 2012), showed that a high content of quartz and other brittle minerals is favorable for the adsorption and enrichment of shale gas, because of their relatively high compaction resistance. The FE-SEM analysis showed a number of microfractures and micropores (Fig. 9c, Fig. 9d) in the quartz, these may greatly improve the shale gas enrichment.

The relation between clay minerals and gas content (Fig. 11d) shows that the clay minerals in the Lower Carboniferous black shale were weakly correlated with the gas content. Although some clay minerals had micro-pores and there are numerous fractures between the brittle and the clay minerals, an increase of clay minerals should result in a decrease of brittle minerals. Therefore, the content of micro-fractures in the brittle minerals was low, so the gas content was not clearly correlated with the clay mineral content. The low correlation found between porosity and gas content (Fig. 11e) demonstrates this concept, although the linear relationship was not obvious. A previous study (Bustin and Ross, 2009) showed that the gas content would increase from 5% to 50% when the porosity increased from 0.5% to 4.2%. Their results are inconsistent with those of our study, perhaps due to the method used for gas collection.

A significant negative correlation was found between permeability and the gas content (Fig. 11f), showing that the gas content of the Lower Carboniferous black-shale decreased with increasing permeability. This relationship was discovered from other places in China (Li et al., 2014), but no specific explanations were provided.

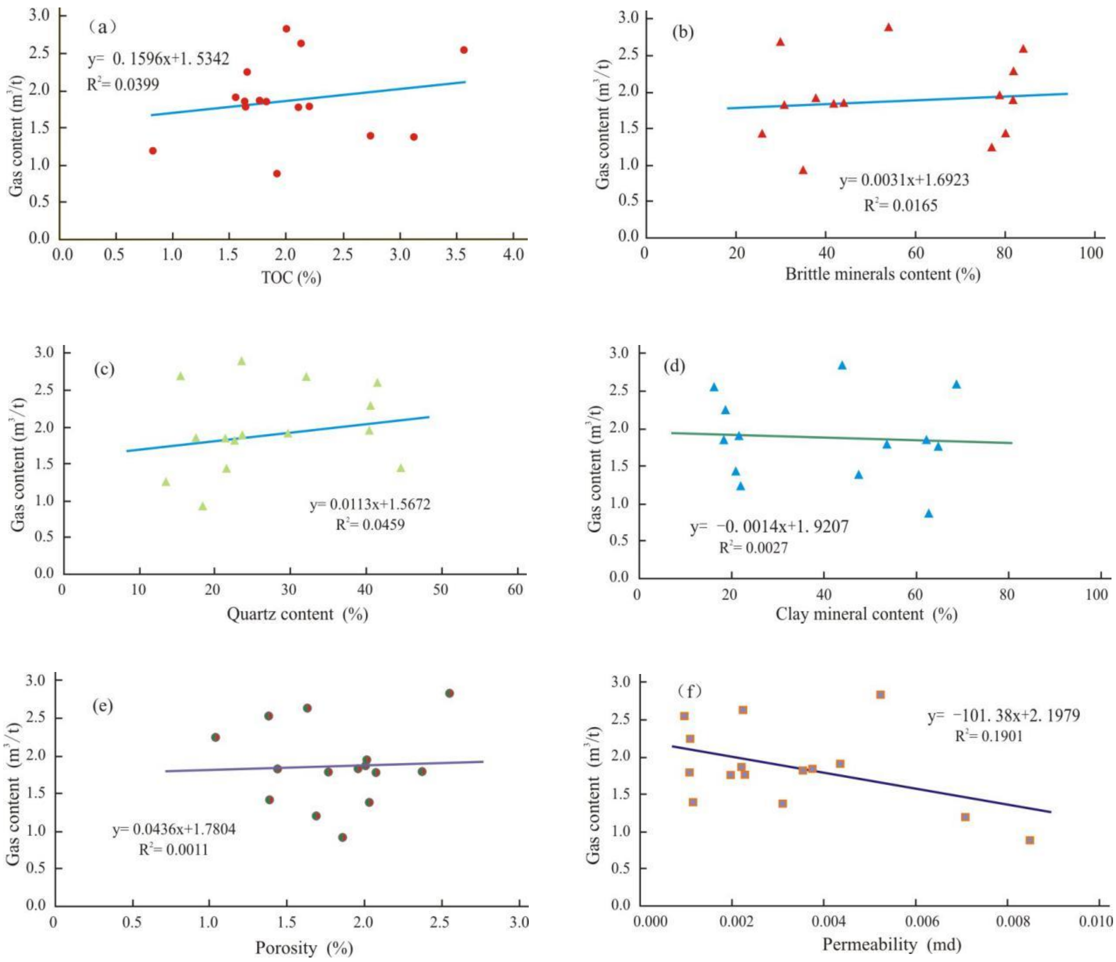

Fig. 11 Influence factors of shale gas content in Well CY-1

(a),Relation of TOC and Gas Content; (b), Relation of Brittle Minerals and Gas Content; (c), Relation of Quartz and Gas Content; (d), Relation of Clay Minerals and Gas Content; (e), Relation of Porosity and Gas Content; (f), Relation of Permeability and Gas Content.

7 Discussions

The Lower Carboniferous Dawuba Formation in the northern Nanpanjiang Depression includes shelf as well as inter-platform basin sedimentary facies, which contain rather thick and homogeneously distributed black shales. Its organic geochemistry index is high, although the maturity is rather high. In well CY-1, this shale shows fundamental parameters and requirements for exploration, such as suitable porosity, permeability, specific surface area, and high gas content. This is a new black shale in southern China, which can be prioritized for future shale gas explorations.

Surveys and explorations of shale gas in the Dawuba Formation (Qiannan area) are still scarce and few drillings have been performed. The comparison between some parameters of the shale reservoir, which had been obtained currently, with the Longmaxi Formation in southern China and five basins in the United States, shows the thickness of the new reservoir is relatively high. Moreover, the TOC is similar to that registered in Ohio, Lewis, and Barnett, but lower than that recorded in the Longmaxi Formation. The maturity is higher than that of the five basins in the United States, but similar to that recorded in the Longmaxi Formation. The gas content is similar to that registered in Antrim, Ohio, New Albany, and Lewis, but lower than that in Barnett and that recorded for the Longmaxi Formation (Table 4). The above characteristics indicate that the Dawuba Formation has a potential for shale gas exploration. At the same time, the Dawuba Formation has low porosity and its organic matter mainly corresponds to types II_2–III. The same characteristics were recorded for the Jurassic Yan'an Formation in the Ordos Basin, which is considered a good shale gas reservoir (Chen et al., 2018). Nevertheless, Further work, such as, evaluation of reservoir modification conditions and optimizing favorable exploration areas, is needed to promote the development of shale gas exploration.

Table 3 Data of geochemical reference comparison of shale gas (Curtis,2002; Guo et al., 2014b)

Property	Antrim	Ohio	New Albany	Barnett	Lewis	Wufeng-Longmaxi (Jiaoshiba in Southern China)	CY-1
Gross thickness(m)	49	91–305	30–122	61–91	152–579	80–120	209
Net thickness (m)	21–37	9–30	15–30	15–6l	61–91	38–42	153
TOC(%)	0.3–24.0	0–4.7	1–25.0	4.5	0.45–2.5	0.55–6.89	0.21–4.51
Vitrinite reflectance (%R_o)	0.4–0.6	0.4–1.3	0.4–1.0	1.0–1.3	1.6–1.88	2.2–3.13	2.13–3.27
Total porosity(%)	9	4.7	10–14	4–5	3–5.5	1.17–8.61	1.04–2.87
Gas content (m^3/ton)	1.13–2.83	1.70–2.83	1.13–2.27	8.50–9.91	0.42–1.27	0.29–5.19	0.2–2.84

8 Conclusions

The Carboniferous Dawuba Formation includes a newly discovered layer of shale gas in the northern margin of the Nanpanjiang Depression in southern China. The distribution characteristics, the organic geochemistry, the reservoir, and the gas content of this gas shale were obtained through a series of surveys and from the CY-1 well. These data will constitute an important reference for the next steps in shale gas exploration. The main results of our study are described below.

(1) The Dawuba Formation is widely distributed in southern Guizhou and includes 2–3 shale layers. Its TOC is generally between 1%–3%, while R_o is generally > 2%, and locally > 4%. The most common types of organic matter are II_2–III, which constitute a good basis for shale gas formation.

(2) The brittle mineral content of the Dawuba Formation shale is generally between 30%–50%, moreover its porosity and permeability are low. The micro-pores are well developed and their specific surface area is between 7.847 m^2/g–13.419 m^2/g.

(3) In the Dawuba Formation, between depths of 708 m–933 m, a good shale gas content was registered. From 708m to 768.58m, the gas content increases from low to high with the increase of depth. The gas content tends to be stable when the depth exceeds 768.58m, and the gas content was generally comprised between 1.5 m^3/ton–2.5 m^3/ton, moreover, it was positively correlated with the TOC and quartz mineral content, and was negatively correlated with permeability. Its relationship with brittle minerals, clay minerals, and pore size remains obscure.

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