The lithofacies and reservoir characteristics of the Upper Ordovician and Lower Silurian black shale in the Southern Sichuan Basin and its periphery, China

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ABSTRACT

The black shale of the Upper Ordovician and Lower Silurian is a significant target for shale gas exploration in the Southern Sichuan Basin. In this study, we introduced a lithofacies classification for shale based on rock mineral composition. Because the pore structure of gas shale reservoirs are complex and greatly affect the gas storage and transport in shale, four different methods of low-pressure nitrogen gas adsorption, high-pressure mercury intrusion, scanning electron microscopy (SEM) and gas expansion methods were used to investigate the reservoir pore structure and storage space. Combined with X-ray diffraction, total organic matter content (TOC), gas content, methane adsorption, porosity and permeability and wireline data, the key factors that affect shale gas content and storage of shale gas were analyzed.

According to our shale classification, three main lithofacies, i.e., calcareous mudstone (CM), high calcareous mixed mudstone (HCMM) and low calcareous mixed mudstone (LCMM), were identified in our study area. The experiment indicates that the shale has a high TOC, thermal maturity and gas content. The methane adsorption isotherms show that the sorbed gas content has a positive correlation with TOC. Difference of TOC between the three is small. Nitrogen adsorption indicates that mesopores dominate the shale pore composition and organic matter is the main source of mesopores. Mercury injection shows that the macropore volume accounts for approximately 14–22% of the total pore volume. No obvious pore structure differences were found for different lithofacies. However, taking the porosity into consideration, LCMM has the largest macropore volume. The SEM observations revealed that organic matter pores, interparticle pores and intraparticle pores are the main pore types. Interparticle pores mainly develop in LCMM which has a relatively high quartz and low carbonate content, it may be the major reason for high porosity, high macropore volume, and high free gas content of LCMM. Free gas and absorbed gas are the major storage form of shale gas. Given similar temperature and pressure conditions, the total organic matter content is the major factor that affects the adsorbed gas content. Therefore, with high free gas and adsorbed gas content, LCMMs with high total organic matter contents would be the most favorable type of lithofacies in this region.

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1. Introduction

Due to the technological innovations of horizontal drilling and hydraulic fracturing, gas production from shale has dramatically improved (Wang and Carr, 2012a, b; Curtis, 2002, 2012; Clarkson et al., 2012a). The recent frontier research on gas shale has focused on lithofacies classification (Hickey and Henk, 2007; Loucks and Ruppel, 2007; Dong et al., 2015), lithofacies identification (Wang et al., 2013, 2014a; Chang et al., 2000, 2002), depositional environments (Stow et al., 2001; Gross et al., 2015) and reservoir characteristics (Loucks et al., 2009, 2012; Curtis et al., 2012; Cao et al., 2015). Lithofacies and reservoir characteristics are two important focuses in the study of gas shale.

Lithofacies, the basic properties of rocks, has been used in
geology, stratigraphy and sedimentology for more than seventy years (Wang and Carr, 2012b). It has a close connection with mineral components, organic matter (Wang and Carr, 2012a, b) and reservoir properties (Chang et al., 2002; Jungmann et al., 2011). A considerable amount of lithofacies research has been conducted in carbonate and siliciclastic reservoirs, in which wireline logs have been widely employed for carbonate and siliciclastic lithofacies identification (Chang et al., 2000; Sagaf and Nebrija, 2003). A sound understanding of the connection between shale lithofacies and reservoir ability could provide guidelines for making modest assessments of undiscovered hydrocarbon resources and designing proper exploration programs. A limited number of shale reservoir lithofacies studies have focused on the Barnett Shale, Marcellus Shale, New Albany Shale, and little concerns on the Upper Ordovician and Lower Silurian shale in the Southern Sichuan Basin.

Shale reservoirs are characterized as a self-contained source reservoir system. Abundant gas can be stored in pores and fractures in the form of free gas, absorbed gas and solution gas (Curts, 2002; Ross and Marc Bustin, 2007), free gas and sorbed gas are two major forms (Labani et al., 2013). Shale reservoirs usually have extremely low permeability, relatively low porosity and contain extensive nanopores, the pore characterization and pore structure is of great significance for gas storage and flow capacity (Ross and Marc Bustin, 2009; Slatt and O’Brien, 2011; Wang et al., 2014a,b; Yang et al., 2014). To reduce exploration risks and achieve economical production, it is important to understand the pore structure, sorption and potential gas capacities of shale reservoirs (Ross and Marc Bustin, 2007, 2009; Yang et al., 2014). The International Union of Pure and Applied Chemistry (IUPAC) made a pore classification based on pore diameter: micropores (<2 nm), mesopores (2–50 nm) and macropores (>50 nm). Shale has a wide pore size distribution ranging from micropores to mesopores and macropores (Loucks et al., 2009). Loucks et al. (2012) created a descriptive classification for matrix-related pores, interparticle pores found between particles and crystals, intraparticle pores located within particles and organic matter pores located within organic matter. Assessments of pore features are typically made by quantitative and visual qualitative analyses (Clarkson et al., 2012a, 2012b; Wang et al., 2014b). FE-SEM images are the most common way to qualitatively characterize pore systems (Curts et al., 2012). Quantitative analyses include high-pressure mercury intrusion (HPMI), low-pressure nitrogen and CO₂ gas adsorption (Clarkson et al., 2012b). Low-pressure nitrogen and CO₂ gas adsorption were used for micro-mesopore analysis, and high-pressure mercury was used for macropore characterization (Rouquerol et al., 1994).

In China, the potential shale gas resources could reach approximately 26 × 10¹² m³ (Chen et al., 2011), and increasing shale gas exploration has been conducted in Sichuan Basin, from which the Upper Ordovician Wufeng shale and Lower Silurian Longmaxi shale have been identified as major exploration targets because of their high organic matter abundance, considerable thickness and high maturity (Chen et al., 2011, 2014; Cao et al., 2015). However, to date, a lithofacies classification has not been performed, which could directly reflect reservoir and pore structure. The major goals of our work are to construct a systematic classification for the Upper Ordovician Wufeng shale and Lower Silurian Longmaxi shale, which is useful for reservoir comparisons, and to provide further theoretical support for future shale gas exploration in similar basins.

2. Geologic setting and stratigraphy

The Sichuan Basin is a tectonically stable sedimentary basin, with an area of 180 × 10³ km². It is located in southwestern China bordered by the Micang-Daba Mountains to the north, the Songpan-Ganzi Terrane (SGT) and Longmen Mountains to the west and the Xuefeng Mountains to the east. The study area is located in the Southern Sichuan Basin (Fig. 1). The Sichuan Basin underwent two tectonic deposition stages, the Sinian-Middle Triassic passive continental margin stage and the Late Triassic-Eocene foreland basin stage (Liang et al., 2014). A series of tectonic movements formed the current structural framework. The Sichuan Basin is covered by the strata from the Neoproterozoic to the Quaternary (Liang et al., 2014; Guo et al., 2014). The Sinian-Middle Triassic deposits mainly consist of thick marine carbonates. In the late Triassic, influenced by the closure of the Palaeo-Tethys Ocean and the subduction of the oceanic crust of the Yangtze Plate, the Sichuan Basin evolved from marine-terrigenous transitional deposition to terrigenous clastic rocks. In the late Ordovician and early Silurian, two third-scale global transgressions occurred, resulting in sedimentation of the Wufeng and Longmaxi shale (Guo et al., 2014).

The Wufeng and Longmaxi shales are widely distributed in the study area. The Wufeng shale has a thickness ranging from 5 to 11 m. The lower Wufeng shale is composed of a series of graptolite-rich black shale. The Guanyinqiao Member, which is the upper part of the Wufeng shale, has a thickness of approximately 0.2–0.6 m and higher calcium content. The Longmaxi shale also has a large distribution, with a considerable thickness of approximately 200 m. The lower Longmaxi shale also contains graptolite-rich black shale and high total organic matter content, whereas the upper Longmaxi shale consists of gray and sandy shale, with low total organic matter content. Our study interval includes the Wufeng and lower Longmaxi black shale, with a thickness of approximately 40 m and abundant organic matter.

3. Samples and methods

A total of 138 core samples collected in the study area were used to analyze the geochemical and mineral characteristics. The gas content determination of 35 samples was performed when a fresh core was taken out. Eighteen core plugs were used for helium porosity and nitrogen permeability. Then, they were prepared as small blocks, with the remaining offsets and other samples crushed to powder with a diameter of less than 250 μm for the total organic carbon (TOC) content measurement and low temperature nitrogen adsorption. Mercury intrusion was performed using a 9510-IV porosimeter. The porosity was tested by a ULTRAPORE-200A using the helium expansion method. Permeability was measured using an ULTRA-PERMTM200. The TOC of all samples was measured using a LECO CS-230 carbon analyzer. A RINT-TTR3 was used for &lt; sup &gt; KX &lt; /sup &gt; &lt; sub &gt; diffraction at a voltage of 45 kV and a current of 100 mA to test the mineral content of all samples. Ar-ion-beam milling could produce a relatively flat surfaces which are suitable for high magnification imaging. In our study, eight samples processed by an Ar-ion-beam were observed using FEI Quata200F equipped with an energy-dispersive spectrometer (EDS). Another eight unmilled samples were observed using a HITACHI S-4800 to determine the microstructure and morphology of the minerals and organic matter.

The thermal maturity was tested using optical microscopy. The most favored way of assessing the thermal maturity is vitrinite reflectance (VRo), however, Longmaxi shale contain no vitrinite (Liang et al., 2014) for VRo measurement. Because VRo has a strong relationship with bitumen reflectance (BRo) (Jacob, 1989; Schoenherr et al., 2007), we were able to obtain VRo using Schoenherr’s equation in cases in which solid bitumen was present and vitrinite was absent. The equation is as follows:
\[ VR_0 = \frac{BR_0 + 0.2443}{1.0495} \]  

4. Results

4.1. Mineralogy and lithofacies

XRD and thin-section analysis show that the shale contains large amounts of quartz, carbonate, clay and small amounts of pyrite and feldspar (Fig. 2a). The quartz content ranges from 3.8 to 43.5 wt%, with an average of 21 wt%, and most of the silica shows a cryptocrystalline texture, suggesting an authigenic origin. The feldspar ranges from 0.8 to 14.1 wt%, with an average of 7 wt%. The carbonate ranges from 8.9 to 65 wt%, with an average of 32 wt%. Clay, mainly including illite, chlorite and an illite-smectite mixed layer, ranges from 16 to 48.9 wt%, with an average of 34 wt%.

Modified based on Lazar’s nomenclature guidelines for fine-grained sedimentary rocks (2015), the lithofacies were classified into four main groups (Fig. 2b), including argillaceous mudstone (AM), siliceous mudstone (SM), calcareous mudstone (CM) and mixed mudstone (MM). The first three lithofacies (AM, SM, and CM) contain a single component that accounts for more than 50%. In the mixed mudstone, no single component is greater than 50%. In our classification, we divide MM into high calcareous mixed mudstone (HCMM) and low calcareous mudstone (LCMM) according to the carbonate content. The carbonate content of HCMM is greater than 33%, whereas LCMM has a carbonate content of less than 33%. In the study area, CM, HCMM and LCMM were identified (Fig. 3a). CM mainly shows massive structure with high carbonate contents, silica, calcite and the other minerals are distributed homogeneously (Fig. 3b). HCMM mainly developed horizontal bedding (Fig. 3c), the laminas are always composed of bright and dark laminas, with the bright laminas mainly containing calcite, and the dark laminas mainly containing clay minerals. LCMM is mainly laminated (Fig. 3d), with silica showing an obvious lamellar distribution.
4.2. Organic geochemical characteristics

4.2.1. Organic matter and TOC content
Organic matter particles have multiform size and shape, always extend parallel to the bedding and are squeezed along rigid grains. The smallest measured diameter of organic matter particles is 100 nm. We also observed organic matter particles up to 200 μm at lower magnification. The shale has a TOC content ranging from 0.24 to 7.9 wt%, with an average of 2.4 wt%. LCMM showed the highest TOC content (average: 2.6%), followed by HCMM (average: 2.5%), with CM showing the lowest value (average: 2.2%).

4.2.2. Thermal maturity
Thermal maturity indicates that the organic matter transformation rate of hydrocarbons and the maximum temperature experienced during the basin history. Under the microscope, no vitrinite were found. We measured the BRo (table) and calculated the VRo using Equation (1). The equivalent VRo ranges from 2.47% to 2.7%, with an average of 2.54%. The equivalent VRo suggests that shales are very high in maturity and have reached the dry gas window.

4.2.3. Gas content
The gas content analyses of cores are in the range of 0.16–3.48 scc/g with an average of 1.96 scc/g. It is common to observe positive correlations between TOC and gas content in shale reservoirs (Wang and Carr, 2012a, b; Liang et al., 2014). In our study, the gas content is also positively correlated with the TOC content (Fig. 4a). The adsorption isotherm represents the total sorbed gas content as a function of pressure and suggests that the sorbed gas content of the six measured samples has a positive correlation with TOC in the study area (Fig. 4b). At the same pressure and temperature, the high TOC samples usually have a high methane adsorption capacity.
4.3. Helium porosity and permeability

Compared with conventional reservoirs, shale has an extremely low porosity and low permeability (Nelson, 2009). The helium porosity of samples averaged 2.37% and ranged from 0.7% to 4.12% (Fig. 5a). Their permeability was between 0.0064 mD and 0.0111 mD with an average of 0.0068 mD (Fig. 5a). Among the three lithofacies, LCMM showed the highest porosity (average: 2.9%), followed by HCMM (average: 2%), with CM showing the lowest porosity (average: 0.9%) (Fig. 5b).

4.4. Nitrogen adsorption isotherm analysis

Nitrogen adsorption can be applied to study mesopores (2–50 nm) (Mastalerz et al., 2013). The nitrogen adsorption isotherms (at −196 °C) of the shale samples are shown in Fig. 5a. According to the IUPAC classification of adsorption isotherms (Sing, 1985), the shapes of the isotherms (Fig. 6a) are type IV and are characterized by hysteresis loops, which are caused by capillary condensation occurring in the mesopores. Labani et al. (2013) asserted that pore filling at a low relative pressures is related to micropores and fine mesopores, and that pore filling at high pressures is correlated with large mesopores and macropores.

De Boer (1958) devised a classification including five types of hysteresis loops and correlated them with different types of pore shapes. Based on this classification, all of the sample isotherms belong to hysteresis type B and the pores can be considered as slit-type pores. IUPAC also developed a classification system (1985) for adsorption hysteresis, and according to this system, the sample isotherms belong to Type H4 loops associated with narrow slit-like pores. The pore volume distribution, derived from the nitrogen adsorption branch for the isotherms, is interpreted using BJH theory. The distribution is unimodal with a large peak at approximately 4 nm in the diameter range of 1–100 nm (Fig. 6b). The cumulative pore volume curve shows that the cumulative pore volume of the shale ranges between 0.0081 and 0.0234 ml/g with the predominant portion of the pore volume from mesopores with a diameter ranging from 2 to 5 nm (Fig. 7a), which increases with increasing TOC ($R^2 = 0.86$) (Fig. 7b).

The nitrogen isotherms of kerogen are shown in Fig. 8a. The isotherms are also type IV and contain hysteresis loops. The hysteresis loops are more similar with Type H3 loops because they do not show any limiting adsorption at high $p/p_0$. The pore volume distribution, interpreted by BJH theory, exhibits bimodal characteristics. The peak at a diameter of approximately 4 nm (Fig. 8b) is correlated with the pore volume distribution of the samples.

4.5. Mercury intrusion and macropore porosity

Mercury intrusion can be used to detect meso-macropores (2 nm–100 μm) (Kaufmann et al., 2009). Mercury intrusion is based on the relationship between the amount of mercury intrusion and pressure. The pressure can be converted to the pore radius using the following equation:

$$P_c = 0.735/r_c.$$
where \( r_c \) is the pore radius (\( \mu m \)) at the pressure \( P_c \) (MPa). This equation is simplified from the Washburn Equation. By measuring the amount of mercury intruded into a pore system at constant pressure, we obtained the pore volume. Before this experiment, we measured the Helium porosity, volume and density of the sample. Combined with the mercury intrusion volume, the mercury injection saturation was calculated (Fig. 9a). The mercury injection saturation (Fig. 9a) shows that macropores (pore radius > 25 nm) account for 14.4–22% (average: 17.4%) of the total pore volume, and the remaining volume was occupied by micro-mesopores. This mercury injection saturation was then multiplied by the porosity to obtain the percentage of macropores in the shale samples, which is termed the macropore porosity. The LCMM showed the highest macropore porosity, followed by HCMM, with CM showing the lowest value (see Fig. 9b).

4.6. Reservoir storage space

The pore type are abundant in the study area. According to the classification of Loucks et al. (2012), we could identify organic matter pores, intraparticle pores and interparticle pores.

4.6.1. Organic matter pores

OM pores are created by the generation and expulsion of hydrocarbons during organic matter thermal evolution (e.g. Jarvie et al., 2007; Loucks et al., 2009; Lu et al., 2015). It is commonly
suggested that organic matter pores are related to the organic matter type. Marine sourced type II kerogen appears to have more potential to form organic matter than terrestrial type III kerogen (Loucks et al., 2012). The relationship between organic matter pores and thermal maturity is still controversial. Valenza et al. (2013) asserted that a higher thermal maturity is accompanied by an increase in surface area and pore volume and the decrease in average pore size. Bernard et al. (2012a, 2012b) suggested that only samples in the gas window contain organic matter pores. However, Reed et al. (2014) found nanopores in oil-window maturity kerogen and Loucks et al. (2014) suggest OM pores form not only in kerogen, but also in solid bitumen and pyrobitumen.

In two dimensions, the organic matter pores were usually isolated with spherical to ellipsoidal shapes, and angular morphologies were also observed. The long dimensions of visible organic matter pores range from a few nanometers to one hundred nanometers (Fig. 10a, b). Through observations of unmilled samples, the pores could be connected to form a three-dimensional pore network (Fig. 10c). Based on the observations, we found organic matter pores in the small organic matter particles, which have diameters of less than 5 μm; however, it is difficult to find organic matter pores in the large organic matter particles (Fig. 10d).

4.6.2. Interparticle pores

Interparticle pores are commonly observed between grains and crystals such as quartz, feldspar, calcite and clay flocculates. In young shallow-buried mud, interparticle pores are abundant, connected and can form an effective pore network (Velde, 1996; Milliken and Reed, 2010). However, they decrease sharply with increasing overburden and diagenesis (Loucks et al., 2012). Using

![Fig. 9. Mercury intrusion curve (a) and macropore porosity comparison (b).](image)

![Fig. 10. Organic matter pore features. (a, b) Organic matter with diameters of less than 5 μm containing abundant organic pores in the milled samples; (c) Organic matter pores have good connectivity in the unmilled samples; (d) Organic matter pores were not found in organic matter particles with larger diameters.](image)
the scanning electron microscope, we could observe interparticle pores between calcite, quartz and clay minerals. Interparticle pores between calcite are always distributed along the sharp edges of calcite, with pore sizes ranging from 50 nm to 1 μm (Fig. 11a), and mainly develop in CM and HCMM. Interparticle pores between quartz have a smooth edge, with pore sizes reaching up to 200 nm (Fig. 11b), they mainly develop in LCMM. Interparticle pores between clay minerals are difficult to observe on samples processed by an Ar-ion-beam. Most interparticle pores are primary pores and are seriously affected by diagenesis and mineral composition.

4.6.3. Intraparticle pores

Most intraparticle pores are found within particles related to authigenic crystals in the study area. However, primary intraparticle pores are difficult to find. Examples mainly include (1) intraparticle pores within framboidal pyrite (Fig. 12a), (2) intraparticle pores of calcite formed via partial dissolution or fluid inclusions left during crystal formation (Fig. 12b,c), (3) cleavage-sheet intraparticle pores within clay and mica-mineral grains (Fig. 12d).

Framboidal pyrite, composed of many small pyrite crystals, are formed in anoxic sea environments. Pore diameters between pyrite crystals range from 25 nm to 325 nm. Intraparticle pores within calcite formed by dissolution, and we identified a maximum pore diameter of 3 μm. Clay and mica-mineral grains develop cleavage-sheet intraparticle pores, with pore sizes of usually less than 100 nm.

4.7. The analysis of shale gas composition calculated from wireline data

Shale gas is stored as free gas in the pores and fractures of the matrix. Adsorbed gas is found on the organic material and clay minerals, and a small amount of gas is dissolved in water or oil (Curtis, 2002; Gasparik et al., 2012, 2013). According to the methane adsorption isotherms and the formation temperature and pressure from the wireline data, the adsorbed gas content could be calculated. Using formation porosity, temperature, pressure and clay minerals, the free gas content was determined using a reservoir saturation model. In our study, we focused on free and adsorbed gas. The gas content wireline data were provided by Schlumberger. Through the comparison of gas composition of different lithofacies, we determined that LCMM had the highest proportion of free gas, with an average of 29% in well 107 and 49% in well 106, whereas the proportion of free gas in CM was only 15% in Well 107 and 5% in Well 106 (Fig. 13).

5. Discussion

5.1. Shale lithofacies

The original definition of lithofacies, defined by Teicher in 1958, is an integration of all lithologic features in sedimentary rocks, such as color, mineral composition, texture and structure. Lithofacies have been widely used in sandstone and carbonate studies (e.g.
The qualitative features of sedimentary rocks, including color, components, texture and grain-size distribution, are significant for the interpretation of hydrodynamic conditions and sedimentary environment. However, shales are formed from fine-grained sediments of which the average grain size is less than 63 μm. They are deposited in much more uniform hydrodynamic conditions and low-action sedimentary environments; thus, the qualitative characteristics tend to be similar (Wang and Carr, 2012a, b). Therefore, the application of qualitative characteristics is limited. A practical shale lithofacies classification must consider the specificity and development of the shale-gas reservoir. There are substantial differences between shale-gas reservoirs and conventional sandstone and carbonate reservoirs. Horizontal drilling and hydraulic fracturing play key roles in the development of shale gas (Curtis, 2002, 2012). The total organic carbon and the amount of hydrocarbon that can be extracted are two main factors in well planning and hydraulic fracturing of unconventional resources. Brittleness could be directly measured to determine the ability of a formation to create avenues for hydrocarbons (Zhang et al., 2015).

Rock mineralogy has a significant influence on the efficiency of hydraulic fractures (Jarvie et al., 2007), and high silica, feldspar and carbonate content are known to correspond to a lower Poisson ratios, higher Young’s modulus values and greater brittleness (Ding et al., 2012; Soua, 2014). In our study area, the brittle mineral content is greater than 60% (Fig. 3a), and the total organic carbon or gas content is a key factor. In our shale lithofacies classification, shale is classified into five main groups: AM, SM, CM, LCMM and HCMM. Three lithofacies, including CM, LCMM and HCMM, are identified. The gas content and reservoir characteristics of these
three lithofacies has a clear distinction. LCMM is the best shale reservoir in the study area. With the help of conventional logs, it is easy to identify different lithofacies in our study area. Our lithofacies classification has strong practicality in terms of reservoir comparisons.

5.2. Nanopore structure

Shale gas was stored in three forms (Zhou et al., 2014), and free gas and adsorbed gas are the two main forms (Labani et al., 2013; Jarvie et al., 2005). A better understanding of pore structure could help to understand the gas storage mechanism. The combined use of nitrogen adsorption, high-pressure mercury injection and SEM is an effective method for the precise description of the pore structure of shales. The nitrogen adsorption hysteresis loops show that shale pores are mainly composed of mesopores (IUPAC, 1985). The combination of mercury intrusion and helium porosity indicates that the macropore volume accounts for approximately 14–22% of the total pore volume, there are no obvious difference between different lithofacies. However, LCMM has the highest porosity, which leads to the highest macropore volume of the three lithofacies. Using SEM, we observed numerous interparticle macropores in the quartz and relatively few interparticle macropores in the CM and HCMM samples. Due to some depositional carbonate minerals (high-Mg calcite and aragonite) is metastable, the dissolution of parts of host rocks and re-predicition of cements are routine during burial diagenesis (Jiang et al., 2015). The chemical compaction and associated cementation responding to increasing thermal exposure and effective stress during burial always lead to progressive destruction of porosity (Ehrenberg et al., 2012). With more carbonate content, the CM and HCMM will lost more primary pores than LCMM. The higher proportion of free gas in LCMM according to the wireline data provides additional evidence.

The shale sample pore volume distribution calculated from nitrogen adsorption shows a peak at approximately 4 nm, which is consistent with the pore volume distribution of kerogen. In addition, high organic matter samples usually have higher peak values than low organic matter samples and pore volume increases with increasing TOC. Such evidence indicates that organic matter pores are the main sources mesopores in shale. Nitrogen adsorption isotherm shows shale pores are mainly composed of silt-type pores. However, a significant portion of the organic matter pore are small, their average pore size is less than 10 nm, and it is not accessible with the resolution of SEM in our in our experiments. It is the main reason why we could not observe silt-type organic matter pores.

5.3. The main control factor for shale gas reservoirs

Using SEM observations, we found that organic matter pores, interparticle pores and interparticle pores act as the main gas storage space. It is commonly suggested that the organic matter content, thermal maturity and organic matter type are the major factors influencing the development of organic matter pores (e.g., Curtis, 2002, 2012; Loucks et al., 2012). The organic matter content always has a strong positive correlation with the gas content (Wang and Carr, 2012a, 2012b; Liang et al., 2014; Ji et al., 2014). The organic matter type also affects the organic matter pore generation. Type I kerogen, with more “live carbon” (Pepper, 1991), can form more organic matter pores (Jarvie et al., 2007). Even the relationship between organic matter pores and thermal maturity is controversial, the thermal evolution degree (Ro) of black shale is 2.54% on average in the study area, it is similar to the Jiaoshiba area which is known for its great success in shale gas exploration and has an average Ro of 2.65% (Guo et al., 2014). Thermal maturity is not a key factor in our area. The Longmaxi shale is mainly Type I kerogen and is high to very high in maturity (Liang et al., 2014). Therefore, TOC is the key factor that affects organic matter pores.

Interparticle pores mainly develop in LCMM which has a relatively high quartz and low carbonate content, it may be the major reason for high porosity, high macropore volume, and high free gas content of LCMM. CM and HCMM, which have higher carbonate contents, have relatively low porosity and macropore volume. Free gas and adsorbed gas are the major storage form of shale gas. Given similar temperature and pressure conditions, the total organic matter content is the major factor that affects adsorbed gas content. Therefore, LCMM with high total organic matter content tend to have a higher free gas and adsorbed gas content, it is the most favorable type of lithofacies for exploration in this region.

6. Conclusions

Sedimentary lithofacies are classified into four main groups based on rock mineral composition: AM, CM, SM and MM. In the study area, CM and MM were identified, and MM was divided into HCMM and LCMM according to the carbonate content. Shale pores are mainly composed of mesopores (in pore volume) and organic matter is the main source of mesopores. Macropores account for approximately 14–22% of total pore volume. The SEM observations revealed that organic matter pores, interparticle pores and intra-particle pores are the main pore types. Interparticle pores mainly develop in LCMM, it may be the major reason for high porosity, high macropore volume, and high free gas content of LCMM. Free gas and adsorbed gas are the major storage forms of shale gas. In the same region, temperature and pressure conditions of strata is similar, the total organic matter content is the major controlling factors that affect adsorbed gas content. Therefore, LCMM with high TOC would be the most favorable type of lithofacies in this region.

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