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Pore Structure and Factors Controlling Shale Reservoir Quality: A Case Study of Chang 7 Formation in the Southern Ordos Basin, China

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Abstract: The lithofacies types, pore structure differences, and main controlling factors on the shale reservoirs are vital problems that need to be addressed in the process of shale oil exploration and development. This study explores the Luohe oilfield in the southern Ordos Basin, which is composed of organic-rich shale in the Chang 7 member, to clarify the reservoir properties and analyze major factors affecting the reservoir quality. The shale reservoir can be divided into five lithofacies using ternary diagrams of TOC, argillaceous minerals, and siliceous minerals: high organic-rich siliceous shale (HOSS), high organic-rich argillaceous shale (HOAS), medium organic-rich siliceous shale (MOSS), medium organic-rich argillaceous shale (MOAS), and low organic-rich shale (LOS). The type of organic matter in the studied samples is mainly Type I kerogen and Type II kerogen, predominantly Type II₁ kerogen. The kerogen mostly lie within the mature zone in the study area. Various types of pores have been identified in the studied shale: intergranular pores, intragranular pores, intercrystalline pores, organic matter pores, and seams around organic matter. The pores are commonly nanoscale to micrometer in scale, with diameters ranging from 10 nm to several microns. The S₁ content in shale is positively correlated with the macropore content, indicating that macropores in shale are the main effective oil storage spaces and are important for oil-bearing reservoirs. There is a good positive relationship between the macropore volume of shale and the content of organic matter. Organic matter in the shale can be beneficial for generating organic matter pores, dissolution pores, and seams at organic matter edge, resulting in better physical properties of shale reservoirs. There is a negative relationship between the quartz/feldspar content and macropores content, indicating that quartz and feldspar are detrimental for the macropore volume development. The lithofacies type is one of the important factors controlling the macropore volume. MOAS and HOAS are favorable lithofacies for the development of macropores. The findings of this study can be utilized for hydrocarbon exploration and development in the lacustrine shale formation of the Ordos Basin and other similar basins.

Keywords: shale reservoir; pore structure; Yanchang formation; Ordos Basin; reservoir quality; controlling factor



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1. Introduction

Shale oil and gas have become a hot spot in global petroleum exploration and development. Shale oil and gas have great exploration potential and development prospects [1]. In the past few decades, research on the sedimentary and reservoir characteristics of shale reservoirs has also become a hot topic in the field of unconventional oil and gas geology [2,3]. The composition of minerals, rock texture, and sedimentary structure in shale

formations commonly display strong heterogeneity, as well as reservoir qualities of shale reservoirs [4–7].

The composition of shale reservoirs is complex, including silt and clay minerals formed by mechanical deposition, organic matter related to biological origin, and carbonate minerals formed by chemical sediment.

Extensive studies have been performed on the reservoir space of shale. Pore types in shale reservoirs can be divided into four categories: organic pores, intergranular pores, intragranular pores, and fractures [8]. According to pore size, pores in shale reservoir are generally classified into micropores (<2 nm), mesopores (2–50 nm), and macropores (>50 nm) by the International Society of Theoretical and Applied Chemistry (IUPAC) standards [9,10]. There are multiple and complex factors that control the quality of shale reservoir systems, including inorganic factors (mineral composition, particle size, lithofacies type, diagenesis, etc.) and organic factors (TOC content, organic matter type, maturity, hydrocarbon generation, etc.)

The Chang 7 member of the Triassic Yanchang Formation in the Ordos Basin has enormous shale oil and gas resources [11,12]. The organic-rich shale in the Chang 7 formation has enormous potential for shale oil exploration and development, making it an important supplement for future petroleum storage and production growth.

Although a large number of studies has been performed on shale reservoirs in recent years, the lithofacies types, pore structure differences, and main controlling factors on the shale reservoirs in the Chang 7 formations of the southern Ordos Basin, especially in the Luohe oilfield, are not clear. For example, how organic matter, different mineral composition and lithofacies affect the shale reservoir quality are not fully understood. Research on differences in the reservoir quality and controlling factors of the different shale lithofacies of the southern Ordos Basin is relatively weak.

To address this gap, this study explores the Luohe oilfield in the southern Ordos Basin, which is mainly composed of organic-rich shale in the Chang 7 member. The main purpose of this study is to characterize the shale reservoir properties of the Chang 7 and analyze major factors that control the reservoir quality. The results of this study can be utilized for hydrocarbon exploration in shale formation in the Ordos Basin and other similar basins.

2. Geological Setting

The Ordos Basin, which is located in the central part of China (Figure 1A), appeared as an asymmetrical rectangle extending from north to south, ranking the second largest basin in China [13,14]. The edge of the Ordos Basin is surrounded by active folded mountain and graben systems, with the basement consisting of the Lower Proterozoic and Archean metamorphic rock series. The internal structure of the Ordos Basin is relatively simple and the subsidence is stable. The overall tectonic movement is descending in the west and rising in the east, resulting in lower strata in the west and higher strata in the east. There are six tectonic units in the Ordos Basin. The north part of the basin is a Yimeng uplift while the south part is a Weibei uplift. The Jinxi fold belt is located in the east part of the basin while the Tianhuan depression and thrust belt are located in the west. The center of the basin is an expansive Yishan slope (Figure 1). The studied area is located in the southern part of the Yishan slope (Figure 1B). The Ordos Basin is a multi-cycle craton basin. The basin has a stable subsidence in the Paleozoic era, with a migration of the depression in the Mesozoic era, and distortion and rifts in the Cenozoic era [15]. During the Late Triassic Period, the southern Ordos Basin became a lacustrine basin with deposition from the fluvial-lacustrine sedimentary system due to the collision between the Yangtze Plate and the North China Plate [16–18].

Combined with sedimentary cycles and lithological assemblages, the Upper Triassic Yanchang Formation of the Ordos Basin is further subdivided into ten members (from top to bottom: Chang 1 to Chang 10) (Figure 2). The Chang 7 member can be further subdivided into three parts: Chang 7₃, Chang 7₂, and Chang 7₁, from bottom to top [19].

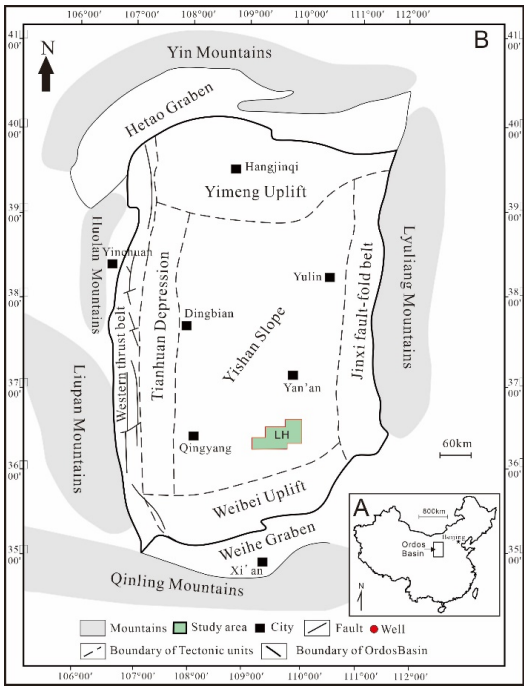


Figure 1. (A) The geographic location of the Ordos Basin. (B) The study area and geological background in the Ordos Basin (modified after [4]).

The lacustrine basin subsided significantly in the Chang 7 period. A series of organic-rich shale and mudstone was deposited at the bottom of the Chang 7 formation, with a thickness of more than 100 m [11]. The Chang 7 member of the Ordos Basin has become an important target for unconventional petroleum exploration and development [20,21].

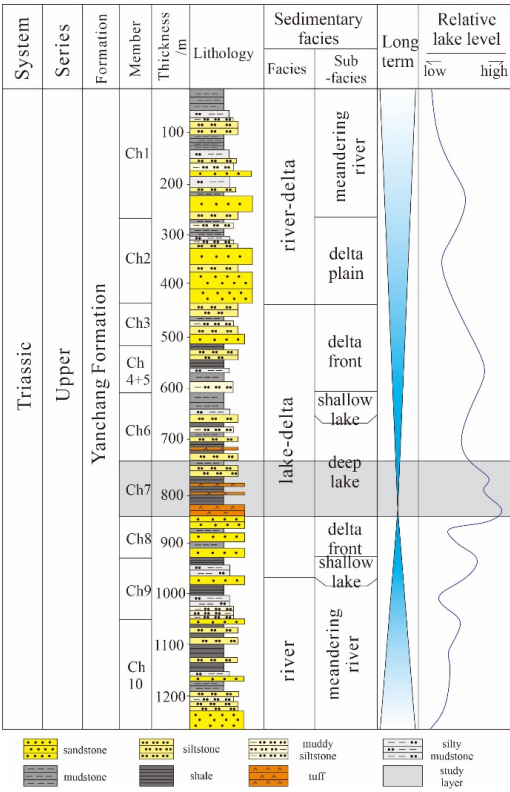


Figure 2. The stratigraphic and lithological column chart of the Yanchang Formation in the Ordos Basin (modified from [16,22]).

3. Samples and Methods

The shale samples used in this study were obtained from the cores in the Chang 7 Member of the Yanchang Formation of the Luohe oilfield, which is located in the southern Ordos Basin (Figure 1). The samples were analyzed by thin section firstly to select representative samples of different lithofacies. The samples were collected for multiple testing experiments, such as microscopic observations, porosity and permeability, X-ray diffraction (XRD) analysis, high-resolution field emission scanning electron microscopy (FE-SEM) analyses, total organic carbon (TOC) testing, Rock-Eval analyses, and the high-pressure mercury injection (HPMI) analysis.

The XRD analysis was used to determine the type and content of different minerals. The instrument for XRD analysis is the D8 DISCOVER system. The voltage and current parameters are 40 kV and 25 mA, respectively. A total of 3 g fresh sample was ground to $<40\ \mu\text{m}$ in an agate mortar before the XRD analysis. The software Jade 6.0 was used to identify mineral types. The relative abundances of different minerals were assessed using semiquantitative analysis in weight percent.

The FE-SEM was used to observe mineral and pore characteristics using FEI Quanta200F produced by FEI Corporation in the United States. The porosity and permeability were measured by the meter CAT112 and CAT113 from American CoreLab in the United States, according to Boyle's theorem and Darcy's law of gas percolation.

The TOC test was performed by using a LECO CS-200 carbon analyzer, according to the Chinese national standard GB/T19145-2003. The ranges of the measuring error of the TOC test and porosity test are both $\pm 0.2\%$. The free hydrocarbons (S1), hydrocarbons cracked from kerogen (S2), carbon dioxide relieved from organic matter (S3), and the maximum temperature of pyrolysate (T_{max}) were obtained by Rock-Eval analyses [23,24]. The computational method of the hydrogen index (HI) and the oxygen index (OI) were used according to Espitalie et al., 1977 [25].

The mesopore structure parameters were measured from nitrogen adsorption (NA) experiments. The automatic specific surface was used to obtain the isothermal adsorption experiments of nitrogen and pore size distribution. The gas adsorption capacity at different relative pressures was tested in the NA analysis by using nitrogen as an adsorbent at $-196\ ^\circ\text{C}$ (77 K). The high-pressure mercury injection (HPMI) method was performed according to the capillary bundle model by the intrusion instruments of American CoreLab CMS300 from the United States.

4. Results

4.1. Mineral Compositions and Lithofacies Classification

Thin-section examination and XRD analysis show that the shale is mainly composed of quartz, feldspar, pyrite, clay minerals, and mica, with few types of carbonate and other minerals. The average quartz content is 17 wt.%. The feldspar ranges from 33 to 46.7 wt.% (with an average of 37.6 wt.%). The clay minerals range from 36 to 54 wt.%, with an average of 45 wt.%. The content of pyrite is commonly less than 2 wt.%. The difference in mineral content has a significant impact on the storage performance and fracturing ability of shale. According to a previous study, quartz, pyrite, and feldspar (siliceous minerals) are brittle minerals, which are in favor of hydraulic fracturing. However, clay minerals and mica (argillaceous minerals) are plastic minerals, which have an adverse effect on the fracturing. Organic matter content affects the storage space and hydrocarbon generation potential of shale reservoir [26].

The total organic carbon (TOC) and minerals contents of shale vary greatly. The shale reservoir can be divided into five lithofacies using the ternary diagrams of TOC, argillaceous minerals (clay minerals + mica), and siliceous minerals (quartz + feldspar + pyrite) (Figure 3A): (1) high organic-rich siliceous shale (HOSS): $\text{TOC} > 6\%$, siliceous minerals/argillaceous minerals > 1 ; (2) high organic-rich argillaceous shale (HOAS): $\text{TOC} > 6\%$, siliceous minerals/argillaceous minerals < 1 ; (3) medium organic-rich siliceous shale (MOSS): $2\% < \text{TOC} < 6\%$, siliceous minerals/argillaceous minerals > 1 ; (4) medium organic-rich

argillaceous shale (MOAS): $2\% < \text{TOC} < 6\%$, siliceous minerals/argillaceous minerals < 1 ; (5) low organic-rich shale (LOS): $\text{TOC} < 2\%$. The lithofacies in the study area is mainly MOSS and MOAS, with few types of HOAS and LOS. According to samples collected from the core of the Chang 7 shale in the study area, the MOSS is the most developed lithofacies in the Luohe oilfield, which accounts for 45.9%, followed by MOAS (30.6%), HOAS (15.3%), and LOS (8.2%) (Figure 3B).

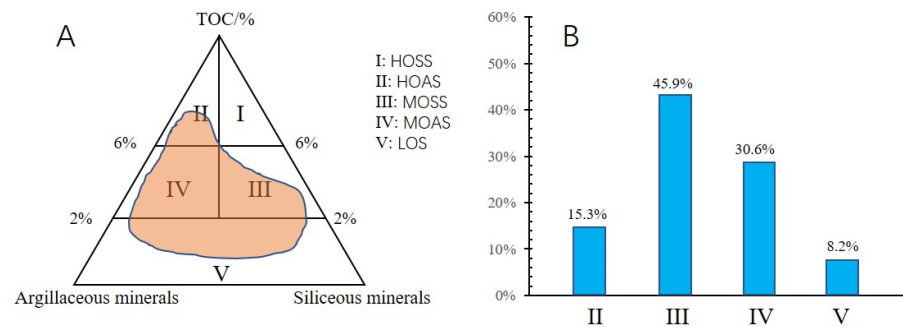


Figure 3. Classification and proportion of lithofacies of the Ch7 shale in the Luohe area. (A) Ternary diagram of the lithofacies in the study area. (B) The proportion of different lithofacies in the study area.

The HOAS is dark-colored with a high organic matter content. The minerals in HOAS are mainly clay minerals and contain a significant amount of pyrite (Figure 4A). MOSS is an important lithofacies distributed in the study area. The color of MOSS is gray black. There are silt lamina and organic matter rich lamina in MOSS. The mineral types in MOSS are mainly siliceous minerals (such as feldspar and quartz) and clay minerals, with a small amount of pyrite (Figure 4B). MOAS is another important lithofacies in the study area. MOAS is dark colored and is commonly composed of regular or irregular laminae (Figure 4C). The mineral type is mainly clay minerals, containing a small amount of pyrite. LOS contains relatively large amounts of terrigenous debris particles and low organic matter (Figure 4D). The mineral type is mainly clay minerals, with little pyrite content.

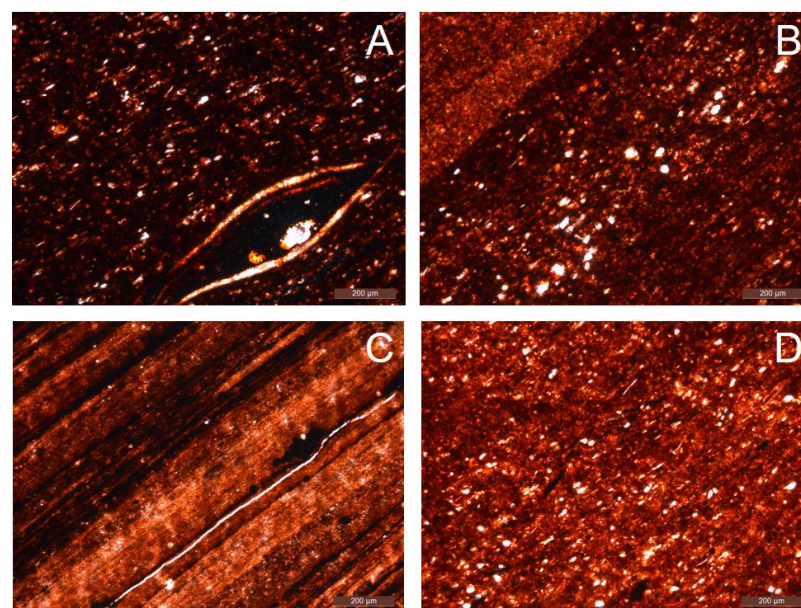


Figure 4. Microscopic characteristics of the different lithofacies within the Chang 7₃ unit. (A) high organic-rich argillaceous shale (HOAS), well LH3, 939.72 m; (B) medium organic-rich siliceous shale (MOSS), well LH2, 962.17 m; (C) medium organic-rich argillaceous shale, well LH2, 934 m; (D) low organic-rich shale (LOS), well LH3, 938.81 m.

4.2. Organic Geochemistry Classification

The TOC values of samples from the Chang 7₃ range from 1.85 wt.% to 7.42 wt.%, with an average of 4.8 wt.%. The HC yield ($S_1 + S_2$) for the samples analyzed range from 5.56 mg HC/g rock to 20.16 mg HC/g rock, with an average of 12.10 mg HC/g rock. The samples from the Chang 7₂ have TOC values ranging from 2.78 wt.% to 3.95 wt.% (average 3.24 wt.%) and HC yield ($S_1 + S_2$) ranging from 3.5 mg HC/g rock to 9.11 mg HC/g rock (5.56 mg HC/g rock), respectively. According to the cross plot of TOC and ($S_1 + S_2$), the generative potential of source rock samples from Chang 7₃ is commonly excellent and that from Chang 7₂ is mainly fair or good (Figure 5A).

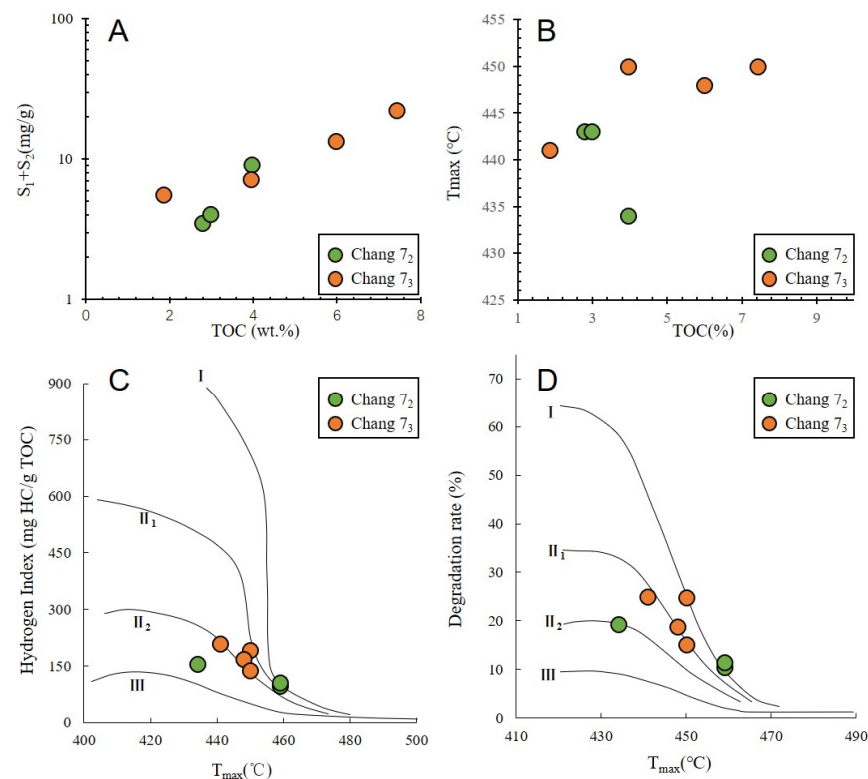


Figure 5. Organic geochemical characteristics of the shale in the Luohe oilfield. (A) Plot of $S_1 + S_2$ versus TOC. (B) Plot of pyrolysis T_{max} versus TOC. (C) Plot of the hydrogen index (HI) versus the T_{max} . (D) Plot of degradation rate versus T_{max} .

The Rock-Eval pyrolysis data (such as HI and T_{max} values) are commonly used to analyze the characterization of organic matter type. The T_{max} value is the temperature when the S_2 peak reaches the maximum. The T_{max} values of Chang 7₃ samples range from 441 to 450 °C (with an average of 447 °C) and the T_{max} values of Chang 7₂ samples range from 434 to 443 °C (with an average of 441 °C) (Figure 5B).

The hydrogen index (HI) values of Chang 7₃ samples range from 138.26 to 208.45 mg HC/g TOC, and average 176.49 mg HC/g TOC. The HI values of Chang 7₂ samples are between 138.26 and 208.45 mg HC/g TOC, with an average of 176.49 mg HC/g TOC (Figure 5C). The degradation rates of Chang 7₃ samples are between 15.19% and 24.91%, with an average of 20.91%, while the degradation rates of Chang 7₂ samples range from 15.19% to 24.91%, with an average of 20.91% (Figure 5D).

A cross plot of the HI versus the pyrolysis T_{max} and a plot of degradation rates (D) versus the pyrolysis T_{max} are usually used to classify the maturity and type of organic matter [24,27]. These two plots show that the organic matter in the studied samples is mainly Type I to Type II kerogen, predominantly Type II₁ kerogen (Figure 5C,D). The T_{max} values suggest that most of the samples reach the mature level of hydrocarbon generation

(430–455 °C) [24,28]. The maturity of Chang 7₃ samples is slightly higher than that of Chang 7₂ samples.

4.3. Porosity

The average porosity difference among different lithofacies in the Luohe area is relatively small. The MOAS has the highest porosities (average, 2.17%), followed by LOS (average, 2.07%), MOSS (average, 1.93%), and HOAS (average, 1.81%) (Figure 6A). The average permeability of different lithofacies varies greatly (Figure 6B). The MOSS has the highest permeability of these lithofacies (average, 0.00184 mD). The average permeabilities of the other lithofacies are all less than 0.00036 mD.

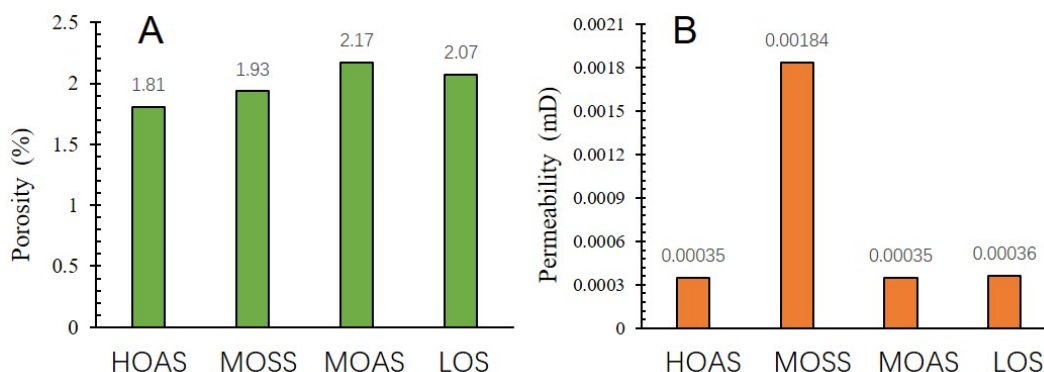


Figure 6. Mean porosity and permeability bar plot of each lithofacies in the Luohe area. (A) Mean porosity bar plot of each lithofacies in the Luohe area. (B) Mean permeability bar plot of each lithofacies in the Luohe area. HOAS: high organic-rich argillaceous shale; MOSS: medium organic-rich siliceous shale; MOAS: medium organic-rich argillaceous shale; LOS: low organic-rich shale.

4.4. Pore Types

To address the pore types, abundance, and connectivity of different pores, the photomicrographs taken by SEM of ion-milled shale samples were studied carefully and the pores were point-counted. Various types and shapes of pores in the studied shale have been identified (Figure 7): (1) intergranular pores, (2) intragranular pores, (3) intercrystalline pores, (4) organic matter pores, and (5) seams around organic matter. The main pore type of the shale is intergranular pores, with a few intragranular pores, intercrystalline pores, organic matter pores, and seams around organic matter. The average plane porosity of the MOSS is 0.97%. The average plane porosity of the MOAS is 1.63%, which is higher than that of MOSS.

The sizes of pores in the shale reservoir are mainly nano-to micron-scale (Figure 8). The diameters of the intergranular pores usually range from 20 nm to 10 µm. The sizes of other pores are relatively small, with diameter mainly less than 1 micron. The abundance of intergranular pores is highest among all of the pore types, followed by intercrystalline pores and organic matter pores. The amount of intragranular pores and seams around organic matter is relatively low (Figure 8).

4.5. Quantitative Analyses of Pore Structure

4.5.1. Pore Structure Characterized by Nitrogen Adsorption (NA)

The NA experiment can obtain isothermal adsorption curves and desorption curves. The shape of the isothermal adsorption curve is related to the pore characteristics of tested material. According to International Union of Pure and Applied Chemistry (IUPAC), the isotherm adsorption curves of NA can be divided into six types (type I–VI) [29].

If the adsorption curve and desorption curve are not completely reversible, a hysteresis loop will occur. According to IUPAC, the hysteresis loops can be divided into four types [29]: H1 type corresponds to capillary pores (columnar pores); H2 type corresponds to small diameter and ink-bottle like pores (pores with columnar and spherical pores); H3

corresponds to trough-shaped pores which are formed by stacking non-rigid aggregates of sheet-like particles (disordered layered pores and narrow wedge-shaped pores); and H4 type corresponds to narrow slit-shaped pores, generated by layered structures.

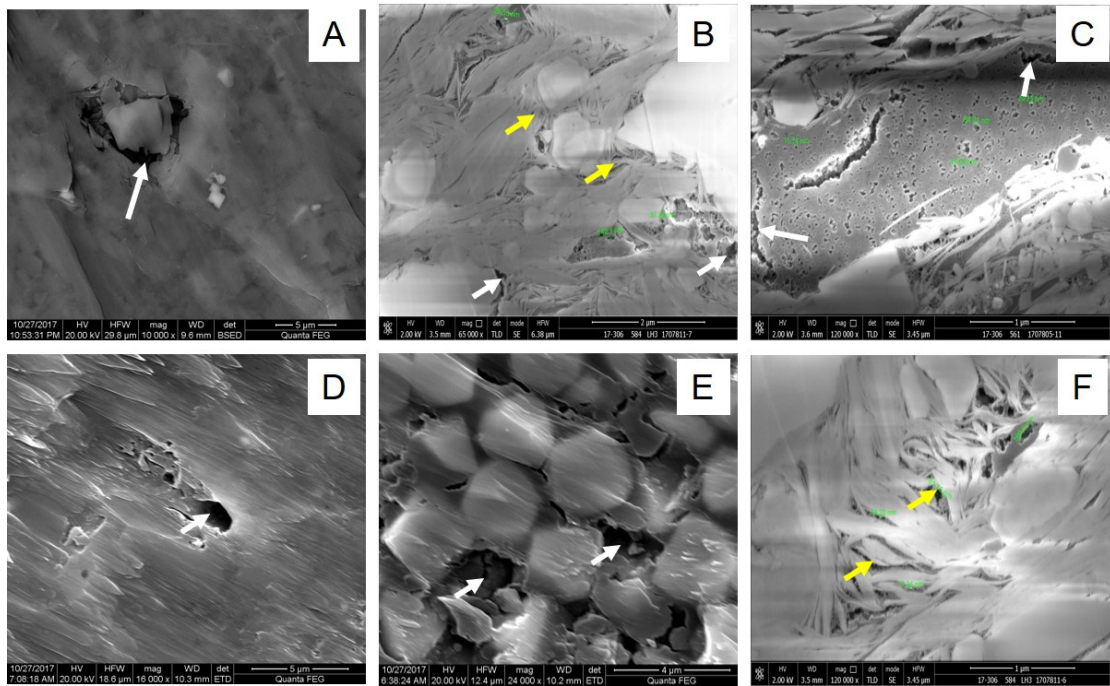


Figure 7. Microphotos of different pore types in the shale reservoir. (A) Intergranular pores, LH2, 970.99 m; (B) intercrystalline pores, LH3 935.96 m; (C) organic matter pores, and seams around organic matter, LH2 967.75 m; (D) intragranular pores, LH2 970.99 m; (E) intercrystalline pores, LH2 970.99 m; (F) intercrystalline pores, LH3 935.96 m.

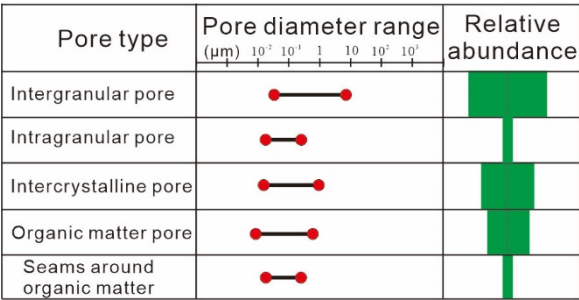


Figure 8. Pore diameter range and relative abundance of various pore types in the shale reservoir.

The isothermal adsorption curves of all lithofacies in the study area are mainly type IV, suggesting that these shales have mesopore capillary condensation phenomenon. When the pressure approaches its maximum value, saturation does not occur, suggesting that the pores system in the shale is continuous from nanometer to micronmeter [30]. The hysteresis loops of high organic-rich argillaceous shale are mainly type H3 (Figure 9), suggesting the development of trough-shaped pores which are formed by stacking non-rigid aggregates of sheet-like particles (disordered layered pores and narrow wedge-shaped pores). The hysteresis loops of MOAS and LOS are between type H2 and H3, suggesting that these lithofacies have not only disordered layered pores and narrow wedge-shaped pores but also small diameter and ink-bottle like pores (pores with columnar and spherical shapes). The hysteresis loops of medium organic-rich siliceous shale are between those of high organic-rich argillaceous shale and medium organic-rich argillaceous shale, including the development of both narrow wedge-shaped pores and ink-bottle pores.

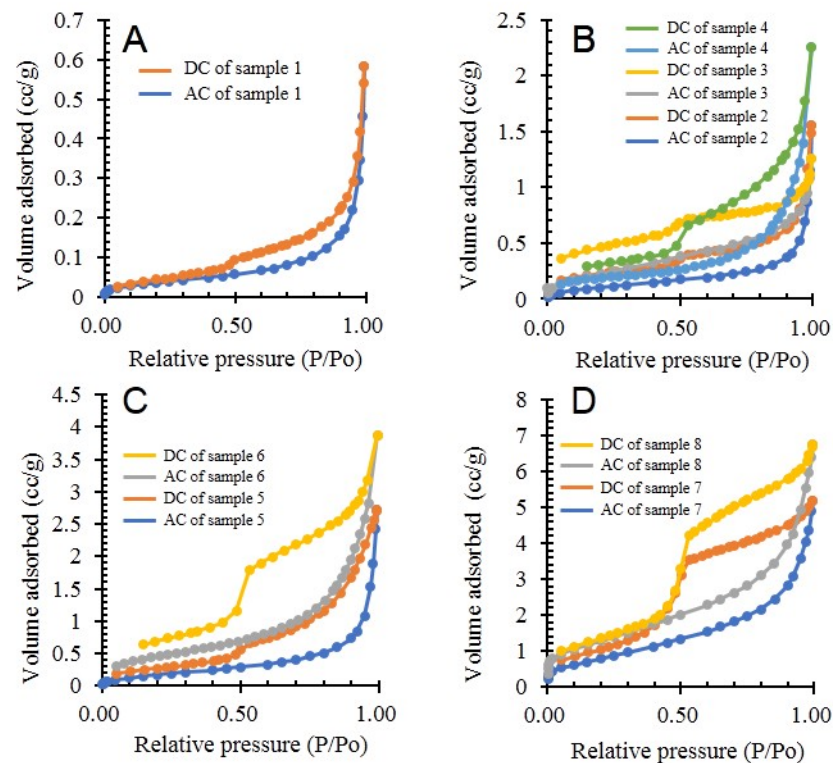


Figure 9. The NA experiments' isothermal adsorption and desorption curves (IADC) of different lithofacies (A) The IADC of HOAS; sample 1: well LH2, 934.48 m; (B) the IADC of MOSS; sample 2: well LH2, 929.12 m, sample 3: LH2 931.7 m, sample 4: LH2 970.99 m; (C) the IADC of MOAS; sample 5: LH2 927.97 m, sample 6: LH2, 966.26; (D) the IADC of LOS; sample 7: LH2 877.36 m, sample 8: LH2 939.46 m. AC: isothermal adsorption curves; DC: isothermal desorption curves.

4.5.2. Pore Structure Characterized by High-Pressure Mercury Injection (HPMI)

The high-pressure mercury injection analysis is commonly used to characterize the pore structure of different reservoirs [31,32]. It is generally believed that the HPMI analyses cannot accurately characterize micropore and mesopore structures of shale reservoirs, because of the influence of compressibility effects. However, the HPMI is a very effective method to measure the characteristics of macropore structures in shale reservoirs [33,34].

The capillary pressure curves of different shale lithofacies in the study area are similar, with all curves upward to the right (Figure 10). The displacement pressure, at which mercury begins to enter the samples in large quantities, is higher than 13 Mpa. Mercury entering the shale pore throats requires a higher capillary pressure, indicating that the pore throat of the shale is overall very small. The average diameters of pore throats in the shales are close, ranging from 22.50 nm to 24.37 nm. The maximum mercury saturation of the shales ranges from 78.89% to 86.5%. The mercury withdrawal efficiency of the shales is from 78.67% to 88.52% (Figure 10). The mercury withdrawal efficiency of medium organic-rich siliceous shale is the highest (88.52%), indicating that mercury easily flows out of the pores and the capillary pressure difference between pores is relatively small compared to other lithofacies. On the contrary, the efficiency of the mercury withdrawal of medium organic-rich argillaceous shale is the smallest (78.67%), indicating that the capillary pressure difference between pore throats is relatively large, which is not conducive to fluid flow.

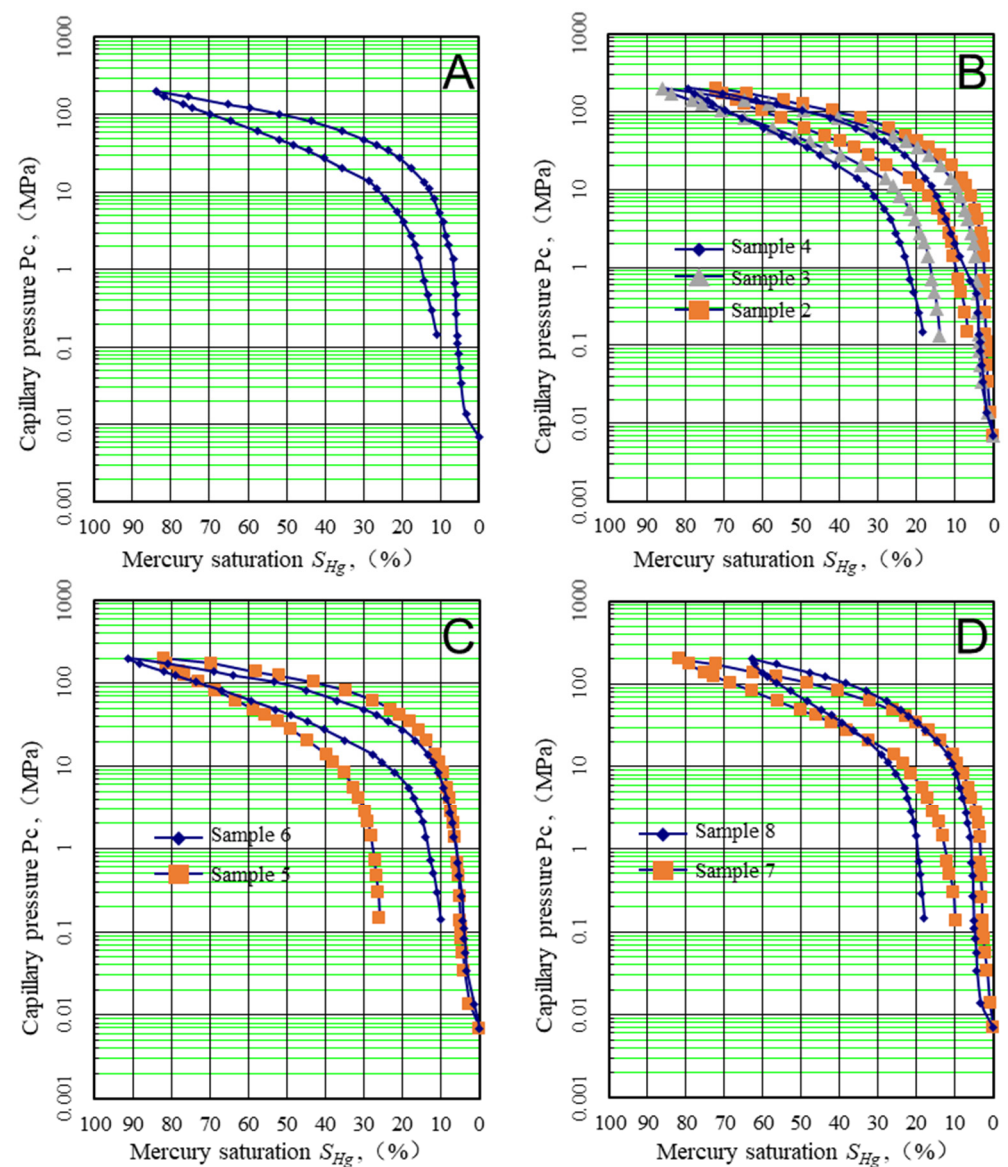


Figure 10. Capillary pressure curves of different lithofacies. (A) Capillary pressure curves of HOAS; well LH2, 934.48 m; (B) capillary pressure curves of MOSS; sample 2: well LH2, 929.12 m, sample 3: LH2 931.7 m, sample 4: LH2 970.99 m; (C) capillary pressure curves of MOAS; sample 5: LH2 927.97 m, sample 6: LH2, 966.26; (D) capillary pressure curves of LOS; sample 7: LH2 877.36 m, sample 8: LH2 939.46 m.

5. Discussion

5.1. PSD Characteristics Integrated NA and HPMT

Although the size, volume, and surface area parameters of pores can be measured by many experimental methods, such as high-pressure mercury injection (HPMI), nitrogen adsorption (NA), and scanning electron microscopy (SEM), it is impossible to quantitatively characterize the full pore size distribution (PSD) by only one experimental method. Previous studies have shown that the HPMI experiment cannot accurately characterize micropore and mesopore structures while NA experiments cannot accurately characterize macropores. NA is suitable for characterizing mesopores. HPMI can be used to evaluate the characteristics of macropore content, which is measured by the specific pore volume of macropores, that is, the volume of macropores per gram of rock. Considering the different pore size measurement range of different measuring methods, the experimental data of NA and HPMI were integrated to analyze the characteristics of the PSD of the shale reservoir.

Using the pore diameter of 50 nm as the boundary, the pore parameters of mesopores and macropores were derived from NA and HPMT experiments, respectively.

The pore size distribution of the HOAS has a bimodal characteristic, located in the mesopore and macropore interval, respectively (Figure 11A). The mesopores of HOAS are concentrated in the range of 6–30 nm and the macropores are concentrated between 60 nm and 150 nm. The pore size distribution of the MOAS also has a bimodal characteristic and the two peaks were both located in the micropore interval (Figure 11C). The pore sizes of the MOAS are concentrated in the range of 6–10 nm and 20–40 nm. The pore size distributions of the MOAS and LOS are both unimodal types, which are concentrated in the range of 3–8 nm and 4–10 nm, respectively (Figure 11). The results show that the HOAS has the largest concentration range of macropores, while for other lithofacies the macropore concentrations are not obvious. The pore size concentration of the mesopores of HOAS and MOAS is larger than that of MOSS and LOS (Figure 11).

The pores in HOAS are mainly macropores, with the highest content of macropores and lowest content of mesopores compared to other lithofacies. The pores in MOSS, MOAS, and LOS are mainly mesopores. The contents of macropore in MOSS, MOAS, and LOS decrease sequentially while the contents of mesopore increase sequentially (Figure 12). The average specific pore volume of macropores in HOAS and MOAS, which is 0.0012 cc/g, is relatively large. The average specific pore volumes of MOSS and low organic-rich shale are 0.0011 cc/g and 0.0010 cc/g, respectively.

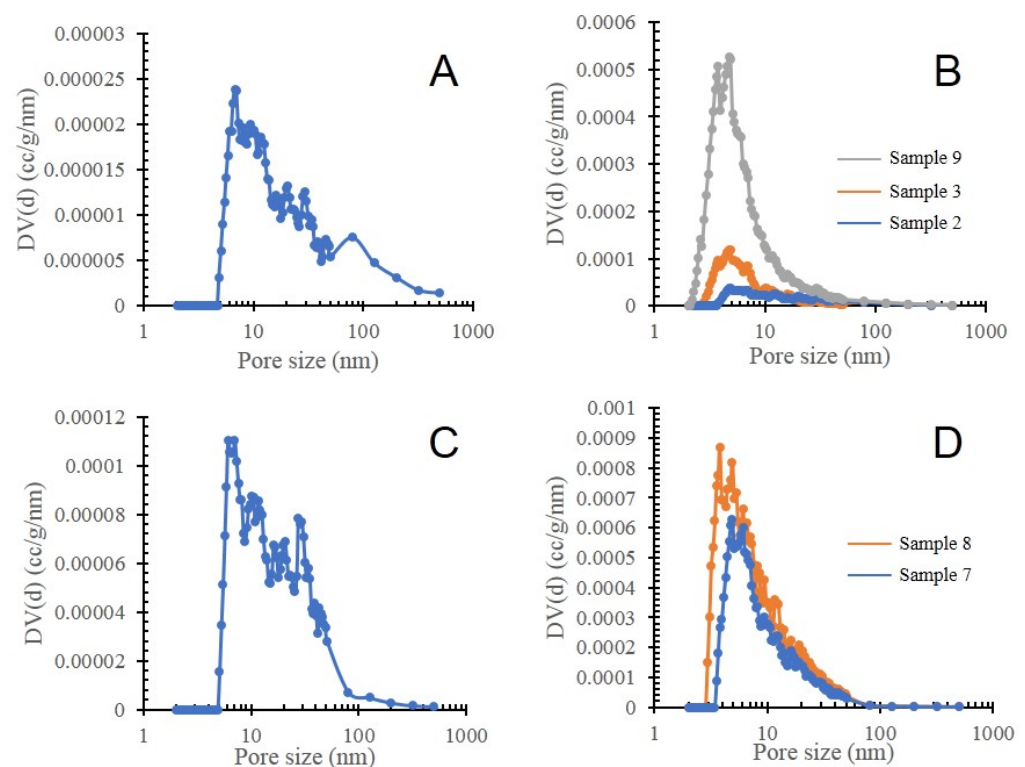


Figure 11. Unit volume of different pore sizes. (A) Unit volume versus pore size of HOAS; well LH2, 934.48 m; (B) unit volume versus pore size of MOSS; sample 2: well LH2, 929.12 m, sample 3: LH2 931.7 m, sample 9: LH2, 928.54 m; (C) unit volume versus pore size of MOAS; LH2 927.97 m; (D) unit volume versus pore size of LOS; sample 7: LH2 877.36 m, sample 8: LH2 939.46 m.

5.2. Effective Pore Type

The parameters measured by Rock-Eval included the free hydrocarbons (S_1), the hydrocarbons cracked from kerogen (S_2), and the carbon dioxide relieved from organic matter (S_3) [23,24]. The free hydrocarbons (S_1) can reflect the oil content in the reservoir. A high S_1 value commonly indicates high oil content. Therefore, the amount of S_1 content can be used to represent the oil-bearing capacity of effective pores in shale reservoirs [35].

Through the correlation analysis between macropores, mesopores, and free oil (S_1), it can be seen that the S_1 content in shale is positively correlated with the macropore content (Figure 13A). However, there is no correlation, or even a negative relationship, between S_1 content and the content of mesopores (Figure 13B). This indicates that macropores in shale are the main effective oil storage space and are important for oil-bearing reservoirs. The content of macropores can indirectly represent the ability of its reservoir storage performance. Thus, a study of the influencing factors on macropore development can uncover the main controlling factors on reservoir storage abilities in the study area.

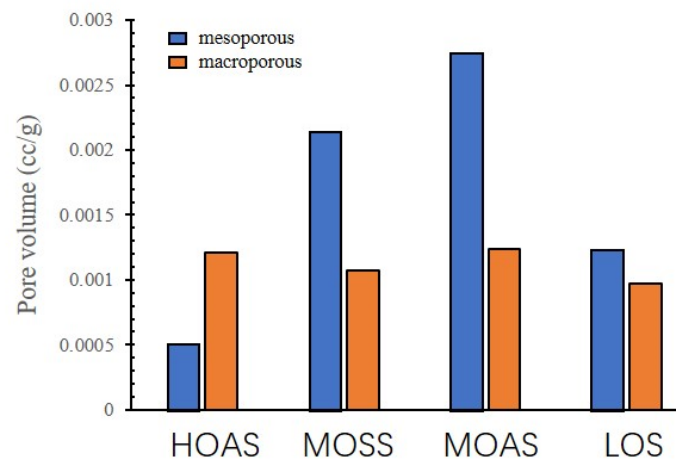


Figure 12. Volumes of mesopores and macropores of different lithofacies. HOAS: high organic-rich argillaceous shale; MOSS: medium organic-rich siliceous shale; MOAS: medium organic-rich argillaceous shale; LOS: low organic-rich shale.

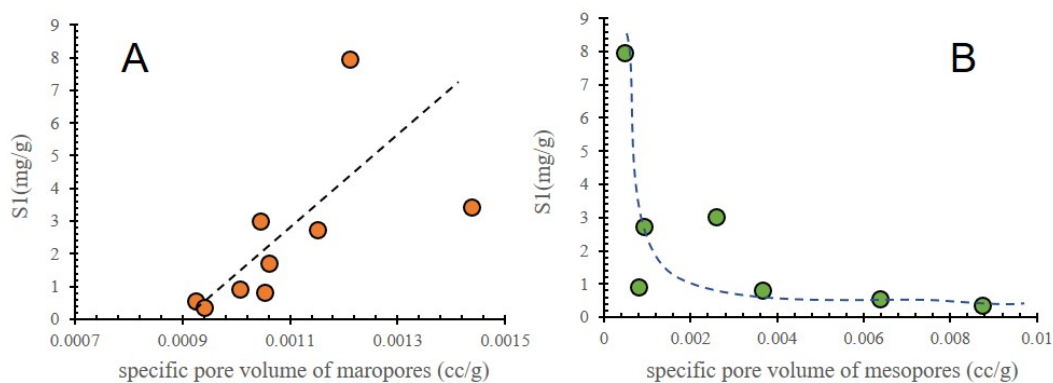


Figure 13. Plot of S_1 versus specific pore volume of different pore types. (A) Plot of S_1 vs. specific pore volume of macropores; (B) plot of S_1 vs. specific pore volume of mesopores.

5.3. Main Controlling Factors on Reservoir Quality

5.3.1. Influence of Organic Matter on Reservoir Quality

The content of shale macropore is significantly influenced by organic matter content. There is a good positive relationship between shale macropore volume and organic matter content (Figure 14A). The higher the organic matter content, the larger the content of macropores and the average pore size.

Organic pores are usually considered to be formed because of the conversion of organic matter during the thermal maturation stage [3]. Organic matter in the study area is in the mature stage of hydrocarbon generation. Organic matter pores can be frequently observed in the shale. Thus, the organic matter abundance is a strong controlling factor on organic pores. Organic acids are commonly produced during the thermal evolution of organic matter and the decarboxylation of kerogen, which can further dissolve minerals producing dissolution pores. In addition, due to differences in the physical properties of organic matter

and minerals, organic matter edge seams commonly develop between organic matter and mineral particles, which can also produce storage space for oil. Therefore, organic matter in the shale can be beneficial for generating organic matter pores, dissolution pores, and organic matter edge seams, resulting in better physical properties of shale reservoirs.

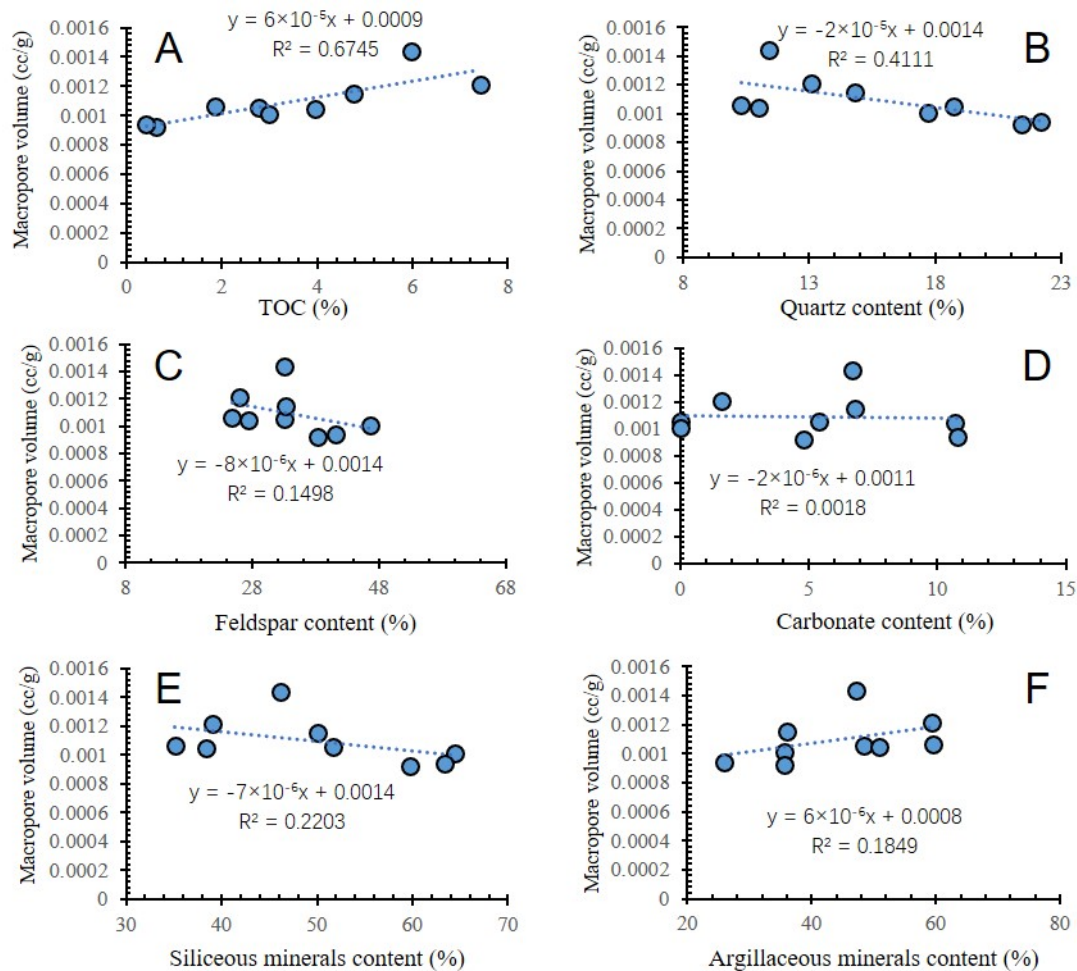


Figure 14. Macropore volume versus different composition content. (A) Macropore volume versus TOC; (B) macropore volume versus quartz content; (C) macropore volume versus feldspar content; (D) macropore volume versus carbonate content; (E) macropore volume versus siliceous minerals contents; (F) macropore volume versus argillaceous mineral content.

5.3.2. Influence of Mineral Composition on Reservoir Quality

The samples display a negative correlation between the quartz content and macropores content (Figure 14B). There is also a negative relationship between feldspar and macropores content (Figure 14C). In contrast, clay minerals content shows a positive correlation with macropores content (Figure 14F). The above relationships suggest that quartz and feldspar are adverse for the generation of macropores, especially quartz content. The quartz and feldspar minerals in the shale mainly originate from terrigenous detrital. The quartz and feldspar content in the study area is not high enough to form a large number of intergranular pores between terrestrial debris like that in sandstones. In contrast, high quartz and feldspar mineral contents commonly reflect a high input of terrestrial debris, which is not conducive to the enrichment of organic matter. Thus, the development of quartz is not beneficial for improving the reservoir quality of the shale in the study area. There is no obvious relationship between carbonate mineral and macropores content, as carbonate mineral content in the shale is low (Figure 14D).

5.3.3. Influence of Lithofacies on Reservoir Quality

As analyzed above, there are significant differences in pore type, pore size, pore structure, specific pore volume of macropores, porosity, and permeability among different lithofacies. The macropore content of HOAS and MOAS is relatively high, while the macropores content of MOSS, and LOS is relatively low. The MOAS has the highest porosity (2.17%) among all lithofacies. It can be seen that lithofacies is one of the important controlling factors on the development of macropores. MOAS and HOAS are favorable lithofacies for the development of macropores.

6. Conclusions

- (1) The shale reservoir can be divided into five lithofacies using the ternary diagrams of TOC, argillaceous minerals, and siliceous minerals: high organic-rich siliceous shale (HOSS); high organic-rich argillaceous shale (HOAS); medium organic-rich siliceous shale (MOSS); medium organic-rich argillaceous shale (MOAS); and low organic-rich shale (LOS). The organic matter type is mainly Type I to Type II kerogen in the study area, predominantly Type II₁ kerogen. Most of the samples lie within the mature stage of hydrocarbon generation.
- (2) Various types of pores were identified in the studied shale: intergranular pores, intragranular pores, intercrystalline pores, organic matter pores, and seams around organic matter. The pores are commonly nanoscale to micrometer in scale, with diameters ranging from 10 nm to a few microns. The NA and HPMT experimental results were integrated to analyze the characteristics of the PSD. The contents of macropore in MOSS, MOAS, and LOS decrease sequentially while the contents of mesopore increase sequentially.
- (3) The S₁ content in shale is positively correlated with the macropore content, indicating that macropores in shale are the main effective oil storage space and are important for oil-bearing reservoirs.
- (4) There is a good positive relationship between shale macropore volume and organic matter content. Organic matter in the shale can be beneficial for generating organic matter pores, dissolution pores, and organic matter edge seams, resulting in better physical properties of shale reservoirs. The samples have a negative relationship between the quartz/feldspar content and macropores content, indicating that quartz and feldspar are adverse for the development of macropores. The lithofacies is one of the important controlling factors for the development of macropores. MOAS and HOAS are favorable lithofacies for the development of macropores.

The findings of this study further clarified the influence of organic matter, mineral composition, and lithofacies on the reservoir quality of shale in the Ordos Basin, which can be utilized for hydrocarbon exploration and development in the lacustrine shale formation of the Ordos Basin and other similar basins.

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