Tightness Mechanism and Quantitative Analysis of the Pore Evolution Process of Triassic Ch-6 Tight Reservoir, Western Jiayuan Area, Ordos Basin, China

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ABSTRACT: Exploring the tightness mechanism through a quantitative analysis of the pore evolution process is the research hotspot of tight oil reservoirs. The physical characteristics of Chang 6 (Ch-6) sandstones in the western Jiayuan area have the typical features of a tight oil reservoir. Based on the reservoir physical property, lithological characteristics, diagenetic types and sequence, and burial and thermal evolution history, this study analyzes the factors leading to reservoir tightness and establishes the model of the pore evolution process. The results show that the sedimentary microfacies type controls the reservoir detrital material and further affects its physical properties. The high content of feldspar and rock fragments and the fine grain size are the material cause for the reservoir tightness. The sandstones of the main underwater distributary channel are the dominant sedimentary bodies for the development of a high-quality reservoir. In terms of diagenesis, compaction is the primary cause for reservoir tightness, and the porosity reduction by cementation is weaker than that by compaction. Meanwhile, the quantitative calculation results indicate that the porosity losses by compaction, carbonate cementation, kaolinite cementation, chlorite coatings, and siliceous cementation are 23.5, 3.1, 3.8, 3.0, and 0.8%, respectively. In addition, dissolution is significant to improve the reservoir physical property, and the increase of dissolved porosity is around 3.2%. More significantly, this study uses a detailed and systematic method for analyzing the tightness mechanism and the pore evolution process of the Ch-6 sandstones in the western Jiayuan area, Ordos Basin, China.

1. INTRODUCTION

Unconventional oil and gas are important components of hydrocarbon resources, including shale gas, shale oil, tight sandstone oil, natural gas hydrates, etc.1−5 Tight sandstone oil comes from sandstone reservoirs with porosity less than 10%, air permeability less than 1 mD, or in situ matrix permeability less than 0.1 mD.6 The sandstones of the Upper Triassic Yanchang formation in the Ordos basin are characterized by low porosity, ultralow permeability, and abundant oil resources.7−10 In the Yanchang formation, Chang 6 (Ch-6) has huge potential for exploration and development of tight oil, with reserves of more than 100 million tons in the Jiayuan, Xifeng, and Huaying areas.11−15

At present, quantitative analysis of the reservoir pore evolution is the research hotspot in the study of reservoir and diagenesis. In 1987, David firstly established the calculation method of porosity evolution using thin-section analysis data and achieved good results in the calculation of the compaction porosity loss of Jurassic feldspathic quartz sandstones in Utah and Ordovician quartz sandstones in Oklahoma.16 Later, Ehrenberg demonstrated the quantitative simulation method of porosity evolution and proposed the useful supplements of the compaction porosity loss calculation method, statistical method of thin sections, effects of particle solution on compaction porosity loss, and repeatability of the calculated results.17 In addition, the studies on the Ventura Basin in California by Wilson and that on the Bermejo Basin in Argentina by Damanti have achieved effective applications.18,19 In terms of Chinese research studies, many scholars have done many works in the quantitative analysis of the reservoir pore evolution and obtained productive results in the Ordos Basin, Bohai Bay Basin, Junggar Basin, and Songliao Basin.

Previous studies focused more on the overall effect of compaction and cementation but ignored the individual effects of various types of cementation and the “specific process” of reservoir tightness.20−23 At the same time, from the simulation method of pore evolution based on thin-section data, it is difficult to accurately evaluate the dissolved contents of each component and the variation of rock skeleton volume in the diagenetic process. Such statistical errors need to be inhibited through the method of sample screening and data processing.24

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Above all, this paper uses a detailed and systematic method for studying the reservoir tightness mechanism via the analysis of the porosity evolution process of the Ch-6 reservoir in the western Jiyuan (WJY) area, hoping that it could provide a scientific basis for the relative studies of tight oil reservoirs in other areas.

2. GEOLOGICAL SETTING

The Ordos Basin is a polycyclic craton margin basin in North China, which is characterized by stable subsidence and multiple migrations of depocenters, and it is composed of the Precambrian basement and Phanerozoic sediments. The oil and gas resources of the Ordos Basin are abundant, and the petroleum geology conditions are relatively simple. The internal structure of the basin is relatively simple, and the strata are relatively gentle with a dip angle of less than 1°, but faults and thrust structures abundantly exist in the western margin due to the later influences of the Yanshan movement. According to the nature of the basin basement, the structure form, and characteristics, it can be divided into six first-level tectonic units: the Yimeng uplift, the Weibei uplift, the west margin thrust belt, the Jinxi flexure belt, the Tianhuan depression, and the Shanbei slope. The western Jiyuan (WJY) area, which is located in the western area of the Ordos Basin, spans the Tianhuan depression (Figure 1a), and presents a gentle monocline structure sloping westward.

3. MATERIALS AND METHODS

All kinds of data used in this study were collected from the core samples of the Ch-6 sandstone reservoirs in the WJY area. First, the data on porosity, permeability, grain size, and the mercury pressure test were collected from the Changqing Oilfield Company. Based on the data on the physical properties of 414 samples and the mercury pressure data of 12 samples, this study analyzed the pore structure and throat features of the Ch-6 tight oil reservoirs. At the same time, data on the grain size obtained from nine samples were utilized to assess particle sizes and calculate the sorting.
coefficient ($S_o$) as well as the initial porosity of the Ch-6 reservoirs according to the method published by Scherer.55

In addition, 62 samples were collected from 43 Wells for microscopic petrology and pore-throat identification in the Key Laboratory of Petroleum Resources Research, Institute of Geology and Geophysics, Chinese Academy of Sciences. By observing 152 thin sections, the statistical analysis was performed, which includes mineral type and content, the degree of sorting and roundness, pore type, current thin porosity, the content of dissolved pores, the content of original intergranular pores, and cements content. The thin sections were impregnated with red and blue epoxy resin to highlight the pore spaces, and some of them were stained with Alizarin Red S and K-ferricyanide for carbonate mineral identification. The mineral composition and pore space were observed with Axioskop 40 polarizing microscope manufactured by Zeiss. An optical collection system was used to quantify thin-section porosity and diagenetic cements content by counting at least 350 points of each thin section. The method of point counting and proportion counting was mainly utilized in the quantitative calculation of detrital components and all kinds of pore content.16,17 Moreover, 11 freshly broken chips of reservoir samples were prepared, and the MERLIN field emission scanning electron microscope (FE-SEM) equipped with the energy-dispersive X-ray (EDS) system manufactured by Zeiss was used to carry out a more detailed observation on the morphology of authigenic clay minerals and intergranular cement. On the basis of thin-section observation, the diagenetic stages of Ch-6 in the WJY area were identified according to the China Petroleum Standard of the Division of Diagenetic Stage in Clastic Rocks (SY/T 5477-2003). At last, mathematical statistics were used in the quantitative calculation of porosity in different diagenetic stages following the methods published by Lai et al.36

The carbon and oxygen isotopes of 45 sandstone samples were measured in the Key Laboratory of Petroleum Resources Research, Institute of Geology and Geophysics, Chinese Academy of Sciences. The specific process is to carry out the accurate measurement of carbon and oxygen stable isotopes of CO$_2$ that were released from the dissolution of carbonate materials by H$_3$PO$_4$ with a MAT-252 isotope mass spectrometer. The measurement accuracy is less than 0.5‰, and all isotope data were calibrated with standard samples including NBS-18, GBW04405, and GBW04406. Ultimately,
the data were presented relative to the Vienna PeeDee Belemnite (V-PDB) and in the δ notation.

4. RESULTS

4.1. Reservoir Lithology. Through observation and statistical analysis of more than 150 thin sections, the Ch-6 reservoirs in the WJY area were found to be mainly composed of lithic arkose, feldspathic litharenite, and a small amount of arkose according to Folk’s classification scheme

4.2. Reservoir Properties. 4.2.1. Porosity and Permeability. The porosity of the Ch-6 sandstones in the WJY area mainly ranges from 6 to 12% with an average of 8.59% and the permeability mainly ranges from 0.1 to 0.5 mD with an average of 0.32 mD (Figure 5). Therefore, these sandstones have the typical characteristics of low porosity and permeability, which belong to the category of tight oil reservoirs defined by Zou et al., Yao et al., and Kuang et al.3,7,38 Moreover, there is a

Figure 3. Rock compositions of the Ch-6 sandstones in the WJY area, Ordos Basin. (a) Ternary diagram showing framework grain compositions. (b) Histogram displaying the compositions of rock fragments. Q, Quartz; F, feldspar; R, rock fragments; I, quartz arenite; II, subarkose; III, sublitharenite; IV, arkose; V, lithic arkose; VI, feldspathic litharenite; and VII, litharenite.

Figure 4. Histograms of (a) grain size and (b) sorting characteristics of Ch-6 in the WJY area, Ordos Basin.

Figure 5. Distribution of (a) porosity and (b) permeability of the Ch-6 reservoirs in the WJY area, Ordos Basin.
roughly exponential correlation ($R^2 = 0.4686$) between porosity and permeability, which shows that the permeability is mainly controlled by the development of the connected pores (Figure 6).

4.2.2. Pore Types and Pore-Throat Characteristics. Porosity determines the reservoir capacity, and permeability is an important factor for reservoir productivity.39,40 The pore types of the Ch-6 reservoirs in the WJY area are mainly original intergranular pores, feldspar dissolved pores, rock fragments dissolved pores, intercrystalline pores, and microcracks, the thin-section porosity of which are 1.60, 0.84, 0.16, 0.09, and 0.03% (Figure 7a), respectively. Therefore, the original intergranular pore and dissolved pores account for 95.58% of the total thin-section porosity (Figure 7b).

Mercury injection analysis is an important method to study the reservoir pore structure, which can quantitatively reflect the microstructure characteristics of the reservoir pore throat. Based on the analysis and calculation of typical capillary pressure curves and pore-throat radius value distribution of the Ch-6 reservoir (Figure 8), it could be found that the mean displacement pressure ranges from 0.21 to 2.53 MPa with an average of 1.22 MPa, the median throat radius value ranges from 0.06 to 0.51 $\mu$m with an average of 0.24 $\mu$m, the measured porosity ranges from 6.4 to 16.3% with an average of 9.94%, and the measured permeability ranges from 0.06 to 0.68 mD with an average of 0.24 mD. It is found by further analysis that the measured porosity and permeability are positively correlated with the median throat radius values and negatively correlated with the mean displacement pressure. However, it must be pointed out that due to the limitations of experimental methods, mercury injection analysis could only characterize the characteristics of the partial pore system but could not characterize the full-scale pore-throat structure of sandstones.41,42 Hence, the experimental data here mainly describe the pore structure features above the mesopores in sandstones.

4.3. Diagenetic Types.

4.3.1. Compaction. Compaction is one of the significant factors leading to the tightness of the Ch-6 reservoirs in the WJY area and could be divided into two types: mechanical compaction and chemical compaction. By observing the thin sections, it could be seen that the contact relation between the particles is mainly a linear contact, which preserves the original intergranular pores (Figure 9a) at the early stage of burial. As the burial depth increases and the paleogeotemperature exceeds 70 $^\circ$C,43 chemical compaction starts and the contact relation between the particles tends to a linear-suture contact (Figure 9b); also some mica particles undergo a plastic deformation (Figure 9c), where the original intergranular pores are relatively less.

4.3.2. Cementation. Cementation is an important consolidation diagenesis due to the precipitation of authigenic minerals in the pores, which lasts throughout the diagenesis process except for compaction. By observing the thin sections, it was seen that the main types of cementation of the Ch-6 reservoirs are composed of carbonate cementation, siliceous cementation, and clay minerals cementation.

4.3.2.1. Carbonate Cementation. Carbonate cement is one of the most common authigenic minerals in clastic rock reservoirs that are continuously superimposed in the vertical direction with multiple argillaceous interlayers. By observing the thin sections of the Ch-6 reservoir sandstones in the WJY area, it was seen that the carbonate cements are dominated by ferrocalcite (Figure 9d,e) with an average content of 4.10%. They are mainly distributed in the intergranular pores and/or the intragranular dissolution pores of feldspar and show up as deep red after being stained. These features indicate that the later dissolution of feldspars is likely to provide the necessary calcium ions for their precipitation.

4.3.2.2. Siliceous Cementation. Compared with carbonate cement, siliceous cement is limited and its average content is 1.1%, which is characterized by terrigenous quartz overgrowth and authigenic quartz crystals in dissolved pores (Figure 9f,g).

4.3.2.3. Clay Cementation. The authigenic clay minerals of the Ch-6 reservoir sandstones in the WJY area are primarily composed of chlorite, kaolinite, and illite. Chlorites primarily...
vitrinite reformation in the WJY area is identified as 1.2%. The smectite content of mixed layer I/S is under 15%; the aforementioned sedimentary characteristics and predecessors results,44 the sedimentary environment of Ch-6 is inferred as a fresh-brackish fluid in the environment at the time of the Ch-6 diagenesis period. The calculation results show that the paleotemperature of carbonate cements in the Ch-6 reservoirs ranges from 95 to 110 °C (Table 1), which corresponds to the mesogenetic A stage.

5. DISCUSSION

5.1. Diagenetic Stage and Sequence. On the basis of the aforementioned sedimentary characteristics and predecessor research results,44 the sedimentary environment of Ch-6 formation in the WJY area is identified as a fresh-brackish inland lake basin. The dividing standard of the diagenetic stage and sequence is according to the China Petroleum Standard of the Division of Diagenetic Stage in Clastic Rocks (SY/T 5477-2003).

The maximum buried depth of the Ch-6 reservoirs in the WJY area ranges from 2500 to 2700 m, corresponding to the maximum paleotemperature ranging from 100 to 125 °C with an ancient land surface temperature of 15 °C and a paleogeothermal gradient of about 3.5−4.0 °C/100 m.45 The vitrinite reflectance (Rv) of the Ch-6 mudstone mainly ranges from 0.5 to 0.9% and a small number of samples exceed to 1.2%. The smectite content of mixed layer I/S is under 15%; the homogenization temperature of fluid inclusions in the margin of quartz secondary enlargement and the microcracks ranges from 70 to 170 °C, which holds two distinct temperature peak areas of 80 to 100 and 120 to 130 °C.10

These data indicate that the Ch-6 tight oil reservoir is at the mesogenetic A stage. Furthermore, the petrographic characteristics of the Ch-6 tight oil reservoirs (e.g., point to linear contact between grains, the types of dissolved minerals, which are mainly composed of feldspar and detritus, etc.) also indicate that they belong to the mesogenetic A stage (Figure 10).

Additionally, the δ18O value of carbonate cements is usually used to calculate the paleotemperature and as a geological thermometer for determining the ambient temperatures, which can evaluate the environmental conditions and the diagenetic stages of cementation. In this study, the mature theoretical equation for geological thermometers proposed by Shackleton et al. is used to calculate the paleotemperature (T).45 The paleotemperature is actually the forming temperature of carbonate cements and it is calculated using the following equation.

\[
T (°C) = 16.9 - 4.38 \times (\delta^{18}O - \delta^{18}O_w) + 0.1 \times (\delta^{18}O - \delta^{18}O_w)^2
\]

where the δ18O uses the PDB standard; δ18Ow is the oxygen isotope values of geological fluids medium at the time carbonate cements formation, and the value of δ18Ow is selected as −2.5‰ according to the overall geological environment at the time of the Ch-6 diagenesis period.

The calculation results show that the paleotemperature of carbonate cements in the Ch-6 reservoirs ranges from 95 to 110 °C (Table 1), which corresponds to the mesogenetic A stage.

Comprehending the observation of diagenesis and textural relationships of authigenic minerals with the results of the diagenetic stage analysis and isotopic data, the diagenetic evolution sequence of the Ch-6 reservoirs in the WJY area is as follows: mechanical compaction, formation of chlorite coating, formation of quartz overgrowth, feldspar dissolution, formation of authigenic kaolinite, formation of authigenic quartz, conversion of kaolinite to illite, precipitation of ferrocalcite, and, finally, hydrocarbon emplacement.

5.2. Controlling Factors of Reservoir Quality.

5.2.1. Sedimentary Conditions Determine the Material Basis of the Reservoir. Sedimentary conditions control the reservoir material basis. Fundamentally, sedimentary facies control the microscopic distribution of reservoirs and affect the basic physical properties of the reservoir. In this study, the
Figure 9. Microscopic characteristics of the Ch-6 sandstones in the WJY area, Ordos Basin. (a) Original intergranular pores (yellow arrow); the brown chlorite coatings on the surface of the grains after being soaked by oil (green arrow); Well F11, 2368.33 m, plane-polarized light (PPL). (b) Grains exhibit a linear contact due to compaction (blue arrow), and some of them have microcracks (yellow arrow); Well Y83, 2492.42 m, PPL. (c) Plastic deformation of mica fragments due to compaction, which are in close contact with the rigid grains (yellow arrow); Well H35, 2515.63 m, PPL. (d) Intergranular pores (green arrow) and feldspar dissolved pores (blue arrow) are cemented by ferrocalcite; Well H307, 2736.84 m, PPL; (e) Intergranular pores are cemented by ferrocalcite (yellow arrow); Well H315, 2580.75 m, PPL. (f) Secondary growth on the surface of...
The physical parameters of sand bodies of different sedimentary microfacies were calculated. The results show that the average porosity and permeability of the main channel sandstones in the delta plain are 6.61% and 0.08 mD, respectively; the average porosity and permeability of the channel margin sandstones in the delta plain are 5.04% and 0.05 mD, respectively; the average porosity and permeability of the main channel sandstones in the delta front are 9.53% and 0.32 mD, respectively; the average porosity and permeability of the channel margin sandstones in the delta front are 4.93% and 0.13 mD, respectively; the average porosity and permeability of interdistributary bay sands is 3.48%, 0.05 mD, respectively (Table 2). In consequence, the main channel sandstone of the underwater distributary channel in the delta front is the...
dominant sedimentary body for the relatively high-quality reservoir development.

Moreover, petrological characteristics (e.g., lithology, composition, grain size, sorting, and roundness) also affect reservoir physical properties, while the detailed impact mechanism is comprehensive and multifactorial.46,47 Therefore, it is difficult to find the correlation between a single factor and reservoir physical characteristics. This study attempts to use the mathematical statistics methods and pick several influence factors that are well correlated with reservoir physical properties (Figure 11 and 12). The result shows that the average particle size is positively associated with thin-section porosity (Figure 12). Quartz content is positively associated with intergranular pore content. The total content of feldspar

Table 1. Carbon and Oxygen Isotopic Data of Ch-6 Carbonate Cements in the WJY Area

| no. | well name | depth (m) | δ13C_PDB (‰) | δ18O_PDB (‰) | value of Z | paleotemperature (°C) |
|-----|-----------|-----------|---------------|---------------|------------|-----------------------|
| 1   | C118      | 2266.5    | −1.913        | −21.547       | 112.65     | 101.78                |
| 2   | C18       | 2153.9    | −0.788        | −20.972       | 115.24     | 97.62                 |
| 3   | C18       | 2145.5    | 1.09          | −15.022       | 122.05     | 58.47                 |
| 4   | C18       | 2184.86   | −0.449        | −20.594       | 116.12     | 94.92                 |
| 5   | F10       | 2216.9    | −0.763        | −22.221       | 114.67     | 106.74                |
| 6   | H132      | 2336.15   | −1.909        | −19.55        | 113.65     | 87.62                 |
| 7   | H132      | 2368.25   | 1.361         | −20.877       | 119.69     | 96.94                 |
| 8   | H269      | 2385.8    | −1.05         | −18.512       | 115.93     | 80.58                 |
| 9   | H269      | 2396.3    | 0.323         | −21.48        | 117.27     | 101.29                |
| 10  | H269      | 2366      | −0.989        | −22.307       | 114.17     | 107.38                |
| 11  | H269      | 2408.7    | −0.289        | −23.109       | 115.2      | 113.41                |
| 12  | H269      | 2419.27   | 0.204         | −20.341       | 117.59     | 93.13                 |
| 13  | H48       | 2480.1    | −0.84         | −21.819       | 114.71     | 103.77                |
| 14  | H83       | 2455.7    | −1.674        | −20.687       | 113.57     | 95.58                 |
| 15  | H83       | 2662      | −8.742        | −21.48        | 98.7       | 101.29                |
| 16  | Y114      | 2273.6    | −2.202        | −21.161       | 112.25     | 98.98                 |
| 17  | Y115      | 2298.3    | 0.184         | −14.506       | 120.45     | 55.41                 |
| 18  | Y115      | 2313.8    | 0.399         | −14.511       | 120.89     | 55.44                 |
| 19  | Y115      | 2382.05   | −2.428        | −18.963       | 112.88     | 83.61                 |
| 20  | Y117      | 2349.4    | −1.751        | −19.647       | 113.93     | 88.29                 |
| 21  | Y117      | 2351.2    | −1.348        | −14.11        | 117.51     | 53.1                  |
| 22  | Y117      | 2353.7    | −1.422        | −17.021       | 115.91     | 70.83                 |
| 23  | Y123      | 2376.1    | −3.806        | −21.038       | 109.03     | 98.09                 |
| 24  | Y28       | 2440.8    | −1.995        | −21.482       | 112.52     | 101.3                 |
| 25  | Y28       | 2443.1    | −1.262        | −22.351       | 113.58     | 107.7                 |
| 26  | Y28       | 2448.28   | −2.138        | −21.219       | 112.35     | 99.4                  |
| 27  | Y41       | 2506.8    | −1.787        | −17.555       | 114.9      | 74.27                 |
| 28  | Y41       | 2508.3    | −0.473        | −15.095       | 118.81     | 58.91                 |
| 29  | Y41       | 2547.7    | −4.491        | −21.982       | 107.16     | 104.97                |
| 30  | Y41       | 2556.65   | −3.48         | −21.208       | 109.61     | 99.32                 |
| 31  | Y41       | 2571.4    | −2.566        | −22.008       | 111.08     | 105.16                |
| 32  | Y71       | 2370.1    | −1.67         | −19.746       | 114.05     | 88.97                 |
| 33  | Y71       | 2415.9    | −0.157        | −20.799       | 116.62     | 96.38                 |
| 34  | Y73       | 2353.5    | 0.056         | −20.652       | 117.13     | 95.33                 |
| 35  | Y76       | 2345.7    | −0.27         | −25.53        | 114.03     | 132.4                 |
| 36  | Y76       | 2337.7    | −0.312        | −23.855       | 114.78     | 119.13                |
| 37  | Y76       | 2339.7    | −0.141        | −24.115       | 115        | 121.16                |
| 38  | Y76       | 2385.62   | 2.317         | −24.793       | 119.7      | 126.49                |
| 39  | Y76       | 2385.62   | −2.128        | −20.397       | 114.65     | 93.53                 |
| 40  | Y76       | 2378.95   | −0.224        | −21.617       | 116.08     | 102.29                |
| 41  | Y76       | 2372.6    | 2.127         | −24.298       | 119.56     | 122.59                |
| 42  | Y76       | 2378.95   | 2.031         | −24.221       | 119.4      | 121.98                |
| 43  | Y76       | 2379.9    | 0.147         | −20.962       | 117.16     | 97.55                 |
| 44  | Y76       | 2385.8    | −0.769        | −21.365       | 115.09     | 100.45                |
| 45  | Y76       | 2393.6    | −3.002        | −19.711       | 111.34     | 88.73                 |

Table 2. Physical Parameters of Sand Bodies with Different Sedimentary Microfacies

| physical parameter | distributary channel | underwater distributary channel | interdistributary bay channel |
|--------------------|----------------------|---------------------------------|-------------------------------|
|                    | main channel sandstones | channel margin sandstones       | main channel sandstones       |
| porosity (%)       | 6.61                 | 5.04                            | 9.53                          |
| permeability (mD)  | 0.08                 | 0.05                            | 0.32                          |

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and rock fragment is positively associated with the thin-section porosity of dissolved pores (Figure 11). Further, according to the lithologic characteristics of the reservoir, the high content of feldspar and rock fragment as well as the fine particle size are the material causes for the weak compaction capability of the reservoirs and partly the reasons for the reservoir tightness.

5.2.2. Reservoir Transformation due to Diagenesis. As mentioned above, sedimentary conditions control the petrologic basis and spatial distribution of reservoirs. Furthermore, after deposition, as the burial depth increases, the diagenetic conditions (temperature, pressure, pH, and fluid solubility) change, and the diagenetic features show obvious diversity in each diagenetic stage. Accordingly, the diagenesis diversity can affect the pore evolution and physical characteristics of the reservoirs.

To assess the relative importance of compaction and cementation in the ultimate reservoir quality, the diagram of Houseknecht et al. is applied in the study16 (Figure 13). The diagram shows that more data points cluster in the lower-left portion of the diagram, which indicates that the reservoirs are mainly controlled by compaction in the process of tightness and the effect of cementation is relatively weak.

In addition, the effects of different diageneses on reservoir properties are studied through correlation analysis. The result suggests that the content of carbonate cements, kaolinite fillings, chlorite coatings, and siliceous cements are all negatively associated with the measured porosity (Figure 14), which indicates that multiple cementsations are an important cause of reservoir densification.

5.3. Quantitative Analysis of the Pore Evolution Process. According to research requirements, original porosity (OP) is obtained as follows. The original porosity (OP) could be calculated with eq 2, where particle diameters of \( P_{25} \) and \( P_{75} \) represent the corresponding cumulative volume fraction of 25 and 75%, respectively. The Trask sorting coefficient \( S_0 \) can be calculated with eq 3. The calculated results show that \( S_0 \) is 1.32 and the original porosity (OP) of the Ch-6 reservoirs in the WJY area is 38.2%.

\[
OP = 20.91 + 22.90/S_0 \quad (2)
\]

\[
S_0 = (P_{75}/P_{25})^{1/2} \quad (3)
\]

In addition, it is significantly necessary to analyze the quantitative influence of various diagenesis on reservoirs. Based on the burial history, paleogeothermal history44 (Figure 15), porosity evolution progress, and the aforementioned diagenetic evolution sequence of Ch-6 in the WJY area, analyzing the reservoir changes due to the various diagenesis types, this study established the quantitative progress of pores evolution and divided the progress into seven main stages (Figure 16).

First, in the early stages of burial and diagenesis, various diagenesis had not yet begun to transform the reservoirs. The reservoir space was mainly composed of primary intergranular
pores and the contact type between particles was point-contact. As calculated above, the optional porosity was 38.2%.

Second, in the compaction porosity loss stage, the burial depth and paleogeotemperature increased to around 1500 m and 65 °C, respectively. Under the gravitational pressure of overlying sediments and tectonic stress, the grains rearranged and intergranular water was discharged, and the contact type between the grains changed to a point-linear contact and the porosity was gradually lost. In fact, compaction occurs throughout the diagenesis process and it is not a specific diagenetic action at a certain diagenetic stage. Therefore, to reflect the changing degree of the reservoir by compaction, this study considers it as an influencing parameter for quantitative analysis. The observation and statistic results of thin sections show that the intergranular volume (IGV) is about 19.2%. Based on the calculation of eq 4, the compaction porosity loss (COPL) is 23.5%. In addition, when the burial depth was around 1500 m and the paleogeotemperature was 65 °C, a small amount of early carbonate cements and clay membrane of chlorite were developed in the reservoirs. However, these two types of diagenesis have little effect on the reservoir in the early diagenetic stage, and the study does not conduct the quantitative analysis. Therefore, under the transformation of compaction, the reservoir pore type was residual primary intergranular pore and the residual porosity was about 14.7%.

Figure 14. Correlation between different cements with measured porosity.

Figure 15. Burial and paleogeothermal history of the Ch-6 reservoir in the WJY area, Ordos Basin.
Third, in the dissolved porosity increase stage, the burial depth and paleogeotemperature increased to around 1700 m and 85 °C, respectively. The soluble components were dissolved due to the change of the diagenetic environment. Similar to compaction, dissolution also occurred throughout the diagenesis process and the study considers it as an influencing parameter for quantitative analysis. The results of the analysis indicate that the dissolution minerals are mainly unstable minerals such as early carbonate cementation, feldspar, and rock fragments. The pore types are residual primary intergranular pores and intergranular dissolved pores during this stage. In addition, with the increase of compaction, the contact relation between grains changes from point to point-line. The observation and statistic results of thin sections show that the dissolved porosity (DP) is about 4.2%. Based on the calculation as in eq 5, the dissolved porosity increase (DPI) was around 3.2% and the residual porosity of the reservoir was 17.9%.

\[
\text{DPI} = \text{DP} \times (1 - \text{COPL})
\]  

Fourth, in the chlorite cementation porosity loss stage, the burial depth and paleogeotemperature increased to around 1900 m and 100 °C, respectively. The authigenic chlorite of the Ch-6 reservoirs is mainly developed in the form of a grain coating. The observation and statistic results of the thin sections show that the content of chlorite cements (CHCEM) is about 4.9%. Based on the calculation as in eq 6, chlorite cementation porosity loss (CHCEPL) was around 3.8% and the residual porosity of the reservoir was 14.1%.

\[
\text{CHCEPL} = (\text{OP} - \text{COPL}) \times \frac{\text{CHCEM}}{\text{IGV}}
\]  

Fifth, in the kaolinite cementation porosity loss stage, the burial depth and paleogeotemperature increased to around 2250 m and 125 °C, respectively. Authigenic kaolinite is one of the common authigenic clay minerals in the Ch-6 reservoir of the WJY area, which is mainly filled in the dissolved pores of feldspar and residual original intergranular pores and closely related to the unstable aluminosilicate minerals (such as feldspar). The observation and statistic results of the thin sections show that the content of kaolinite cements (KCEM) is about 3.9%. Based on the calculation as in eq 7, the kaolinite cementation porosity loss (KCEPL) was 3.0% and the residual porosity of the reservoir was 11.1%.

\[
\text{KCEPL} = (\text{OP} - \text{COPL}) \times \frac{\text{KCEM}}{\text{IGV}}
\]  

Finally, in the carbonate cementation porosity loss and siliceous cementation porosity loss stage, the burial depth of...
the Ch-6 reservoir increased to the maximum burial depth of about 2700 m, and then the stratum was continually uplifted to the present burial depth of about 2100 m. The medium-term carbonate cements are mainly sparry calcite or ferrocalcite, but the late carbonate cements are mainly ankerite and to a lesser extent ferrocalcite in the Ch-6 reservoirs of the WJY area. The early carbonate cements are scarcely observed due to the dissolution. The observation and statistic results of the thin sections show that the content of carbonate cements (CACEM) is about 4.1%. Based on the calculation as in eq 8, the carbonate cementation porosity loss (CACEPL) was 3.1% and the residual porosity was around 8.0% after the carbonate cementation. In addition, the main types of siliceous cements in the Ch-6 reservoirs of the WJY area are terrigenous quartz overgrowth and authigenic quartz crystals in dissolved pores. The observation and statistic results of the thin sections show that the content of siliceous cements (SCEM) is about 1.1%. Based on the calculation as in eq 9, the siliceous cementation porosity loss (SCEPL) was 0.8% and the residual porosity of the reservoir was about 7.2%. Inescapably, the illite was rarely developed in the reservoirs in this stage and had little effect on the reservoir. Therefore, the study ignores it as an influencing parameter and does not conduct a quantitative analysis of illite cementation.

\[
CACEPL = (OP - COPL) \times \frac{CACEM}{IGV} \tag{8}
\]

\[
SCEPL = (OP - COPL) \times \frac{SCEM}{IGV} \tag{9}
\]

Above all, on account of the quantitative analysis of porosity evolution, compaction is the primary cause leading to reservoir tightness. The other diagenetic factors leading to reservoir tightness are cementation of chlorite, carbonate, kaolinite, silica, and illite, ranked from a strong to a weak degree of influence on reservoir tightness. In addition, dissolution is the key factor to improve the physical property of the reservoir. The tightness process and por evolution model of the Ch-6 reservoir in the WJY area are shown in Figure 16 (Table 3).

6. CONCLUSIONS

Sedimentary facies types primarily controlled the material basis of the Ch-6 reservoirs in the WJY area and further affected their physical properties. The high content of feldspar and rock fragments and the fine grain size are the material causes for the reservoir tightness. The main channel sandstone of the underwater distributary channel is the dominant sedimentary facies type for the high-quality reservoir development. The diagenetic stage of the reservoir Ch-6 in the WJY area is identified as the late stage of eodiagenesis A to the early stage of mesodiagenesis B. The main diagenetic factors that lead to the reservoir tightness include compaction and the cementation of carbonate, chlorite kaolinite, and silica, the porosity loss of which are 23.5, 3.1, 3.8, 3.0, and 0.8%, respectively. The dissolved porosity increase is around 3.2%. Therefore, compaction and the cementation of chlorite, kaolinite, and carbonate are the key factors to damage the physical property of the reservoir. The dissolution is the most significant factor to improve reservoir physical property.

### Table 3. Meaning of the Abbreviations in the Above Equations

| Abbreviation | Description |
|--------------|-------------|
| OP | original porosity: the porosity before all kinds of diagenesis |
| COPL | compaction porosity loss: the percentage of the pore volume reduced after compaction in the apparent original rock volume |
| IGV | intergranular volume: the volume that has undergone compaction but without dissolution |
| DPI | dissolved porosity increase: the percentage of pore volume resulting from dissolution in the apparent volume before all kinds of diagenesis |
| DP | dissolved porosity: the percentage of pore volume resulting from dissolution in the apparent volume at present |
| CHEPL | chlorite cementation porosity loss: the percentage of reduced pore volume due to chlorite cementation in the apparent volume before all kinds of diagenesis |
| CHCEM | chlorite cements content: the percentage of chlorite cements content in the rock volume |
| KCEPL | kaolinite cementation porosity loss: the percentage of reduced pore volume due to kaolinite cementation in the apparent volume before all kinds of diagenesis |
| KCEM | kaolinite cements content: the percentage of kaolinite cements content in the rock volume |
| CACEPL | carbonate cementation porosity loss: the percentage of reduced pore volume due to carbonate cementation in the apparent volume before all kinds of diagenesis |
| CACEM | carbonate cements content: the percentage of carbonate cements content in the rock volume |
| SCEPL | silica cementation porosity loss: the percentage of reduced pore volume due to silica cementation in the apparent volume before all kinds of diagenesis |
| SCEM | silica cements content: the percentage of silica cements content in the rock volume |
| CAC | carbonate cements content: the percentage of carbonate cements content in the rock volume |

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