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The distribution of movable fluid and its coupling influencing factors in ultra-low permeability sandstone reservoirs: a case study of Chang 6 member, Wuqi area, Ordos Basin

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Abstract: To figure out the distribution and influencing factors of movable fluids in ultra-low permeability sandstone reservoirs, this research takes Chang 6 member in the Wuqi area as an example. Through a series of experiments, the occurring and influencing factors of the movable fluid were analyzed. The results show that the ultra-low permeability sandstone reservoirs in this research have porosity values ranging from 8.78% to 16.12%, permeability values ranging from 0.094mD to 1.467mD, and the values of movable fluid saturation ranging from 31.38% to 62.67%. All the samples can be comprehensively divided into two types, type I samples have higher content of feldspar, more developed dissolved pores, and generally locate in middle part or top part of thicker sand bodies. For all the samples, the movable fluid saturation, permeability, r_{peak} , and r_{50} have a strong correlation with each other, which may be associated with the development of large pore-throats. Although the movable fluid occurs in pore-throat with a wide size range, the development of micron pore-throats is the key influence on the values of movable fluid saturation, differentiating ultra-low permeability reservoirs and tight sandstone reservoirs.

Key words: Chang 6 member, ultra-low permeability sandstone reservoirs, saturation of movable fluid, pore-throat structure, Wuqi area, Ordos Basin

1. Introduction

Drove by the growth of population and income, the total production of primary energy in the world has shown a continuous linear growth,¹ which poses a huge challenge to global oil and gas exploration and development.^{2,3} Unconventional hydrocarbon resources provide opportunity to alleviate this pressure,^{4,5} which account for 39% of the total reserves of oil and gas resources.¹ China has abundant unconventional oil and gas resources amounting to $514.5 \times 10^8 \text{t}$.⁵⁻⁷, which are becoming one of the important areas for increasing oil and gas reserves and production. As an important unconventional oil and gas reservoir type, low-permeability sandstone reservoirs exhibit strong macroscopic and microscopic heterogeneity, and how to accurately predict the "sweet spots" in low-permeability sandstone reservoirs is still a challenge. In China, low-permeability sandstone reservoirs are generally divided into four levels⁶, they are general low-permeability reservoirs (10-50mD), ultra-low permeability reservoirs (1-10mD), super-low permeability (0.1-1mD) and tight reservoirs (<0.1mD), respectively. The Ordos Basin is known as the largest tight oil bearing sedimentary basin in China, most of the crude oil resources is mainly distributed in low-permeability to tight sandstone reservoirs (*TSRs*) of Chang 6-Chang 8 member, Upper Triassic Yanchang Formation.^{5,8,9} Over the past decade, there are more and more researches focused on movable fluids in *TSRs*. While, the research on that in ultra-low permeability reservoirs is relatively weak.

As a core parameter, the saturation of movable fluid (*MFS*) directly affect the oil recovery

rate, and is commonly used to characterize the of low-permeability sandstone reservoirs.^{7,10} It is found that, for *TSRs*, the movable fluids occurs in pore throats with radii ranging from a few nanometers to tens of micrometers^{7,10}. The influencing factors of *MFS* include physical properties, mineral compositions, pore-throat radius distribution, and heterogeneity of pore-throat structure, etc.¹¹⁻¹⁴ There are still some issues with low-permeability reservoirs that require further research, such as the correlation between the movable fluid occurring and seepage capability, as well as the differences in the occurrence of movable fluids between *TSRs* and ultra-low permeability sandstone reservoirs. Generally, previous research has mostly focused on the impact of a single parameter on *MFS*, the synergistic effect of the macroscopic and microscopic properties on *MFS* is weakly researched. How to accurately describing the impact mechanisms of various factors on *MFS* of ultra-low sandstone reservoirs remain a challenge, the collaborative relationship between the influencing factors and *MFS* still needs to be analyzed. This article aims to (1) characterize the distributions of movable fluid in ultra-low permeability sandstone reservoirs, (2) to reveal the influencing factors and the synergistic impacts of multi factors on *MFS*, (3) and to compare the differences in distribution of movable fluid between *TSRs* and ultra-low permeability sandstone reservoirs.

2. Geological setting

The Ordos Basin is a cratonic superimposed oil-bearing sedimentary basin, extending in north-south direction, and can be divided into six core structural units:⁸ the Yimeng uplift, the Yishan slope, the Jinxi fold belt, the Weibei uplift, the western margin thrust belt, and the Tianhuan depression (Figure 1a). The studied Wuqi area is located in the central western part of

the Yishan Slope (Figure 1a), which is uplift gradually from west to east without large-scale faults.⁸ Upper Triassic Yanchang Formation is the main crude oil bearing strata in the Ordos Basin, presented as interbedded sandstone and mudstone deposit.^{9,15} When Yanchang Formation deposited, the sedimentary environment of the Ordos Basin is a large inland lake surrounded by multiple deltas.⁸ During Chang 7 period, the ancient lake reached the largest area and the deepest water depth, a set of essential hydrocarbon source rocks formed.¹⁵ During Chang 6 period, the ancient lake contracted, and the peripheral deltas migrated towards the sedimentary center of the basin, forming well-developed oil and gas bearing sandstone reservoirs.^{8,9} The Chang 6 member in the study area is predominantly composed of interbedded fine-grained sandstone and mudstone, belonging to delta front sedimentary subfacies, controlled by the northeast provenance (Figure 1c).

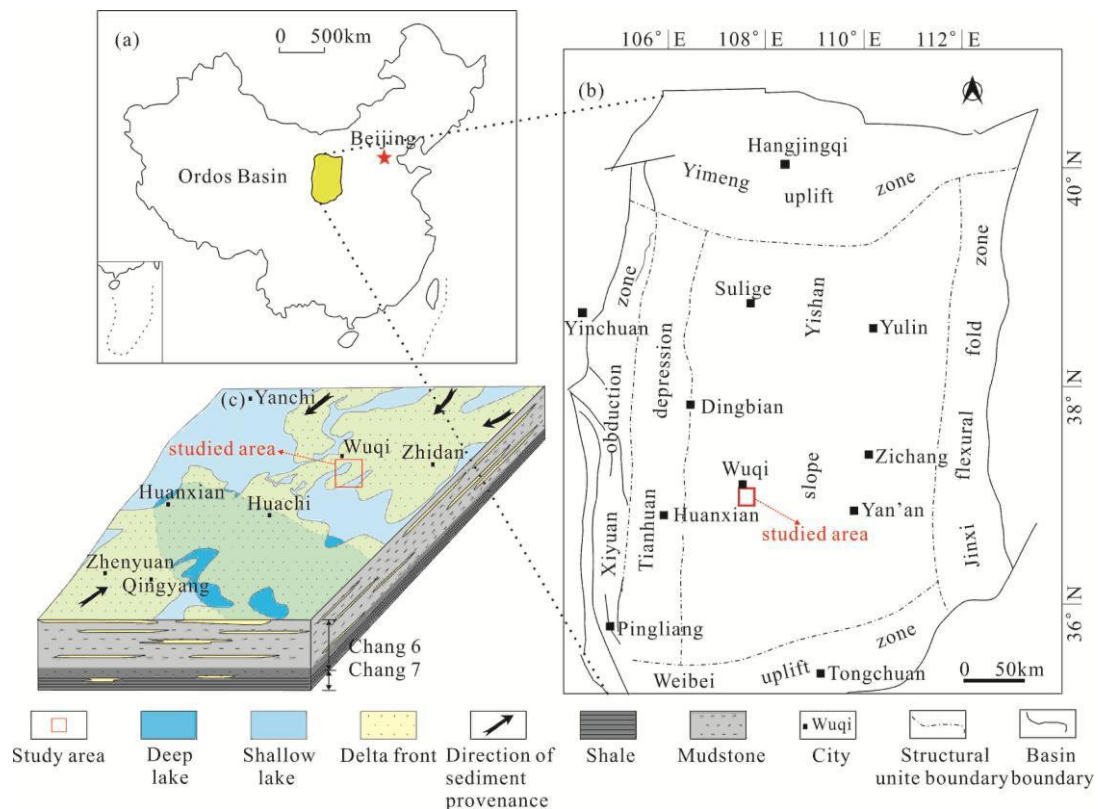


Figure 1. The location of the Ordos Basin in China (a), the tectonic units of the Ordos Basin and the location of the studied area (b), the sedimentary facies of Chang 6 to Chang 7 member in the study area (c)

3. Samples and methods

Twenty samples were collected from drilled cores of Chang 6 sandstone reservoirs in Wuqi area (Table 1), which are mainly light gray to gray fine sandstone. To obtain the microstructure parameters of pore-throats, and to provide insight into the occurrence of the movable fluids in ultra-low permeability sandstone reservoirs, the collected samples were conducted on a series of tests, including physical property tests, casting thin section analysis (*CTS*), scanning electron microscopy (*SEM*) observation, high pressure mercury injection (*HPMI*), and combined experiment of nuclear magnetic resonance (*NMR*) and centrifugation. All the experiments were conducted in the Geological Test and Analysis Center of Xi'an Shiyou University.

3.1 Examination of *CTS* and *SEM*

Ten core samples were injected with blue epoxy resin, and half of each section was stained with Alizarin red *S* to distinguish calcite from other carbonate minerals. Then *CTS* were observed under a polarization microscope (Leica DMRXHC). The authigenic minerals and pore types were identified, the contents of minerals and thin section porosity were estimated. Fifteen *SEM* samples coated with a gold film were examined using a field emission scanning electron microscope (Tescan). The acceleration voltage is 15kV, and the working distance is 10mm. The morphology of pore-throat and authigenic minerals were obtained through high resolution *SEM* images.

3.2 X-ray diffraction analysis on the relative content of clay minerals

Ten samples were washed oil and dried, then prepared to powder with particle sizes less than 1mm. Then, samples were conducted on a Ultima IV X-ray diffractometer, the content of different

clay minerals and the proportion of illite montmorillonite mixed layer were measured.

3.3 HPMI experiment

Ten cylindrical shaped core samples with a diameter of 2.5cm and a length of 5cm were conducted for the *HPMI* experiment, a high-pressure mercury injection instrument (Quantachrome) were used. The maximum mercury injection pressure is limited to 200.65MPa. The pore-throat radius distribution can be obtained through the capillary calculation formula as following¹⁶.

$$P_c = 2\sigma \cos\theta/r \quad (1)$$

where P_c is mercury injection pressure, σ is the surface tension, θ is the contact angle between mercury (non wetting phase) and the inner surface of the pore, r is the pore-throat radius. In this research, σ and θ are taken as an empirical values of 480 mN/m and 140°, respectively.

3.4 Combined NMR and centrifugation experiment

Ten samples were conducted on the combined *NMR* and centrifugation experiment, the transverse relaxation time (T_2) and its corresponding echo signal intensity under water saturated and centrifugal conditions were measured. Each T_2 can be calibrated to the corresponding pore-throat radius.^{17,18} The *NMR* experiment were conducted on a low field *NMR* analyzer (MICROMR12-040V) at a constant temperature of 25 °C, the echo interval is 0.3ms, the waiting time is 3000ms, and the maximum centrifugal is 200psi (approximately 1.38MPa).

Based on the power function relationship between r and T_2 ,²⁰ each T_2 values can be transformed to certain pore-throat radii. Simultaneously, a linear function is also commonly

used,^{21,22} and it can be considered as a special form of power formula, when the power exponent n takes a value of 1. Considering that linear function is not limited by the maximum mercury saturation (S_{max}), and is easy to calculate,²³ linear calculation formula was used in this research.

$$r = CT_2^{1/n} \quad (2)$$

where C is the conversion coefficient, n is the power exponent. Using Eq. (2), the values of n and C can be obtained using regression methods.²⁴ The MFS can be obtained by comparing the T_2 spectral cumulative curves under water saturated and maximum centrifugal force conditions.^{19,20}

4. Results

4.1 Petrology and pore characteristics based on CTS and SEM

The observation of CTS show that the frameworks of Chang 6 sandstone reservoirs in the study area are mainly composed of quartz, feldspar, and rock debris. The contents of quartz range from 17% to 55%, which are mainly single crystal quartz. The contents of feldspar range from 20% to 43%, which are mainly plagioclase (Table 1, Figure 2a, b). The contents of rock debris range from 5% to 10%, which are mainly metamorphic rock debris, sedimentary rock debris. According to sandstone classification scheme proposed by Folk,²⁵ the Chang 6 sandstone reservoirs in the study area belong to arkose and lithic arkose (Figure 2a). The proportion of interstitial materials is 12% to 48% (Table 1), which are primarily silty and muddy materials (Figure 2a, b). The cements are mainly authigenic carbonate, siliceous, and clay minerals. (Table 1). The proportion of carbonate cements rank the highest, which appears locally (Figure 3b). The clay cements are mainly composed of kaolinite, illite, and chlorite (Figure 2b), among them, the coated chlorite is

the most commonly observed (Figure 3c, e). Additionally, thin section porosity of all the samples range from 3.15% to 15.25% (Table 1).

Table 1. Mineral composition and thin section porosity of Chang 6 sandstone reservoirs samples in the study area.

Abbreviation: Qz (quartz), Fsp (feldspar), Sil (siliceous), Cal (calcareous), Kln (kaolinite), Chl (chlorite), Ill (illite),

I/M (illite montmorillonite mixed layer), S% in I/M (montmorillonite content in illite montmorillonite mixed layer),

RIP (residual intergranular pore), *DP* (dissolved pore), *Mc*(microcrack).

No.	Well name	Depth (m)	Framework			Cements				Clay cements				Matri x	Thin section porosity				
			Qz	Fsp	Debris	Sil	Clay	Cal	Kln	Chl	Ill	I/M	S% in		<i>RIP</i>	<i>DP</i>	<i>Mc</i>	Total	
			(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	I/M		(%)	(%)	(%)	(%)	
14	Well 5	1860.55	55	20	10	2	1	10	20.7	57.6	10	11.7	20	2	9.00	1.10	/	10.10	
7	Well 5	1875.95	52	23	10	2	2	9	17.5	42.7	25.5	14.3	15	2	6.00	1.15	/	7.15	
12	Well 3	1787.70	44	33	10	2	1	8	24.7	54.2	11.8	9.3	15	2	6.00	1.10	/	7.10	
15	Well 6	1870.66	42	35	8	2	2	7	20.2	56.6	9.9	13.3	15	4	12.00	1.20	/	13.20	
16	Well 6	1878.25	39	40	8	2	3	5	22.8	56.6	12.1	8.5	15	3	5.00	2.25	/	7.25	
17	Well 6	1880.50	41	38	8	2	2	5	29.1	60.7	6.1	4.1	15	4	8.00	2.20	0.10	10.30	
18	Well 6	1886.90	17	30	5	0	2	45	2.1	5	48.6	44.3	25	1	1.50	0.65	1.00	3.15	
13	Well 4	1788.35	42	37	8	2	1	8	19.5	68.6	6.3	5.6	15	2	13.00	2.25	/	15.25	
4	Well 1	1883.10	39	40	9	2	2	3	21.8	48.6	15.9	13.7	15	5	6.00	1.15	0.05	7.20	
11	Well 2	1824.30	37	43	8	2	1	4	25.6	48.6	14.3	11.5	15	5	6.00	1.15	/	7.15	

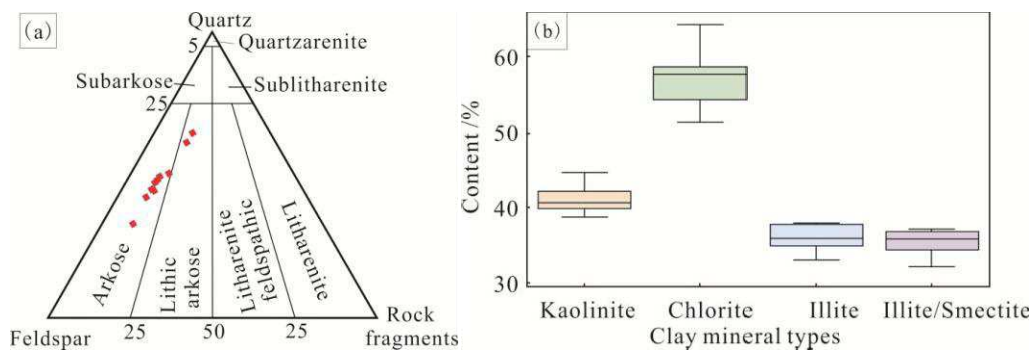


Figure 2. Ternary of frameworks of Chang 6 sandstone reservoirs (a), plot of different clay mineral content (b)

Under *SEM*, the oriented arranged frameworks (Figure 3a-f), the plastic bending deformed biotite (Figure 3a), and locally cemented calcite can be observed (Figure 3b). It shows that the residual intergranular pores (*RIPs*) and dissolved pores (*DPs*) are the dominated pore types

(Figure 3a-f). *RIPs* exist between frameworks, exhibiting as a polyhedral shape. *DPs* exhibit as irregular shapes, and can be further subdivided into intergranular dissolved pores (Figure 3a), feldspar dissolved pores (Figure 3f), and rock debris dissolved pores, etc. (Figure 3c). Among them, the intergranular dissolved pores usually have a larger radius, ranging from tens of micrometers to nearly 100 micrometers (Figure 3a, e). The *DPs* within feldspar grains and cleavage fractures of biotite are relatively small (Figure 3b, c). Intercrystalline pores (*IPs*) occur between authigenic mineral crystals, and usually have a smaller pore radius less than 1 μ m. The microcracks can be occasionally observed, which usually penetrate frameworks (Figure 3f). It is worth mentioning that when the framework particle surface, which enclose *RIPs* was dissolved, the *RIPs* will be dramatically expanded and exhibit an irregular shape (Figure 3c, e). The throat is a channel that connects pores, which is mainly manifested as non completely enclosed frameworks contact surfaces, with width generally less than 1 μ m, or even 0.1 μ m (Figure 3d-f).

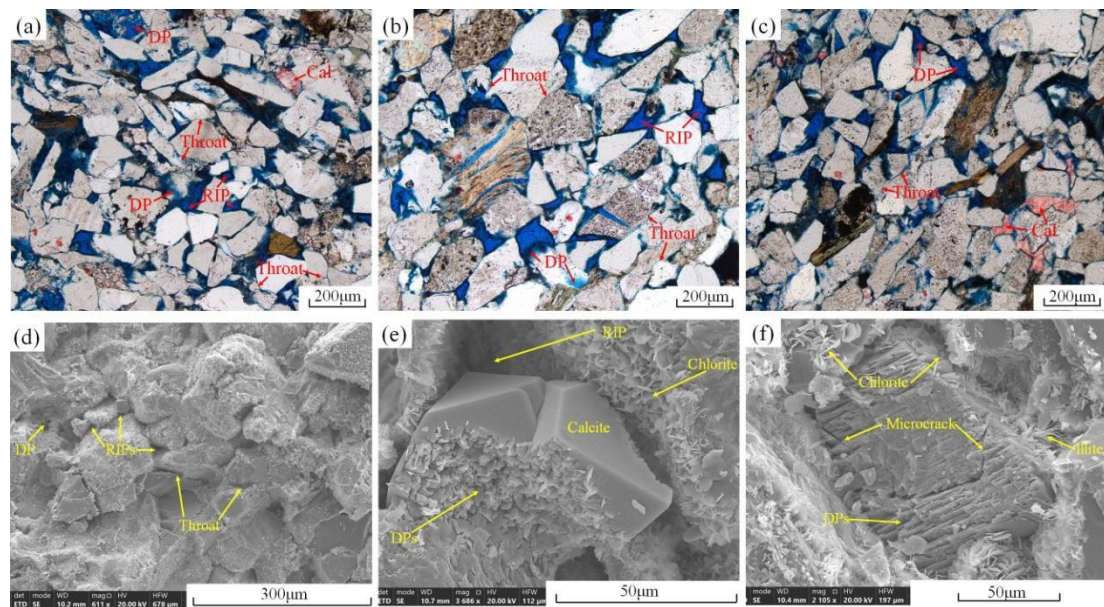


Figure 3. Pore types and morphology of sandstone reservoirs of Chang 6 member in study area. (a), Sample 4, 1883.10m, *DPs* are interconnected with *RIPs*. (b), Sample 53, Well 6, 1874.15m, authigenic calcite cements fills *RIPs* and *DPs*, curved sheet shaped throats. (c), Sample 55, Well 6, 1870.66m, dissolution in the cleavage cracks of

biotite and rock debris. (d), Sample 81, Well 5, 1875.95m, *DPs*, *RIPs* and the interconnected throats. (e), Sample 12, Well 6, 1874.15m, coated chlorite cementation and dissolution of authigenic calcite cements (f), Sample 24, Well 2, 1842.15m, dissolution of feldspar, coated chlorite and illite cements, microcrack.

4.2 *HPMI derived parameters of pore-throat structure*

The porosity and permeability of all the *HPMI* samples range from 8.778% to 16.119%, and 0.122 mD to 2.453mD, respectively (Table 2). The P_{cd} values range from 0.297 MPa to 0.676MPa (Table 2). Overall, the sandstone reservoirs of Chang 6 member in the study area belong to ultra-low permeability sandstone reservoirs.⁶ The significant differences in pore throat structure parameters among different samples indicate that the samples may belong to different types.

All the *HPMI* samples exhibit great variations in a series of *HPMI* experiment parameters and the physical property parameters (Table 2), and can be comprehensively classified into two types, according to the pore-throat distribution curves (Figure 4 ,Table 2). Type I samples have higher permeability, ranging from 1.444 to 2.453 mD, with an average of 1.702 mD, together with higher r_{max} (2.463-2.478 μ m), r_{ave} (0.529-0.557 μ m), S_p (2.246-3.145), S_{max} (81.92-84.48%), and lower P_{cd} (0.297-0.298MPa). Type II samples have lower permeability, and higher S_{kp} , K_p , P_{cd} (Table 2). Type I samples exhibiting bimodal pore-throat radius distribution, and are predominantly composed of pore-throats with radii ranging from 0.01 μ m to 2 μ m, (Figure 4a). Type II samples also exhibit bimodal pore-throat radius distribution, and the pore-throat radii predominantly range from 0.01 μ m to 1 μ m (Figure 4b), implying that type II samples have more submicron and nano scale pore-throats (Figure 4b).

Table 2. The *HPMI* derived parameters. The Φ represent porosity, the K represent permeability. The r_{max} , r_{50} , r_{ave} , r_{peak} represent maximum connected pore-throat radius, pore radius corresponding to 50% of the pore-throat volume filling by mercury, the average pore-throat radius, and the peak pore-throat radius, respectively. S_p , S_{kp} , K_p represent the sorting coefficient, skewness, and kurtosis of pore-throat radius distribution, respectively. S_{max} , W_e , P_{cd} represent maximum mercury saturation, mercury removal efficiency, and displacement pressure, respectively.

Type	No.	Well name	Depth /m	K /mD	Φ /%	r_{max} / μ m	r_{50} / μ m	r_{ave} / μ m	r_{peak} / μ m	S_p	S_{kp}	K_p	S_{max} %	W_e /%	P_{cd} /MPa
I	1	Well 3	1776.46	1.444	16.12	2.471	0.109	0.557	1.093	2.459	0.103	0.675	84.48	34.80	0.297
	2	Well 3	1793.05	1.467	11.47	2.478	0.122	0.529	0.540	2.246	0.194	0.664	83.31	36.77	0.297
	3	Well 6	1874.15	0.473	9.53	2.471	0.098	0.516	0.538	2.493	0.289	0.682	80.24	34.30	0.297
	4	Well 1	1883.10	2.453	12.81	2.463	0.197	0.536	0.541	3.145	0.079	1.214	81.92	30.33	0.298
	Ave.	/	/	1.702	14.13	2.471	0.134	0.535	0.678	2.577	0.120	0.807	83.55	34.18	0.297
II	5	Well 2	1821.60	0.235	11.53	1.574	0.094	0.303	0.540	2.578	0.148	0.936	81.67	27.38	0.467
	6	Well 4	1801.25	0.094	8.78	1.093	0.089	0.185	0.178	1.988	0.363	0.882	79.19	23.82	0.673
	7	Well 5	1886.30	0.361	13.70	1.089	0.079	0.177	0.541	1.976	0.095	0.715	82.46	32.16	0.675
	8	Well 5	1875.85	0.382	12.21	1.570	0.097	0.281	0.538	3.142	0.172	1.854	82.73	31.89	0.468
	9	Well 6	1877.12	0.219	11.89	1.093	0.068	0.192	0.358	2.108	0.156	0.715	81.21	28.74	0.672
	10	Well 6	1880.70	0.122	13.78	1.088	0.069	0.185	0.358	2.043	0.173	0.792	80.40	25.20	0.676
	Ave.	/	/	0.236	11.98	1.251	0.083	0.221	0.419	2.306	0.185	0.982	81.28	28.20	0.605

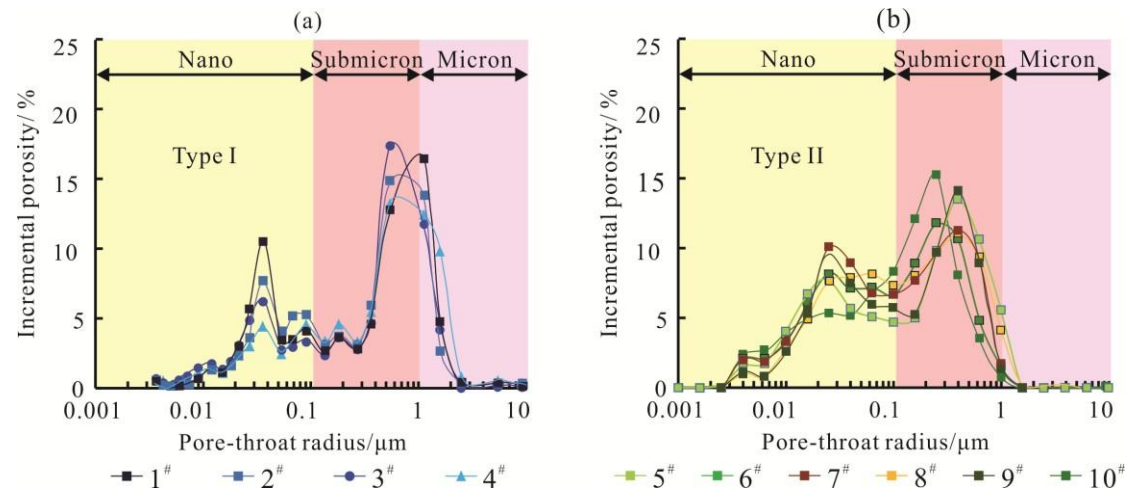


Figure 4. The *HPMT* derived pore-throat radius distribution curves of type I samples (a), and those of type II samples (b). Both types of samples exhibit bimodal distribution, and type I samples have more developed micron sized pore-throats.

4.3 The NMR derived movable fluid distribution

It shows that C values of all the samples range from 30 to 60 (Table 3). The MFS of all the samples range from 33.78% to 54.67% (Table 3). The movable fluid mainly occurs in submicron and micron pore-throats, a small amount of movable fluid is distributed in nano scale pore-throats (Table 3). Type I samples have overall higher MFS with an average of 54.86%, and the movable fluid mainly occurs in micron pore-throats, accounting for 46.48% of the total MFS on average (Table 3, Figure 6). Type II samples have lower MFS with an average of 41.59%, the movable fluid mainly in submicron pore-throats (Table 3, Figure 6).

Table 3. The NMR test parameters. C is the conversion coefficient between T_2 and pore-throat radius, MFS_n , MFS_s , MFS_m represent the volume of movable fluid within nano scale, submicron, and micron pore-throats to total pore-throat volume, respectively. MFP_n , MFP_s , MFP_m represent the proportion of movable fluid saturation within three size grades of pore-throats to the total MFS , respectively. Φ_n , Φ_s , Φ_m represent the volume proportion of movable fluid within three size grades of pore-throats to the appearance volume of samples, respectively.

Type	No.	Well name	$T_{2cutoff}$ (ms)	MFS (%)	C	Nano scale			Submicron			Micron		
						MFS_n (%)	MFP_n (%)	Φ_n (%)	MFS_s (%)	MFP_s (%)	Φ_s (%)	MFS_m (%)	MFP_m (%)	Φ_m (%)
I	1	Well 3	2.40	52.03	60	4.12	7.92	0.66	21.35	41.03	3.44	26.56	51.05	4.28
	2	Well 3	2.96	53.15	60	7.77	14.62	0.89	21.95	41.30	2.52	23.67	44.53	2.71
	3	Well 6	3.91	51.01	45	4.43	8.68	0.71	22.7	44.50	3.66	24.39	47.81	3.93
	4	Well 1	2.96	62.67	50	8.00	12.77	1.02	29.87	47.66	3.83	26.64	42.51	3.41
	Ave.	/	3.06	54.86	54	6.08	11.00	0.82	23.97	43.62	3.36	25.32	46.48	3.58
	5	Well 2	2.76	48.29	50	6.74	13.96	0.78	28.90	59.85	3.33	12.51	25.91	1.44
	6	Well 4	4.50	47.95	40	5.45	11.37	0.48	25.11	52.37	2.20	17.73	36.98	1.56
II	7	Well 5	4.19	41.33	50	5.50	13.31	0.75	20.99	50.79	2.88	14.71	35.59	2.01
	8	Well 5	12.75	31.38	35	1.61	5.13	0.20	18.59	59.24	2.27	11.03	35.15	1.35
	9	Well 6	4.17	42.66	40	4.02	9.42	0.48	23.10	54.15	2.75	15.48	36.29	1.84
	10	Well 6	3.18	38.77	40	4.99	12.87	0.69	23.18	59.79	3.19	9.93	25.61	1.37
	Ave.	/	5.26	41.59	43	4.72	11.01	0.56	23.31	56.03	2.77	13.57	32.59	1.59

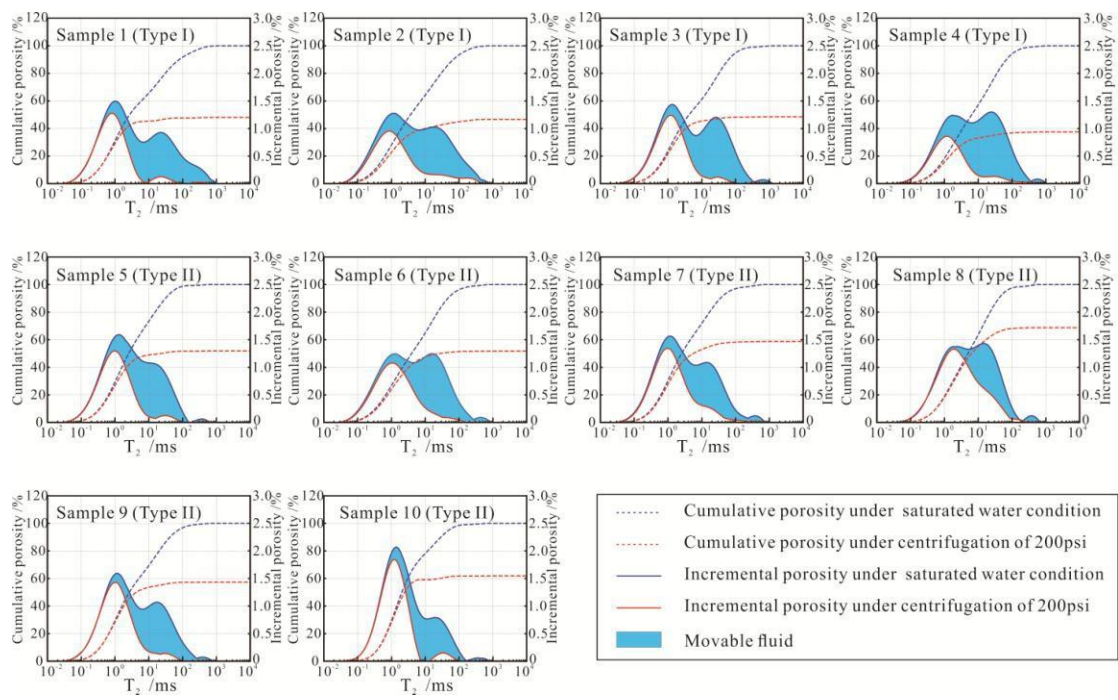


Figure 5. The T_2 spectral, T_2 cumulative spectral and movable fluid distribution of all the NMR test samples

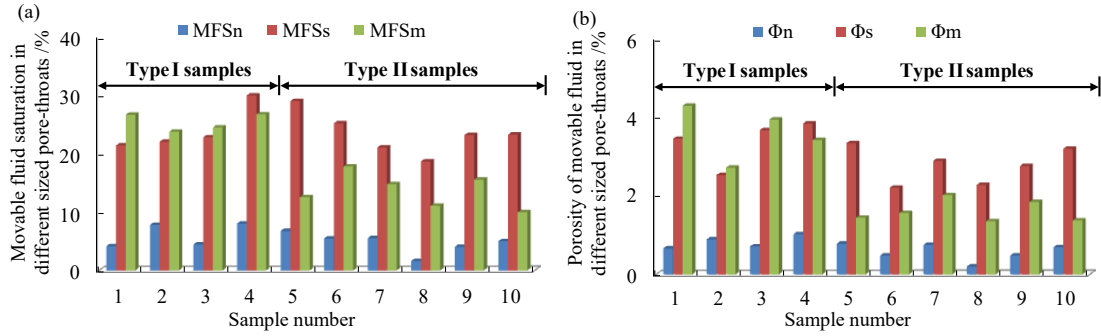


Figure 6. The comparison of the proportion of movable fluid in submicron and nano scale pore-throats of two types of samples. The movable fluid saturation within three size grades of pore-throats to the MFS of samples (a), the ratio of movable fluid volume within three size grades of pore-throats to the appearance volume of samples (b)

5. Discussion

5.1 The influence of sedimentary and diagenesis on MFS

The ultra-low permeability sandstone reservoirs of Chang 6 member in the study area are predominantly sand bodies of subaqueous distributary channels (Figure 7). Type I samples usually

correspond to the main distributary channel with overlapped thick sand bodies and less mud interlayers (Figure 7). For example, Sample 1, Sample 4 is located in the middle part of thick sand body, with a high content of feldspar, having higher *MFS* of 52.03% and 62.67%, respectively. Although Sample 3 is not located in the middle part of sand bodies, and has higher content of carbonate cements, the coarser granularity promotes higher *MFS* values (Figure 7). Type II samples, such as Sample 7, Sample 8, which is located at thinner sand bodies, or the bottom of sand bodies, with more developed mud interlayers (Figure 7). The exchanging of numerous Fe^{2+} , Ca^{2+} , and Mg^{2+} at sand-mudstone interface promoted the formation of carbonate cements.^{26,27} Therefore, the sand bodies usually have worse reservoir properties and lower *MFS*.

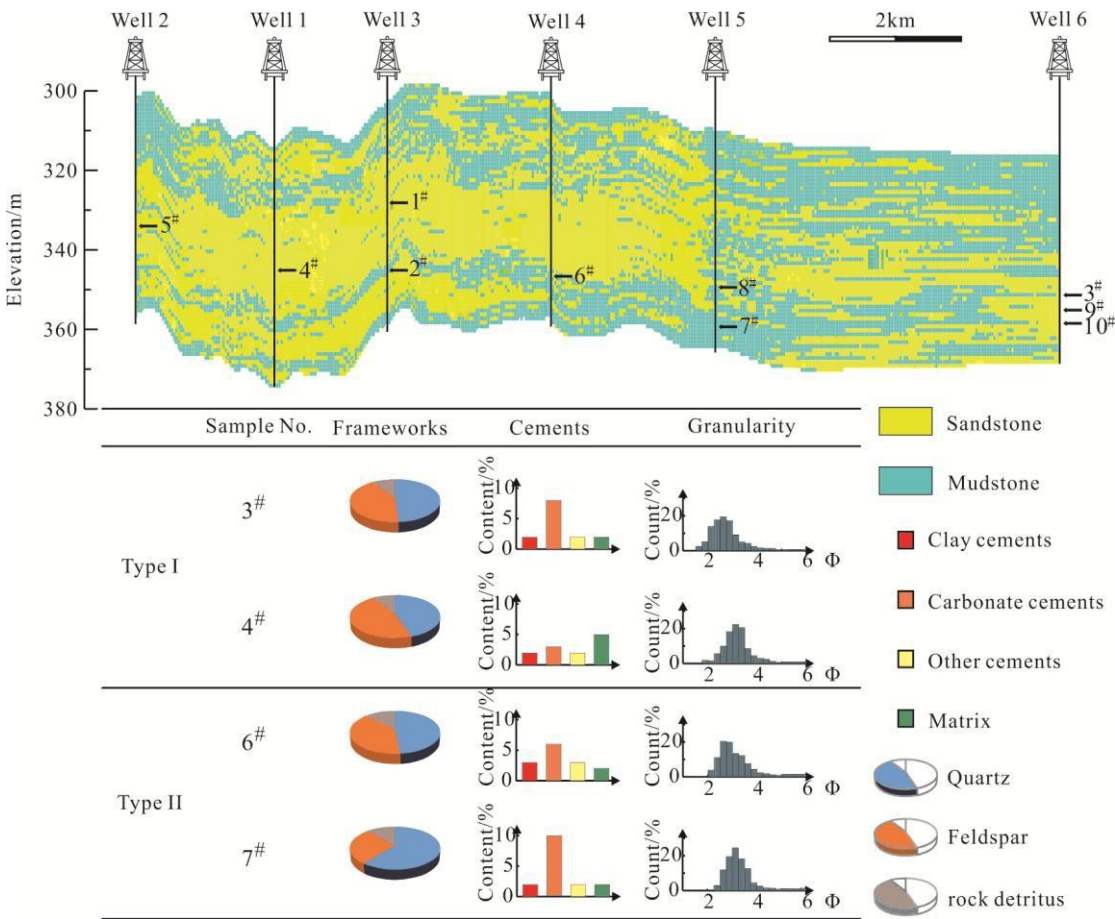


Figure 7. The comparison of two types of samples on location in sand body, framework composition, cement

content and granularity

Abundant diagenesis phenomena imply that Chang 6 member in the study area is in the Mesodiagenesis stage A, the corresponding evidences are as follows, frameworks are mainly point-line contact, dissolved pores are well developed, the proportion of montmorillonite ($S\%$) in illite montmorillonite mixed layers (I/M) is in range of 15%-25% (Figure 8a), etc. Houseknecht proposed a function calculating the degree of compaction and cementation, from the ratio of the present volume percentage of cement and the intergranular volume.²⁸⁻³¹ Wang raised an improved calculation equation, based on the thin section statistical data.³² The porosity decrease caused by compaction and cementation can be calculated through the following calculating equation.³²

$$\Phi_{loss_compaction} = \Phi_0 - C_t + \frac{(\Phi_{pm} + \Phi_{ca}) \cdot \Phi_p}{\Phi_t} \quad (3)$$

$$\Phi_{loss_cementation} = \frac{(\Phi_{pm} + \Phi_{ca}) \cdot \Phi_p}{\Phi_t} - \frac{\Phi_{pm} \cdot \Phi_p}{\Phi_t} \quad (4)$$

where $\Phi_{loss_compaction}$ and $\Phi_{loss_cementation}$ are the decrease in porosity caused by compaction and cementation, respectively. C_t is the cement content, Φ_0 is the original porosity, Φ_{pm} , Φ_{ca} , Φ_t , are the thin section porosity of *RIPs*, cement dissolved pores, and total thin section porosity, respectively. Φ_p is the measured porosity.

It shows that the compaction caused the greatest damage to the pore-throat space, reducing the porosity by 65% to 85% (Figure 8b). The cementation caused secondary destruction to the pore-throat space, reducing the porosity by 15%-35% (Figure 8b). All the samples suffered similar degree of compaction and cementation (Table 4).

While, there is a significant difference in the development degree of micron pore-throats between these two types of samples. For type I samples, the micron sized pore-throats with larger radius are more developed, and it may be due to the relatively developed dissolution process,

which resulted in an increase in the volume of large pore-throats and the *MFS* values (Table 2, 4).

For type II samples, the lower proportion of micron pore-throats, higher proportion of nano scale pore-throats (mainly *IPs* and narrow throats), and smaller r_{peak} are unfavorable to *MFS* (Table 4).

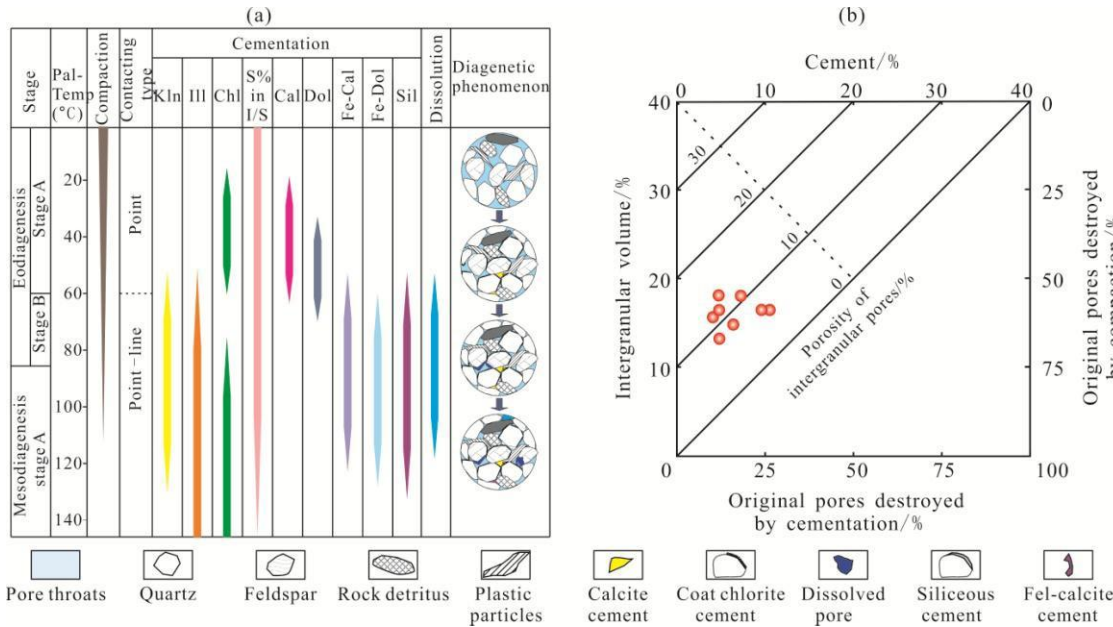
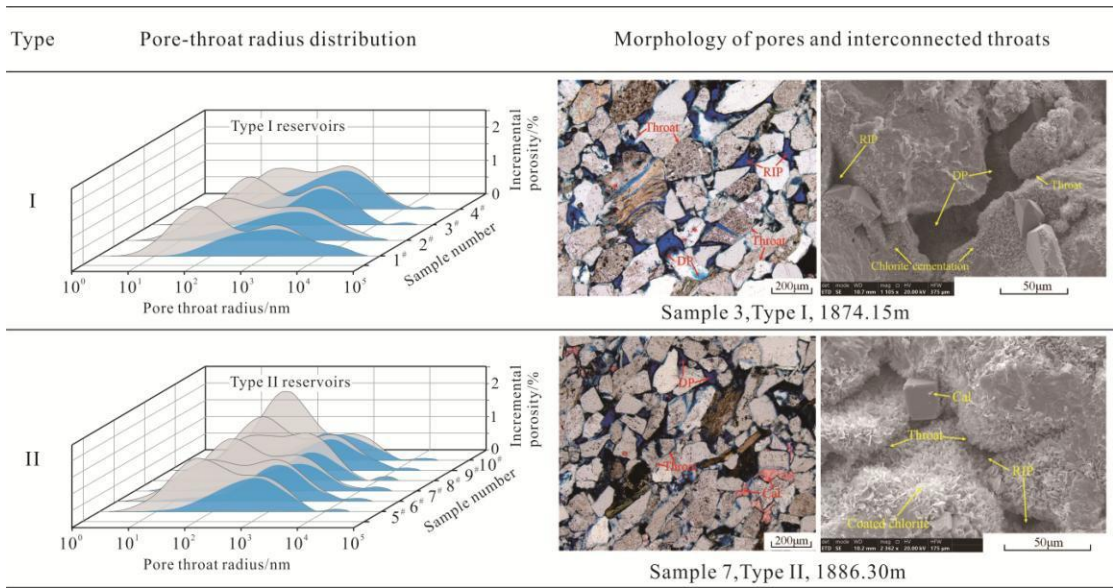


Figure 8. The diagenesis stages and sequences of the Chang 6 sandstone reservoirs in the study area (a), and the influence of compaction and cementation on the original porosity (b)

Table 4. The distribution of pore-throats size and movable fluid of two types of sandstone reservoirs, attached with the comparison of size and morphology of the pore-throats.



5.2 The correlation between physical properties and *MFS*

Similar to the *TSRs*^{11,12,14}, ultra-low permeability reservoir samples have no significant correlation between porosity and *MFS* in this research (Figure 9a). Figure 9a shows that Sample 4 although has moderate porosity (12.81%), its *MFS* value is higher (62.67%). While Sample 7 and Sample 10 have higher porosity (13.70%, 13.78%) but lower *MFS* values (41.33%, 38.77%). Figure 9b compares the pore throat size distribution and movable fluid distribution of these samples, all these three samples exhibit a bimodal pore throat size distribution, the peak radius of small pore throats is 0.09 μm , and that of large pore throats is 1 μm (Figure 9b). Simultaneously, the movable fluid is concentrated in pore throats ranging from 0.1 to 10 μm (Figure 9b), and the *MFS* values are determined by the development of pore throats in radius range of 0.1-1 μm (Figure 9b). Sample 4 have more developed large pore throats with radius in range of 0.1-1 μm , while, Sample 7 and Sample 10 lack those large pore throats (Figure 9b), that's why Sample 4 has higher *MFS*, while Sample 7 and Sample 10 have lower *MFS*. Additionally, the peak radii of movable fluid distribution is prone to move towards the direction of the small pore throat (Figure 9b), accompanied by a decrease in *MFS* values. It implies that, the movable fluid will squeeze into small pore throats, when large pore throats are less developed.

Figure 9c shows that there is a significantly positive correlation between permeability and *MFS*, and in this research, 0.5mD is the boundary value for dividing these two types of samples (Figure 9c). For all the samples, the main permeability contribution ranges are generally consistent with the pore throat radius ranges when the accumulated movable fluid volume increases rapidly (Figure 9d), it can explain why there is a close relationship between permeability and *MFS*, which

supports the viewpoint of previous researches^{11,33,34}. Simultaneously, the main permeability contribution ranges are narrower, and the movable fluid occurring ranges are wider. The movable fluid enters connected larger or smaller pore throats through the main seepage pore throats, especially pore throats with radius ranging from $0.3\mu\text{m}$ to $3\mu\text{m}$ significantly impact the MFS in this research (Figure 9d).

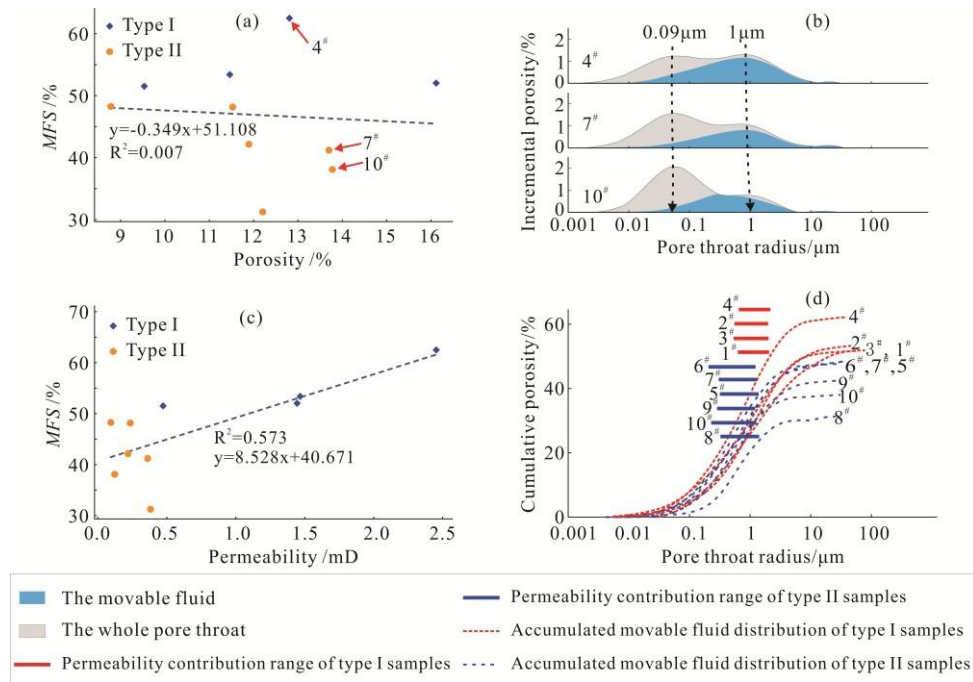


Figure 9. Correlation plot of porosity versus MFS (a), the comparison of movable fluid distribution in Sample 4, Sample 7 and Sample 10 (b), the correlation of permeability versus MFS (c), and the cumulative distribution curves of movable fluid in pore throats (d)

5.3 The synergistic effects of HPMT parameters on MFS

Concerning the impact of a single HPMT parameter on MFS , there is a negative correlation between MFS and P_{cd} (Figure 10a), a positive correlation with between MFS and r_{50} , r_{ave} and r_{peak} , respectively (Figure 10b, c, d), which is similar to those of $TSRs$.^{13,14,17} P_{cd} corresponds to the maximum connected pore-throats, which determines the development of large sized pore-throats

where movable fluid is mainly distributed, and strongly affects the values of MFS . (Table 4). Simultaneously, the r_{50} , r_{ave} and r_{peak} all represent the overall size of pore-throats. The greater r_{50} , r_{ave} , and r_{peak} , the easier it is for the fluid to overcome capillary forces and flow freely. Additionally, a parameter was used, which reflects the development of pore-throat space where fluids cannot flow freely, and can be calculated by $(1-MSF) \times \text{porosity}$. It shows that this parameter has a moderate negative correlation with MFS (Figure 11f), confirming that the development of connected pore-throat volume impact MFS .

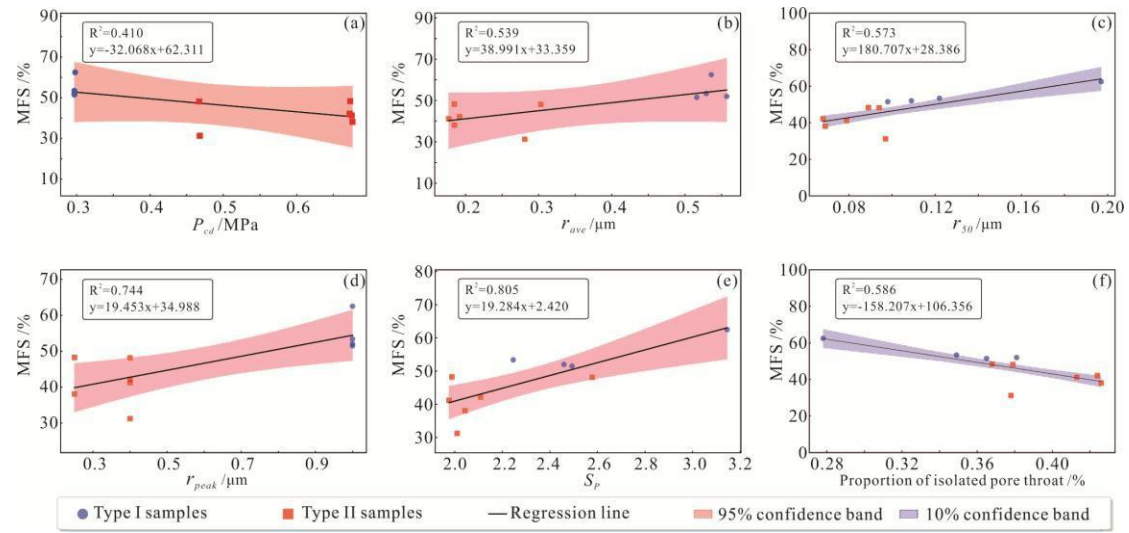


Figure 10. The correlation of pore-throat parameters versus MFS of all the samples

It can be observed that there are varying degrees of correlation between MFS and a series of $HPMI$ parameters, as well as between these parameters themselves (Figure 11a). Principal component analysis shows that permeability, r_{max} , r_{ave} , and r_{50} contribute the most to the explanatory variance of the first principal component, (Figure 11b) which may be related with the development degree of large pore throats. Simultaneously, porosity, S_{max} , S_{kp} contributes the most to the second principal component, (Figure 11b) which may be related with the overall connected pore-throat volume. The first principal component has good discrimination between two types of

samples (Figure 11b), the development of large pore throats with a radius greater than $1\mu\text{m}$ is one of the key differences between the two types of samples (Figure 4). The MFS values have correlation with both the first principal component and the second principal component, implying that the occurrence of movable fluids is not only controlled by the large pore-throats, but also by the development level of overall connected pore throat volume.

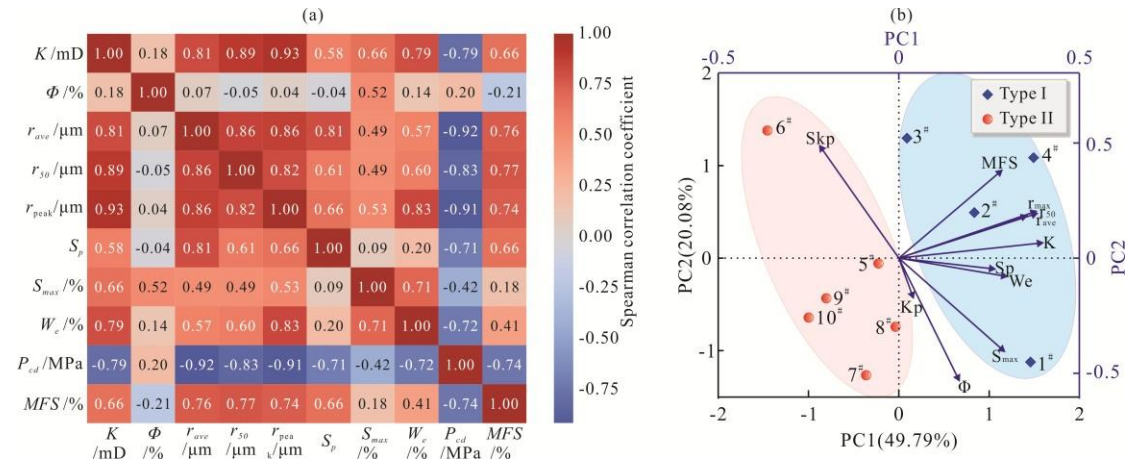


Figure 11. Pearson correlation coefficient plot of porosity, permeability, and pore-throat structure parameters

derived from *HPMI* test

In particular, the S_p has a significant positive contribution to the first principal component, but almost no contribution to the second principal component (Figure 11b), implying a poor sorting of pore-throat size is beneficial for the development of large pore throats. Actually, whether the correlation between S_p versus MFS is positive or negative may be related to the pore-throat radius range of all the samples.^{13,14,17,23,24} The samples in this research have consistent pore-throat size ranges (Table 4), higher S_p essentially means not concentrated pore throat size distribution, therefore, the large pore-throats are more developed, which is favorable to MFS (Figure 10e).

5.4 The impact of different sizes of pore-throats on MFS

For three size grades of pore-throats (nano scale, submicron and micron), most previous researches consider that the higher proportion of movable fluid in micron or submicron pore-throats, the higher MFS .^{18,24} This research found similar results: the proportion of movable fluid within nano scale pore-throats (MFS_n) has little effect on MFS (Figure 12a), the proportion of movable fluid within micron sized pore-throats (MFS_m) and submicron sized pore-throats (MFS_s) have significant impact on MFS . (Figure 12)

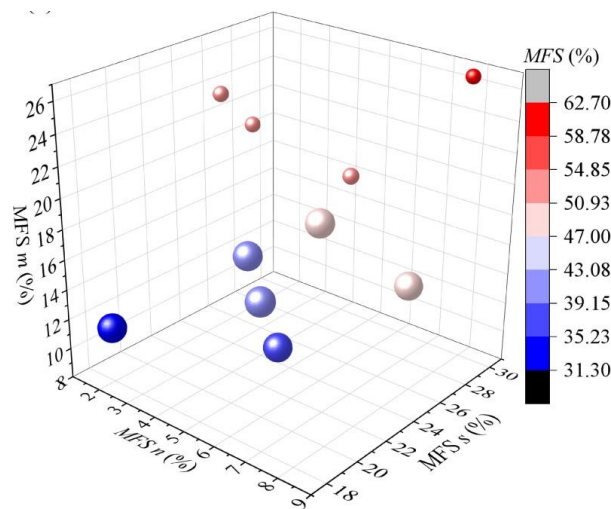


Figure 12. The 3D scatter plot of the movable fluid saturation within nano scale, submicron, and micron pore-throats, named MFS_n , MFS_s and MFS_m , respectively. The two types of samples are distinguished by the size of the spheres, smaller spheres represent type I samples, and larger ones represent type II samples

Comparing the differences in pore throat radius and MFS distribution between ultra-low permeability sandstone reservoirs and $TSRs$, it can be seen that movable fluid is mainly distributed in micron and submicron pore-throats, irrespective of these two grades of pore throats developed or not (Figure 13a). $TSRs$ lack micron pore-throats, the movable fluid squeeze in submicron, even nano scale pore-throats, the MFS is generally lower (Figure 13a). Simultaneously, there are

different influence of the proportion of micron and submicron pore-throats on movable fluids. When the proportion of submicron pore-throats increases from 0 to 30%, MFS will significantly increase (Figure 13b). However, as the proportion of submicron pores continues to increase, it may not necessarily promote the increase of MFS , this situation often occurs in $TSRs$. When the proportion of micron pore-throats increases, MFS will significantly increase, and this situation often occurs in ultra-low permeability reservoirs. Overall, the well-developed micron and submicron pore throats are a characteristic that distinguishes ultra-low permeability sandstone reservoirs from $TSRs$. The development degree of micron pore-throats is the main factor in distinguishing the grade of ultra-low permeability sandstone reservoirs, and determining the values of MFS (Figure 13a).

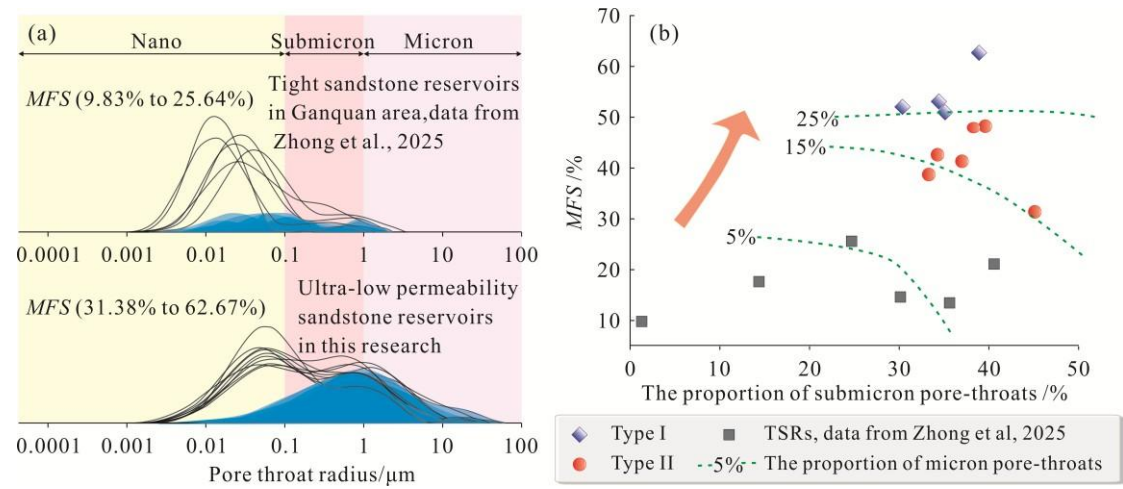


Figure 13. The comparison of $TSRs$ and ultra-low permeability sandstone reservoirs in movable fluid distribution and pore-throat radius distribution, (a) the correlation of MFS and proportion of submicron pore-throats for different types of sandstone reservoirs (b)

6. Conclusions

(1) The ultra-low permeability sandstone reservoirs of Chang 6 member in Wuqi area are mainly composed of $RIPs$, DPs and IPs . All the samples exhibit similar bimodal shape pore-throat

radius distribution, the two peak radii of the pore throat are approximately 0.1 μ m and 1 μ m, respectively. The *MFS* values range from 31.38% to 62.67%, and the movable fluid is mainly distributed in submicron to micron sized pore-throats, accounting for 85.40% to 92.31% of the total amount.

(2) The samples can be comprehensively classified into two types with various parameters. Type I samples generally correspond to thick sand bodies in the main subaqueous distributary channels, have higher content of feldspar and lower content of carbonate cements, as well as higher *MFS* values. Type II samples correspond to thinner sand bodies, or the top/bottom part of sand bodies, and are prone to have lower *MFS*. All the samples underwent similar degrees of diagenesis process. The original porosity decreased by compaction and cementation are 15%-35% and 65%-85%, respectively. It is the degree of development of dissolved pores that differs type I and type II samples. The developed dissolved pores enlarge the *RIPs*, and are beneficial for improving *MFS*.

(3) For ultra-low permeability sandstone reservoirs, *MFS* value exhibit significant correlation with permeability, which may be due to the permeability contribution intervals and movable fluid distribution ranges are basically the same. *MFS* values are significantly influenced by the development of large pore throats, especially micron pore-throats with radius range of 0.3 μ m to 3 μ m. Compared with *TSRs*, the ultra-low permeability sandstone reservoirs have more developed micron pore-throats, which are favorable for the occurring of movable fluid, and generally have higher *MFS* values.

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Conflicts of Interest: The authors declare no conflict of interest.

Data availability: I used or generated research data in this study, and all raw experimental data, well logging data, core analysis data and geological interpretation data supporting the findings of this study are included within the article.

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