DOI 10.1007/s12182-013-0277-2

Controlling effects of the Ordovician carbonate pore structure on hydrocarbon reservoirs in the Tarim Basin, China

Wu Guanghui[1, 2*], Yang Haijun[3], Li Haowu[2] and Sun Lixia[3]

[1] School of Marine Sciences, Sun Yat-sen University, Guangdong 510006, China
[2] PetroChina Research Institute of Petroleum Exploration and Development, Beijing 100083, China
[3] PetroChina Tarim Oilfield Company, Korla, Xinjiang 841000, China

Abstract: The Ordovician carbonate reservoirs in the Tarim Basin with secondary dissolution pores and vugs have complicated pore structures. The weathering crust reservoirs mainly consist of large cavities or vugs connected by fractures, but most of the reef-shoal reservoirs have complex and small throats among matrix pores. The pore structure can be divided into four types: big pore and big throat, big pore but small throat, small pore and small throat, and fracture type. Most of the average throat radius falls between 0.03 and 0.07 μm, close to that of unconventional reservoirs except in local areas with developed fractures. Fluid driving force analysis shows that the differentiation of fluid is mainly controlled by the throat radius in two kinds of mechanism separated by the critical throat radius about 0.1 μm. There is obvious fluid differentiation and oil/gas/water contact in fracture-cavity reservoirs with big throats. However, most of reservoirs under the critical throat radius have high capillary pressure, which resulted in incomplete differentiation of gas/oil/water, and complicated fluid distribution and fluid properties in the unconventional reservoirs.

Key words: Carbonate, throat radius, critical hydrocarbon column, unconventional reservoir, mechanism

1 Introduction

Characterization of porous media has been a challenge for scientists and engineers (Do et al, 2008; Jamaloei et al, 2010; Clarkson et al, 2012), especially the research into petrophysical and capillary pressure properties and application in petroleum geology and engineering (Nelson, 2009; Amann-Hildenbrand et al, 2012), and more attention has been given to unconventional reservoirs in recent years (Smith et al, 2009; Zou et al, 2010). Several papers introduced methods for estimating the height of hydrocarbon accumulation, which showed that the throat size of reservoirs and seal rocks plays an important role in the hydrocarbon seal and migration even though these are generally not known well in most exploration settings (Bretan et al, 2003; Nelson, 2009).

There have been large oil and gas resources found in lower Palaeozoic marine carbonates in the Tarim Basin, which attracted much attention to the special hydrocarbon reservoirs (Zhao et al, 2009; Liu et al, 2011). Much work has been done on the reservoir characteristics and their effects on hydrocarbon richness and distribution (Jiao and Zhai, 2008; Du, 2010), but hardly any focus on the roles of carbonate pore structures in hydrocarbon distribution. Based on the mass of data from exploration and development, this paper presents a pore structure analysis of Ordovician carbonate reservoirs and its controlling effects on fluid distribution.

2 Geological background

The Tarim Basin, in northwestern China, is an old craton basin with a large sedimentary thickness and a wide distribution of Cambrian-Ordovician marine carbonates (Li et al, 2010). Although there are well-developed source-reservoir-cap combinations and excellent reservoir-forming conditions, the complicated hydrocarbon reservoirs, different from the typical marine carbonate hydrocarbon reservoirs in Meso-Cenozoic but less in preSilurian of the world (Gu et al, 2012), have undergone more than 20 years of exploration struggle due to the multi-stage structure evolution and strong reservoir heterogeneity. With the advances in exploration technology and reservoir research in recent years, more and more reserves have been discovered. The proved reserves are about 20×10^8 t oil equivalent, and the proved, probable and possible reserves are more than 40×10^8 t oil equivalent in Ordovician carbonates in the Tarim Basin, mainly in the Northern and Central uplifts (Fig. 1) (Du, 2010).

*Corresponding author. email: guanghui_wu@petrochina.com.cn
Received April 8, 2012

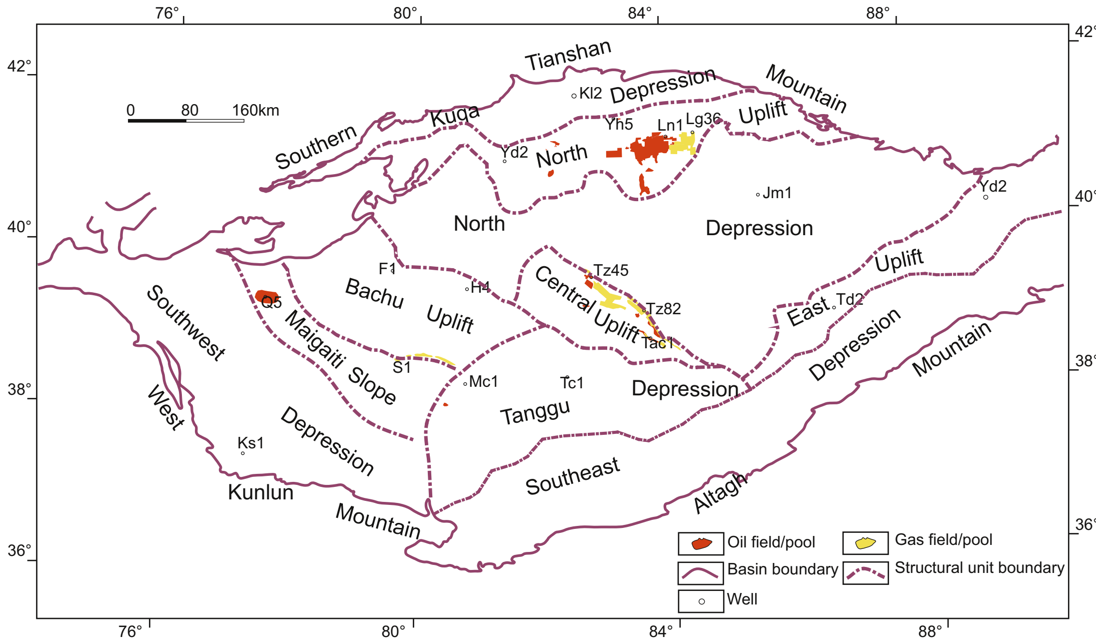


Fig. 1 Structure division and carbonate hydrocarbon fields/pools distribution in the Tarim Basin

There are reef-shoal type and weathering crust type reservoirs in Ordovician hydrocarbon-bearing carbonates of the Tarim Basin (Jiao and Zhai, 2008; Du, 2010), mainly limestone of complicated diagenesis and buried up to 4,000-7,000 m. Most of the primary porosity has been lost and secondary pores account for nearly 85% of the current porosity. One of the most important characteristics of Ordovician carbonate reservoirs is extensive heterogeneity because of multi-stage non-fabric dissolution and fracturing, in which many kinds of secondary porosity developed and their distributions were complicated and varied in space (Du, 2010; Li et al, 2010; Yang et al, 2011). The matrix porosity and permeability are extremely low and poorly correlated (Fig. 2). According to the analysis of 1,448 conventional core samples in 34 wells in the Lungu buried hill, the average matrix porosity is 1.29%, and the average matrix permeability is about $0.3\times10^{-3}\mu m^2$. Reef-shoal type reservoirs have better physical properties than weathering crust type reservoirs, but the porosity is usually <3%, and permeability is $<1\times10^{-3}\mu m^2$. The porosity of logging interpretation is generally 1.2%-6%, with only local high porosity of up to 10%-50% in fracture-cavity reservoir, and the permeability range is mainly $(0.01\text{-}10)\times10^{-3}\mu m^2$.

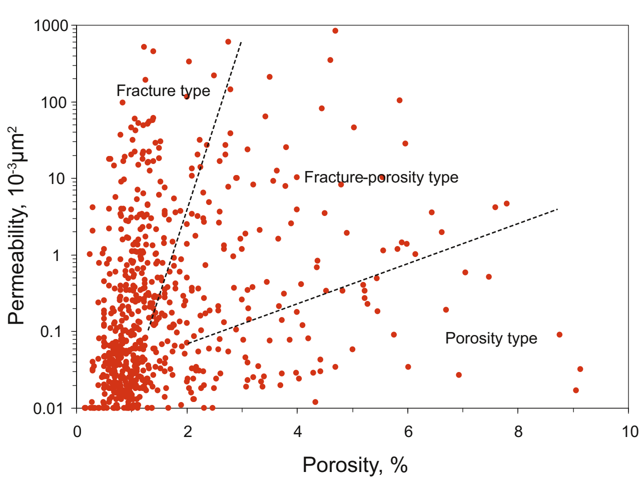


Fig. 2 Porosity-permeability relation of Ordovician carbonate reservoirs in the Tarim Basin

Both weathering crust type and reef-shoal type reservoirs are highly heterogeneous which results in drastic variation of reservoir properties both vertically and laterally. The statistics show that fracture-cave reservoirs account for 20% of the total area of oil/gas field, but contribute more than 70% of petroleum reserves. Carbonate reservoirs are characterized by rich secondary pores, low matrix porosity and permeability, and extensive heterogeneity, which is different from the late Palaeozoic-Cenozoic porosity type reservoir (Gu et al, 2012).

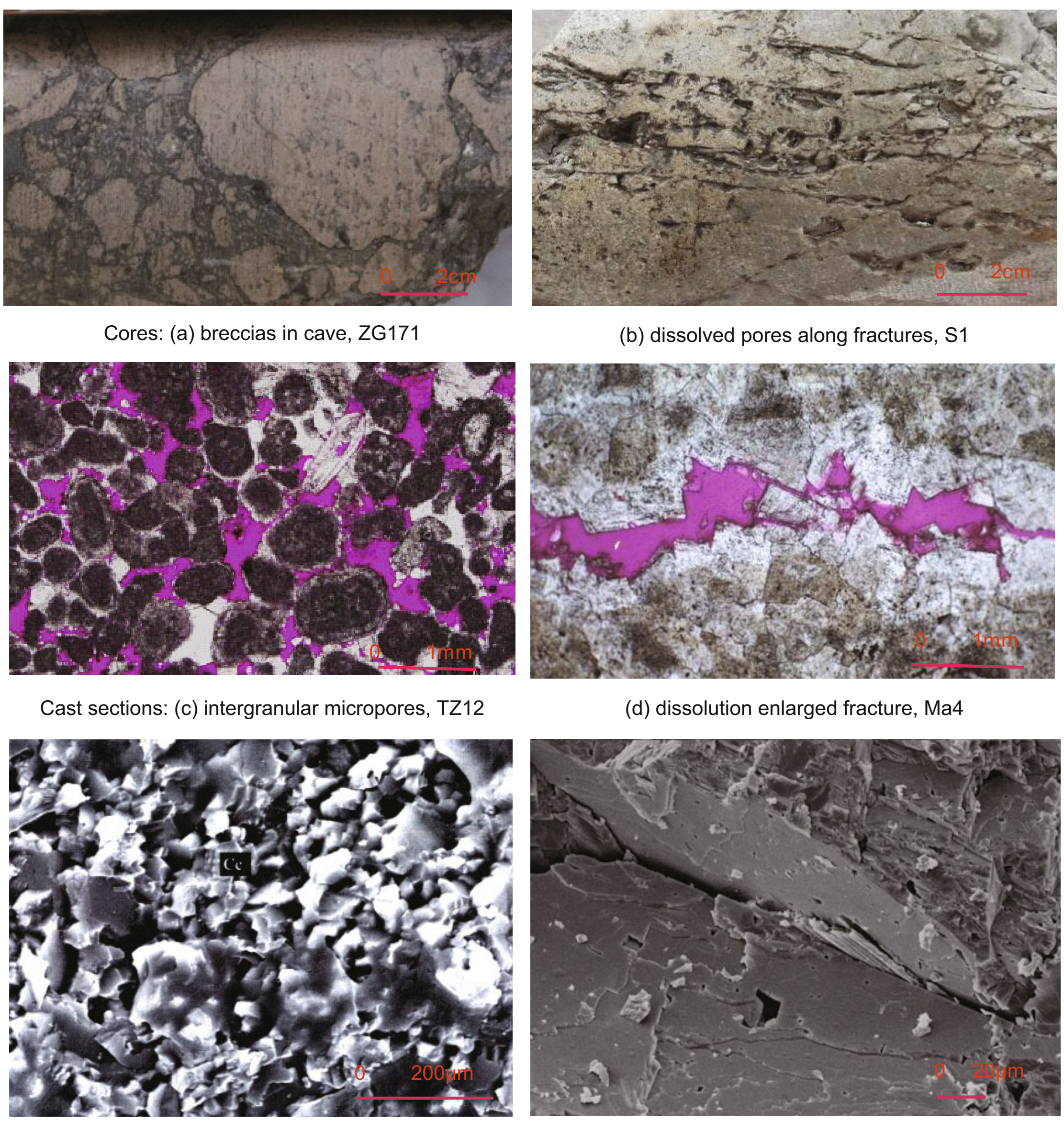
The old carbonate fields in the Tarim Basin have particular complexities (Jiao and Zhai, 2008; Wu et al, 2010; Zhang et al, 2011). There are mainly non-structural type pools with irregular geometry and rapidly changing hydrocarbon abundances. The fluid physical properties vary with different kinds of heavy oil, normal density oil and condensate oil, as well as wet gas and dry gas even in the same field. It is difficult to identify the oil/gas/water boundaries and to prepare hydrocarbon reservoir descriptions with conventional methods. The hydrocarbon distribution controlled by reservoir and multi-stage charging is complex (Li et al, 2010). The 20%-30% high efficiency wells contribute more than 70% of the production, which is non-uniform, with high and low yield wells and water producers coexisting. The rapid production decline rate and low recovery ratio make development evaluation very difficult. They are considered as unconventional hydrocarbon reservoirs since they are so different from the world's high matrix porosity carbonate fields (Jiao and Zhai, 2008; Zou et al, 2010).

3 Characteristics of carbonate pore structure

3.1 Pore structure in weathering crust type reservoirs

Mainly distributed in the Northern and Central uplifts and Maigaiti Slope in the southwest of the Tarim Basin, the weathering crust reservoirs are mainly controlled by relic karst landforms (Li et al, 2010), with features of vertical layers and horizontal belts, where karst slope is the most favorable area for this kind of reservoir.

The macropore space of weathering crust type reservoir is mainly composed of cavities from karstification and fractures from tectonism. Matrix porosity is low in the intraplatform compact limestone (Jiao and Zhai, 2008; Du, 2010) (Fig. 3). Cavities as the main pore space are distributed widely in the highlands and slopes of karst landforms, which can be multi-layered in the vadose zone and phreatic zone in profile, with thicknesses up to 200 m. There are different scales of sinkholes filled with various breccias and mud in the vertical vadose zone, and irregular dissolved cavities controlled by underground water flow developed in the horizontal phreatic zone. In some cases, some of the dissolved pores and vugs developed along the grainstone layers or fractures. There are structural fractures, stylolites and corroded fissures in weathering crust reservoirs, mainly high angle micro-fractures and half-filled mostly by mud or calcites in multi-stage tectonic evolution. The fracture density changes a lot and is centralized near faults along the palaeouplift slope. It is common to see dissolved pores and vugs along fractures. The fracture porosity is usually less than 0.5%, and fractures with apertures of 0.2-20 mm are mostly filled. The permeability can be increased 1-3 orders of magnitude by fractures in low matrix porosity. The reservoir micro-space includes intergranular and intragranular dissolution pores, intercrystalline pores and micro-fractures. Seldom seen in tight limestones, intergranular and intragranular dissolution



Cores: (a) breccias in cave, ZG171

(b) dissolved pores along fractures, S1

Cast sections: (c) intergranular micropores, TZ12

(d) dissolution enlarged fracture, Ma4

SEM: (e) micropores, bad connectivity, ZG7

(f) intercrystal fracture and micropores, LG201

Fig. 3 Pore characteristics of Ordovician weathering crust type reservoirs pores commonly develop near fractures. Intercrystalline dissolution pores mainly exist in dolomites and calcites filled with fractures. Micro-fractures, frequently seen in thin sections, are mainly half-filled structural fractures with the aperture of 0.01-0.1 mm.

Large scale karst cavities and vugs constitute the major pore space in weathering reservoirs, in which it is rare to see dissolved pores or good matrix pores adjacent and among the cavities from cores, and fractures are the primary throats in tight limestone only if dissolved pores developed between neighboring cavities in some cases (Fig. 3). Except for fractures, some of the dissolution pores or vugs can be connected by tiny throats to some extent. Fracture-cavity systems, formed by different scales of cavities and vugs connected by fractures, are the main target in weathering crust type reservoir exploration and development in the Tarim Basin (Jiao and Zhai, 2008; Du, 2010). Having undergone deep burial, most of the fracture-cavity systems represent isolated reservoirs since the connecting channels were filled by collapse and cement in the long burial history and the connecting fractures not well develop between the far apart cavities on the gentle slope of the palaeo-uplift. Otherwise, some cavities developing near faults can be connected by fractures or by matrix pores in some cases (Du, 2010; Wu et al, 2012).

On seismic profiles most single strong reflections represent isolated fracture-cavity systems and multiple linked strong reflections represent fracture-connected cavity systems of different sizes. All of the high yield wells in the Northern and Central uplifts have large scale fracture-cavity systems, accompanied by well blowdown, kick or circulation loss during drilling. On the other hand, dry wells penetrate between the cavities with undeveloped fractures, which indicates that cavities in weathering crust reservoirs are effective in accumulating petroleum, but poor in connectivity. In this kind of pore-throat combination, the initial production is generally high due to the effective connectivity by fractures, but the production in most wells declines quickly as the oil drainage area of an isolated cavity is limited, which results in periodical drawdown during the production (Fig. 4). The decline rate in the Lunnan area in the Northern Uplift is up to 22%-32% per annum, which is a typical feature of Ordovician carbonate reservoirs in the Tarim Basin (Du, 2010).

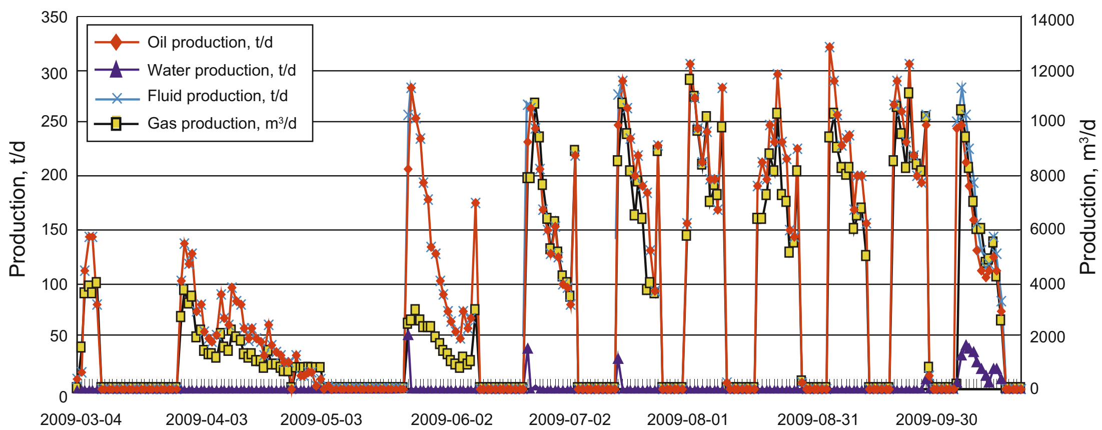


Fig. 4 Production history of Ordovician carbonate reservoirs in Ha7, Tarim Basin

3.2 Pore structure of reef-shoal type reservoir

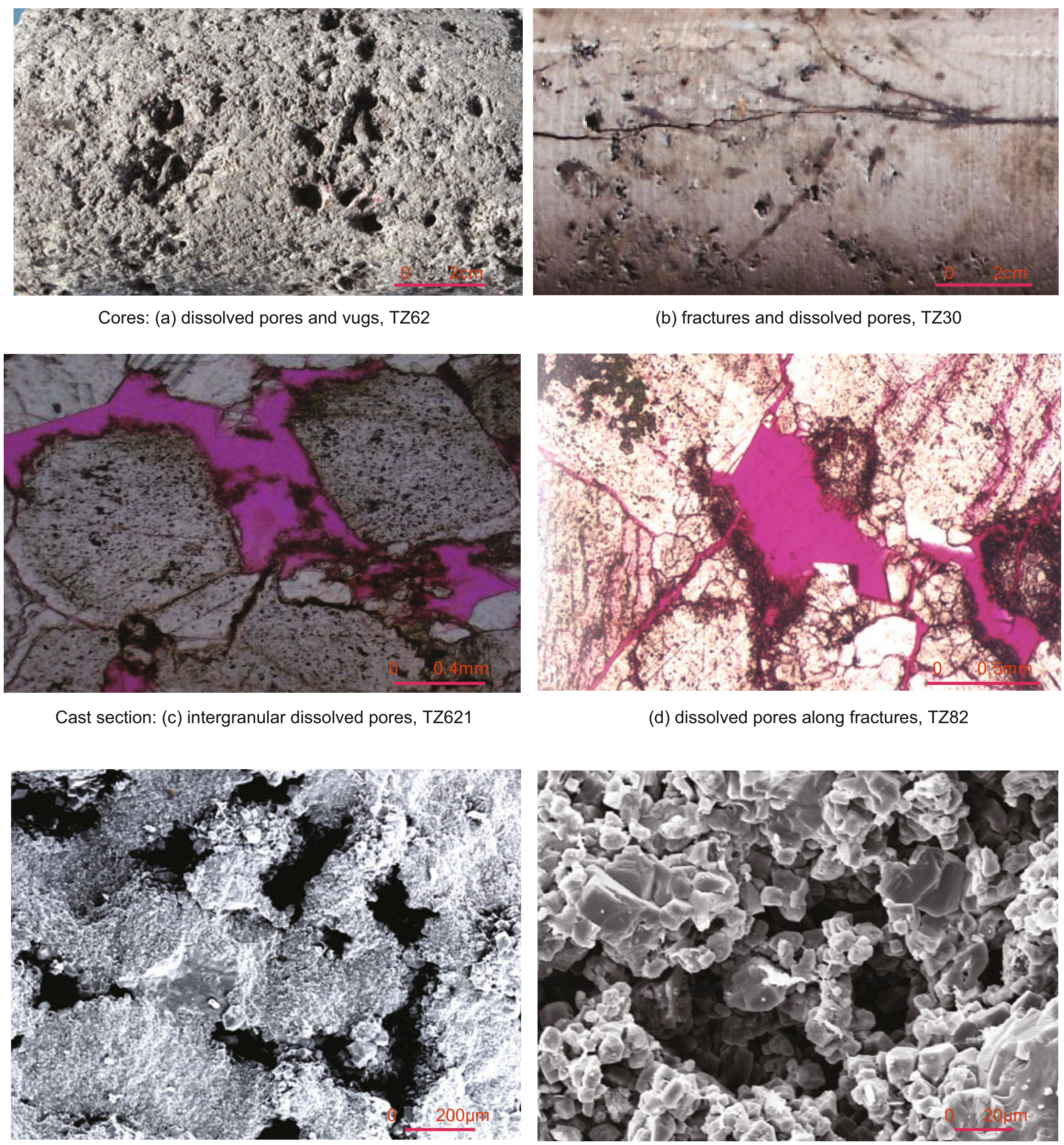
The reef-shoal type reservoirs are chiefly located in the upper Ordovician Lianglitage Formation along the north slope margin of the Central Uplift and in the middle Ordovician Yijianfang Formation in the south slope of the Northern Uplift.

The macroscopic reservoir space in reef-shoal type reservoirs is composed of a great deal of dissolution pores and holes (Du, 2010), meaning the matrix porosity is better than the weathering type reservoir. In the upper Ordovician platform margin of the northern slope in the Central Uplift, dissolved vugs and holes are very common in grainstone (Fig. 5), in round, elliptic or irregular shapes with radius of 1-3 mm generally, partial filled to unfilled, providing porosity up to 2%-8%. The dissolution pores and holes commonly developed along bedding planes or fractures, which form layers of different thickness of 0.2-1 m, and the porous section is often on the top 30-50 m of the reef-shoal complex. There are many kinds of fractures in this kind of reservoir, structural fractures are the richest, mainly high angle micro-fractures very uneven in distribution. Most of the wide aperture fractures are filled with calcite, so the fracture porosity is low at about 0.05%-0.3% in many fracture sections. In some areas there are also large fracture-cavity systems superimposed on reef-shoal type reservoirs due to multi-stage dissolution (Wu et al, 2010), for example, Well TZ62-2 encountered a fracture-cavity system, resulting in fluid loss of 636.5 m^3.

Micropores primarily include intergranular, intragranular, and intercrystalline dissolution pores and microfractures (Fig. 5). Intergranular dissolution pores are common, making up to 60% in thin sections, contributing more than 80% of the porosity. This type of pore developed mainly in grainstone, irregular in shape and different in size, with a pore diameter of 0.1-1.5 mm. Intragranular dissolution pores often occur in bioclastic limestone, smaller in size than intergranular pores, and most are micropores with a diameter of 0.1-0.5 mm.

Microfractures, mainly structural fractures and stylolites, are also common in thin sections. Most structural fractures are straight, some half-filled by calcite. The width of fractures is smaller than that in weathering crust reservoirs, but they can also form networks in some places with low fracture porosity of about 0.1%-0.5% and high permeability of more than $10\times10^{-3}\ \mu m^2$.

Since there are many kinds of secondary dissolved pores with irregular shape, the throats among the pores are complicated with different sizes and shapes (Fig. 5). Except in places where wide fractures act as good connections, most throats between big pores or small pores are micro-throats. Some throats are long and wide, others short and narrow. In fracture-cavity reservoirs or fracture-porosity type reservoirs, the pores connected by fractures are high in permeability, which form fracture-cavity type or fracture-porosity type pore structure. Nevertheless, most of the pores, not connected by fractures, are irregular, narrow and tiny, distributed heterogeneously, which results in complex pore structure and low permeability.



Cores: (a) dissolved pores and vugs, TZ62 (b) fractures and dissolved pores, TZ30

Cast section: (c) intergranular dissolved pores, TZ621 (d) dissolved pores along fractures, TZ82

SEM: (e) intergranular pores, ZG203 (f) intergranular pores, bad connectivity, TZ62

Fig. 5 Pore characteristics of Ordovician reef-shoal type reservoirs

3.3 Classification characteristics of pore structure

Since the pore scale and pore throats in reservoir rocks are large enough to accumulate economic quantities of petroleum, whereas pore throats in seals are small enough to block the passage of petroleum at the applied level of buoyant pressure, the classification of pore structure is often according to pore size and pore throat radius (Ying et al, 2001; Nelson, 2009). The matrix pores, mainly secondary dissolution pores, complicate the pore structure in Ordovician carbonates in the Tarim Basin. These can be divided into four types: big pore and big throat, big pore but small throat, small pore and small throat, and fracture type by the shape and parameter of capillary pressure curves (Fig. 6). In the TZ62 area, the matrix pores developing in reef-shoal type reservoir, can be taken as an example.

The big pore and big throat type is about 18% of the total samples, while it is less than 10% in most other areas. This type of reservoir is low in expulsion pressure, on average 0.24 MPa, high in mercury injection saturation more than 70% and 80% on average, partially rough skewness with a skewness factor of 1.0-2.0. The capillary pressure curve has a low flat or gentle slope, which indicates poor sorting and good connectivity of pore throats. Most of throats are wide with the mean throat radius of about 0.3-1.5 μm. This type of reservoir is generally over 5% in porosity and more than 1×10^{-3} μm^2 in permeability.

It is worth noting that cores are difficult to obtain from large cavity layers, resulting in the lack of mega-pore and mega-throat data for fracture-cavity systems. The porosity is more than 8% and the permeability is up to $(10\text{-}1{,}000)\times10^{-3}$ μm^2 by logging in most cavities although most of them are filled by breccias and mud. The openness of fracture is more than 100 μm in cores, which is much bigger than the big throats of matrix pores. Thus, the fracture-cavity system has extremely low expulsion pressure, where high oil production of more than 100 t/d is common, quite different from reef-shoal type reservoirs with big pores and big throats.

The big pore but small throat type accounts for about 32% of the total samples. This type of reservoir has high expulsion pressure of 1.71 MPa on average, mercury injection saturation about 46%-80% with the mean of 59%, thin skewness and skewness factor of about 1.4-2.8. The capillary pressure curves have an obvious high flat, suggesting good sorting and connectivity of the throats, but the throat radius is thin with mean throat radius of about 0.03-0.3 μm, with a porosity of about 2%-6% and permeability of around $(0.04\text{-}1)\times10^{-3}$ μm^2.

The small pore and small throat type reservoir is about 43% of the total samples. This type of reservoir has high expulsion pressure of up to 3.5-11.4 MPa, low mercury injection saturation of less than 50%, averaging at 24.1%, partially thin skewness and skewness factor of about 2.1-3.7. The capillary pressure curves are inclined without obvious flat, suggesting poor connectivity and complicated throat structures. Throats are tiny with a mean radius of about 0.01-0.05 μm. The porosity is about 2%-4% and permeability is usually less than 0.5×10^{-3} μm^2.

The fracture type reservoir comprises about 7% of the total samples. This kind of reservoir has extraordinary low expulsion pressure, mostly less than 0.1 MPa, and the mercury injection saturation is between 34%-61%. The capillary pressure curves are steep and the pore throats are nonsorted, suggesting developed microfractures. The throat radius is big, generally more than 2 μm. The porosity of typical fracture reservoirs is less than 2% and the permeability is more than 5×10^{-3} μm^2.

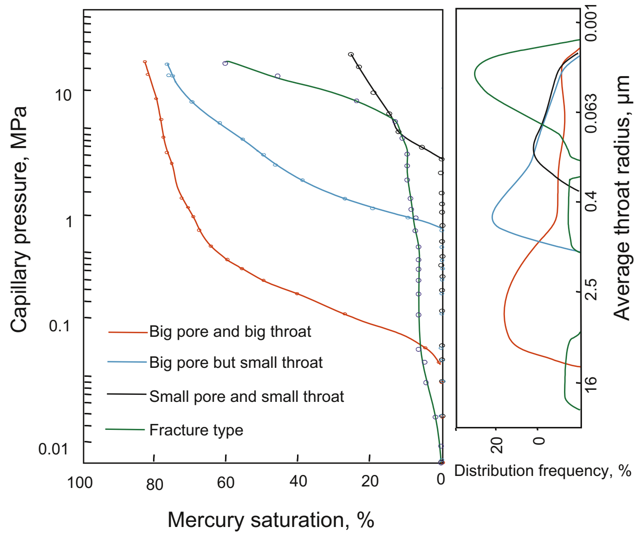


Fig. 6 Typical capillary pressure curves and pore-throat distribution of Ordovician carbonate

Throat radius is an important parameter affecting fluid flow in reservoirs (Javadpour, 2009; Zou et al, 2009; Han et al, 2010). The statistics of throat radius on samples without fractures in the Central and Northern uplifts show that the average throat radius is generally less than 1 μm, in which 87% of the samples are less than 0.1 μm (Fig. 7). The average throat radius of Ordovician carbonates in the Northern Uplift is about 0.02-0.5 μm with a mean of 0.05 μm. The average throat radius of Ordovician reef-shoal reservoirs in the Central Uplift is about 0.02-1.8 μm with a mean of 0.12 μm. The average throat radius mainly ranges from 0.02 to 0.8 μm, with a disparity of 2 orders of magnitude. The average throat radius of carbonate rocks of between 0.03 and 0.07 μm in different well blocks, is on the low side in general, significantly lower than that of conventional carbonate and clastic reservoirs, and close to that of unconventional oil and gas reservoirs, representing microthroats (Shanley et al, 2004; Nelson, 2009; Zou et al, 2009). The throat diameter is generally greater than 2 μm in conventional reservoir rocks,

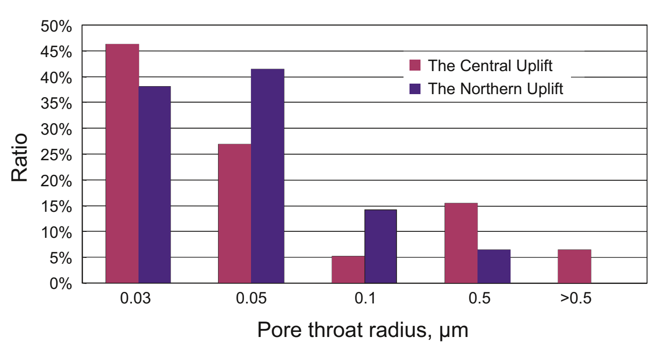


Fig. 7 Scattergram of mean pore throat radius of Ordovician carbonates

from about 0.03 to 2 μm in tight-gas sandstones, and from 0.005 to 0.1 μm in shales.

Almost all the fracture-cavity reservoirs, connected by fractures or large dissolved pores, are similar to the fracture type with big throats. The data above do not include the fracture type and large fracture-cavity system without cores, in which the throats are mostly fractures with diameter of more than 10 μm, much bigger than other types. The diameter of fractures ranges from 2 μm to over 100 μm, even cavities with no fractures have super large throats, which could be analogous to high porosity clastic or carbonate rocks (Nelson, 2009). The exploration and development of Ordovician carbonates in the Tarim Basin indicate that only a small proportion of reservoir porosity is connected by fractures with high and stable output in local areas (Jiao and Zhai, 2008; Du, 2010), but the majority of reservoirs are connected by matrix porosity even in and between large cavities. Most of the throats are very small but with some big throats of fractures or large dissolution throats, indicating the statistical data can represent the throat size distribution of Ordovician carbonates.

To sum up, except for some fractures and large dissolution throats, the throats of Ordovician carbonates in the Tarim Basin are tiny and mainly small pore and small throat type and big pore but small throat type, with a big sknewness factor, heterogeneous throat distributions and high expulsion pressure, which results in the extremely low matrix permeability (Fig. 2), and poor and complex reservoir connectivity.

4 Effect of pore structure on hydrocarbon accumulation

The driving forces for hydrocarbon accumulation mainly include buoyancy, abnormal fluid pressure, hydrodynamic pressure and capillary pressure (Li, 2004), in which different forces have different effects on oil/gas migration and accumulation in different conditions. Since most of the oil and gas in Ordovician carbonates is located in the gentle slope of the Tarim Basin, where abnormal high pressure and hydrodynamic pressure have little effect, gas/oil/water can only be totally differentiated when the buoyancy of oil/gas column height overcomes the capillary pressure. The critical oil/gas column height of carbonate reservoir can be deduced by buoyancy and capillary pressure calculation formula (Li, 2004):

$$H = \frac{2\delta(1/\gamma_t - 1/\gamma_p)}{g(\rho_w - \rho_h)}$$

where δ: interfacial tension (N/m); γ_t: throat radius (m); γ_p: pore radius (m); ρ_h/ρ_w: oil or gas/water density (kg/m^3); g: gravity acceleration (9.8 m/s^2).

The formula shows that the critical oil/gas column height depends on the throat radius, the interfacial tension between water and hydrocarbons, and the pressure differences caused by buoyancy forces. To a large extent, this method requires an estimate of pore throat size and the interfacial tension of hydrocarbon to water at reservoir conditions (O'Connor, 2000; Bretan et al, 2003). It can be seen that buoyancy is determined by the oil/gas column height as oil/gas/water density is relatively constant. Calculation shows that the critical oil/gas column height increases with hydrocarbon density (Fig. 8), especially when it is heavy oil that has extremely low mobility influenced by other factors. It is easy to see that the critical column increases with density much more significantly when the throat radius is below 0.1-0.2 μm, but there is not much difference for normal oil and gas with big throats. The matrix pores of the Ordovician carbonates in the Tarim Basin are mainly intergranular dissolution pores usually with a radius of 0.1-1.5 mm which is much bigger than throat radius, and 0.001 m was used in the calculation though it can be ignored. In terms of capillary effect, the size of throat radius inversely governs the displacement pressure (Bretan et al, 2003). In the same reservoir, the interfacial tension is invariable so the capillary pressure depends on throat radius mainly (Li, 2004). Calculation also shows that the critical column rises with the interfacial tension (Fig. 9), and the difference is not obvious when the throat radius is larger than 0.1 μm. Therefore, it is demonstrated that the throat radius is the main parameter influencing the gas/oil/water differentiation, and the critical throat radius is about 0.1 μm in low permeability carbonate reservoirs. When the throat radius is smaller than this value, the critical oil/gas column height climbs drastically.

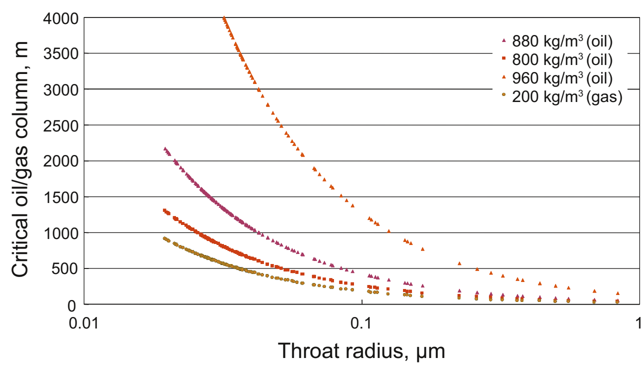


Fig. 8 Critical oil/gas column height vs. density and throat radius

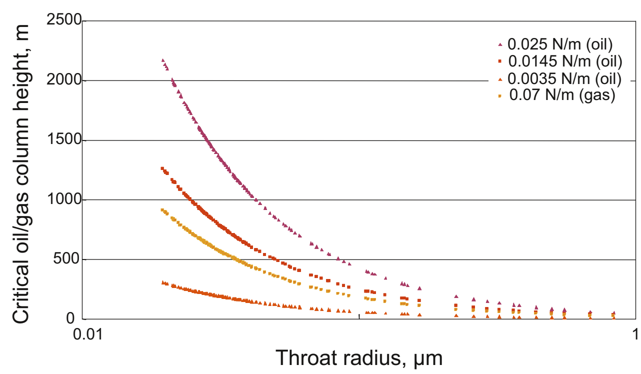


Fig. 9 Critical oil/gas column height vs. interfacial tension and throat radius

Using the actual measured throat radii of Ordovician carbonates (Fig. 7), an oil density of 850 kg/m^3 and 900 kg/m^3 respectively in the Central Uplift and Northern Uplift, and a reservoir gas density of 200 kg/m^3, and a constant interfacial tension of oil and gas of 0.025 N/m and 0.07 N/m from Li (2004), the critical oil/gas column height to overcome the capillary pressure was calculated for carbonate reservoirs with fine throats (Fig. 10). In the Central Uplift, the critical oil/gas column height is about 40-150 m and 20-80 m respectively when the reservoir is connected by big throats, but the height is up to 400-1,600 m with a mean of 920 m of oil and 100-840 m with a mean of 480 m of gas in small throat radius reservoirs. In the Northern Uplift Ordovician carbonates with small throat radius, oil/water and gas/water cannot be totally differentiated until the oil and gas column height is from 68 to 1,735 m with the mean of 990 m, 35-911 m with a mean of 520 m respectively. In general, except some of the big throat type and fracture type reservoirs in the most Ordovician carbonate reservoirs connected by matrix pores, the critical oil column height is about 400-1,600 m with a mean of 800-1,000 m, and the critical gas column height is about 200-800 m with a mean of 400-600 m.

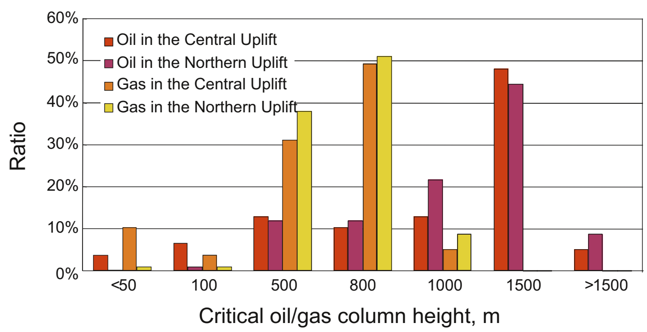


Fig. 10 Critical oil/gas column height of carbonate reservoirs

It is indicated that in the normal pressure and gentle slope area, the oil/gas/water differentiation needs to overcome high capillary pressure resulting from the small throats of carbonate matrix pores. The oil/gas column height needed to overcome the capillary pressure could be hundreds even thousands of meters, and the difference in pore throat structure could lead to the discrepancy of 2 orders of magnitude in the critical column height (Fig. 11) for the oil/water or gas/water total differentiation in the same oil/gas pool. It is obvious that there is no gas/oil/water differentiation below a critical throat radius about 0.1 μm although it can be changed to a certain degree by other factors (Fig. 11). When the throat radius is lower than this value, the reservoir will have poor percolation

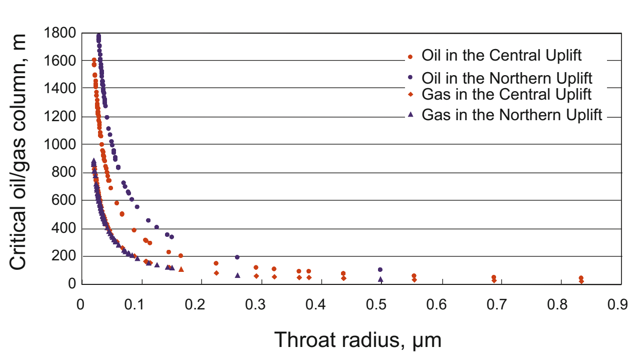


Fig. 11 Critical oil/gas column height of carbonate reservoirs

and indistinct phase separation. Therefore, in that case, buoyancy cannot overcome the capillary pressure to form an effective driving force for fluid, rather diffusion becomes the main driving force. That is the unconventional hydrocarbon reservoir driving mechanism leading to non-Darcy flow.

In high porosity and permeability reservoirs of big pore and big throat, when the throat radius is bigger than 0.5 μm, the critical oil/gas column height is less than 30 m since the capillary pressure is tiny, and gas/oil/water can totally separate with united edge/bottom water contact (Fig. 11). In a cavity or fracture-cavity system connected by fractures, the throat radius is usually >10 μm since most fractures are flat and straight, resulting in little capillary pressure which can hardly form an effective resistive force (Shen, 2000; Liang et al, 2010). The oil/gas/water can totally separate under the buoyancy force with an oil/gas column of a few meters high. Thus there is an obvious bottom water interface in isolated cavities or fracture-connected holes (Fig. 12), which results in a series of isolated hydrocarbon reservoirs with high production and high decline rate in the Ordovician weathering crust in the Lunnan and Central uplifts (Jiao and Zhai, 2008; Du, 2010).

However, micropore structure plays an important role in low permeability reservoirs (Cui et al, 2009; Zou et al, 2010). The Ordovician carbonate pore structure characteristics in the Tarim Basin, small throat and high expulsion pressure and low permeability, are similar to unconventional oil/gas reservoirs. In fracture-cavity reservoirs poorly connected by low permeability pores or filled fractures, the oil/gas column height is often less than 50 m, and the buoyancy cannot overcome the capillary resistance, causing incomplete differentiation of oil/gas/water, inconsistent oil/water contact in different cavities, and differences in fluid properties. In the same way, the matrix pores connected by intergranular and intragranular pores in reef-shoal reservoirs have tiny throats, high interfacial energy to overcome, which results in indistinct oil/gas/water separation, and thus simultaneous output of oil/gas/water. For example, most of the Ordovician reef-shoal reservoirs along the platform margin in the Central Uplift are weakly connected by tiny throats, with low matrix porosity and permeability, and multi-stage hydrocarbon charge and adjustment (Li et al, 2010; Zhang et al, 2011), leading to differences in fluid properties from one well to another (Fig. 13), such as gas/oil ratio, oil density and geochemistry, and different oil/gas/water contacts in different reservoirs. Multiple reservoirs are connected by certain pressure drawdown and recharge periodically during production, which results in the cyclical variation of fluid properties and output, even the complicated phenomena of erratic high and low yield or oil and water production alteration now and then (Gu et al, 2012; Tian et al, 2010; Wang et al, 2011). This kind of large-scale oil/gas distribution with no obvious boundary along platform margin, such as No.1 fault zone in the Central Uplift, is similar to the “continuous” petroleum reservoir (Zou et al, 2009).

In brief, the complexity of pore structure and differences in connectivity are the main factors affecting hydrocarbon migration and separation in the heterogeneous carbonates in

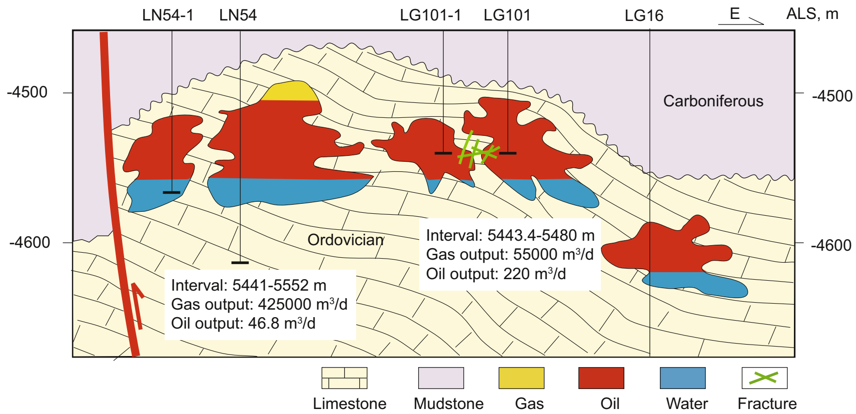


Fig. 12 Weathering crust type reservoir model in the Northern Uplift

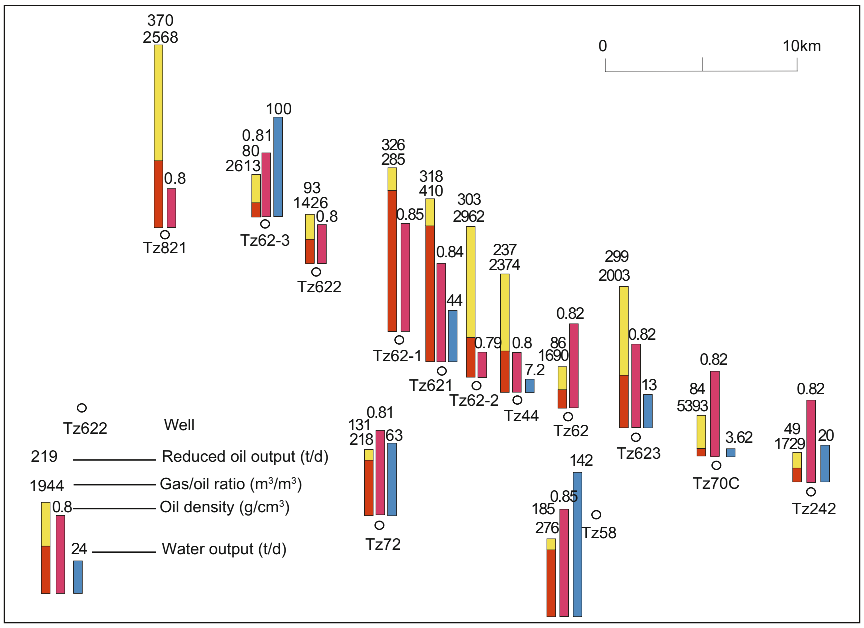


Fig. 13 Gas/oil ratio, oil density and water production of reef-shoal reservoirs in the Central Uplift

the Tarim Basin. There is obvious oil/gas/water separation in reservoirs effectively connected by fractures, but there are no obvious fluid separation and different critical oil/gas column heights in weakly connected reservoirs with small throats and low permeability. It is indicated that the critical throat radius is about 0.1 μm. When throats are smaller than this, the reservoir could be unconventional and beyond the control of buoyancy.

5 Conclusions and discussion

Ordovician carbonate reservoirs in the Tarim Basin have complicated pore structures, in which the fracture-cavity reservoirs in the weathering crust developed large cavities connected by fractures with mega-throats over 10 μm diameter, but most of the reef-shoal reservoirs, mainly containing secondary dissolution pores, have complex and small throats with an average throat radius of less than 0.1 μm. The pore-throat combinations can be divided into four types: big pore and big throat, big pore but small throat, small pore and small throat, and fracture type by the shape and parameter of capillary pressure curves. Due to lack of large fracture-cavity reservoir data, the pore-throat quantitative description needs much more research.

The fluid differentiation in Ordovician carbonates is mainly controlled by the throat radius according to fluid driving force analysis. It is demonstrated that there are two kinds of mechanism separated at the critical throat radius of about 0.1 μm, which results in the typical fracture-cavity hydrocarbon reservoir with obvious fluid differentiation but reef-shoal hydrocarbon reservoir with unconventional fluid distribution. There is obvious oil/gas/water contact in large fracture-cavity reservoirs, but the oil/water and gas/water cannot totally differentiate until the oil/gas column is up to 800-1,000 m and 400-600 m in and between the reservoirs connected by matrix pores. It is shown that tiny throats in carbonate reservoirs are the main reason behind complex fluid distribution and production fluctuation. Complicated reservoir conditions make it difficult to obtain accurate critical throat radius measurements, which also changes with geological conditions, but a rough critical throat radius is of great significance for distinguishing conventional and unconventional carbonate reservoirs in the Tarim Basin.

Acknowledgements

This work is supported by the National Basic Research Program of China (973 Program, Grant No. 2011CB201106). The authors would like to thank Mr. Li Qiming, Pan Wenqing, Cai Chunfang, Chen Zhiyong for their instructive suggestions, especially for the review by Mr. Song Lichen and other anonymous reviewers.

References

Amann-Hildenbrand A, Ghanizadeh A and Krooss B M. Transport properties of unconventional gas systems. Marine and Petroleum Geology. 2012. 31(1): 90-99

Bretan P, Yielding G and Jones H. Using calibrated shale gouge ratio to estimate hydrocarbon column heights. AAPG Bulletin. 2003. 87(3): 397-413

Clarkson C R, Jensen J L, Pedersen P K, et al. Innovative methods for flow-unit and pore-structure analyses in a tight siltstone and shale gas reservoir. AAPG Bulletin. 2012. 96(2): 355-374

Cui X, Bustin A M M and Bustin R M. Measurements of gas permeability and diffusivity of tight reservoir rocks: Different approaches and their applications. Geofluids. 2009. 9(3): 208-223

Do D D, Herrera L F and Do H D. A new method to determine pore size and its volume distribution of porous solids having known atomistic configuration. Journal of Colloid and Interface Science. 2008. 328(1): 110-119

Du J H. Oil and Gas Exploration of Cambrian-Ordovician Carbonate in Tarim Basin. Beijing: Petroleum Industry Press. 2010. 1-130 (in Chinese)

Gu Z D, Wang Z C, Hu S Y, et al. Tectonic settings of global marine carbonate giant fields and exploration significance. Natural Gas Geoscience. 2012. 23(1): 106-118 (in Chinese)

Han F S, Busch A, Krooss B M, et al. Experimental study on fluid transport processes in the cleat and matrix systems of coal. Energy and Fuels. 2010. 24(12): 6653-6661

Jamaloei B Y, Kharrat R and Asghari K. Pore-scale events in drainage process through porous media under high- and low-interfacial tension flow conditions. Journal of Petroleum Science and Engineering. 2010. 75(1-2): 223-233

Javadpour F. Nanopores and apparent permeability of gas flow in mudrocks (shales and siltstones). Journal of Canadian Petroleum Technology. 2009. 48(8): 16-21

Jiao F Z and Zhai X X. Large Unconventional Marine Carbonate Oilfields—The Research and Practice in the Tahe Oilfield. Beijing: Petroleum Industry Press. 2008. 189-251 (in Chinese)

Li M C. Oil & Gas Migration (3rd Edition). Beijing: Petroleum Industry Press. 2004. 26-142 (in Chinese)

Li Q M, Wu G H, Pang X Q, et al. Hydrocarbon accumulation conditions of Ordovician carbonate in Tarim Basin. Acta Geologica Sinica. 2010. 84(5): 1180-1194

Liang Q S, Hao Q, Zhang L X, et al. Hydrocarbon sealing dynamic model research and application for shale cap rock of lithological reservoir. Chinese Journal of Geology. 2010. 45(3): 777-788 (in Chinese)

Liu L F, Sun S Z D, Yang H J, et al. Seismic attributes and integrated prediction of fractured and caved carbonate reservoirs in the Tarim Basin, China. Petroleum Science. 2011. 8(4): 455-461

Nelson P H. Pore-throat sizes in sandstones, tight sandstones, and shales. AAPG Bulletin. 2009. 93(3): 329-340

O'Connor S J. Hydrocarbon-water interfacial tension values at reservoir conditions: Inconsistencies in the technical literature and the impact on maximum oil and gas column height calculations. AAPG Bulletin. 2000. 84(10): 1537-1541

Shanley K W, Cluff R M and Robinson J W. Factors controlling prolific gas production from low-permeability sandstone reservoirs. AAPG Bulletin. 2004. 88(8): 1083-1121

Shen P P. Oil-water Motion Theory and Practice in Porous Media. Beijing: Petroleum Industry Press. 2000. 6-49 (in Chinese)

Smith T M, Sayers C M and Sondergeld C H. Rock properties in low-porosity/low-permeability sandstones. The Leading Edge. 2009. 28(1): 48-59

Tian J, Chen J Q, Jiao J, et al. Comparison of the surface and underground natural gas occurrences in the Tazhong Uplift of the Tarim Basin. Acta Geologica Sinica. 2010. 84(5): 1097-1115

Wang X, Zhang M, Liu Y H, et al. Origin of natural gases and their differences between the eastern and western parts of central Tarim Basin. Chinese Journal of Geochemistry. 2011. 30(1): 75-83

Wu G H, Wang H, Chen Z Y, et al. The characteristics of Ordovician carbonate hydrocarbon in Tarim Basin. Oil & Gas Geology. 2010. 31(6): 763-769 (in Chinese)

Wu G H, Yang H J, Qu T L, et al. The fault system characteristics and its controlling roles on marine carbonate hydrocarbon in the Central Uplift, Tarim Basin. Acta Petrologica Sinica. 2012. 28(3): 793-805 (in Chinese)

Yang H J, Sun S Z D, Cai L L, et al. A new method of formation evaluation for fractured and caved carbonate reservoirs: A case study from the Lundong area, Tarim Basin, China. Petroleum Science. 2011. 8(4): 446-454

Ying F X, Yang S S, Zhang M, et al. Application of laser scanning confocal microscopy to the measurement of pore texture in reservoirs. Acta Sedimentologica Sinica. 2001. 20(1): 75-79 (in Chinese)

Zhang N, Tian L, Xing Y L, et al. Characteristic of hydrocarbon fluid inclusions and analysis of reservoir formation in Ordovician reservoir of Tazhong area, Tarim Basin. Acta Petrologica Sinica. 2011. 27(5): 1548-1556 (in Chinese)

Zhao W Z, Zhu G Y, Zhang S C, et al. Relationship between the later strong gas-charging and the improvement of the reservoir capacity in deep Ordovician carbonate reservoir in Tazhong area, Tarim Basin. Chinese Science Bulletin. 2009. 54(20): 3076-3089

Zou C N, Tao S Z, Yuan X J, et al. Global importance of "continuous" petroleum reservoirs: Accumulation, distribution and evaluation. Petroleum Exploration and Development. 2009. 36(6): 669-682 (in Chinese)

Zou C N, Zhang G Y, Tao S Z, et al. Geological features, major discoveries and unconventional petroleum geology in the global petroleum exploration. Petroleum Exploration and Development. 2010. 37(2): 129-145

(Edited by Hao Jie)