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Research paper

Controls on reservoir heterogeneity of tight sand oil reservoirs in Upper Triassic Yanchang Formation in Longdong Area, southwest Ordos Basin, China: Implications for reservoir quality prediction and oil accumulation

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A B S T R A C T

Compared to conventional reservoirs, pore structure and diagenetic alterations of unconventional tight sand oil reservoirs are highly heterogeneous. The Upper Triassic Yanchang Formation is a major tight-oil-bearing formation in the Ordos Basin, providing an opportunity to study the factors that control reservoir heterogeneity and the heterogeneity of oil accumulation in tight oil sandstones.

The Chang 8 tight oil sandstone in the study area is comprised of fine-to medium-grained, moderately to well-sorted lithic arkose and feldspathic litharenite. The reservoir quality is extremely heterogeneous due to large heterogeneities in the depositional facies, pore structures and diagenetic alterations. Small throat size is believed to be responsible for the ultra-low permeability in tight oil reservoirs. Most reservoirs with good reservoir quality, larger pore-throat size, lower pore-throat radius ratio and well pore connectivity were deposited in high-energy environments, such as distributary channels and mouth bars. For a given depositional facies, reservoir quality varies with the bedding structures. Massive- or parallel-bedded sandstones are more favorable for the development of porosity and permeability sweet zones for oil charging and accumulation than cross-bedded sandstones.

Authigenic chlorite rim cementation and dissolution of unstable detrital grains are two major diagenetic processes that preserve porosity and permeability sweet zones in oil-bearing intervals. Nevertheless, chlorite rims cannot effectively preserve porosity-permeability when the chlorite content is greater than a threshold value of 7%, and compaction played a minor role in porosity destruction in the situation. Intensive cementation of pore-lining chlorites significantly reduces reservoir permeability by obstructing the pore-throats and reducing their connectivity. Stratigraphically, sandstones within 1 m from adjacent sandstone-mudstone contacts are usually tightly cemented (carbonate cement > 10%) with low porosity and permeability (lower than 10% and 0.1 mD, respectively). The carbonate cement most likely originates from external sources, probably derived from the surrounding mudstone. Most late carbonate cements filled the previously dissolved intra-feldspar pores and the residual intergranular pores, and finally formed the tight reservoirs.

The petrophysical properties significantly control the fluid flow capability and the oil charging/accumulation capability of the Chang 8 tight sandstones. Oil layers usually have oil saturation greater than 40%. A pore-throat radius of less than 0.4 μm is not effective for producible oil to flow, and the cut off of porosity and permeability for the net pay are 7% and 0.1 mD, respectively.

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1. Introduction

Tight oil is crude oil trapped in unconventional reservoirs with extremely low porosity and permeability. With the decline of conventional oil production and advances in horizontal drilling and hydraulic fracturing techniques, tight oil reservoirs are now considered to be an important contributor to the global crude oil supply (Jarvie et al., 2007; Maugeri, 2013), such as the Barnett tight oil play in the Fort Worth Basin (Hill et al., 2007), the Bakken tight oil play in the Williston Basin (Sonnenberg and Pramudito, 2009) and the Eagle Ford tight oil play in South Texas (Mullen, 2010). There are a considerable amount of potential tight oil resource plays in the petroliferous basins of China, such as those in Songliao Basin, Sichuan Basin, Bohai Bay Basin and Ordos Basin (Zou et al., 2010; Dai et al., 2012). Tight oil is now expected to be an important emerging source of oil supply in China (Zou et al., 2012a,b; Jia et al., 2012).

Ordos Basin is the second largest sedimentary basin in China, in which, the Upper Triassic Yanchang Formation is an important oil-bearing formation. Tight oil herein refers to oil that accumulated in oil shale or interbedded tight sandstone reservoirs adjacent to source rocks with subsurface matrix permeability of less than 0.1 mD (Clarkson et al., 2011a,b). The tight oil resource plays in the Ordos Basin are characterized by a wide areal distribution of source rocks, tight sandstone reservoirs, complex pore-throat structures, and high oil saturation (Yang et al., 2013; Yao et al., 2013). The proved reserves of tight oil in the Yanchang Formation of the Ordos Basin were more than two billion tons in 2012 (Yang et al., 2013). With the increasing difficulty of exploiting and developing conventional oil fields in the Ordos Basin, tight oil resources will become increasingly realistic and important supplementary sources in the future.

With continuing growth in the exploration and development of tight oil sands, fluid storage and flow capability in such low-permeability systems have become a major concern for petroleum geoscientists and engineers. An understanding of the petrophysical properties of tight oil reservoirs is essential for reservoir evaluation and successful exploitation (Padhy et al., 2007; Clarkson et al., 2011a,b). Pore-throat, rather than overall pore volume (i.e., porosity), controls flow capability, producible pore volumes and hydrocarbon flow rates in reservoir rock. Therefore, porosity alone is not an accurate predictor of reservoir quality, especially in tight sands with significant diagenetic alterations (Rushing et al., 2008; Golab et al., 2010). Identification and quantification of various pore types and their contribution to the overall porosity and flow is an essential step in understanding and predicting the producibility of tight gas/oil reservoirs (Golab et al., 2010). Many detailed papers have been published to investigate the relationship between pores, pore-throats, and reservoir properties in tight-sands (Sakhaee-pour and Bryant, 2014; Loucks et al., 2012; Camp, 2011; Nelson, 2009; Padhy et al., 2007). However, characterizing pore structure could be difficult because a wide pore size distribution is typical for tight oil reservoirs, with pore sizes ranging from several nanometers to several hundred microns (Zou et al., 2012a,b). The routine methods developed for conventional reservoirs are limited when applied to tight oil reservoirs. Limitations exist in conventional analytical methods (e.g., pressure-controlled mercury injection and petrographic thin section point-counting) when quantitatively describing the full 3D granular and porous microstructures (Zhao et al., 2015). Recent developments in rate-controlled porosimetry experiments and 3D X-ray micro-CT imaging coupled with conventional petrographic analysis allow direct measurements of the throat radius, pore structure and pore connectivity in three dimensions at the pore scale.

Compared to conventional reservoirs, pore structure and diagenetic alterations of tight oil sandstone reservoirs are highly heterogeneous, which is responsible for the heterogeneity of oil accumulations within the same sandstone units. Predictions of sandstone reservoir quality have been well discussed in previous studies (Dutton and Finley, 1988; Ehrenberg, 1990; Lander and Walderhaug, 1999; McKinley et al., 2011), including the characterization of grain size, sorting, composition, early diagenesis, burial history and tectonic fracturing (Laubach, 1997; Laubach et al., 2004; Laubach and Ward, 2006). Various proposed porosity controls have been reviewed by Taylor et al. (2010), such as dissolution of unstable framework grains and early cements, grain-coated cementation, cement inhibition by early emplaced hydrocarbons and decreased thermal exposure. However, difficulties remain when applying these models and control factors to predicting higher porosity and permeability sweet zones within tight oil sandstone reservoirs. Although the effects of sedimentation and diagenetic alterations have been well studied to understand the post-depositional alterations of the reservoir quality of tight oil sands (Dutton and Finley, 1988; Ehrenberg, 1990; Morad et al., 2000, 2010; Taylor et al., 2010; Zhang and Yang, 2009; Stroker et al., 2013), less attention has been paid to the diagenetic heterogeneity within similar depositional lithofacies, the characterization of the pore-throat distribution and its control on reservoir quality or the effects of the reservoir quality on the heterogeneity of oil accumulations.

To bridge this gap, this study focused on the following questions:

(1) How should the pore structure and pore-throat distribution of tight oil reservoirs be characterized?
(2) What control factors significantly affect reservoir heterogeneity in tight oil sandstones, especially the diagenetic heterogeneity and the heterogeneity of oil accumulations in similar depositional facies?
(3) What are the implications of the reservoir petrophysical properties on the heterogeneity of oil accumulations in tight oil reservoirs?

The results of this study will provide insights into reservoir quality prediction and increase the chance of success when exploring and developing tight oil reservoirs in similar settings.

2. Geological settings

The Ordos Basin is a typical cratonic basin with an area of 25×10^4 km^2 located in the western part of the North China block (Fig. 1A). The basin is bordered by the Yin Mountains to the north, the Luliang Mountains to the east, the Qinling Mountains to the south and the Liupan-Helan mountains to the west (Yang et al., 2005). The evolution of the Ordos Basin during the Paleozoic–Mesozoic is divided in three stages: (1) a Cambrian to Early Ordovician cratonic basin with divergent margins; (2) a Middle Ordovician to Middle Triassic cratonic basin with convergent margins and (3) a Late Triassic to Early Cretaceous intraplate remnant cratonic basin (Yang et al., 2005). During the Late Triassic, the Liupan Mountains were thrust underneath the southwestern Ordos area, which led to the formation of the Southwestern Ordos Foreland Depression (Liu and Yang, 2000). By the end of the Late Triassic, the termination of thrusting and the subsequent erosion of the Liupan Mountains led to an isostatic rebound of the Ordos Basin, which produced a regional unconformity between the Triassic and the Jurassic sediments in the basin (Liu, 1998). The Ordos Basin is divided into six structural units: the Yimeng Uplift, the Weibei Uplift, the Western Edge Thrusting Belt, the Jinxi Flexural Fold Belt, the Tianhuan Depression and the Shanbei Slope