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Research paper

Geological control factors of micro oil distribution in tight reservoirs

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ABSTRACT

Understanding the oil distribution characteristics in unconventional tight reservoirs is crucial for hydrocarbon evaluation and oil/gas extraction from such reservoirs. Previous studies on tight oil distribution characteristics are mostly concerned with the basin scale. Based on Lucaogou core samples, geochemical approaches including Soxhlet extraction, total organic carbon (TOC), and Rock-Eval are combined with reservoir physical approaches including mercury injection capillary pressure (MICP) and porosity-permeability analysis, to quantitatively evaluate oil distribution of tight reservoirs on micro scale. The emphasis is to identify the key geological control factors of micro oil distribution in such tight reservoirs. Dolomicrites and non-detrital mudstones have excellent hydrocarbon generation capacity while detritus-containing dolomites, siltstones, and silty mudstones have higher porosity and oil content, and coarser pore throat radius. Oil content is mainly controlled by porosity, pore throat radius, and hydrocarbon generation capacity. Porosity is positively correlated with oil content in almost all samples including various lithologies, indicating that it is a primary constraint for providing storage space. Pore throat radius is also an important factor, as oil migration is inhibited by the capillary pressure which must be overcome. If the reservoir rock with suitable porosity has no hydrocarbon generation capacity, pore throat radius will be decisive. As tight reservoirs are generally characterized by widely distributed nanoscale pore throats and high capillary pressure, hydrocarbon generation capacity plays an important role in reservoir rocks with suitable porosity and fine pore throats. Because such reservoir rocks cannot be charged completely. The positive correlation between hydrocarbon generation capacity and oil content in three types of high porosity lithologies (detritus-containing dolomites, siltstones, and silty mudstones) supports this assertion.

1. Introduction

Tight oil refers to oil produced from shale, or other rocks with very low permeability including tight sandstone and carbonate adjacent to shale (EIA, 2012). The oil contained within these rocks typically will not flow to the wellbore at economic rates without assistance from technologically advanced drilling and completion processes, i.e., horizontal wells and multi-stage hydraulic fracturing (Clarkson and Pedersen, 2011; IEA, 2011; 2012; NEB, 2011; NPC, 2011; Jia et al., 2012; Zou et al., 2012a; EIA, 2013; NRC, 2014). Tight oil reservoirs have become an important target for hydrocarbon exploration in recent years (Sonnenberg and Pramudito, 2009; BP, 2011).

Previous studies on tight oil distribution characteristics are mostly concerned with the basin scale, and these studies conclude that there is no clear trap boundary in such a scale, and the oil is not driven by buoyancy (Clarkson and Pedersen, 2011; NEB, 2011; Zou et al., 2013). Tight oil is regarded as a "continuous-type petroleum accumulation" mainly retained within the source rock strata and continuously distributed over a large area (Schmoker, 2005; Zou and Tao, 2008; Sonnenberg and Pramudito, 2009; NEB, 2011; Zou et al., 2012b, 2013). However, at the drill core scale, there are only

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a few reports about oil distribution characteristics. Cao et al. (2016) presents that oil-bearing heterogeneity can be obviously observed at the core scale in a lacustrine tight reservoir (Lucaogou Formation in Jimusar Sag, Juggar Basin).

Nevertheless, there is no discussion about geological control factors of oil distribution characteristics at the core scale, an important subject for identifying favorable targets of petroleum exploration and reducing exploration risks in tight reservoirs.

Lucaogou Formation in Jimusar Sag is a set of mixed fine-grained deposits and one of the most representative areas for tight oil reservoir research in China. The stratum is characterized by continuously distributed thin single layers and frequently interbedded lithology (Cao et al., 2016). Core samples from Lucaogou Formation provide a unique possibility to study geological control factors of core-scale tight oil distribution characteristics as its lithologies are complex and comprise siltstones, carbonatites, and mudstones, covering most of the lithologies relevant to known tight oil studies.

The objective of this work is to understand geological control factors of oil content heterogeneity in core-scale tight oil reservoirs. Soxhlet extraction is applied for oil content quantitative evaluation. Microscopic observation, Soxhlet extraction, Rock–Eval pyrolysis, total organic carbon (TOC) analysis, reservoir rock property analysis and pore structure analysis are applied to investigate geological control factors on oil content. The overarching goal is to establish a general methodology that is applicable for other tight oil reservoirs. To our knowledge, this is the first attempt on such a subject.

2. Geological setting

The Jimusar Sag is located in the southwestern region of the Eastern Uplift, Junggar Basin of China (Fig. 1a, b). It is bordered by the Guxi Uplift in the east, the Santai Uplift in the west, the Fukang Fault Zone in the south, and the Shaqi Uplift in the north (Fig. 1c). It is a west-faulting and east-overlapping dustpan-shaped sag with an area of approximately 1300 km^2. The sag's basement comprises Middle Carboniferous flexure, covered by Permian to Quaternary sedimentary sequences (Cao et al., 2016). Lucaogou Formation is a set of mixed fine-grained deposits, and is characterized by vertically frequent interbedded lithology (Fig. 1d) with large vertical thickness and a wide horizontal distribution across the whole depression. About 725 km^2 of Lucaogou Formation is thicker than 200 m (Kuang et al., 2012).

The shales interbedded with sandstones and carbonates deposited within saline lacustrine environment when the basin experienced uplifting and folding during Permian, forming the major source rock in the Jimusar Sag (Kuang et al., 2013). Although these three kinds of lithologies all have hydrocarbon generation potential, shales present the best characteristics for oil generation (Cao et al., 2016). Lucaogou Formation has been within the oil-generating window since the middle to end of the Triassic, with current R$_o$ between 0.76 and 0.96%, and commercial oil flow obtained from many oil wells. Core observation indicates that all kinds of lithologies contain oil, but exhibit strong oil-content heterogeneity at the core scale (Cao et al., 2016).

3. Samples and experiments

3.1. Samples

More than 200 core samples including different lithologies which cover the entire Lucaogou Formation are chosen from 7 wells and prepared for thin section observation. On the basis of the core observations and the thin section analytical results, 67 core samples are chosen for organic geochemical analysis, including 22 dolomite, 19 shale and 26 siltstone samples (Table 1). Among the 67 core samples, 47 are selected for reservoir rock physical property tests. The samples have present burial depths in the range of 2712.61–4216.28 m.

3.2. Experiments

3.2.1. Organic geochemical analysis

85 core samples are pulverized to 200 mesh in preparation for Rock–Eval pyrolysis and TOC measurements. An OGE-II instrument (Beijing Aotao Tech. Co., China) is used for Rock–Eval pyrolysis. TOC contents of the 85 core samples are determined using a LECO CS–400 analyzer (LECO Corp., USA).

As effective reservoir rock types, Lucaogou siltstones, sandstones and dolomites are interbedded with the shales (Cao et al., 2016). The migration of oil into siltstones and dolomites from adjacent shales makes the measurements of in situ organic matter abundance of the siltstones and dolomites questionable. To exclude this influencing factor, 85 parallel samples are Soxhlet extracted using chloroform/methanol (97:3) for 72 h to remove the soluble organic matters. By doing so, the TOC contents and Rock–Eval pyrolysis parameters (S$_1$, S$_2$, and T$_{max}$) are tested again with extracted 85 core samples according to the above procedures. Therefore, its source quality may be better understood.

The chloroform extract is weighed after adequate volatilization of chloroform. Oil content is measured by extract content, a ratio of chloroform extract mass to rock sample mass, as described in Baker (1962). Taking volatilization of light component into account in the process of chloroform volatilization, Rock-Eval S$_1$ is applied and compared with Soxhlet extract, as it is more effective at quantifying the more volatile fraction of petroleum (Jarvie and Baker, 1984).

3.2.2. Reservoir rock physical property analysis

Porosity measurements are carried out with an Ulltrapore-200A (Core Lab., USA) using a helium expansion method, while permeability measurements are conducted using an Ultraperm 400 (Core Lab., USA) according to Chinese Petroleum Industry Standard SY/T5336 (2006).

The mercury injection capillary pressure (MICP) method is based on the fact that mercury behaves as a non-wetting liquid when in contact with most solids. Consequently, it does not penetrate into the openings and cracks of these substances without the application of pressure. The pressure (P_w) required for mercury to penetrate pores is a function of the contact angle (θ_{Hg}) of mercury with the porous material to be intruded, its gas/liquid surface tension (γ_{Hg}) and pore radius (r_p). This relationship is given by the Young-Laplace law for the particular case of cylindrical pores as the Washburn equation:

$$r_p = -\frac{2\gamma_{Hg}\cos\theta_{Hg}}{p_w} \tag{1}$$

Eq. (1) indicates that with increasing pressure, the mercury will intrude into progressively narrower pores for constant values of γ_{Hg} and θ_{Hg}. The volume of mercury (V) penetrating the pores is measured directly as a function of applied pressure. Such P-V data provide a unique characterization of the pore structure.

The MICP is carried out with a PORE SIZER 9320 (Micromeritics Instrument Corp., USA). The equivalent pore radius is computed according to the capillary pressure using the Washburn Equation (1) with P_w ranging from 0.003 to 136 MPa, using a contact angle of 130° (Gan et al., 1972) and surface tension of 485 dyne/cm (Gregg and Sing, 1982).

All the experiments are performed at State Key Laboratory of