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The tight oil potential of the Lucaogou Formation from the southern Junggar Basin, China

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ABSTRACT

The mudstones of the Lucaogou Formation are the most important and organic-rich sediments and tight oil exploration target in the northwestern China. The organic and stable isotope geochemistry, and organic petrology were used to evaluate their sedimentary environments and hydrocarbon generative potential. The Lucaogou mudstones contain abundant organic matter, S_2, hydrogen index (HI) and extractable organic matter (EOM), whereas S_1 values are low. The $\delta^{13}C$ values of EOM are very light and display a negative correlation with HI. Rock pyrolysis data imply a low maturity (0.6–0.7 $\%R_o$ equivalent) of the Lucaogou Formation, consistent with aliphatic and aromatic hydrocarbon ratios. The biological sources are predominately algae and bacteria, with less contribution of higher plants in the Lucaogou Formation as indicated by $\delta^{13}C_{EOM}$, biomarkers and maceral composition. The Lucaogou mudstones contain low ratios of $C_{31}R/C_{30}$ hopane, C_{29}/C_{30} hopane and C_{22}/C_{21} tricyclic terpane, and high C_{24}/C_{23} tricyclic terpane value, which are consistent with their depositional environments (i.e., lacustrine). The abundant β-carotane, gammacerane and hop-17(21)-enes indicate a hypersaline and anoxic environment. The studied samples are predominantly oil-prone with a dominant type I and II_1 kerogen. High contents of total organic carbon (TOC), S_2, HI, EOM, saturated and aromatic hydrocarbons indicate that the Lucaogou Formation hold significant exploration potential of tight oil.

1. Introduction

In order to satisfy the increasing demand of energy and due to the decreasing amount of conventional petroleum, the unconventional petroleum, e.g., tight/shale oil and shale gas, has attracted more and more attention, which has been a hot topic in recent years, especially following their successful development in the marine sediments of North America from the 'shale revolution' [1–12]. In comparison with the unconventional petroleum within the marine sediments in North America, a lot of money and effort have been paid to the exploration of the unconventional petroleum in the Chinese lacustrine sediments, e.g. the middle Permian Lucaogou Formation in the Junggar Basin and Santanghu Basin, the upper Triassic Yanchang Formation in the Ordos Basin and the Palaeogene Xingouzui Formation in the Jianghan Basin [1,13–23]. The Lucaogou Formation contains the most significant and organic-rich sediments and is a primary exploration target for shale/tight oil in the northwestern China [1,13,24–34].

The Lucaogou mudstones contain high TOC contents (up to 20 wt.%), which are regarded as the most prolific hydrocarbon source rocks and one of the thickest and richest hydrocarbon source rocks on the earth [25]. Significant commercial tight oil was found in the Junggar Basin and was thought to be derived from the Lucaogou Formation

Abbreviations: EOM, extractable organic matter; TOC, total organic carbon; HI, hydrogen index; OM, organic matter; IRMS, isotope-ratio mass spectrometer; GC-MS, Gas chromatography mass spectrometry; MPI, methylphenanthrene index; MPDF, methylphenanthrene distribution fraction; MPR, methylphenanthrene ratio; DMPR, dimethylphenanthrene ratio; MNR, methylnaphthalene ratio; TNR-2, trimethylnaphthalene ratio 2; TMNr, trimethylnaphthalene ratio; TeMNr, tetramethylnaphthalene ratio; TIC, total ion chromatogram; CPI, carbon preference index; TT, tricyclic terpanes; TeT, tetracyclic terpane; $C_{29}/C_{30}H$, C_{29} norhopane/C_{30} hopane; $C_{31}R/C_{30}$, C_{31} 22R homohopane/C_{30} hopane; $C_{29}Ts/(Ts + H)$, $C_{29}Ts/(C_{29}Ts + C_{29}$ αβ hopane); GI, Gammacerane/C30 hopane; C_{29}/C_{27} 20R, C_{29}/C_{27} ααα 20R sterane; H/S, hopane/sterane; Ts, C27 22,29,30-trisnorneohopane; Tm, C27 22,29,30-trisnorhopane; $C_{29}H$, 30-norhopane; $C_{29}Ho$, 30-norneohop-13(18)-ene; $C_{30}H$, C_{30} hopane; C_{31}–C_{34} H, C_{31}–C_{34} homohopane (22S + 22R); $C_{30}He$, hop-17(21)-ene; C_{31}–C_{34} He, C_{31}–C_{34} homohop-17(21)-ene (22S + 22R); DBT/P, dibenzothiophenes/phenanthrene; FL, fluorene; DBF, dibenzofuran; MBG, mineral-bituminous groundmasses; V, vitrinites; I, inertinites; P, Prasinophyte green algae; $EqVR_o$, equivalent vitrinite reflectance; OEP, odd-to-even predominance

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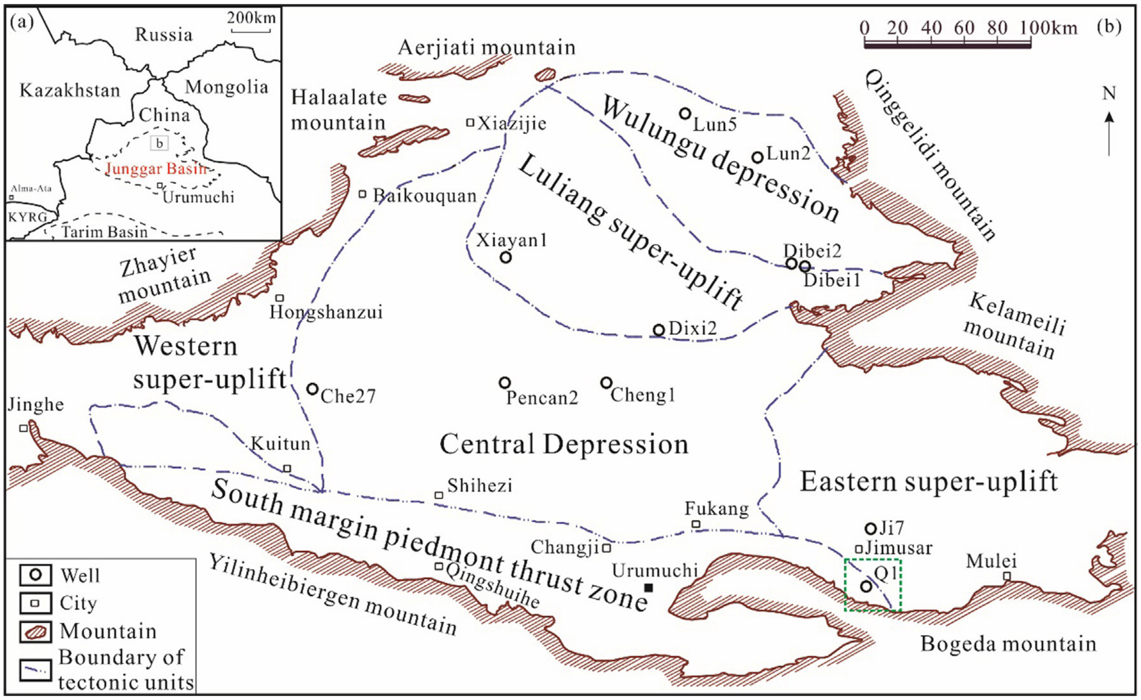

Fig. 1. The location of well Q1 in the Junggar Basin, northwestern China.

[13,35], and the tight oil resources are estimated to be 370 million tons in the Jimusar Sag, southern Junggar Basin [28,36]. There are two permeable and porous sweet spots for tight oil interbedded in the mudstones and the major lithology of the sweet spots is silt-fine sandstone, carbonatite and mudstone [13]. On the basis of the geological and geochemical evidences, the oil in the sweet spots was thought to be derived from neighboring mudstones [13].

Until now, there are not many publications available concerting on the organic geochemical and petrological characteristics of the Lucaogou mudstones. Thus, bulk and organic geochemistry, and organic petrology are applied to contribute to a better understanding of the types and origins of OM, sedimentary environments, maturity levels, hydrocarbon potential and oil/gas proneness of the Lucaogou Formation.

2. Geological setting

The Junggar Basin is located in the Xinjiang Uygur Autonomous Region, northwest China (Fig. 1). The Junggar Basin contains Paleozoic to Cenozoic sediments (Fig. 2), and the thickness of the sedimentary rocks is up to 5000 m in the Jimusar Sag and displays a decreasing trend towards east [37]. The thickness of lacustrine fine-grained sediments is exceeding 1000 m close to the foothills of the Bogeda mountain [26,38]. [25] described that the Upper Permian includes three sets of organic-rich mudstones: the Jingjingzigou, Lucaogou, and Hongyanchi Formations. The Junggar lake evolved from a relatively shallow, saline lake to a freshwater lake during their deposition [26]. The Lucaogou Formation contains much higher TOC and HI than the other two Formations, and hosts good petroleum systems in the Junggar Basin [13,25,26]. It mainly consists of lacustrine fine-grained laminated organic rich shales, sandstones, conglomerates and dolomites (Figs. 2 and 3). In comparison with conventional lacustrine source rock models, the Lucaogou Formation is characterized by two aspects: (1) it was deposited at 39–43°N; (2) the primary productivity was low to moderate during its deposition [26]. The major reservoirs in the study area are the Lucaogou Formation, the Permian Wutonggou Formation and the Triassic Jiucaiyuan Formation. The Lucaogou Formation is an exploration target of unconventional tight oil, however, the Wutonggou and Jiucaiyuan Formations are the exploration targets for conventional oil and gas. The studied well Q1 was drilled in the southeastern Junggar Basin close to the Bogeda mountain (Fig. 1), and abundant oil was found in the Lucaogou mudstones from well Q1 (Fig. 3a and b).

3. Sampling and methods

68 cuttings and core samples of the Lucaogou Formation from well Q1 were chosen for geochemistry analyses (Appendix Table A1). TOC was measured on a Leco CS230. Rock pyrolysis was conducted on an OGE-II oil evaluation workstation as described by [39].

The powder samples were extracted with dichloromethane and methanol (97:3, v/v) for 72 h. Carbon isotope of EOM was analyzed using a Thermofisher Flash 2000EA–Mat253 IRMS as described by [40]. The polished blocks were made for microscopic examination as described by [41,42]. The maceral observation was carried out on a Leica microscope under reflected and fluorescent lights. The aliphatic and aromatic hydrocarbons, non-hydrocarbon and asphaltene were separated from EOM in order. The aliphatic and aromatic hydrocarbon distribution was analyzed on GC–MS as described by [43]. Abbreviations, definitions and references to the aromatic maturity parameters used in this paper are given in Table 1.

4. Results

4.1. Bulk geochemical characteristics

The studied shales contain variable TOC concentrations, falling between 0.84% and 9.89% (ave. = 4.05%) (Appendix Table A1, Figs. 4 and 5), and this average can be compared with the average (~4.30%) based on a calculation of over one 800 m interval in this Basin [25]. These samples contain low S_1 values (range: 0.20–3.82 mg HC/g rock, ave. = 0.95 mg HC/g rock), while S_2 values are much higher (range: 1.39–84.66 mg HC/g rock, ave. = 28.00 mg HC/g rock) (Appendix Table A1, Figs. 4 and 5). T_{max} values ranged from 428 to 446 °C, with a mean of 437 °C (Appendix Table A1). HI values range from 149 to 922 mg HC/g TOC (ave. = 624 mg HC/g TOC) (Appendix Table A1, Figs. 4 and 5). TOC shows positive correlations with both S_1 and S_2