Fuel 160 (2015) 583–595

Contents lists available at ScienceDirect

Fuel

journal homepage: www.elsevier.com/locate/fuel

Ultra-deep liquid hydrocarbon exploration potential in cratonic region of the Tarim Basin inferred from gas condensate genesis

Shuichang Zhang [a,b], Haiping Huang [c,d,*], Jin Su [a,b], Mei Liu [c]

[a] Key Lab of Petroleum Geochemistry, CNPC, Beijing 100083, China
[b] State Key Lab for Enhancing Oil Recovery, Research Institute of Petroleum Exploration & Development, PetroChina, Beijing 100083, China
[c] School of Energy Resource, China University of Geosciences, Beijing 100083, China
[d] Department of Geoscience, University of Calgary, 2500 University Drive NW, Calgary, AB T2N 1N4, Canada

HIGHLIGHTS

- Oil and gas condensate are formed at wide maturity range and genetically related.
- Gas condensates can be classified into thermogenic, retrograde and mixed types.
- Thermal cracking and TSR alteration occur in deeper strata than current penetration.
- Reservoir temperature history and pressure depression support deeper oil prospects.

ARTICLE INFO

Article history:
Received 17 April 2015
Received in revised form 4 August 2015
Accepted 5 August 2015
Available online 18 August 2015

Keywords:
Gas condensate
Oil thermal cracking
Evaporative fractionation
Tarim Basin

ABSTRACT

A suite of gas condensate and crude oil samples from cratonic region of the Tarim Basin has been analyzed by routine GC–MS technique to elucidate their molecular compositions and genetic origins. Maturity parameters derived from biomarkers, aromatic hydrocarbons and diamondoids suggest very different maturity ranges for both condensates and oils, implying different stages of hydrocarbon emplacement and entrapment. Similar maturity range in two sample types without depth control suggests that condensates and oils are genetically close but different in gas oil ratios. Using diamondoid concentrations as a measure of loss of oil due to cracking indicates that majority condensates are not formed by thermal cracking of oils. The key controls on hydrocarbon phases are multiple charges and subsequent dysmigration. Thermal cracking and thermochemical sulfate reduction occur mainly at the depth deeper than current penetration (around 7000 m). The window of liquid hydrocarbon preservation may be shifted towards greater depths and previously unrecognized deep-basin oil and condensate resources are expected.

1. Introduction

The formation of crude oils in source rocks is generally attributed to progressive catagenesis of kerogen in sedimentary basins. With further increasing temperature and burial depth, crude oils migrated into reservoir or bitumens retained in source rock systems will be cracked into light oil, condensate and dry gas with pyrobitumen as residue [1–4]. Gretener and Curtis [5] believed that source rocks will pass entirely through the oil window in little more than 10 Ma at 140 °C. Some pioneer work also suggests oil is only stable to 150–160 °C [1,2,6]. Other studies indicate that the thermal stability of oils in geological conditions is higher than such temperature limit based on system openness and pressure suppression [7–9], presence of water [10,11], re-evaluation of kinetic parameters for oil generation [12,13], considerations of the order of kerogen reactions [14], thermodynamic and redox calculations [15] and delay of cracking by hydrogen donors [16]. However, liquid oil is generally reservoired at shallow and moderate depths and dry gas is normally discovered in deep reservoirs. A pronounced basinal zonation occurs worldwide in petroleum basins with very rare commercial oil discovered in the deep strata at temperature above 180 °C. Unfortunately, causes of such a zonation have rarely been understood in most of petroleum basins.

Several post accumulation alteration processes including thermal cracking, biodegradation, water washing, gas washing,

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* Corresponding author at: Department of Geoscience, University of Calgary, 2500 University Drive NW, Calgary, AB T2N 1N4, Canada. Tel.: +1 403 2208396; fax: +1 403 2840074.

E-mail address: huah@ucalgary.ca (H. Huang).

http://dx.doi.org/10.1016/j.fuel.2015.08.023

evaporative fractionation, and thermochemical sulfate reduction (TSR) will exert various impacts on hydrocarbon compositions and distributions [17–22]. Oil reservoirs can be charged by multiple phases from different organofacies or the same facies at different maturity continuously or periodically, resulting in complex distributions of fluid quality [23]. Recognizing which of the above processes are operative in the field is important because they impact oil quality, field development and near-field exploration.

The occurrence of gas condensate in reservoir can be derived from several different ways. Majority gas condensate is formed at high maturity stage from kerogen degradation [1], while some resin rich gas-prone organic matter may generate gas condensate in a wide maturity range [24]. Thermal cracking of crude oil at high-temperature reservoirs and evaporative fractionation are also important processes for gas condensate formation [3,13,17,18]. Understanding which of these processes is active in a basin deserves thorough assessment because this may have implications for the existence of a deeper oil leg. However, the task can be difficult because these processes and their effects are interrelated especially in the case like the Tarim Basin.

Deep Palaeozoic reservoirs (>7000 m) in the Tarim Basin are traditionally regarded as gas plays as some gases are proved to be derived from thermal cracking of oil [25]. Recent exploration and production reveal that ultra-deep oil potential seems beyond expectation [26,27]. Being able to understand and predict the composition of hydrocarbons in such settings becomes economically important because it might shift a field from a non-commercial category into a commercial one. However, no rigorous studies have been performed to understand the geological–geochemical reasons for the observed hydrocarbon distribution. The present study focuses on genetic origin of gas condensates in the cratonic region of the Tarim Basin based on geochemical compositions of produced oils and gas condensates to infer the deep exploration risk. The purpose of our study is to reduce uncertainty in the ultra-deep reservoir exploration where the presence and distribution of liquid hydrocarbons is not clear.

2. Geological background

The Tarim Basin, with an area of about 560 × 10^3 km^2, is the largest oil- and gas-bearing basin in China. It is a Palaeozoic marine cratonic basin, overlain in the south and north by the Mesozoic–Cenozoic continental foreland depressions [28]. The Tabei and Tazhong uplifts are inherited structural highs in the cratonic platform, separated by the Manjiaer Depression in between (Fig. 1). Since the Palaeozoic, up to 16 km of sediments have accumulated in the Manjiaer Depression, an area largely characterized by continuous subsidence. Fluctuating crustal activity has resulted in multiple unconformities in uplifted region [28]. The general stratigraphic column of the Tabei and Tazhong uplifts can be divided into several tectonic stratigraphic sequences. Briefly, the Precambrian basement of the basin is composed of thick metamorphosed detrital rocks and limestone, dolostone, quartzite and schist. The Cambrian strata are composed of tidal, platform and platform-marginal marls, mudstones and carbonates. A mixed carbonate-siliciclastic sequence associated with salt beds and anhydrites occurs in the Middle Cambrian rocks. The overlying Ordovician section is primarily composed of platform dolomite and marginal slope-shelf carbonate sediments (Fig. 1, right). The upper Palaeozoic marine and continental transitional sediments are accumulated after deposition of the Silurian and Devonian fine-grained reddish mudstones and tidal sandstones. After a major hiatus during Late Permian, renewed subsidence led to the accumulation of up to 6 km of the Mesozoic–Cenozoic fluvio-lacustrine sandstone and mudstone in the depocenter [29–35].

The source rocks for oil and gas accumulations in the Palaeozoic reservoirs are believed to be the Cambrian-Lower Ordovician marine carbonate successions and the Middle–Upper Ordovician marls [29,30,33,36]. They are currently buried to depths of more than 5000 m in most areas of the basin and are at a high-mature or over-mature stage [34,37]. Multiple tectonic events and multiple phases of oil and gas generation and expulsions result in the diverse hydrocarbon types including dry gas, gas condensate, volatile oil, black oil and bitumen in the Tabei and Tazhong uplifts [29–33, 35,36,38–41].

3. Methods

Twenty-one (21) gas condensate and twenty (20) oil samples are collected at wellhead separators with majority samples from the Ordovician carbonate reservoirs, two from the Cambrian carbonate and six from the Silurian, Carboniferous and Triassic sandstone reservoirs (Table 1). Molecular composition is characterized by gas chromatography–mass spectroscopy (GC–MS) in Schlumberger geochemical laboratory in Canada. Known amount of oil/condensate spiked with a suite of internal standards is separated into different fractions using a small scale column (pipette) liquid chromatography method [42]. The GC–MS analyses of the hydrocarbon fractions are performed using an Agilent 5975C MSD system interfaced to an Agilent 7890A gas chromatograph. A DB-1MS fused silica capillary column (60 m × 0.32 mm i.d. × 0.25 μm film thickness) and a HP-5MS column (60 m × 0.32 m × 0.25 μm) are used for saturated and aromatic hydrocarbon fractions, respectively. The oven temperature is initially set at 40 °C for 5 min, programmed to reach 325 °C at 3 °C/min increments, held for 20 min. Helium is used as the carrier gas with constant flow rate of 1 ml/min. Both interface temperature and injector temperature are 300 °C. The transfer line temperature is 250 °C, and the ion source temperature is 230 °C. The ion source is operated in the electron ionization (EI) mode at 70 eV and selected ion monitoring (SIM) is performed. Quantitation of individual component is achieved by integration of peak areas with respect to corresponding standards.

4. Result

4.1. Bulk compositions

Great variations can be observed in API gravity, viscosity, sulfur and wax content, gas/oil ratio (GOR) and bulk composition (SARA) of the studied oil and gas condensate samples (Table 1). Wide range of API gravity occurs at any depth, indicating variable controls on oil physical properties. Slight decrease in API gravity with increasing burial depth is obviously not a result of progressive thermal maturation commonly observed in other basins (Fig. 2a). Dead oil viscosities of gas condensates vary from 0.8 to 20.3 cP (50 °C), while average slightly higher but narrow range viscosities from 1.1 to 12.7 cP occur in oils. Sulfur contents vary from 0.02% to 0.42% in all other condensates with one exceptional value of 2.08% in the ZS1C condensate. Sulfur contents in normal oils are generally above 0.2% with the highest amount of 0.94% in the XK7C oil. The wax contents are mostly below 10% in both sample types with two exceptions in the TZ83 condensate (23.4%) and the LN631 condensate (37.8%). GOR values vary dramatically in both sample types although gas condensates have generally higher GOR values than those in oils. The highest GOR value occurs in the TZ83 condensate, which contains very high amount of wax. The second highest GOR occurs in the ZS1C condensate, which has very low API gravity. Again, no obvious depth control can be observed from GOR profile (Fig. 2b).