Hydrocarbon geochemistry and charging history of the deep tight sandstone reservoirs in the Dabei Gas Field, Kuqa Depression, Tarim Basin, NW China

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Abstract
The geochemical feature and evolutionary history of hydrocarbons from the deep Cretaceous Bashijiqike (K1bs) Formation tight sandstone reservoir in the Dabei Gas Field, Kuqa Depression were investigated using gas chromatography, gas chromatography–mass spectrometry, inclusions petrography and micro-thermometry, laser Raman spectroscopy, and quantitative grain fluorescence. The result indicates that natural gases from the deep sandstone reservoir are mainly composed of alkanes and belong to dry gases, of which methane accounts for 94.30–97.20% (avg. 95.64%), and ethane is 1.23–2.45% (avg. 1.95%). The stable carbon isotopic value of methane and ethane is $\delta^{13}C_{CH_4}$ = 31.9‰ to 29.3‰ (avg. 30.3‰) and $\delta^{13}C_{C_2H_6}$ = 24.2‰ to 19.4‰ (avg. 21.7‰), respectively, and this reflects the features of high-mature coal-derived gases. In addition, natural gases in the Dabei Gas Field have characteristics of coal-derived gases which were sourced from Jurassic coal measures. Oils in the Dabei Gas Field predominately originated from Triassic Huangshanjie (T3h) Formation mudstones with some contributions from Jurassic coaly rocks.

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Petrological and micro-thermometry results of fluid inclusions suggest that the \( K_1 bs \) Formation tight sandstone reservoirs have experienced two phases of hydrocarbons charge histories, namely “early oil and later gas.” The quantitative grain fluorescence analysis indicated that sandstone samples with quantitative grain fluorescence index value \( > 5 \) and quantitative grain fluorescence-extraction intensity \( > 40 \) pc in Wells DB101 and DB2 can be used as indicators for the paleo oil layers or the migration channels of later charged natural gas. The aforementioned analyses and burial and thermal histories of \( K_1 bs \) sandstone reservoir demonstrated that oil charged at 10 Ma and natural gas charged at approximately 3 Ma in the study area. Furthermore, paleo-tectonic evolution enabled source rocks to mature and expel hydrocarbons, and the structurally related faults and traps provided pathways and places for hydrocarbon migration and accumulation.

**Keywords**
Geochemical feature, hydrocarbon charge history, deep tight sandstone reservoir, origin of hydrocarbons, Dabei Gas Field, Kuqa Depression

**Introduction**
The Kuqa Depression, which is located in the north part of the Tarim Basin, north western China, is an area with hydrocarbon-rich resources and broad prospects. Large gas fields, such as Kela 2, Dabei, Keshen, and Bozi have been recently exploited in Cretaceous and Paleogene sandstone reservoirs (Gao et al., 2018; Wei et al., 2019; Zhang et al., 2011; Zhu et al., 2015). The latest explorations indicate that the ultra-deep layer (burial depth \( > 6000 \) m) of the Kuqa Depression shows the potential of trillion cubic meters of natural gas, which is one of the most realistic areas for increasing reserves and production in the Tarim Basin (Yu et al., 2019). Particularly, the proved natural gas geological reserves from the ultra-deep layer (burial depth \( > 7000 \) m) in the Keshen and Bozi–Dabei sections have been enhanced to be \( 4000 \times 10^9 \) m\(^3\), which greatly expanded the lower limit of the burial depth of ultra-deep oil and gas exploration (Zeng et al., 2020). Natural gases from above two sections are dry gases, indicating that the underlying source rocks in these areas have experienced a high thermal evolution process. Notably, the discovery of minute quantities of condensate oil in the Dabei Gas Field provides important information for the origin and accumulation analyses of hydrocarbons (Zhu et al., 2019).

The Dabei Gas Field is located in the western portion of the Kuqa Depression; the geochemical features and origins of hydrocarbon in this area have been widely studied (Dai et al., 2001; Guo et al., 2016a; Zhu et al., 2015). Natural gases are dominated by methane (\( > 85\% \)) and also contain a minor content of heavy hydrocarbon (\( C_2^+ \)), and the other components are mainly \( N_2 \) and \( CO_2 \). Moreover, stable carbon isotope values of alkane gases are generally heavy. In addition, abundant saturated and aromatic hydrocarbons were detected in oil samples from the studied area (Liang et al., 2003). However, oils and gases are characterized by complex geochemical characteristics, and their accurate sources are controversial. Zhang et al. (1995) proposed a method for identifying the coal-type oil on the basis of the relative proportion of \( C_{24} \) tetracyclic terpenoids, Ts and Tm, by comparing the typical biomarker parameters in oils and source rock. Guo et al. (2016b) believed that light
oil and gas were originated from Jurassic coaly rocks in the Dabei Gas Field. The estimated maturity of the former is 1.4–1.6% $R_o$ on the basis of diamondoid hydrocarbon ratios and that of the latter is 1.7–2.3% $R_o$. Zhang et al. (2011) believed that oils in the Dabei Gas Field are originated from Jurassic and Triassic source rocks, which are similar to the plane distribution of source rocks. Moreover, natural gases are predominantly coal-derived, but the contribution of oil-related gases should be considered. Zhao et al. (2002) and Li et al. (2008) demonstrated that natural gases in the Dabei Gas Field are coal-derived gases and mainly sourced from Jurassic and Triassic coal measures. Ji et al. (2017) considered that a considerable part of natural gas is oil cracked gas but with various maturity or of which is mixed with humidity gas.

Various technologies were applied to investigate the hydrocarbon charge histories in the Kuqa Depression. The indirect methods include trap entry time (Shen et al., 2017), history of hydrocarbon generation (Li et al., 2008, 2004, 2005), and saturated pressure/dew-point pressure of oil and gas reservoirs (Zhao and Dai, 2002), which provide the indicators for hydrocarbon charging history associated with structural evolution. The direct methods are the analyses of geochemical characteristics of hydrocarbons (Krooss and Littke, 1995), fluid inclusions, K–Ar dating of authigenic illite (Zhang et al., 2007), (U–Th)/He dating of apatite (Yu et al., 2014), petrology (Peksa et al., 2017; Yu et al., 2017), and quantitative grain fluorescence (QGF) (Shi et al., 2018). Fluid inclusions show the history of hydrocarbon captured and stored in the minerals due to valuable evidence on the temperature, pressure, salinity, and component during fluid intrusion and migration processes (Cao et al., 2006; Parnell, 2010). The accurate timing of hydrocarbon charge can be estimated from thermal and burial histories and homogenization temperature of aqueous inclusions. The QGF technique was applied to ascertain the presence of residual paleo oil and analysis of paleo oil–water contact and route of hydrocarbon migration on the basis of QGF index values and wavelengths and intensities of QGF extraction (QGF-E) (Liu and Eadington, 2005).

This study aims at to (1) investigate the geochemical features and determine the origins of hydrocarbon from deep tight sandstone reservoir in the Dabei Gas Field; (2) provide an approach that analyzes the period and timing of oil and gas charge using petrological characteristics, laser Raman spectroscopy, Th, the QGF technique, and burial–thermal history; and (3) examine the charge history of hydrocarbon by incorporating the tectonic evolution. Our study scientifically investigated the geochemical characteristics of hydrocarbons and reestablished the processes of hydrocarbon migration and accumulation of the deep tight sandstone reservoir in the Dabei Gas Field. These results could be helpful to deepen the understanding of the origin and accumulation of hydrocarbons from the deep reservoir in the Kuqa Depression, and to provide a reference for the accumulation and exploration evaluation of deep and ultra-deep gas fields in the foreland basin of China.

**Geological setting**

Kuqa Depression is bordered by the South Tianshan Mountains in the north part and Southern Gentle Slope in the south part, and covers approximately $3.7 \times 10^4$ km$^2$ (Liang et al., 2003). The three tectonic evolution stages in the Kuqa Depression, namely periphery, extensional rifting, and rejuvenation, resulted in numerous north-dipping thrust faults and associated folds (Graham et al., 1993; Jia, 1992). The tectonic movements from the middle–late Yanshan to the Himalayan period (13.5 – 0.7 Ma) have laid the structural pattern of the “three sags and four belts” (Lei et al., 2007). The seven sub-structural units are as follows:
Yiqikelike Thrust Belt, Kelasu Thrust Belt, Qiulitage Thrust Belt, Northern Moncline Belt, Wushi Sag, Baicheng Sag, and Yangxia Sage (Figure 1(a)). The former three thrust belts were generated during the geological age of $23-12$ Ma and are the favorable structural units for gas and oil accumulations; the main source rocks are Jurassic coal measures and Triassic lacustrine mudstones (Jia and Li, 2008). The latter three Sags are the important zones for the generation and preservation of mature or high–over mature source rocks.

The deep sandstone gas reservoirs of the Dabei Gas Field are Dabei 1 (DB 1), Dabei 2 (DB 2), and Dabei 3 (DB 3) gas reservoirs (Figure 1(a)). The structural-related folds are the product of compression from the Tianshan Mountains, forming several traps that are conducive to hydrocarbon accumulation. Gas reservoirs accumulated in the anticlines, which were composed of multiple normal faults or two broken anticlines separated by three normal faults (Figure 1(b) and (c)). The Mesozoic–Cenozoic sedimentary strata are thick and well-developed with a thickness exceeding 8000 m (Figure 1(d)). The Dabei Gas Field was extensional during the Mesozoic, wherein well-developed Jurassic and Triassic source rocks exhibit several characteristics, such as large thickness, wide distribution, and high abundance of organic matter and that at stage of high to over maturity, which is favorable for dry gas generation. The Cretaceous Bashijiqike ($K_1bs$) Formation and Paleogene

![Figure 1. Dabei Gas Field in the Kuqa Depression. (a) Location map, structural units, and wells of Kuqa Depression; (b) sample sites; (c) structural cross section AB showing the location of wells; and (d) stratigraphic column.](image-url)
Kumugliemu (E1–2 km) Formation sandstone layers are the main reservoirs. By contrast, the Cenozoic was generally in a structural compression setting, and the spatial heterogeneity in the strata distribution is associated with this depositional environment. However, the fractures and traps are the potential migration channels and storage sites for gas and oil, respectively. In addition, the E1–2 km and Neogene Suweiyi (N1 s) Formation gypsum–mudstone layers are excellent regional caps due to the large thickness (>1000 m) and few faults that were broken through in these layers.

Sample collection and experimental process

Sample collection

In this study, 12 natural gas, 15 oil, and 57 sandstone samples were collected from five sample sites (Figure 1). In addition, a total of 35 source rocks from the Jurassic Kezilenuer (J2 k2), Qiakemake (J2 q), Yangxia (J1 y), Triassic Huangshanjie (T3 h) Formations in Well YN2, Dabei block, and Baicheng Sag were gathered for hydrocarbon–source correlation analysis. Before the aforementioned analysis, the Jurassic and Triassic source rock samples were selected for tests of organic abundance, type and maturity, and extraction with organic solvents. Notably, oils in the Dabei Gas Fields demonstrated a low density of 0.80–0.83 g/cm³ at room temperature.

Analysis of biomarkers in oil and source rocks

Typical biomarkers of all oil and source rock samples were obtained from gas chromatography–mass spectrometry (GC–MS) analysis. An Agilent 7890A instrument equipped with HP-5MS silica column was used in accordance with the China National Standard GB/T 18606-2017. Helium with purity of >99.99% was used as the carrier gas. Before measurements, almost of all light and aromatic hydrocarbons in oil and source rock samples were eluted by gradually rising oven temperatures. In the GC–MS analysis, the oven temperature was kept at a temperature of 100°C and then to 220°C at 4°C/min. Then, the temperature ramped to 300°C at 4°C/min and retained approximately 20 min. The biomarker parameter of each component was calculated by peak height and area.

Natural gas geochemistry analysis

Natural gas constituents were measured on an Agilent 6890N GC in accordance with the China National Standard GB/T 13610-2014. Gas components were separated using a silica column, and helium was the carrier gas. In measurements, the temperature of GC oven was programmed at 30°C initially and then raised to 180°C at 10°C/min. Keep this maximum oven temperature for 20 min.

The stable carbon isotopic values (δ13C) of alkanes in natural gases were analyzed on a Finnigan Mat Delta Plus GC/C/IRMS instrument in accordance with the Chinese Oil and Gas Industry Standard SY/T 5238-2008. Prior to measurement, gas components were initially fractionated using a silica column, the oven temperature was 35°C at beginning and then set to 80°C. Finally, temperature was programmed to 250°C at 8°C/min for 20 min. After separation, each component was subjected to copper oxide activation treatment, and the maximum temperature of the oxidation furnace was set at 850 ± 10°C. The values of
$\delta^{13}$C were acquired by a Delta V Advantage IRMS. The measured values were calculated in the Vienna Pee Dee Belemnite standard and that of precision for $\delta^{13}$C is ±0.1‰.

**Petrography, micro-thermometry, and laser Raman analyses of inclusion**

Twenty-four core samples from the K$_{1}$bs Formation in Wells DB101, DB102, DB2, and DB202 were selected for inclusion petrography, micro-thermometry, and laser Raman measurements. The fluid inclusion petrographic analyses were conducted on the Zeiss Axiovert 200 fluorescence microscope. The micro-thermometry was analyzed using a calibrated LINKAM THMS600 instrument in accordance with the Chinese Nuclear Industry Standard EJ/T 1105-1999. Micro-thermometry experiments were carried out at 25°C and a humidity of 40% in the laboratory. Before measurements, double-polished sections of 0.30 mm thickness for the core samples were prepared. The homogenization temperature (Th) was measured at 10°C/min and each sample was analyzed in triplicate with a precision of <1°C. Furthermore, the final ice melting temperature (Tm) is indicative of salinity in aqueous inclusions associated with hydrocarbon charging at different periods (Guo et al., 2016b). The timing of hydrocarbon charge history was inferred from the combined results of Th, Tm of aqueous inclusion, and their burial–thermal history. Laser Raman measurements of fluid inclusions were performed using double polished sandstone slices and a RM1000 laser Raman spectrometer equipped with an Olympus BX50 microscope. During the process, this instrument was programmed at a wavelength of 514.5 nm and an output power of 30 mW.

**QGF analysis**

Thirty-three sandstone samples from Wells DB101, DB102, DB2, and DB202 were selected to detect the paleo oil layer using QGF techniques. In measurements, a highly sensitive spectrophotometer was used to detect approximately 1 g of cleaned and dried quartz grains and the solvent extracts that removed surface contaminants by a pre-cleaning process. Notably, this method used short UV excitation wavelengths and recorded continuous spectrums in the range of 300–600 nm.

**Results**

**Geochemical features of natural gas**

As shown in Table 1, natural gases from the Dabei Gas Field mostly consist of alkanes and are dry gases, with a mean value of dryness coefficient is 0.97. The compositions range from 94.30 to 97.20% (avg. 95.64%) for methane and 1.23 to 2.45% (avg. 1.95%) for ethane, with a minor content of propane (avg. 0.34%) and butane (avg. 0.27%). Similarly, natural gases from the Kela 2 Gas Field have high content of methane (>95%) and are dry (Guo et al., 2016b). However, natural gases in the neighboring Dawanqi oil pool show quite different features with the Dabei Gas Field and consist of high C$_2$+ components, which may indicated low gas maturity in the Dawanqi oil pool (Zhu et al., 2015).

Stable carbon isotopic value of methane, ethane, and propane of natural gases is in the range of $-31.9_{-00}$ to $-29.3_{-00}$ (avg. $-30.3_{-00}$), $-22.6_{-00}$ to $-19.4_{-00}$ (avg. $-21.7_{-00}$), and $-22.5_{-00}$ to $-19.2_{-00}$ (avg. $-20.9_{-00}$), respectively. Figure 2(a) reveals that isotopic values of almost all natural gases exhibit positive carbon isotope sequences ($\delta^{13}$C$_{1} < \delta^{13}$C$_{2}$
<\delta^{13}C_3 > \delta^{13}C_4 \) (Dai, 1993) and partial isotope reversals \((\delta^{13}C_2 > \delta^{13}C_3 \text{ or } \delta^{13}C_4 > \delta^{13}C_3)\) that occurred in Wells DB202 and DB301 (Figure 2(b)) due to the anomalous high ethane isotope values of \(-21.8\%_\text{o} \text{ to } -19.4\%_\text{o}\).

**Geochemical characteristics of oils and source rocks**

Organic abundance, type, and maturity of the selected source rocks in Well YN2 were measured and shown in Table 2. The total organic carbon and vitrinite reflectance \((R_o)\) of mudstone samples are 0.93–2.57\% (avg. 1.66\%) and 0.69–1.47\% (avg. 1.03\%), respectively. Moreover, those for the coal samples are 48.23 and 0.73\%, respectively. In addition, the organic matter types of source rocks are mainly type II_2 and type III. Figure 3 shows the mass fragmentograms of the tricyclic terpane, hopane, and sterane for four representative samples in Kuqa Depression. The distributions of terpane, hopane, and sterane in T_3h and J_2kz Formation source rock extracts are generally different, except for the ratio values of C_{27}–C_{29} regular sterane and dibenzothiophene to phenanthrene (Table 2). The result reveals that J_2kz Formation source rocks display a relatively high composition of C_{29} within C_{27}–C_{29} regular sterane, whereas all of which in T_3h Formation source rocks are lower than 35\%. However, the \(18\zeta(H)–/(18\zeta(H)–+17\zeta(H)–)\) trisnorhopane ratio \((Ts/(Ts+Tm))\) in the J_2kz Formation source rocks is significantly lower than those of T_3h Formation but show a particularly high value in pristane/phytane \((Pr/Ph)\) ratio.

As shown in Table 3, abundant saturated and aromatic hydrocarbons were detected in the selected samples. The saturated and aromatic hydrocarbons vary from 74.62 to 86.62\% (avg. 82.60\%) and 7.65 to 13.45\% (avg. 10.57\%), respectively. The resin accounts for 5.19–11.26\% with a mean value of 6.55\%, and asphaltene was not detected in oil samples. The Pr/Ph ratio values in most oil samples were lower than 2.0 with an exception from Well DB102 (Table 2). The ratio values of C_{27}–C_{29} regular sterane range from 0.50 to 0.95 with an average of 0.74. The C_{19}/C_{23} tricyclic terpane values from the Dabei Gas Field are in the range of 1.01–1.99, which are lower than those from Dawanqi oil pool but are anomalously higher than those of Kela 2 Gas Field (Guo et al., 2016). The benzoanthracene/chrysene
Figure 2. Stable carbon isotopic ratios of natural gases in the Dabei Gas Field. (a) $\delta^{13}C_1$–$\delta^{13}C_4$ connecting lines and (b) correlation between the values of ($\delta^{13}C_1$–$\delta^{13}C_2$) and ($\delta^{13}C_2$–$\delta^{13}C_3$). VPDB: Vienna Pee Dee Belemnite.
Table 2. Typical biomarker parameters of the selected samples in the Kuqa Depression.

| Well  | Formation | Depth (m) | Sample type | TOC (%) | Ro (%) | Organic matter type | C27 (%) | C28 (%) | C29 (%) | C27/C29 | C19TT/ C23TT | Ts/(Ts+Tm) | T24/(T24 + T26) | Gl | BAN/CH | DBT/P |
|-------|-----------|-----------|-------------|---------|--------|---------------------|---------|---------|---------|---------|----------------|------------|----------------|-----|--------|-------|
| DB1   | K1bs      | 5576–5658 | Oil         | – – –   | 1.58   | 37.69               | 20.77   | 41.54   | 0.66    | 1.15    | 0.49           | 0.58       | 0.17           | 0.04 | 0.07   |
| DB101 | E-K       | 5725–5783 | Oil         | – – –   | 1.96   | 40.6                | 15.2    | 44.2    | 0.92    | 1.53    | 0.54           | 0.76       | 0.09           | 0.06 | 0.07   |
| DB102 | K1bs      | 5451–5479 | Oil         | – – –   | 2.14   | 24.17               | 27.23   | 48.6    | 0.5     | 1.99    | 0.42           | 0.44       | 0.12           | 0.05 | 0.14   |
| DB2   | E-K       | 5567–5570 | Oil         | – – –   | 1.41   | 30.64               | 24.57   | 44.79   | 0.68    | 1.01    | 0.58           | 0.71       | 0.1            | 0.02 | 0.09   |
| DB2   | E-K       | 5658–5669 | Oil         | – – –   | 1.17   | 31.93               | 22.29   | 45.78   | 0.7     | 1.16    | 0.55           | 0.53       | 0.13           | 0.04 | 0.09   |
| DB202 | E-K       | 5711–5845 | Oil         | – – –   | 1.95   | 41.81               | 13.97   | 44.22   | 0.95    | 1.29    | 0.41           | 0.75       | 0.1            | 0.04 | 0.09   |
| YN2   | J2q       | 3702      | Mudstone    | 1.26    | 0.69   | II                     | 0.6     | 24.34   | 44.65   | 0.69    | 1.52           | 0.13       | 0.69           | 0.03 | 0.04   |
| YN2   | J2kz      | 4317      | Coal        | 48.23   | 0.73  | III                   | 0.39    | 23.36   | 46.07   | 0.64    | 1.88           | 0.14       | 0.9            | 0.02 | 0.03   |
| YN2   | J2kz      | 4321      | Mudstone    | 2.51    | 0.85   | II                     | 1.2     | 24.18   | 44.57   | 0.7     | 1.55           | 0.2        | 0.61           | 0.06 | 0.06   |
| YN2   | J1y       | 4404      | Mudstone    | 2.57    | 0.84   | III                   | 0.55    | 23.55   | 45.79   | 0.67    | 1.49           | 0.18       | 0.76           | 0.04 | 0.05   |
| YN2   | T3h       | 5248      | Mudstone    | 1.04    | 1.47  | III                   | 1.02    | 37.59   | 34.12   | 0.83    | 1.31           | 0.76       | 0.46           | 0.11 | 0.04   |
| YN2   | T3h       | 5244      | Mudstone    | 0.93    | 1.31  | III                   | 0.67    | 39.58   | 34.98   | 0.73    | 1.06           | 0.57       | 0.43           | 0.13 | 0.18   |

BAN/CH: benzoanthracene/chrysene; C19TT/C23TT: C19/C23 tricyclic terpane; C27/C29: C27/C29 regular sterane; DBT/P: dibenzothiophene/phenanthrene; Gl: gammacerane/(gammacerane+C30 hopane); Pr/Ph: pristane/phytane; Ro: vitrinite reflectance; TOC: total organic carbon; Ts: 18α(H)/18α(H)+(18α(H)+17α(H)) trisnorhopane; T24/(T24 + T26): tricyclic terpane.
(BAN/CH) and dibenzothiophene/phenanthrene (DBT/P) in oil samples are 0.02–0.06 (avg. 0.04) and 0.07–0.14 (avg. 0.09), respectively. Notably, the $T_{24}/(T_{24}+T_{26})$ tricyclic terpane and gammacerane/(gammacerane+$C_{30}$ hopane) (GI) in the oil samples present no significant differences.

Figure 3. Chromatograms of m/z 191 (left) and m/z 217 (right) of four representative samples in Kuqa Depression. $C_{21}$p: $C_{21}$ pregnane; $C_{27}$, $C_{27}$: regular sterane; $C_{28}$, $C_{28}$: regular sterane; $C_{29}$, $C_{29}$: regular sterane; $C_{30}$H: $C_{30}$ hopane; $C_{31}$H: $C_{31}$ homohopane; $C_{33}$H: $C_{30}$ trishomohopane; Ds: diasterane; G: gammacerane; TeT: tetracyclic terpane; Tm: 17α(H)-trisnorhopane; Ts: 18α(H)-trisnorneohopane; TT: tricyclic terpane.
Fluid inclusion petrography and micro-thermometry

Petrological characteristics of fluid inclusions. Various types of fluid inclusions were observed in 24 sandstone samples. Aqueous inclusions are rich in the selected samples with max diameter of 12 \( \mu \)m, and which are characterized by two-phase gas–liquid flow. Aqueous inclusions coexisting with hydrocarbons are relatively rare and only detected in Wells DB101 and DB102 (Figure 4). Oil inclusions with diameter of 3–14 \( \mu \)m predominately occurred in samples from Well DB101 (Figure 4(b)), almost all of which developed with two phases and contained relatively minute bubbles at normal temperature. Fluorescence observation reveals that oil inclusions with blue–white fluorescence color primarily occurred along healed micro-fractures in the quartz grains. Notably, gas inclusions are rich in Wells DB101 and DB102 (Figure 4(c) and (f)). Laser Raman spectroscopic analysis indicates that gas phases of these inclusions are abundant in methane (Figure 4(d)), which changed into vapor bubbles during the cooling process and homogenized to liquid state at a temperature of \(-78^\circ\text{C}\) to \(-70^\circ\text{C}\).

Micro-thermometry analysis of fluid inclusions. As shown in Figure 5(a) and (b), the Th values of aqueous inclusions in Wells DB101 and DB102 range from 80 to 150°C and 90 to 145°C, respectively. Multi-peaks are observed around at the intervals of 100–110, 125–130, and 135–140°C. Aqueous inclusions in Wells DB2 and DB202 yield Th values of 95–145 and 95–150°C, respectively (Figure 5(c) and (d)). Notably, a major peak occurs within Th value of 125–130°C, and two minor peaks exist in the ranges of 110–115 and 135–140°C. Aqueous inclusions coeval with oil inclusions were detected in Well DB101, which display a uni-modal Th distribution and yield values of 100–110°C (Figure 5(a)). Moreover, aqueous inclusions coeval with gas inclusions were found in Wells DB101 and DB102, and Th values are 125–140 and 130–145°C, respectively (Figure 5(a) and (b)).

Aqueous inclusions and those coexisting with oil or gas inclusions were used to calculate salinity from Th and final ice melting temperature values. Salinity values of aqueous inclusions are in the range of 1.40–22.43 wt% NaCl equivalent and slightly positively correlated with Th (Figure 6). Salinity increases relatively slow with Th values lower than 130°C, but linearly and gradually increases at values greater than 130°C. Figure 6(a) shows oil and gas inclusions with Th values of 105–107 and 126–138°C, yielding salinity values of >9 wt% NaCl equivalent. Figure 6(b) displays that gas inclusions from Well DB102 exhibit relatively high salinity values of 19.87–22.43 wt% NaCl equivalent.

### Table 3. Group compositions of the selected oil samples in the Dabei Gas Field.

| Well | Formation | Depth (m) | Saturated hydrocarbon | Aromatic hydrocarbon | Resin | asphaltene |
|------|-----------|-----------|-----------------------|---------------------|-------|------------|
| DB1  | K1bs      | 5576–5658 | 74.62                 | 13.45               | 11.26 | 0          |
| DB101| E-K       | 5725–5783 | 83.81                 | 10.16               | 5.82  | 0          |
| DB102| K1bs      | 5451–5479 | 85.94                 | 8.72                | 5.23  | 0          |
| DB2  | E-K       | 5567–5570 | 82.16                 | 11.41               | 6.35  | 0          |
| DB2  | E-K       | 5658–5669 | 82.47                 | 12.04               | 5.46  | 0          |
| DB202| E-K       | 5711–5845 | 86.62                 | 7.65                | 5.19  | 0          |

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Figure 4. Micrographs under UV and transmitted light observations for four representative sandstone samples in the Dabei Gas Field. (a) Aqueous inclusions along healed micro-fractures, (b) oil inclusions along healed micro-fractures with blue–white fluorescence color, (c) gas inclusions along healed micro-fractures, (d) Raman spectrum of gas inclusions (from c), (e) aqueous inclusions along healed micro-fractures, (f) gas inclusions along healed micro-fractures, and (g) to (i) aqueous inclusions along healed micro-fractures.
Figure 5. Histograms of Th distribution for fluid inclusions in the Dabei Gas Field. (a) DB101, (b) DB102, (c) DB2, and (d) DB202.
Figure 6. Plots of relationship between salinity and Th of fluid inclusions in the Dabei Gas Field. (a) DB101, (b) DB102, (c) DB2, and (d) DB202.
Evidences of hydrocarbon migration

QGF and QGF-E spectra of samples were plotted and are shown in Figure 7. The QGF spectra present characteristic peak at wavelength range of 375–500 nm, and the max intensity occurred at 400 and 475 nm (Figure 7(a) to (d)), suggesting that paleo oil in the selected samples is the mixing of light oil and ordinary crude oil (Liu and Eadington, 2005). Similarly, QGF-E spectra develop with obvious asymmetric morphology, which tilted toward at wavelength interval of 400–450 nm with max intensity of 300–450 nm (Figure 7(e) to (h)).

The QGF index values of paleo oil–water contact are generally greater than 4–5, whereas paleo water contact demonstrated an index that is relatively lower than 5 (Liu and Eadington, 2005). A value of 0–40 pc of QGF-E intensity is indicative of sandstone sections that have never experienced oil charging and have a residual paleo oil layer of between 40 and 150 pc (Barclay et al., 2000; Liu and Eadington, 2005). As shown in Figure 8, QGF index values and QGF-E intensities of all the measured samples are 2–24 (avg. 5.35) and 8.60–1060 pc (avg. 310.13 pc), respectively. Figure 9(a) indicates that QGF index values are between 3.5 and 24 with the highest value at burial depth of 5793 m and the lowest value at 5863 m. QGF index values abruptly decrease from 5790 to 5823 m and do not increase below this depth. This finding indicates that the baseline value of the paleo oil–water contact is 5, and the burial depth is 5823 m. QGF-E intensities of all samples in Well DB101 are 157–961 pc (Figure 8(e)). Similarly, the paleo oil–water contact appears at 5810 m in Well DB2 (Figure 8(c) and (g)), which is close to that of Well DB101. This finding suggests that Wells DB101 and DB2 may be located in the same paleo trap. In terms of criterion for QGF and QGF-E analyses, no oil charged in the sandstone samples of Wells DB102 and DB202 (Figure 8(b), (d), (f), and (h)).

In Wells DB101 and DB2, 10 sandstone samples were considered to experience oil charging, and 18 sandstone samples were interpreted to be invaded by later-charged natural gas for the QGF-E intensity above 40 pc. The analysis reflects the information that sandstone samples in Wells DB101 and DB2 have experienced earlier oil charge history and then became migration channels for the later-charged natural gas.

Discussions

Origin of natural gases from deep tight sandstone reservoir

Figure 10(a) indicates that natural gases from the Dabei Gas Field exhibit the feature of thermogenic gases, which are in agreement with the natural gases originated from type III kerogen. Moreover, $\delta^{13}$C$_1$ value was selected to reflect the maturity of source rocks due to the correlation between $\delta^{13}$C$_1$ and $R_o$ (Dai and Qi, 1989). Result from Table 1 manifests suggests that natural gases were produced at a maturity of 1.50–2.29% $R_o$, which corresponds to the high–over maturity stage of source rocks. Notably, the C$_1$/C$_2+3$ ratios are strongly positively correlated with $\delta^{13}$C$_1$, thereby indicating that the heavy hydrocarbon content in natural gas decreases when maturity increases. Figure 10(b) shows that carbon isotope values of alkenes are heavy, and a positive correlation between $\delta^{13}$C$_1$ and $\delta^{13}$C$_2$ was observed. The $\delta^{13}$C$_2$ variation trend demonstrates that natural gases in the Dabei Gas Field originated from type II and III kerogen. Dai (1993) suggested that $\delta^{13}$C$_2$ value of coal-formed gas is heavier than $-25.1\%_o$ and that of lighter than $-28.8\%_o$ is oil-formed gas. $\delta^{13}$C$_2$
Figure 7. Wavelength spectra of QGF (a–d) and QGF-E (e–f) for K mes Formation sandstone samples in the Dabei Gas Field. (a) DB101, (b) DB102, (c) DB2, (d) DB202, (e) DB101, (f) DB102, (g) DB2, and (h) DB202. QGF: quantitative grain fluorescence.
Figure 8. Relationship between QGF index (a–d) and QGF-E intensity (e–f) and burial depth of sandstone samples in the Dabei Gas Field. (a) DB101, (b) DB102, (c) DB2, (d) DB202, (e) DB101, (f) DB102, (g) DB2, and (h) DB202. QGF: quantitative grain fluorescence.
values of natural gases in the study area are heavier than $-25.1\%$, with a mean value of $-21.73\%$, which is indicative of coal-formed gases.

Jurassic coal measures and Triassic lacustrine mudstones were widely developed in the Kuqa Depression, both of which could contribute to the formation of gas reservoirs. However, the obvious differences in the geochemical characteristics of natural gases from above two types of source rocks are as follows: coal-derived gases are rich in methane, whereas oil-derived gases contain relatively more contents of ethane and other alkane components (Wei et al., 2019); stable carbon isotopes of natural gases originated from coal measures are positive than those from lacustrine source rocks (Liang et al., 2003; Liu et al., 2016). Shen et al. (2017) also demonstrated that these differences of natural gases may be attributed to the variations in parent material types and maturity of source rocks. Zhang et al. (2011) pointed out that a certain amount of gas samples in the Dabei Gas Field are mixtures of coal-derived and oil-derived gases based on the linear correlation between carbon isotope values and carbon numbers of natural gases. When the coal-derived and oil-derived gases mix together, the phenomenon with carbon isotope inversion of alkanes will appear. However, compositions and stable carbon isotopic ratios of the selected natural gas samples illustrated that similarities occurred in the relative proportions of alkane and non-alkane gases and stable carbon isotopic values of methane, ethane, and propane (Table 2). In the Dabei Gas Field, natural gases mostly consist of alkanes and are dry gases, with a mean value of dryness coefficient of 0.97. Moreover, methane and the non-hydrocarbon components are at interval of 94.3–97.2% and 1.35–2.97%, respectively. Thereby, the analysis infers that the contributions of oil-derived gases to the deep-burial natural gas samples in the Dabei Gas Field are limited.

Notably, high pressure and temperature also affect the carbon isotopic sequence of alkanes, which mainly exist in the process of natural gas generation, migration, and fractional distillation (Thompson, 1988). When hydrocarbons were formed, the higher pressure and temperature can increase the degree of polymerization of light carbon radicals, thus resulting in the enrichment of light carbon molecules in carboniferous compounds (Du et al., 2003). With this focus, the $^{12}\text{C} - ^{12}\text{C}$ bond preferentially breaks and then combines
Figure 10. Genesis distinction diagram of natural gases in the Dabei Gas Field. (a) Correlation between $\delta^{13}C_1$ and $C_1/C_2 + 3$ (Dai et al., 2001) and (b) correlation between $\delta^{13}C_1$ and $\delta^{13}C_2$ (plate modified from Hu et al., 2014). VPDB: Vienna Pee Dee Belemnite.
with hydrogen molecules forming a hydrocarbon compound with rich $^{12}\text{C}$ but poor $^{13}\text{C}$. Therefore, the low $\delta^{13}\text{C}$ value leads to the abnormality of the carbon isotope sequence of alkanes. Furthermore, $^{12}\text{C}$ preferentially participated in the chemical reactions between heavy hydrocarbons and water during natural gas accumulation process, thus leading to the heavy carbon isotopic values of residual alkanes. The large consumption of $^{12}\text{C}_2\text{H}_6$ will result in the $\delta^{13}\text{C}_2 > \delta^{13}\text{C}_3$ phenomenon (Burruss and Laughrey, 2010). The maximum burial depth of underlying source rocks in Dabei Gas Field is $>7000\text{m}$, and that of Cretaceous reservoirs is $>5000\text{m}$, which can provide geological conditions for carbon isotopic reversal.

According to the above analyses, natural gases in the Dabei Gas Field have characteristics of coal-derived gases which were sourced from Jurassic coal measures, and partial isotope reversals of alkanes may be related with the high pressure and temperature conditions of deep reservoir and source rocks.

**Origin of oils from deep tight sandstone reservoir**

Based on the aforementioned analysis, the typical biomarker parameters of oils were plotted in Figure 11. For facilitating comparisons, seven oil samples from adjacent areas of the Dabei Gas Field were collected. As shown in Figure 11, all the oil samples can be categorized into three groups, of which oils in the Dabei Gas Field fall into the latter two. Group 1 comprises all samples of Kela 2 Gas Field with $\text{C}_{19}\text{TT}/\text{C}_{23}\text{TT}$ ratio value of 0.24–0.27. Group 2 contains almost all samples from Dabei Gas Field except for one sample, which is characterized by the similar biomarker parameters as Group 3 oils from Dawanqi oil pool (Figure 12). Group 3 oil samples exhibit $\text{T}_{24}/(\text{T}_{24}+\text{T}_{26})$ and $\text{C}_{27}/\text{C}_{29}$ ratio values ranging from 0.41 to 0.49 and 0.33 to 0.50, respectively, which are lower than those of oil samples from Groups 1 and 2.

The $\text{C}_{19}\text{TT}/\text{C}_{23}\text{TT}$ ratio is indicative of the origin of oils and has been widely applied. Liang et al. (2003) proposed that the ratio of $\text{C}_{19}\text{TT}/\text{C}_{23}\text{TT}$ in coaly oil is generally higher than 1.5, and that of lacustrine oils is approximately 1.0. As shown in Figure 11(a), the Group 3 oils display higher $\text{C}_{19}\text{TT}/\text{C}_{23}\text{TT}$ ratios compared with Groups 1 and 2, suggesting that the higher plants are the main organic matter source for the Group 3 oils. The Group 2 oil samples probably originated from the lacustrine mudstone. Moreover, the GI index for almost all oils shows no difference. This result suggests that source rocks for all oils were generally in a sedimentary environment with similar salinity (Peters et al., 2005).

The $\text{T}_s/(\text{T}_s+\text{T}_m)$ ratio can be used to indicate the maturity (Song et al., 2017). The Group 3 oils demonstrate similar $\text{T}_s/(\text{T}_s+\text{T}_m)$ values to those of Group 2 oils, but both are lower than the Group 1 oils, thereby suggesting that oils in the study area originated from different source rocks (Figure 11(b)). The $\text{Pr}/\text{Ph}$ ratio can be used to ascertain redox depositional environment but is not an exclusive indicator, which is affected by the source facies variations and maturities of organic matter (Wenger et al., 2002). The $\text{DBT}/\text{P}$ ratio alone is an excellent indicator of oils and extracts of source rocks with a high ratio, thereby suggesting the oxidation environment. Hughes et al. (1995) reported that the combination of $\text{Pr}/\text{Ph}$ and $\text{DBT}/\text{P}$ ratios offers a new and convenient method for inferring the sedimentary environment and provides valuable guidance for further exploration. As shown in Figure 11(c), the oil samples fall into the zone III, which indicates that oils originated from marine and other lacustrine source rocks in an anoxic environment. Notably, the
Figure 11. Distributions of biomarker parameters in source rocks and light oils in Kuqa Depression (data of Kela 2 Gas Field and Dawanqi oil pool were collected from Tarim Oilfield Company, PetroChina). Plate of Figure 11(c) modified by Hughes et al. (1995). Zones Ia and Ib: anoxic depositional environment with free $\text{H}_2\text{S}_n$ species; Zone II: anoxic depositional environment with fermentative condition; Zone III: anoxic depositional environment with no sulfide exists; Zone IV: periodically oxic or dysoxic depositional environment. DBT/P: dibenzothiophene/phenanthrene.
Group 1 oils show a higher DBT/P ratio than those of Groups 2 and 3 oils, except for one sample from Kela 2 Gas Field with lower DBT/P ratio of 0.13.

The BAN/CH ratio is indicative of organic matter input of source rocks. Tuo (1996) reported that CH is mainly derived from lower aquatic organisms because of a negative correlation that occurred between CH and high plant-derived naphthalene compounds. Furthermore, the presence of BAN indicates the contribution of high terrestrial plants to organic matter input and that of relatively high values in oils are believed to be derived from coal measures (Guo et al., 2016a). Xiao et al. (2004) believed that the lacustrine oils develop with relatively more C_{27} regular sterane (>35%) and less C_{27} regular sterane (<45%), which were much less affected by higher plants than coaly oils. Figure 11(d) shows that the BAN/CH ratios of almost all oil samples are 0.01–0.20 with an exception from Well DB101 with an extremely high BAN/CH ratio of 0.47. This finding demonstrates that source rocks for most oil samples contained lacustrine organic matter input.

As shown in Figure 12, oils exhibit similar percentages of C_{27}, C_{28}, and C_{29} regular steranes, except for Group 3 oils from Dabei Gas Field and Dawanqi oil pool, which are characterized by low C_{27}/C_{29} ratios of 0.33–0.50. However, the origins of Groups 1 and 2 oils cannot be distinguished through C_{27}/C_{29} ratio (Figure 12(d)). Zhang et al. (2011) reported that oils in the Dabei Gas Field present low steranes due to the high maturity and fairly serious cracking caused by strong acid dissolution under thermal stress. The aforementioned discussion indicated that the proportions of regular steranes and C_{27}/C_{29} ratio cannot be used to clarify the oil–source relationship in the study area.

Plots of typical biomarker parameters for oils and source rock extracts provided significant evidence on the correlations between source rocks and oils. The Group 1 oils show similar biomarkers with T_{3h} mudstone at BAN/CH ratio, GI index, DBT/P ratio, and Ts/(Ts+Tm) ratio. This finding suggests that these oils mainly originated from T_{3h} lacustrine mudstone. Similarity, the above biomarker characteristics of Group 2 oils effectively correlated with the T_{3h} mudstone extracts, except for an oil sample from Well DB101 with relatively high C_{19}TT/C_{23}TT ratio of 1.53, which displays the features of coaly oils. Thus, Group 2 oils were primary derived from T_{3h} mudstone with a certain contribution from
Jurassic coaly rocks. Group 3 oils present abnormally high $C_{19}TT/C_{23}TT$ and $BAN/CH$ ratios with 1.99–2.20 and 0.38–0.47, respectively, which are quite different from those in Groups 1 and Group 2. These geochemistry characteristics show a significant relationship with Jurassic coal measure extract, thereby Jurassic coal measures made some contributions to the selected oils. To sum up, oils in the Dabei Gas Field predominately originated from T3$h$ mudstones and some contribution from Jurassic coaly rocks.

**Charge periods and timing of hydrocarbons**

Petrography and micro-thermometry demonstrated that three types of fluid inclusions were observed in the selected sandstone samples, two of which coexisting with oil and gas inclusions. Oil and gas originated from Jurassic and Triassic source rocks but with distinct maturities on the basis of hydrocarbon–source correlation analyses and petrography of fluid inclusions. The blue–white fluorescent aqueous inclusions coeval with oil inclusions developed along healed micro-fractures in the quartz grains, thereby showing a uni-modal Th distribution with values of 100–110°C. The aqueous inclusions coeval with gas inclusions were observed along healed micro-fractures with Th values of 125–145°C. The above results imply that two periods of oil and gas charging were observed in the K1$bs$ Formation reservoir of the Dabei Gas Field.

Additional evidences can be observed in the salinity evolution processes of fluid inclusions from Wells DB101, DB102, DB2, and DB202 (Figure 13). Plots of salinity and geological age indicate that trends of salinity evolution of fluid inclusions are similar and two distinct periods can be observed in the measured samples. The first period is 15–10 Ma, and the second one is 5–3 Ma. Salinities in the first period varied slowly with values of <12 wt% NaCl equivalent. Salinities of fluid inclusions from Well DB101 show a slightly increasing trend, which may be related to fluid injection associated with oil (Figure 13(a)). During the second period, salinities increased dramatically at 5 Ma and attained the maximum value at approximately 3 Ma. The aqueous inclusions exhibit salinity up to 22.43 wt% NaCl equivalent (Figure 13(b)), thereby implying the fluid injection associated with natural gas charge. Persuasive evidence was obtained from thermal simulation results and is revealed in Figure 14(a) (Li et al., 2008, 2005); the main stage of gas generation of Jurassic coal measures commenced in depositional period of the N2$zk$ Formation (5 Ma).

The above-mentioned analyses and combined with the burial–thermal history of K1$bs$ sandstone reservoir indicated that two periods of hydrocarbons charging were defined (Figure 14). The timing of the first period was estimated at approximately 10 Ma, which corresponds to the aqueous inclusions coexisting with oil inclusions. The second period possibly started at approximately 3 Ma, which corresponds to the aqueous inclusions that are symbiotic with gas inclusions with higher Th and salinities.

**Hydrocarbon charging process**

The aforementioned analyses indicated that two periods of hydrocarbon charge history were verified in the study area. The oil inclusion with blue–white fluorescence color is indicative of the first period of oil charge and was estimated at 10 Ma. The second period of high-mature natural gas occurred at 3 Ma. The similarity of natural gas composition and maturity (Table 1), geochemical characteristics of oil (Table 2), and salinity evolution of aqueous inclusions in the selected five Wells indicate that the paleo-tectonic of Dabei Gas
Figure 13. Salinity evolution of fluid inclusions in the Dabei Gas Field. (a) DB101, (b) DB102, (c) DB2, (d) DB202.
Figure 14. Maturity evolution of source rocks (modified from Li et al., 2011, 2005) and charge periods and timing of oil and gas in the Dabei Gas Field.
Figure 15. Hydrocarbon charge histories in the Dabei Gas Field (modified from Ma et al., 2013). (a) Depositional period of the $N_{1.2}k$ Formation (12–5 Ma), (b) depositional period of the $N_{2}k$ Formation (5–2 Ma), and (c) depositional period of the Quaternary (2–0 Ma).
Field was a unified trap in the early stage. The different fault blocks exhibit a similar fluid evolution history. Oil–source rock correlation demonstrated that oils originated from T3/h mudstones and certain contributions from the Jurassic coaly rocks. Natural gases are coal-derived gases but from different sources. These above-mentioned features are inseparable from the paleo-tectonic evolution of the Dabei Gas Field.

Tectonic analysis indicated that the Dabei tectonic block has experienced multistage tectonic movements (Pang et al., 2018), and the tectonic evolution associated with hydrocarbon charging mainly began at the depositional period of the N1–2k Formation. (Zhao et al., 2005). At this stage, the early trap (paleo-structure) has been formed. The mature oil discharged from the T3/h mudstone and then accumulated in the early trap (Figure 15).

At depositional period of the N2k Formation (5–2 Ma), the strata of Dabei tectonic block suffered strong compression and destruction with the intensification of tectonic events in the Southern Tianshan Mountains (Lei et al., 2007). The plastic flow of Paleogene gypsum strata led to large thickness variations of salt and N2k Formation sedimentary strata. Meanwhile, the Dabei paleo trap was separated by a series of faults, thereby forming multiple fault-related blocks (Figure 15(b)). Meanwhile, the vertically developed faults provided migration pathways that are conducive to oil and gas. The Jurassic source rocks began to mature as the buried depth increased, and large amounts of natural gases were expelled and mixed with the early oil (Tang et al., 2014). The early charged oil may migrate, adjust, or even be lost by gas intrusion, which was demonstrated by the QGF index values, intensities, and wavelengths of the QGF-E of measured sandstone samples in Wells DB101 and DB2 (Figures 7 to 9). As shown in Figure 15(b), a portion of hydrocarbons migrated upward through faults and lost in strata where no effective cap-rock is present. In addition, the oil vertically moved along the fault and then entered into the N1j Formation, thus forming an oil reservoir in the high part of the anticline.

During the Quaternary (2–0 Ma), Paleogene gypsum strata flowed southward with increase of burial depth (Figure 15(c)). The Paleogene gypsum strata were squeezed into the sedimentary strata of the N2–3s, N1j, and N1–2k Formation. Thus, the upward migration pathways for oil and gas were disconnected. Thereafter, the subsalt-faults continued to move and formed a large number of effective traps, where large-scale high–over mature natural gas accumulated.

Conclusions

1. Natural gas in the Dabei Gas Field is dominated by methane, accounting for 94.30–97.20% (avg. 95.64%), and ethane is 1.23–2.45% (avg. 1.95%). Stable carbon isotopic value of methane and ethane is \(-31.9‰ \) to \(-29.3‰ \) (avg. \(-30.3‰ \)) and \(-24.2‰ \) to \(-19.4‰ \) (avg. \(-21.7‰ \)), respectively. Natural gases are high-mature coal-derived gases and mainly sourced from Jurassic coal measures.

2. Oils are rich in saturated and aromatic hydrocarbons, with a content of 74.62–86.62% (avg. 82.60%) for saturated hydrocarbon, and aromatic hydrocarbon varies from 7.65 to 13.45% (avg. 10.57%). Their biomarkers indicate that they were derived from Triassic Huangshanjie (T3/h) Formation mudstones with a minor contribution from Jurassic source rocks.

3. Petrological, microscopic temperature, and laser Raman analyses of fluid inclusions show that oil inclusions with blue–white fluorescence color is indicative of the first period oil charge and the time was estimated at 10 Ma, whereas the second period of high-mature
natural gas occurred at 3 Ma. The charge history of hydrocarbons accompanied with paleo-tectonic evolution in the Dabei Gas Field, which not only enabled the source rocks to mature, but also provided channels and places for hydrocarbons’ migration and accumulation.

Acknowledgements
The authors would like to thank Prof. Guoqi Wei, Prof. Jian Li, Prof. Jianfa Chen, Senior engineer Zhenye Xie and Jin Li for giving significant help in the sampling and information collection. All the editors and anonymous reviewers are gratefully acknowledged.

Declaration of conflicting interests
The author(s) declared no potential conflicts of interest with respect to the research, authorship, and/or publication of this article.

Funding
The author(s) disclosed receipt of the following financial support for the research, authorship, and/or publication of this article: This research was financially supported by the National Science and Technology Major Project of China (No. 2016ZX05007-003), the National Natural Science Foundation of China (Nos. U1810201, 41572125), the Fundamental Research Funds for the Central Universities (No. 2010YM01), and the start-up fund for doctoral research of Suzhou University (No. 2019jyb20).

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