Oil charge history of Paleogene–Eocene reservoir in the Termit Basin (Niger)

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ABSTRACT

A total of 73 oils from the sandstone reservoir of Paleogene–Eocene Sokor 1 Formation in the Termit Basin (eastern Niger) were analysed to investigate the distribution characteristics of biomarkers. Most of the oil samples are quite similar in their organic geochemical characteristics and should have been derived from the same source bed/source kitchen. The homogenisation temperatures of aqueous inclusions in Paleogene–Eocene reservoir of the Termit Basin vary with a range of 76–125°C. By combining the homogenisation temperatures with the burial and geothermal histories reconstructed by 1-dimensional basin modelling, the timing and episode of oil charge can be obtained, i.e. 13 to 0 Ma for Paleogene–Eocene reservoirs in the Termit Basin. Two presentative geochemical parameters, i.e. Tg / (Ts + Tm) and 2,4-dibenzothiophene/1,4-dibenzothiophene (2,4-DMDBT/1,4-DMDBT) were applied to trace the oil migration direction and filling pathway. The preferred oil-filling points in the northwest section of the Termit Basin were determined, and the promising exploratory targets were proposed for further oil exploration in this region.

Introduction

The Termit Basin, located in the north of the West and Central African Rift System, is a Mesozoic–Cenozoic intracontinental rift basin (Fairhead & Binks, 1991; Genik, 1992, 1993; Guiraud, Bosworth, Thierry, & Delplanque, 2005) (Figure 1). It is the largest basin of West African Rift System (WARS) with an area of approximately 27 000 km\(^2\) (Liu et al., 2012a, 2012b). The Mesozoic sequence is composed of Lower Cretaceous (K\(_1\)), Upper Cretaceous Donga, Yogou and Madama formations, while the Paleogene sequence includes Sokor 1 (Paleocene–Eocene) and Oligocene Sokor 2 formations (Wan, Liu, Mao, Lv, & Liu, 2014). The majority of oil discoveries are in the Paleocene–Eocene Sokor 1 Formation (Liu et al., 2015; Wan et al., 2014). The hydrocarbons are mainly sourced from Upper Cretaceous marine mudstones and sealed by Oligocene lacustrine mudstones (Harouna & Philp, 2012; Liu et al., 2015; Mao et al., 2016a).

The overall geochemical features of potential source beds in the Termit Basin have been summarised in recent literature (e.g. Harouna & Philp, 2012; Liu et al., 2015). Thermal maturity analysis of source rocks (Harouna, Pigott, & Philp, 2017), biomarkers related maturity parameters of oils (Wan et al., 2014), and oil–source rock correlations (Liu, Zhang, Mao, Liu, & Lü, 2017; Wan et al., 2014) indicate the source rock and oils correspond to a relatively low level of thermal maturity. Based on biomarker distribution patterns and bulk stable carbon isotope values of 60 oil samples, Wan et al. (2014) classified two oil populations in this basin. Most oil samples have similar organic geochemical characteristics and may be of marine mudstone origin. Only minor oils discovered in a couple of wells belong to another oil group and may be of lacustrine origin (Genik, 1993; Wan et al., 2014). However, less research has been conducted on the oil migration orientation and filling pathway in the Paleocene–Eocene sandstone reservoirs (Zhao & Li, 2016) and the oil charge timing and episodes have not been reported. This paper systematically studied the oil migration orientation and charge pathway based detailed molecular organic geochemical analyses of a set of 73 oil samples in the Termit Basin. Integrated with fluid inclusion observation, homogenisation temperatures, reconstruction of burial and geothermal histories of representative wells, the timing and episodes of oil filling in the Paleocene–Eocene Sokor 1 Formation were determined.

Geological settings

The geological settings for the petroleum reservoirs in the Termit Basin have been summarised widely (e.g. Genik,
Deposition of the syn-rift Lower Cretaceous (K1 Formation), which is made up of clastic sediments, primarily lacustrine sandstones and mudstones, overlies the pre-rift pre-Cambrian–Jurassic basement and epimetamorphic rocks in the study area (Figure 2). The residual thickness of K1 Formation is about 0–2500 m and no source rocks have been proven.

Above a regional unconformity, post-rift Cenomanian–Masstrichtian Donga, Yogou and Madama formations were deposited (Figure 2). The Donga Formation comprises marine sandstone in the lower interval, and mudstone, shales and siltstone in the middle–upper intervals. The Yogou Formation consists mainly of mudstone and shale deposited in marine and transitional environments. The Madama Formation is characterised by massive sandstone interbedded with thin layers of muddy sandstone and coal seams (Liu et al., 2012a, 2015; Wan et al., 2014). The Upper Cretaceous shales are the main proven source rocks for discovered oils in the Termit Basin (Liu et al., 2012a, 2015; Wan et al., 2014).

The second syn-rift Paleocene–Oligocene strata, which is made up of thick lacustrine and deltaic mudstones and sandstones, forms the main plays (Figure 2). The Paleocene–Eocene Sokor 1 Formation comprises sandstone interbedded with mudstone/shale. Petroleum reservoirs discovered in the Termit Basin include pay zones in the E1, E2, E3, E4 and E5 members of the Sokor 1 Formation and the Upper Cretaceous Yogou Formation. The Sokor 2 Formation is mainly composed of lacustrine mudstone (100–500 m) interbedded by thin sandstone layers, which represents regional seal rocks for Sokor 1 sandstones.

Figure 1. Map of the location and schematic structure of the Termit Basin, Niger.
| System       | Stage | Strata thickness (m) | Age (Ma) | Lithology | Structural evolution |
|--------------|-------|----------------------|----------|-----------|----------------------|
| Neogene      |       |                      |          |           |                      |
| Pliocene     |       | 20-500               | 1.8      |           | Post-rift            |
| Miocene      |       |                      |          |           |                      |
| Oligocene    | Sokor2| 30-1100              | 3.7      |           | Syn-rift             |
| Eocene       | Sokor1| 300-900              | 33.7     |           | Second filling period|
| Paleogene    |       |                      |          |           |                      |
| Paleocene    |       |                      |          |           |                      |
| Cretaceous   |       |                      |          |           |                      |
| Upper Cretaceous |    |                      |          |           |                      |
| Upper Cretaceous | K2   | Maastrichtian        | 71.3     |           | First-rifting period |
| Upper Cretaceous | Cretaceous | Campanian, Santonian | 300-1700 |           |                      |
| Lower Cretaceous | K1   | Coniacian, Turonian, Cenomanian | 200-1000 |         |                      |
| Lower Cretaceous |    |                      |          |           |                      |
| Jurassic     |       |                      |          |           |                      |
| Cambrian     |       |                      |          |           |                      |
| Pan-African  |       |                      |          |           |                      |
| Pre-Cambrian |       |                      |          |           |                      |

**Figure 2.** Generalised stratigraphic column for the Termit Basin (after Liu et al., 2015).
During Miocene and Pliocene, the thermal subsidence was accompanied by deposition of coarse continental clastic sediments (Liu et al., 2015).

Previous studies indicated that marine shales of the Upper Cretaceous Yogou Formation, which are found across the entire Termit Basin, are the principal source rocks for the majority of current oil discoveries. They are fair to good source rocks with average TOC higher than 2.50 wt% and dominated by type II and III kerogen (Harouna & Philp, 2012; Liu et al., 2015; Wan et al., 2014). The thermal maturity history by Wan et al. (2014) suggests that the source bed of the Yogou Formation is in a high mature to wet gas stage in the subsidence centre and at mid to late maturation levels in the proximal basin.

The fluvial, deltaic and lacustrine sandstones of the Sokor 1 Formation are the main reservoir rocks for known oil discoveries. They have a relatively higher porosity with a mean of 20%, and permeability from 250 md to 1 darcy (Wan et al., 2014). Current oil accumulations mainly occur in structural traps related to faults.

**Experimental**

A total of 73 oils were sampled from the sandstone reservoir of the Sokor 1 Formation. The asphaltene fractions of oils were filtered out by using n-hexane as a solvent. The resulting n-hexane solutions were then separated into saturated and aromatic hydrocarbon fractions using a silica/alumina liquid chromatographic column, then eluted by n-hexane and dichloromethane: n-hexane (2:1 v:v) solvents, respectively.

The saturated and aromatic fractions were geochemically analysed by gas chromatography-mass spectrometry (GC-MS) on an Agilent 5895i GC-MS system equipped with an HP-5MS (5% phenyl methylpolysiloxane) fused silica capillary column. For the saturated fractions, the GC-MS system was performed using the following conditions: the initial GC oven temperature was set at 50°C for 1 min, then ramped to 120°C at a rate of 20°C/min, subsequently to 310°C at 3°C/min, and finally held isothermally for 25 min. For the aromatic fractions, the GC oven temperature was initially set at 50°C for 1 min, then gradually increased to 310°C at a rate of 3°C/min then held isothermally for 16 min. Helium was utilised as the carrier gas. The MS was operated in electron impact mode with an ionisation energy of 70 eV, and a scanning rage of 50–600 Da.

A total of six sandstone cores from the Paleocene–Eocene Sokor 1 Formation from Well Ag-2 were collected. Double-polished thin-sections (0.08 mm thick) were prepared for fluid observation and measurements. The measurements were performed using the Linkam THMSG 600 heating–freezing stage attached to a Leica model DMRXP optical microscope following standard procedures. The heating program was started at 15°C/min during the initial stages of each heating run and reduced at 0.3–1°C/min when close to the phase change points.

**Results and discussion**

**Oil correlation and family classification**

Wan et al. (2014) identified two oil families (groups I and II) in the Termit Basin by comprehensive oil-to-oil correlation. All but three of our samples have a high degree of similarity in molecular composition, characterised by relatively lower Pr/Ph and high gammacerane/C30 hopane ratios, small amounts of C24 tetracyclic terpanes but abundant C23 tricyclic terpane, and may belong to the same oil group (group I). In contrast, oils from wells DD-1, DD-2, D-1 and Ta-1 have different geochemical features and belong to another oil group (group II) (Figure 3). The plot of Pr/nC17 vs Ph/nC18 of Termit oils indicates possible marine sources within a reducing sedimentary environment for the source rocks (Figure 3). Therefore, group I oils have similar source affinity and are derived from the same source kitchen/bed with a similar oil charge history, which is a prerequisite for tracing oil migration orientation and charge pathway.

**Timing and episodes of oil fill**

In the sandstone reservoirs of the Paleocene–Eocene, oil inclusion fluorescence is principally yellowish green in colour, indicating a mature oil (Figure 4). The microthermometry of hydrocarbon inclusions in sandstone reservoir rocks from representative samples from Well Ag-2 indicates that there was one single phase of hydrocarbon inclusion formation. The homogenisation temperatures of aqueous inclusions, which are paragenetic with hydrocarbon inclusions, have been measured.

In the Sokor 1 Formation, more than 100 homogenisation temperatures (Th, °C) were measured, and the histogram of Th shows a unimodal distribution pattern (Figure 5). The homogenisation temperatures range from 76 to 125°C with most 85–95°C, indicating the entrapment temperatures of fluid inclusions for one oil charge event in the reservoir. Figure 6 shows the burial and geothermal history for representative samples from Well Ag-2 reconstructed by

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**Figure 3.** Cross-plot of Pr/nC17-Ph vs Ph/nC18 showing the oil families, Termit Basin.
using one-dimensional numerical modelling. The approximate oil charge and entrapment temperatures from fluid inclusion analysis can be converted to corresponding geological age. **Figure 6** shows that the initial oil charge of sandstone reservoir of Paleocene–Eocene Sokor 1 Formation started at ca 13 Ma (**Figure 6**).

**Oil migration orientation and charge pathway**

The heterogeneities of chemical compositions in oils are generally thought to be determined by the oils that were initially charged into the traps (England, 2007; England, Mackenzie, Mann, & Quigley, 1987; Horstad & Larter, 1997;...
Figure 5. Histogram of homogenisation temperatures ($T_h$, °C) of fluid inclusions in oil reservoir of the Eocene Sokor 1 Formation in Well Agadi-2.

Figure 6. Burial and geothermal histories and oil charge and entrapment timing in the reservoir of the Paleocene–Eocene Sokor 1 Formation in Well Agadi-2, Termit Basin.

Figure 7. Isopleth map of $T_s / (T_s + T_m)$ ratios of oils showing the oil migration orientation and charge pathway for oil reservoirs of the Paleocene–Eocene Sokor 1 Formation in the Termit Basin.
Leythaueser & Rückheim, 1989). Oils generated and charged earlier are commonly less mature than later oils. Therefore, oil migration direction and charge pathway can be predicted by the subtle differences in maturity indicators relative to molecular markers within a reservoir system (England et al., 1987; Larter & Aplin, 1995; Wang, Li, & Zhang, 2004a; Wang, He, Li, Hou, & Guo, 2004b). The oil migration direction and preferential filling pathway in a reservoir can be traced by a decreasing locus of maturity indicators (Wang, He, Wang, Zhang, & Wang, 2008).

The parameter values of some commonly used molecular geochemical indicators for oils in sandstone reservoir of the Sokor 1 Formation in the Termit Basin are in the Supplementary papers (Table S1). The isopleth map of Ts / (Ts + Tm) ratios (defined as C27 18α-22,29,30-trisnorneohopane/(C27 18α-22,29,30-trisnorneohopane + C27 17α-22,29,30-trisnorhopane)) has been successfully applied in Ordovician carbonate reservoirs of the Tarim Basin, northwest China (Wang et al., 2008; Xiao et al., 2016). Figure 7 illustrates the isopleth map of Ts / (Ts + Tm) ratios of oils in the Termit Basin. In the northwest section of the Termit Basin, oils migrated from southwest to northeast in the Araga Graben and from northeast to southwest in the Dinga Fault Zone. Therefore, oils in the northwestern part of the Termit Basin were mainly sourced from the Dinga Depression. It can be clearly seen in Figure 7 that there are three charge points around wells DD1, G-3 and SE-1 from north to south in the Dinga Fault Zone and one charge point around Well AD-1 in the Araga Graben. In the southeastern section of the Termit Basin, oils were mainly sourced from the Moul Depression (Figure 7). The oil migrated from southeast to northwest along the Fana Uplift and from north to south in the southern region of the Moul Depression.
Fang et al. (2016), Li et al. (2008, 2012, 2014), Wang et al. (2004b) and Yang, Li, Wang, and Shi (2016) demonstrated that some molecular parameters relative to methylated dibenzothiophenes in oils, such as the relative abundances of 4-methyldibenzothiophene to 1-methyldibenzothiophene (abbr. 4-/1-MDBT), the relative abundances of 2,4-dimethyldibenzothiopehen to 1,4-dimethyldibenzothiophene (abbr. 2,4-/1,4-DMDBT) and 4,6-dimethyldibenzothiophiene to 1,4- and +1,6-dimethyldibenzothiophene (abbr. 4,6-/1,(1,4 + 1,6)-DMDBT), are effective molecular indicators tracing oil migration orientation and charge pathway. They have been successfully applied in marine carbonate and lacustrine sandstone reservoirs. The isopleth map of 2,4-/1,4-DMDBT ratio was applied to trace the oil migration orientation and charge pathway for sandstone oil reservoirs in the Termit Basin (Figure 8). This isopleth map shows similar oil migration orientation and pathway to that indicated by Ts / (Ts + Tm) isopleth.

Figure 9 plots Ts / (Ts + Tm) and 2,4-/1,4-DMDBT ratios vs burial depth of each pay zone of the Sokor Formation oil reservoirs. Neither the Ts / (Ts + Tm) nor 2,4-/1,4-DMDBT ratios have clear charge trends with burial depth or pay zones. Oils from well DD-1 have particularly higher parameter values (Figures 7 and 8). Wan et al. (2014) indicated that these oils are of lacustrine origin and may be derived from Sokor 1 Formation source rocks. The API gravity for these oils have a similar charge trend with burial depth (Figure 10). Therefore, it can be inferred that oils generated by source rocks in the Dinga and Moul depressions accumulated mainly by the lateral migration via sandstone of E1 to E5 pay zones.

One of the NE–SW cross-sections of the Paleocene–Eocene Sokor 1 Formation reservoir of the Termit Basin is shown in Figure 11. The Ts / (Ts + Tm) and 2,4-/1,4-DMDBT ratios are 0.59 and 0.68 respectively in Well AD-1, decreasing to 0.34 and 0.56 in Well DN-1. This apparently indicates an oil migration direction from SW to NE in the Araga Graben. These parameters also have a decreasing trend in the Dinga Fault Zone from Well ASE-1 to Well
DE-1 (Figure 9), indicating an oil migration orientation from NE to SW in the Dinga Fault Zone.

**Implication for oil exploration**

Both the isopleth maps of Ts / (Ts + Tm) (Figure 7) and 2,4-/1,4-DMDBT (Figure 8) indicate that oils in the northwest section of the Termit Basin were mainly sourced from the Dinga Depression. The preferred oil charge pathway occurred around wells DD-1, G-3 and SS-1 in the Dinga Fault Zone and wells AD-1 in the Araga Graben. Therefore, the promising prospects may be located in the upstream region of the preferred charge pathway towards the Dinga Depression. The results provide new insights for the exploration programs and the study of oil accumulation in the Termit Basin. Recently, considerable oil accumulations have been discovered in wells in the Fana Uplift and in the southern part of the Moul Depression (Zhou et al., 2018).

**Conclusions**

The Paleocene–Eocene oils in the Termit Basin can be divided into two oil families on the basis of their differences in organic molecular compositions. The majority of oil samples investigated in this study belong to the same oil family and may have a similar oil source and charge history.

On the basis of the homogenisation temperatures of fluid inclusions in the Paleocene–Eocene sandstone reservoir rocks, coupled with their stratigraphic-burial and geothermal histories as reconstructed by 1-D basin modelling, this indicates that the Paleocene–Eocene sandstone reservoir has experienced one charge event.

The oil migration orientation and charge pathway can be traced and mapped by using Ts / (Ts + Tm) and 2,4/1,4-DMDBT ratios as molecular indicators. Oil in the northwest part of the Termit Basin was mainly sourced from the Dinga Depression and in the southeast part from the Moul Depression. The preferred oil charge points and pathways were also determined.

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