Hydrocarbon potential of the Meso-Cenozoic Turkana Depression, northern Kenya. II. Source rocks: quality, maturation, depositional environments and structural control

M.R. Talbot*, C.K. Morleyb, J.-J. Tiercelin,c,d, A. Le Hérisse,c,d, J.-L. Potdevine, B. Le Gallc,d

*Geological Institute, University of Bergen, Allégt. 41, 5007 Bergen, Norway
bUniversiti Brunei Darussalam, Jalan Tunghu Link, Gadong BE1410, Brunei
cUMR CNRS 6538 ‘Domaines Océaniques’, Institut Universitaire Européen de la Mer, Place Nicolas Copernic, 29280 Ploézané, France
dUniversité de Bretagne Occidentale, 6, avenue Le Gorgeu, B.P. 809, 29285 Brest, France
eUniversité des Sciences et Technologies de Lille, UFR des Sciences de la Terre, UMR CNRS Processus et Bilans des Domaines Sédimentaires, 59655 Villeneuve d’Ascq Cedex, France

Received 14 March 2003; received in revised form 12 November 2003; accepted 14 November 2003

Abstract

Source rocks identified by drilling (Loperot-1 well) in the Lokichar Basin of the northern Kenya Rift were evaluated for source potential using RockEval pyrolysis and palynofacies analysis. Results indicate moderate to good oil source potential from algal-prone source rocks. The original sediments accumulated in a large freshwater lake similar to some modern rift lakes. In the Loperot-1 well, the section with the highest source potential lies within the Lokhone Shale Member (up to 17% total organic carbon (TOC), average 2.4% TOC from well-log calculation). The other potential source interval is the deeper Loperot Shale Member, which is highly mature to post-mature (Rø = 1.1%; average 1.2% TOC from well-log calculation). The poorer quality of the lower shale interval while partly due to maturity, is thought to be largely a result of the basin evolution. The Loperot Shale Member was restricted to the Lokichar Basin, while the Lokhone Shale Member was deposited during a time when displacement on the main boundary fault system was greater, and adjacent basins had been established. Consequently, lacustrine conditions appear to have extended into adjacent basins, thus allowing the accumulation of relatively higher concentrations of algal material in sediment-starved parts of the basin.

Keywords: Northern Kenya Rift; Lokichar Basin; Lacustrine source rock; RockEval; Palynofacies

1. Introduction

Hints that significant quantities of hydrocarbons can be generated in the East African Rift System (EARS) have come from several sources over the years. Oil seeps and the presence of organic-rich lacustrine shales in an onshore well at Lake Albert (western branch of EARS) were perhaps the first evidence (Harris, Pallister, & Brown, 1956; Schull, 1988). Subsequently oil seeps and natural tar balls have been described from Lake Tanganyika (Simoneit, Aboul-Kassim, & Tiercelin, 2000; Tiercelin et al., 1993), and the organic-rich Poi Shales have been identified in the Miocene

fluvio-lacustrine Ngorora Formation of central Kenya Rift (Morley, 1999c; Renault, Ego, Tiercelin, Le Turdu, & Owen, 1999; see Fig. 1 in companion paper). Source rocks have also been encountered in the Lokichar Basin, northern Kenya Rift, where they can be seen at outcrop, and have been sampled in shallow and deep exploration wells, and can also traced on seismic reflection profiles. A general description of the Lokichar Basin in terms of structure, sedimentary infill, quality of reservoir, and source rocks has been given in Morley et al. (1999) and in the companion paper to this work. The aim of this paper is to provide more details on the geochemistry of the source rocks, the evidence for their depositional setting, and to discuss the link between basin structure and source-rock quality. Two sets of shale samples from the Loperot-1 well, cleaned cuttings and sidewall cores, have been used in this work.
Fig. 1. (A) Location map of the N–S-oriented string of Palaeocene–Miocene basins in the northern Kenya Rift: Lokichar, North Kerio, North Lokichar and Lothidok (modified from Hung (1996)). The Loperot-1 well is located a few km north of the TVK-12 seismic line. The black star indicates the location of shale outcrops. (B) Schematic 3D view of geological cross-sections illustrating the main structural and stratigraphic elements of the Lokichar, North Lokichar and Lothidok basins, and correlation with the Loperot-1 well (projected). The top Oligocene time line cuts across the volcanic rocks filling the Lothidok Basin. Based on outcrop, seismic reflection (TVK-2, -12 and -13 lines; see box A) and well data.
2. Source rocks in the Lokichar Basin

Hydrocarbon exploration interest in the Lokichar Basin (Fig. 1(A); see also Figs. 2(B) and 5(A) in companion paper) was first sparked by gravity data, which revealed a large, negative Bouger anomaly with a typical half-graben geometry (Morley et al., 1992). Subsequent reconnaissance seismic reflection data demonstrated the presence of a deep half-graben and tilted fault blocks (Morley et al., 1992, 1999). The presence of a section some 6–7 km thick indicated that any source rocks located in the lower half of the basin fill section were likely to be mature, assuming normal or elevated crustal temperatures. Consequently, a key subsequent step in exploration was to establish the presence of source rocks in the basin. Typically, where rift sections outcrop they tend to be representative of flexural margins, which are sand-prone areas (Lambiase & Bosworth, 1995). Major episodes of fine-grained lacustrine deposition, where present, tend to be located closer to the boundary fault, in areas of maximum subsidence, and remain buried unless the basin is subsequently subjected to significant inversion. Consequently, considerable optimism was generated when a 100-m thick black, organic-rich shale (now called the Lokhone Shale Member) was found as discontinuous outcrops close to the Lokhone Horst at lat. 02°23.005'S; long. 35°55.850'E (Fig. 1(A); see also Fig. 5(A) in companion paper).

Further definition of the Lokhone Shale Member was made using a water-well rig to drill a series of shallow wells (maximum depth about 100 m), along selected seismic lines.

Fig. 2. (A) Seismic-well tie between seismic line TVK-12 and Loperot-1 well (projected). Note high-amplitude, continuous reflections from the top and base of the Lokhone Shale Member, a typical response associated with the impedance contrast between organic-rich shales and fluvio-deltaic sandstones. (B) Stratigraphic log of the Loperot-1 well, and sonic and gamma ray curves (modified from Hung (1996) and Morley et al. (1999)). (C) Distribution of TOC in the Loperot Shale Member, Loperot-1 well, based on sidewall core samples (after Morley et al. (1999)).
between the strike-projection of the shale outcrops (Fig. 1(A)). This drilling program established that the shale interval is at least 100 m thick, thermally immature ($R_0 = 0.32–0.37\%$), with average total organic carbon (TOC) content for cuttings samples ranging between 0.05 and 8.6%. Selected pieces of shale were as rich as 11% (Morley et al., 1999). Following a standard continental rift, half-graben sedimentation model (Katz, 1995; Lambiase & Bosworth, 1995), it was anticipated that the source rocks would thicken considerably towards the basin centre, and that their source quality would be maintained or improve in the same direction.

The Loperot-1 exploration well (Figs. 1 and 2(A) and (B)) was a very important test of the assumed source potential of the basin. The well lay about 7 km closer to the basin centre than the water wells and penetrated the Lokhone Shale Member between 925 and 1385 m. Significant basinward thickening of the shale interval, from about 100 to 460 m, occurs over the 7 km, confirming the predictions based upon a half-graben depositional model. Well logs clearly record the presence of this thick shale interval. For example, the predominantly high gamma ray, low resistivity and SP readings are indicative of a consistently shale-prone section (Fig. 2(B)). Within this section, the most organic-rich zone, defined by the TOC content of shale samples from sidewall cores (1–17% TOC, average 2.4% TOC; Hung, 1996; Morley et al., 1999), lies between 1100 and 1385 m (Morley et al., 1999; Fig. 2(C)). Correlation of the Loperot-1 well with seismic reflection data demonstrates that high-amplitude, continuous to shingled reflections characterize the top and bottom of the Lokhone Shale Member, which internally displays continuous low amplitude events (Fig. 2(A) and (B)). Thus, the lacustrine facies can be extrapolated with some confidence into the deeper part of the basin (Figs. 3 and 4).

In other rift basins it has been demonstrated that organic-rich lacustrine sequences tend to produce such distinctive reflection packages due to their internal homogeneity and a marked reduction in seismic velocity passing from adjacent sand-prone units into the shale (Liro & Pardus, 1990). Vitrinite reflectance values for the Loperot-1 well are 0.6–0.65% for the depth interval 1050–1390 m, indicating a rapid transition to maturity from the outcrops to the well. The main depocentre lies a further 6–16 km west of the Loperot-1 well; seismic data indicate that the Loperot Shale Member here reaches thicknesses in excess of 1 km (Fig. 4).

The Loperot-1 well yielded a surprise when it encountered a second, deeper potential source interval called the Loperot Shale Member, of questionable Eocene to Oligocene age (Morley et al., 1999; Fig. 1(B)). The Loperot Shale Member is found between 2325 and 2950 m (T.D.), and in comparison with the Lokhone Shale Member is a much less discrete and less obvious shale package on the well logs (Fig. 2(B)). The gamma ray and sonic logs are very ragged (Fig. 2(B)), and suggest that silt- and sandstones occur interbedded within the shale. The most organic-rich interval lies between 2410 and 2600 m, with TOC values of between 0.2 and 3.3%. Burial has rendered the section highly mature to post-mature for oil ($R_0 = 1.1\%$; depth 2410–2600 m; Morley et al., 1999; Fig. 4).

3. Basin structure

The Lokichar Basin has a classic half-graben geometry, with the basin fill thickening westwards towards the east-dipping Lokichar Fault (Fig. 1(B); see also Fig. 5(A) and (B) in companion paper). The fault shows some evidence for early linkage of three separate faults, although the dominant displacement pattern that affects the basin fill is a simple one where the displacement maximum lies at the centre of the fault (Morley, 1999a). Isopach maps of the two source rock intervals (Lokhone and Loperot Shale Members) show three isopach maxima located in similar areas for both intervals (Figs. 5 and 6). For example, the strata are relatively thin between seismic lines TVK 107 and 109 (Fig. 1(A)), within the main depocentre for both shale intervals. This isopach minimum might represent an early linkage point between two faults that amalgamated to form the boundary fault.

The top of the basin fill is marked by lava flows of the Auwerwer Hills (Auwerwer Basalts), which are of middle Miocene age (Morley et al., 1992; Fig. 1(B); see also Fig. 5(A) and (B) in companion paper). Subsequent to their extrusion, the flexural margin of the basin was uplifted and
Fig. 4. (A, B) Isopach maps for the Loperot and Lokhone Shale Members, based on extrapolation of seismic reflections bounding the units from the Loperot-1 well, creating time-structure maps of the horizons, depth converting the maps and deriving isopach maps from the time-structure maps. $R_0$ contours are based on the Loperot-1 well data, extrapolated to time-structure maps. (C) Burial history plots for the Loperot-1 well, and pseudo-well locations on seismic lines using the depth to mapped horizons. See Fig. 1(A) for seismic lines location.
eroded. This erosional event might be due to footwall uplift in response to late Miocene–Pliocene motion on the Lokhone Fault (which bounds the North Kerio Basin on the eastern side of the Lokhone Horst; Fig. 1(A)). The amount of uplift can be estimated from extrapolation of seismic horizons, and suggests about 650 m of erosion. Maturity data from the Loperot-1 well also indicate that erosion has occurred. Assuming the normal vitrinite reflectance value at the Earth’s surface is 0.2% (Dow, 1977), and considering a geothermal gradient value of 4.2 °C/100 m in this area, extrapolation of the subsurface vitrinite reflectance values to the 0.2% value indicates about 600 m of uplift has occurred.

4. The Lokichar black shales

Cleaned cuttings from three shale intervals in the Loperot-1 well were sampled at depths of 925–1385 m (corresponding to the Lokhone Shale Member), 1770–1818, and 2325–2950 m (Loperot Shale Member) at the National Oil Corporation of Kenya laboratory, Nairobi, in December 1998. These three units are informally named the ‘Lower’, ‘Intermediate’ and ‘Upper’ Black Shale Intervals,
respectively (Fig. 6(A)). In addition, green, dark grey and black shales were sampled in the Lokhone Basin near Lokhonne (lat. 02°23.005’N; long. 35°55.850’E; Fig. 1(A)). TOC values from the well cuttings and field samples were obtained using RockEval pyrolysis at the Institut Français du Pétrole. Data are summarised in Table 1. Palynofacies studies were performed at the Laboratory of Micropaleontology, UMR 6538 ‘Domaines Océaniques’ in Brest.

4.1. Organic matter content and hydrocarbon source potential

TOC values for the exposed shales near Lokhonne are uniformly low (<1%), in agreement with the values cited by Morley et al. (1999). Values obtained on our samples (cuttings) of the Lokhone Shale Member from the Loperot-1 well range from 0.1 to 7.15% TOC. However, values of up to 17% are cited for selected samples from sidewall cores in the well (Morley et al., 1999; Fig. 2(C)). High TOC contents (>1%) are largely confined to the depth interval between 1130 and 1385 m (Lokhone Shale Member), and a thin interval with 2% average TOC just above 2500 m (within the Loperot Shale Member; Fig. 7(A)). Hydrogen Indices (HI) vary from <90 to 611. A few relatively high HI values (>300) were obtained from samples with very low TOC content (<0.2%). As HI determinations from rocks with such low organic matter (OM) contents are known to be unreliable (Peters, 1986), these results were rejected. Shales with HI suggesting moderate to good oil source potential (>300) all occur in the high TOC section of the Loperot-1 well (between 1130 and 1385 m; Lokhone Shale Member; Fig. 7(B)). This is confirmed by source rock quality as measured by the petroleum potential, S2. Many samples from the OM-rich section have S2 > 5 and several exceed S2 = 10 mg HC gm⁻¹ rock, indicating good to very good source quality (Peters, 1986).

More detailed insight into the HC potential is provided by plotting TOC versus S2 (Langford & Blanc-Valleron, 1990). Fig. 7(D) shows that the OM-rich samples define one highly correlated (r = 0.99) linear population, while a second group is defined by samples with very low S2 and low to moderate TOC. The slope of each line represents the mean HI of the two groups and in the case of the HC-rich shales indicates that the pyrolizable OM is today still highly oil-prone with a mean HI of 670 (this mean is higher than any of the measured HI values because it defines the character of the pyrolizable fraction. Individual HI values are influenced by the presence of dead carbon with no generation potential). The most OM-rich horizons within this group represent high-quality oil source rocks, and as the section as a whole is of the order of 300 m thick (Fig. 7(A)), this interval clearly represents a potentially major source of hydrocarbons within the Lokichar Basin. The second OM population has a very low HI (mean ca. 90), with insignificant oil source potential.

A further parameter of significance to potential hydrocarbon production is the maturity. One measure of source-rock maturity is provided by the RockEval Tmax (Peters, 1986; Tissot & Welte, 1984). The main shale section has a Tmax of 438–452 °C (Table 1; Fig. 7(C)) and the lower, HC-poor shales have a Tmax mainly in the range of 463–478 °C. One measurement of 523 °C (Table 1; Fig. 7(C)), suggesting the presence of reworked or highly degraded OM. Both sets of Tmax are in generally good agreement with vitrinite reflectances (R0) of 0.6–0.65 between 1050 and 1390 m, and 1.1 between 2410 and 2600 m (Shell Exploration and Production Kenya B.V., unpublished report). The maturity of the OM-rich shales is relatively high in relation to their present burial depth (1.0–1.4 km), suggesting either a recent period of uplift or above-average heat flow in the region, or a combination of both. The latter is certainly a possibility, given the magmatic rift setting (see below) and a modern geothermal
Fig. 7. (A) Total organic carbon content of the ‘Upper’ (Lokhone), ‘Intermediate’, and ‘Lower’ (Loperot) black shale intervals in the Loperot-1 well. Samples are cleaned cuttings provided by National Oil Corporation of Kenya (see Table 1). (B) Hydrogen Index (HI) versus depth for shales in the Loperot-1 well. Shales with good oil source potential are confined to the depth interval between 600 and 1100 m (‘Upper’ Lokhone interval). (C) $T_{\text{max}}$ versus depth in the Loperot-1 well. (D) Plot of total organic carbon (TOC) versus RockEval $S_2$ for shales from the Loperot-1 well. Note the two very different, but highly correlated populations, one rich in oil-prone organic matter, the other of no significance as a hydrocarbon source rock. For comparison, similar plots are shown for core MPU-10 taken from a water depth of 443 m in the southern basin of Lake Tanganyika (Mondeguer, 1991), and core M98-3P from 392 m water depth in the northern basin of Lake Malawi (Barry, Filippi, Talbot, & Johnson, 2002) (RockEval data for Lakes Malawi and Tanganyika from Talbot et al., in preparation). (E) Hydrogen Index versus $T_{\text{max}}$ plot showing RockEval data from the Lokhone Shale Member (solid squares) and Loperot Shale Member (open squares) in the Loperot-1 well. Curves I–III show the maturation trajectories for, respectively, Types I–III kerogens. Also plotted are corresponding data from OM in modern African lake sediments (Filippi & Talbot, in press; Talbot & Lærdal, 2000; Talbot et al., in preparation). The field defined by the latter represents the range of likely precursor compositions for OM that accumulated in the Lokichar palaeolake. Extrapolation to the immature precursors (arrows) suggests that some of the Lokhone Shales were extremely rich in oil-prone OM at the time of deposition (see text for further discussion). Kerogen trajectories and vitrinite ($R_0$) contours courtesy of Birger Dahl (personal communication, 2003).
A gradient in the well of 42 °C km⁻¹. The oil window is conventionally regarded as beginning at a \( T_{\text{max}} \) of 430–435 °C (Peters, 1986; Tissot & Welte, 1984), the shales can thus be regarded as mature with respect to oil generation, a \( T_{\text{max}} \) of 438–452 °C suggesting that they are probably close to their maximum generative capacity (Tissot & Welte, 1984). Evidence of possible oil generation from the Loperot shales was provided by traces of oil encountered at several levels in the Loperot-1 well (Shell Exploration and Production Kenya B.V., unpublished report), although geochemical fingerprinting would be required to confirm the source. The deeper shale section is already close to the point of transition from oil to wet gas generation (Peters, 1986).

Despite being close to peak generation today, the upper (Lokhone) shale member still has relatively high HI, implying that it was probably extremely rich in oil-prone OM when it entered the oil window (see discussion on kerogen types below). It is thus probable that significant volumes of liquid hydrocarbons have already been generated from this unit. In addition, today’s moderate to high HI indicates that the unit still has considerable generative potential. The lower unit lacks significant potential today, and even when its high maturity is taken into account (see below), it seems likely that it never had the oil-generation capacity of the upper shale.

### 4.2. Use of well logs to calculate TOC content

The response of sonic velocity to OM content and the resistivity response to the level of maturation can be used to estimate TOC content of source intervals. The method proposed by Passey, Creaney, Kulla, Moretti, and Stroud (1990) was applied to the log data for the Loperot-1 well, to test the method against the Lokhone Shale Member where the TOC content has been measured, and to estimate the TOC content of the Loperot Shale Member which was not cored (Fig. 8). Gamma ray, sonic and resistivity logs were digitized and scaled to 100 m/s/ft per two logarithmic cycles. According to the method of Passey et al. (1990), the TOC content is proportional to the separation \( \Delta \log R \) between the sonic and resistivity logs:

\[
\Delta \log R = \log_{10}(R/R_{\text{baseline}}) + 0.02(\Delta t - \Delta t_{\text{baseline}})
\]

where \( R_{\text{baseline}} \) and \( \Delta t_{\text{baseline}} \) are the values of the fine-grained non-source rocks chosen after superimposing the two logs: \( \Delta t_{\text{baseline}} = 127 \text{ ms/ft} \); \( R_{\text{baseline}} = 1.2 \Omega \text{m} \). Then, the TOC values were calculating using:

\[
\text{TOC} = (\Delta \log R) \times 10^{(2.297 - 0.1638 \times \text{LOM})}
\]

where LOM is the level of maturation.

Based on the available vitrinite reflectance values, LOM was chosen as 8.5 for the Lokhone Shale Member. The calculated values were calibrated with the TOC data from sidewall cores from the Loperot-1 well, and resulted in a good match. The separation of calculated TOC and sidewall core data below 1325 m (Fig. 8) is probably due to the poor quality of the resistivity curve over that interval. The Loperot Shale Member is a less discrete shale interval than the Lokhone Shale Member, with more numerous sandy and silty intervals. The organic-rich interval of the shale lies between 2140 and 2600 m. It has relatively low TOC content (0.2–3.3%) estimated from cuttings only, and has a vitrinite reflectance (\( R_a \)) of 1.1.

Calculation of the TOC from sonic and resistivity logs for the Loperot Shale Member was conducted using the following values: \( \Delta t_{\text{baseline}} = 90 \text{ ms/ft} \); \( R_{\text{baseline}} = 3 \Omega \text{m} \); LOM = 12. The calculated TOC values shows the high TOC intervals tend to be narrow bands 10–30 m thick that spike to values of about 2–3% TOC. Some high TOC intervals are calculated to be present below 2600 m. The average log-calculated TOC values are 4.5% for the Loperot Shale Member and 1.2% for the Lokhone Shale Member. However, the 4.5% value for the Loperot Shale appears to be an overestimate due to the problems with the poor quality logs over the lower interval of the shale (Fig. 8). Consequently, when log calculated values for the upper part of the interval are combined with average sidewall core values for the lower part of the interval, the average TOC for the shales is 2.4%.

### 4.3. Palynofacies analysis

Palynofacies analyses were performed on cleaned cuttings from the three ‘black shale’ intervals identified in the Loperot-1 well, in relation to the study of potential source rocks (Fig. 2(B)). In addition, the Lokhone surface samples (near the Lokhone Horst at lat. 02°23.005′N and long. 35°55.850′E; Fig. 1(A)) have also been analysed. Optical studies were carried out on kerogen separated by standard palynological techniques and provide the following results:

**Upper black shale interval (Lokhone Shale Member: 920–1385 m) (Fig. 7(A); Table 2):** the upper part of this interval (920–1164 m) is characterized by mixed palynofacies with abundant palynomacerals (cuticle, woody fragments), exoskeleton remains, and structureless OM, associated with spores and pollen. The OM is yellow in colour and very well preserved. The palynofacies is consistent with the correspondingly low TOC values (0.04–0.7%: Fig. 7(A); Table 2). From 1164 to 1385 m, the organic facies is dominated by amorphous organic matter (AOM; Table 2), with proportions that follow the abundance of preserved OM versus the volume of siliciclastic sediment. The unstructured OM is accompanied by fungal remains, multicellular algae, Botryococcus spp. (Fig. 9(A)), Pediastrum spp. (Fig. 9(B)), and some cysts of Prasinophycean algae (Fig. 9(C)). Pediastrum as well as Botryococcus are unequivocal indicators of fresh water.
conditions, associated with lakes, ponds or lowland rivers (Batten, 1996; Fritsch, 1961; Reynolds, 1980). The petroleum generation potential of chlorophycean algae, particularly *Botryococcus* and *Pediastrum*, has frequently been underlined (Batten & Grenfell, 1996; Hutton, 1988; Péniguel, Couderc, & Seyve, 1989; Tyson, 1995; Wang et al., 1994; Wood & Miller, 1997). These algae, whose modern counterparts are commonly associated with eutrophic to hypertrophic conditions in lakes (Reynolds, 1984; Zippi, 1998), have here clearly contributed to the excellent HC source potential of these levels, but their percentages are generally limited compared to the AOM.

**Intermediate black shale interval (1770–1818 m)** (Fig. 7(A); Table 2): This interval contains variably
degraded, dispersed AOM, with locally abundant pyrite and associated heavy minerals, and disseminated structured elements (Fig. 9(E)). Terrestrial microfossils (spores and pollen) are more abundant than in the overlying interval, and TOC content is very low.

**Lower black shale interval (Loperot Shale Member: 2325–2950 m)** (Fig. 7(A); Table 2): Samples from this lower interval contain abundant AOM (Fig. 9(F)), although it is less important in volume compared to the upper black shale interval. The palynofacies are also rich in fresh water coenobial algae, fungal spores and hyphae, and few spores and pollens (Fig. 9(G) and (H)). The dominance of *Pediastrum* and *Botryococcus*, together with abundant AOM in the palynomorph assemblages at 2418 m, is an indication of eutrophication. These algae can have contributed to the generation of hydrocarbons, but the OM in this interval is at a higher level of maturity, probably corresponding to a stage of gas generation (Fig. 9(H)). This observation is clearly corroborated by the RockEval data (Fig. 7(E)).

**Outcrop samples.** The surface samples collected at Lokhone (Fig. 1(A)) belong to the upper Lokhone Shale Member. They contain degraded AOM with few structured elements. One sample has a palynofacies dominated by small spores and organic fragments of uniform size, suggesting sorting during transport and deposition. The OM appears to be slightly degraded.

### 4.4. Kerogen types

A mean HI of 670 for the OM-rich shales suggests a Type I/II composition for the productive kerogen (Cornford, 1990). Their TOC versus $S_2$ character compares well with phytoplankton-dominated OM assemblages accumulating in some large modern rift lakes such as Lakes Tanganyika and Malawi (Fig. 7(D)), suggesting the existence of a similar water body in the Lokichar Basin at the time of source rock accumulation. Palynofacies analysis reveals relatively abundant remains of the green algae *Pediastrum* and *Botryococcus*, both of which are prominent components of the phytoplankton flora in many of the modern African rift lakes (Hecky & Kling, 1987), and are relatively common in sediments that accumulated during Pleistocene–Holocene dilute phases in some East African lakes such as Lakes Bogoria and Victoria (Grall, 2000; Talbot, 1988; Talbot & Lærdal, 2000; Tiercelin, Périnet, Le Fournier, Bieda, & Robert, 1982; Tiercelin & Vincens, 1987; see Fig. 1 in companion paper). Further insights into the probable nature of the original OM can be obtained by plotting HI against $T_{max}$ and then extrapolating along the probable maturation trend back to the precursor OM (Fig. 7(E)). As a baseline for the likely starting material we have used late Pleistocene to recent OM in sediments from modern African lakes (Filippi & Talbot, in press; Talbot & Lærdal, 2000; Talbot, Lærdal, Jensen, & Filippi, submitted; Fig. 7(C)), which probably

### Table 2

Percentages of the different palynofacies elements from shale samples (cleaned cuttings) of the Upper (Lokhone), Intermediate, and Lower (Loperot) 'black shale' intervals in the Loperot-1 well

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>AOM (%)</th>
<th>CE (%)</th>
<th>DW (%)</th>
<th>Pyrite</th>
<th>Sp.-Poll. (%)</th>
<th>Fungi (%)</th>
<th>Algae</th>
<th>HM</th>
<th>OI</th>
<th>HI</th>
<th>$T_{max}$</th>
<th>TOC</th>
</tr>
</thead>
<tbody>
<tr>
<td>1062</td>
<td>9</td>
<td>83.60</td>
<td>5.30</td>
<td>0.40</td>
<td>0.80</td>
<td>U—0.50%</td>
<td>438</td>
<td>321</td>
<td>531</td>
<td>0.04</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1086</td>
<td>42</td>
<td>53.30</td>
<td>2</td>
<td>2.10</td>
<td>0.80</td>
<td>P</td>
<td>68</td>
<td>134</td>
<td>444</td>
<td>0.73</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1140</td>
<td>55</td>
<td>42</td>
<td>P</td>
<td>1.70</td>
<td>P—B</td>
<td>P</td>
<td>28</td>
<td>281</td>
<td>446</td>
<td>1.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1164</td>
<td>87</td>
<td>9.50</td>
<td>0.80</td>
<td>P</td>
<td>1.60</td>
<td>P—B</td>
<td>13</td>
<td>607</td>
<td>445</td>
<td>5.21</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1170</td>
<td>98</td>
<td>1.30</td>
<td>P</td>
<td>0.70</td>
<td>P—B</td>
<td>P</td>
<td>10</td>
<td>609</td>
<td>444</td>
<td>7.15</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1188</td>
<td>67.50</td>
<td>32</td>
<td>P</td>
<td>0.50</td>
<td>P—B</td>
<td>P—B</td>
<td>16</td>
<td>473</td>
<td>443</td>
<td>4.38</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1242</td>
<td>96.80</td>
<td>2.90</td>
<td>P</td>
<td>0.20</td>
<td>P—B</td>
<td>P</td>
<td>21</td>
<td>433</td>
<td>446</td>
<td>3.51</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1290</td>
<td>99.80</td>
<td>2.00</td>
<td>P</td>
<td>0.20</td>
<td>P—B</td>
<td>P</td>
<td>71</td>
<td>261</td>
<td>443</td>
<td>1.26</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1314</td>
<td>99.70</td>
<td>0.30</td>
<td>P</td>
<td>0.30</td>
<td>P—B</td>
<td>P</td>
<td>36</td>
<td>448</td>
<td>451</td>
<td>1.93</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1326</td>
<td>97.50</td>
<td>1.40</td>
<td>0.20</td>
<td>P</td>
<td>P—B</td>
<td>P</td>
<td>21</td>
<td>596</td>
<td>452</td>
<td>3.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1350</td>
<td>96</td>
<td>0.20</td>
<td>1.60</td>
<td>A: 1.2%</td>
<td>0.90</td>
<td>B</td>
<td>182</td>
<td>153</td>
<td>448</td>
<td>0.55</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1380</td>
<td>96</td>
<td>2.60</td>
<td>P</td>
<td>0.10</td>
<td>0.60</td>
<td>B—0.3%</td>
<td>P</td>
<td>50</td>
<td>328</td>
<td>448</td>
<td>1.21</td>
<td></td>
</tr>
<tr>
<td>1770</td>
<td>96</td>
<td>1.80</td>
<td>0.20</td>
<td>A</td>
<td>0.10</td>
<td>0.60</td>
<td>P—B</td>
<td>42</td>
<td>208</td>
<td>451</td>
<td>0.24</td>
<td></td>
</tr>
<tr>
<td>1776</td>
<td>87.50</td>
<td>8.50</td>
<td>1.20</td>
<td>A: 2%</td>
<td>0.10</td>
<td>0.30</td>
<td>P—0.1%</td>
<td>P</td>
<td>283</td>
<td>139</td>
<td>447</td>
<td>0.41</td>
</tr>
<tr>
<td>1809</td>
<td>92.80</td>
<td>6.40</td>
<td>0.30</td>
<td>P</td>
<td>0.08</td>
<td>0.10</td>
<td>B—0.1%</td>
<td>P</td>
<td>52</td>
<td>113</td>
<td>462</td>
<td>0.6</td>
</tr>
<tr>
<td>2418</td>
<td>86</td>
<td>1.40</td>
<td>6.90</td>
<td>A: 3.4%</td>
<td>0.10</td>
<td>B—2.2%</td>
<td>A</td>
<td>42</td>
<td>208</td>
<td>451</td>
<td>0.24</td>
<td></td>
</tr>
<tr>
<td>2571</td>
<td>97</td>
<td>1.20</td>
<td>1.60</td>
<td>P</td>
<td>0.20</td>
<td>P</td>
<td>182</td>
<td>153</td>
<td>448</td>
<td>0.55</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2622</td>
<td>92.80</td>
<td>3.70</td>
<td>1.80</td>
<td>0.06</td>
<td>0.20</td>
<td>P—1.3%</td>
<td>P</td>
<td>41</td>
<td>43</td>
<td>467</td>
<td>0.4</td>
<td></td>
</tr>
<tr>
<td>2847</td>
<td>87.60</td>
<td>6.80</td>
<td>4.30</td>
<td>0.20</td>
<td>0.20</td>
<td>P—0.8%</td>
<td>37</td>
<td>69</td>
<td>459</td>
<td>0.35</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2856</td>
<td>85.60</td>
<td>12</td>
<td>1.90</td>
<td>0.04</td>
<td>0.20</td>
<td>P</td>
<td>133</td>
<td>163</td>
<td>523</td>
<td>0.34</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2862</td>
<td>97.60</td>
<td>0.70</td>
<td>0.90</td>
<td>0.20</td>
<td>U—0.40%</td>
<td>P</td>
<td>14</td>
<td>644</td>
<td>471</td>
<td>0.12</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

provide close analogues to the sediments that accumulated in the Lokichar palaeolake (see preceding discussion). This baseline suggests that OM in much of the upper shale unit had HI values that were over 600 and, at some levels, in excess of 800 and was thus closer to a pure Type I kerogen (Fig. 7(D)). The relatively high maturity of the deeper shales precludes precise identification of their OM type from the pyrolysis data alone, but the palynofacies analyses indicate the presence of relatively abundant cuticle and woody material in these rocks, suggesting a Type III kerogen, a conclusion that is supported by the HI versus T_max plot (Fig. 7(E)). Poor source potential in these intervals is thus probably due to a dominance of highly degraded OM.

4.5. Basin temperature

The temperature at 2950 m, at the bottom of the Loperot-1 well, was 149 °C (corrected), which using a surface temperature of 25 °C, yields an average geothermal gradient of 4.2 °C/100 m. Vitrinite reflectance values for the well are as follows: 1050 m, R_0 % 0.6; 1110 m, R_0 % 0.64; 1390 m, R_0 % 0.65; 2500 m, R_0 % 1.1, and suggest that about 650 m of strata have subsequently been removed (see above). Heat flow values from the Kenya Rift are generally highly variable, ranging between 40 and 110 mW/m², with geothermal gradients between 2.5 and 6.6 °C/100 m (Whieldon, Morgan, Williamson, Evans, & Swanberg, 1994). The Loperot-1 well indicates that the Lokichar Basin today lies in the middle range of the data, however, during the active rifting and volcanic phase, it is quite likely that heat flow, and thus temperatures, were higher.

4.6. Generating potential of the basin

The high geothermal gradient and vitrinite reflectance data gathered from the Loperot-1 well indicate the following approximate depths of maturity for the basin: 1100 m early mature (0.5–0.8% R_0); 2100 m mid-late mature (0.8–1.2% R_0); 2800 m overmature (>1.2% R_0). Using structure maps, derived from seismic data, of the Loperot and Lokhone Shale Members, the volume of source rock for the two intervals, at the different maturity levels has been calculated. The results are as follows: Loperot Shale Member, early mature 246 106 acre-ft; mid-late mature 135.3 106 acre-ft; post-mature 38.7 106 acre-ft; Lokhone Shale Member, early mature 13 106 acre-ft; mid-late mature 46 106 acre-ft, post-mature 197 106 acre-ft. Using an average value of S_2 = 5 mg HC/gm⁻¹, and a kinetic model based on Tissot and Espitalié (1975), the potential generating capacity of the Lokhone Shale Member (for the areas above if they were fully mature) is estimated at 10.5 billion barrels. Given that about 40% of the shale volume is at mid to post mature levels this suggests the Lokhone Shale Member could have generated about 4 billion barrels of oil.

5. Consequences of regional structure on source rock-trap relationships

The presence of source rocks in the Lokichar Basin is encouraging for exploration in Northern Kenya, however, it is well established that in rifts thick, high-quality source rocks can be restricted to a single half-graben basin. So what do the Lokichar source rocks indicate about regional prospectivity?

Despite the differences in maturity, the Lokichar Basin source rocks have clear similarities with OM-rich sediments that have accumulated during the Holocene in the deep, offshore waters of Lakes Tanganyika and Malawi (Fig. 7(D)). In both the latter examples, accumulation has occurred below the chemocline in permanently anoxic waters and it is likely that similar conditions prevailed during deposition of at least the oil-prone population of Lokichar samples. The OM-poor population with no hydrocarbon potential (Fig. 7(D)) also has its analogues in modern rift lakes and is typical of areas subject to fluvial influence where highly degraded OM enters the lake (Talbot, in preparation). In addition, the palynofacies suggests a freshwater environment, conditions that are also compatible with a lake basin similar to the modern, hydrologically open giant rift lakes. Consequently, a strong structural control on source-rock distribution in the Lokichar Basin is implied, where displacement on the boundary fault caused subsidence rates to outpace sediment supply. The resulting accommodation space coupled with a favourably humid climate (rainfall perhaps five times higher than today) (Roche, 2002; Vincens, pers. comm.) enabled the development of prolonged periods of deep anoxic lacustrine conditions.
Despite the presence of two shale members separated by fluvo-deltaic sediments close to the flexural margin of the Loperot-1 well, it is likely that closer to the basin centre these two shales merge into a thicker, vertically more continuous sequence (Fig. 1(B)). The Loperot Shale Member is not seen at outcrop, and is interpreted to onlap the flexural margin west of the Lokhone Horst. Consequently, the Loperot Shale Member was restricted to the Lokichar Basin. The Loperot Shale Member lies deep in the section, and formed at a relatively early stage in the basin history, hence the early stage of fault linkage and propagation is reflected in the limited distribution of the Loperot Shale Member (Morley & Wescott, 1999—Chapter 13, Fig. 4). The early linkage of three faults is also reflected in the presence of three isopach maxima near the boundary fault, each coincident with splay in the Lokichar Fault (Fig. 4).

The Lokhone Shale Member thins from about 460 m in the Loperot-1 well to 100 m at outcrop near the Lokhone Horst. The presence of source rocks so close to the (eroded) flexural margin suggests that at least during one depositional phase, presumably during a high stand of the Lokichar Lake, anoxic lacustrine conditions extended eastwards into the neighbouring North Kerio Basin (Fig. 5). This is encouraging for extending hydrocarbon plays beyond the Lokichar Basin. The northwards extent of the Lokhone Shale Member is more problematic. During the Oligocene—lower Miocene, the basin north of the Lokichar Basin, called the Lothidok Basin, deepened eastwards (Morley et al., 1999; Fig. 1(A)). The uplifted and eroded hanging wall of this basin, now exposed in the Lothidok Hills (Figs. 1(A) and 5) reveals an Oligocene—middle Miocene section dominated by volcanic flows, pyroclastic and volcaniclastic rocks (Boschetto, Brown, & McDougall, 1992). Consequently, the Lokhone source rock interval passes northwards into a volcanic-dominated sequence across a conjugate convergent transfer zone, into the neighbouring Lothidok Basin. A major volcanic centre lay at the northern margin of the Lothidok Basin (Figs. 1(A) and 5). The final infilling phase of the Lokichar Basin is marked by the presence of volcanic flows, following the propagation of the volcanic centres to the south, into the Napeted Hills area (Fig. 1(A)).

Accumulation of lacustrine source-rock precursors in the Lokichar Basin was terminated by two effects: (1) the development of volcanic centres just north of the Lokichar Basin, and (2) a major structural reorganization of the region in the middle—late Miocene. The southern part of the North Kerio Basin, the Lokichar Basin and the Lothidok Basin all became inactive in the middle Miocene. Active extension switched to the North Lokichar Basin, the northern part of the North Kerio Basin and the Turkana Basin (Morley et al., 1999; Fig. 1). Consequently, new depocenters and new areas of lacustrine sedimentation were established during the late Miocene—Pliocene. No high-quality source rock intervals related to these new depocenters have been identified in outcropping late Miocene—Pliocene deposits in the Napeted Hills or at Lothagam Hill (Fig. 1(A)). However, such negative evidence does not eliminate the possibility of good quality source rocks existing at depth, closer to the basin depocenter, or offshore beneath Lake Turkana. Indeed the Lokichar Basin suggests that such source rocks might occur in the region.

The Lokichar Basin appears to be little affected by inversion structures, which developed elsewhere in Western Turkana during the Plio-Pleistocene (Morley, 1999b). This late inversion occurred after subsidence ceased in the Lokichar Basin during the middle Miocene. Hence hydrocarbon generation and migration occurred before inversion. Since inversion creates new traps and tends to destroy older traps, the late timing of inversion could potentially have destroyed older hydrocarbon accumulations and requires late hydrocarbon generation to fill the inversion structures. From this perspective, it is fortuitous for the petroleum potential of the Lokichar Basin that the effects of inversion are minimal.

6. Conclusions. Implications for exploration

The Lokichar Basin contains lacustrine shales, which exhibit many of the characteristic features of source rocks developed in continental rifts. The highest quality source rock is the Lokhone Shale Member which accumulated in freshwater, and is a Type I algal-prone source with an average TOC of 2.4% (based upon well-log calculations and sidewall cores) and containing intervals with up to 17% TOC (Hung, 1996; Morley et al., 1999). Towards the boundary fault, the Lokhone Shale Member probably attains a maximum thickness of 1 km. The deeper Loperot Shale Member has only marginal source potential, with an average TOC of 1.2% from well-log calculation. Only one thin interval at ca. 2500 m yielded high TOCs of around 2%. The poorer quality of the lower potential source interval, while partly due to higher maturity, is thought to be largely a result of the basin evolution. The Loperot Shale Member was restricted to the Lokichar Basin. Hence the lake was relatively small (50-km long by 20-km wide), and the algal OM subject to dilution by the influx of siliciclastics and terrestrial plant material, as shown by palynofacies analysis (Table 2). The Lokhone Shale Member was deposited during a time when displacement on the boundary fault system was greater, and adjacent basins had also been established. Subsidence occurred over a broad area and exceeded sediment supply, thus favouring the establishment of a deep, anoxic waterbody, possibly similar to modern Lakes Tanganyika or Malawi. Palaeoclimatic conditions characterized by precipitation amounts that may have been as much as five times higher than today (modern mean annual precipitation is ca. 200 mm) (Roche, 2002; Vincens, pers. comm.) also contributed to the development of a large, deep freshwater body that extended into adjacent half-graben basins, and was favourable to the development of
Pediastrum, Botryococcus and other phytoplankton blooms. The highest concentrations of algal material accumulated in sediment-starved parts of the basin. Regional structure, through its control of regional drainage networks, was probably partly responsible for sediment starvation, but dense vegetation cover (humid montane forest) in the watershed, may also have reduced sediment input to the basin, and thus dilution of the autochthonous OM.

The Lokichar Basin source rocks are important in demonstrating the potential for some East African Rift basins to have generated billions of barrels of oil from geographically restricted, but thick lacustrine shale deposits, analogous to the older but extremely prolific rift basins of southern Sudan and Chad (Genik, 1993; Mohamed, Pearson, Ashcroft, Iliffe, & Whiteman, 1999; Schull, 1988). In such cases, tectonic control on source-rock distribution is a major key, but prevailing palaeoclimatic conditions during the development of the Lokichar Basin also clearly played a key role in the generation of such an oil potential.

Acknowledgements

This study represents part of a cooperative program conducted with the National Oil Corporation of Kenya (NOCK), and funded by the 3D-3G Project supported by Elf Petroleum Norge AS (grant No. 2231-01 ELF to J.-J. Tiercelin) as well as grants from SUCRI-2E and UMR CNRS 6538 'Domaines Océaniques', European Institute of Marine Studies, University of Western Brittany. Research authorization was provided by the Office of the President of the Republic of Kenya. Special thanks to Institut Français du Pétrole (IFP) for their help in the RockEval procedure. The authors express their thanks to NOCK Managing Director for permission to publish this work, and to Dr F.M. Mbatau, NOCK Exploration and Production Manager, for scientific, administrative and logistic support. Two anonymous reviewers made a number of helpful suggestions, which helped improve an earlier version of this paper. Special thanks to B. Colêno for patient assistance with illustrations. This is publication No. 150 of the International Decade of East African Lakes (IDEAL) programme.

References


