Source Rock Characteristics, Burial History Reconstruction, and Hydrocarbon Generation Modeling of Late Cretaceous Sediments in the Chad (Bornu) Basin, Northeastern Nigeria*

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Abstract

The Upper Cretaceous Gongila and Fika Formation sediments, which are believed to be the major prospective source rocks in the Chad (Bornu) Basin, were analysed using organic geochemistry and petrology. The total organic carbon (TOC) contents of the sediments range from 0.42 to 4.90%. The samples analysed have vitrinite reflectance in the range of 0.58–1.79% Ro and SRA Tmax in the range of 429–475°C, which indicate that the Gongila and Fika sediments contain immature to late mature organic matter. Moderate oil and gas-generating potential is anticipated from the sediments with fairly high hydrogen indices (150–250 mg HC/g TOC). This is supported by their Py-GC (S_2) pyrograms with n-alkane/alkene doublets extending beyond n-C_{30}. The sediments are dominated by mixed Type III/II and Type III kerogen and are thus considered oil and gas prone (mainly gas). One-dimensional basin modelling was performed to analyse the hydrocarbon generation and expulsion history of the Upper Cretaceous sediments in the Chad (Bornu) Basin based on the reconstruction of the burial and thermal maturity histories. This is to improve our understanding of the of hydrocarbon generation potential of the source rocks. Calibration of the model with measured vitrinite reflectance (Ro) and borehole temperature data reveals that the present-day heat flow in the Chad (Bornu) Basin varies from 55.0 mW/m^2 to 60.0 mW/m^2 and paleo-heat flow value at approximately 68–75 mW/m^2. The source rocks of the Gongila and Fika Formation are presently at a stage of oil, condensates and gas generation with thermal maturity ranging from 0.58% to 1.79% Ro. The modelled burial history also suggest that maximum burial occurred in the late Miocene and that erosion might have been the cause of the thinning of the Tertiary sediments in the present time.

Introduction

There has been renewed interests in the Nigerian part of the Chad Basin (also known as Bornu Basin) in response to the commercial hydrocarbon discovery in the other parts of the rift trend in neighbouring countries of Chad (Doba, Doseo, and Bongor fields), Niger (Termit-Agadem Basin), and Sudan (Muglad Basin), which are genetically related and have the same structural settings (Obaje et al., 2004; Abubakar et al., 2008). These basins constitute parts of a series of rift basins in central and west Africa whose origin is linked to the separation of the African crustal blocks in the Cretaceous as part of the West and Central African Rift System (Genik, 1993; Figure 1).

The poor knowledge of the evolution of the subsurface rocks in the Chad (Bornu) Basin may have been responsible for the unsuccessful exploration attempts within the basin. Although, few reports are available on the organic richness and thermal maturity of the sediments (Obaje et al., 2004; Alalade and Tyson, 2010), detailed organic geochemical investigations on the organic matter quantity and quality, origin of the organic matter as well as the burial and thermal histories of source rocks and the timing of hydrocarbon generation in the framework of the basin evolution are lacking.

This study focuses on the detailed geochemistry of the Upper Cretaceous sediments in Chad (Bornu) Basin, to provide an overview of the organic richness, hydrocarbon generation potential, and level of maturity of the organic matter in the sediments. The results will also provide information on the burial and thermal histories as well as predict the timing of hydrocarbon generation and expulsion of the source rocks. This is aimed at providing further insight into the source rocks of the basin, for the current and future petroleum exploration programme and resource assessment in the basin.

Samples and Methods

Organic geochemical analyses were carried out on a total of 115 cutting samples from five exploratory wells (Kanadi-1, Kemar-1, Kinasar-1 Kuchalli-1, and Tuma-1 Wells) drilled by the Nigerian National Petroleum Corporation in the Chad (Bornu) Basin (Figure 1). The majorly shale samples were collected from Gongila and Fika formations, which have been generally regarded as potential source rocks in the basin (Alalade and Tyson, 2010).

Geochemical Analyses

The Geochemical methods used to evaluate the hydrocarbon potential of the sediments include Rock-Eval type Pyrolysis using Weatherford Source Rock Analyzer-TPH/TOC (SRA) instrument. Parameters measured include TOC, S_1, S_2, S_3, and Tmax. Hydrogen (HI), oxygen (OI), production yield (PY), and production (PI) indexes were calculated. Following pyrolysis, some samples were selected for further geochemical analyses and microscopic examinations. Open system pyrolysis-gas chromatography (Py-GC) was applied to provide compositional and structural characteristics of kerogen. This analysis was performed on isolated kerogen samples using a *Double-Shot Pyrolyzer PY-2020iD* from Frontier Laboratories Ltd. Samples for petrographic examinations were made using standard organic petrographic preparation techniques. Petrographic examinations were carried out under oil immersion in a plane polarized reflected light, using a LEICA DM 6000M microscope and LEICA CTR6000 photometry system equipped with fluorescence illuminators. 25 samples were subsequently selected for Soxhlet extraction of bitumen and followed by molecular organic geochemical analysis (GC). Approximately 25-30 g of the crushed samples was extracted in a Soxhlet apparatus for 72 h, using an azeotropic mixture of dichloromethane (DCM) and methanol (93:7). Bitumen extracts were fractionated using liquid column chromatography, into saturated hydrocarbon, aromatic hydrocarbon and NSO-compound fractions. The saturated fractions were further analysed using gas chromatography (GC).

1-D Basin Models

The reconstruction of the burial and thermal histories was modelled using PetroMod 1-D (version 11.0 SP1) software developed by IES, Aachen, Germany. Major 1-D model input parameters comprise events or formations within the chronostratigraphy, deposition age, present and eroded thicknesses of formations and events, volumetric lithological mixes, kerogen types, and kinetics and further geochemical parameters such as initial %TOC. The modelling results were calibrated with measured vitrinite reflectance and borehole temperatures (BHT) of the five wells in the study area.

Results and Discussion

Source Rock Characteristics

More than 90% of the analysed samples have TOC > 0.5 wt.%. The shale samples also have S_2 pyrolysis yield and HI values in the range of 0.06–2.96 mg HC/g rock and 58–250 mg HC/g TOC, respectively. These values reveal that most of the analysed samples meet the standard of a source with fair hydrocarbon generative potential (Figure 2). Characterization of organic matter type conducted based on whole rock samples using pyrolysis data such as HI, OI, and Tmax values indicates that the organic matter in the shale samples is predominantly Type III kerogen (Figure 2). All of the shale samples have hydrogen indices that can be expected for mainly gas-prone source rocks. The thermal maturity, as indicated by measured Tmax values and vitrinite reflectance data suggests that the top of the Fika Formation is immature to early mature, while the lower section and the whole of Gongila Formation is in the peak to late maturity zone for hydrocarbon generation. This seems to correlate with the biomarker maturity parameters, the carbon preference index (CPI), based on the formula proposed by Peters and Moldowan (1993) and the improved odd: even preference (OEP1) by Scalan and Smith (1970).

The Py-GC pyrograms of the isolated kerogen from shales samples are generally dominated by a homologous series of *n*-alkene/alkane doublets, reaching a maximum chain length of > 30 carbon atoms. The Py-GC pyrograms also display prominent *n*-alkane/*n*-alkene doublets in the low molecular weight end ($<n\text{-}C_{10}$) and high molecular weight end ($>n\text{-}C_{15}$) with some abundant light aromatic compounds such as benzene, toluene, ethylbenzene, xylenes, alicyclic compounds such as naphthalenes, and sulphur compounds, mainly thiophenes. These are indicative of slightly aliphatic- rich with significant aromatic compounds and suggest a mixture of oil and gas generation, but mainly gas. Eglinton et al., (1990) introduced a ternary diagram based on pyrolysate 2,3-dimethylthiophene, o-xylene and C_9:1 (alkane component), which represents the organic sulfur, aromatic and aliphatic structures within the macromolecular organic matter. Furthermore, the selected compounds can be directly related to different kerogen types (I, II, III and II-S). Following this classification, most of the organic matter in the analysed samples comprises a mixed Type III/II to Type III kerogen (Figure 3).

Horsfield (1989) also showed that the distribution of *n*-alkyl chains within kerogen pyrolysates can be directly related to the petroleum type formed from the respective kerogen in nature. The majority of the analysed shale samples fall within the field of low wax paraffinic-naphthenic-aromatic (PNA) oils with a gradual transition into the high wax PNA and paraffinic oil field.

Organic Matter Source Input and Paleodepositional Conditions

Biomarker concentration ratios were used to describe source input and conditions of depositional environment of the analysed samples (Peters et al., 2005; Peters and Moldowan, 1993). The distribution of *n*-alkanes may be indicative of the source input of original organism(s). The chromatograms indicate that the saturated hydrocarbons are dominated by n-C_{12}–n-C_{33} and isoprenoid hydrocarbons (pristane and phytane). The *n*-alkane patterns in the analysed samples show both unimodal and bimodal distributions and a clear dominance of short-chain/low to medium molecular weight (n-C_{13}–n-C_{20}) versus long-chain n-alkanes (n-C_{27}–n-C_{31}) in most of the samples. This suggests that the organic matter likely originated from phytoplankton and algae deposited under marine conditions with significant inputs from terrestrial higher plants (Peters et al., 2005).

Pristane/phytane (Pr/Ph) ratio has been widely used to assess the redox condition during sediment accumulation (Didyk et al., 1978). Low Pr/Ph ratio values (< 0.8) indicate anoxic conditions, commonly carbonate or hypersaline environments and high values (> 3.0) usually typify oxic conditions often associated with terrigenous organic matter input (Peters et al., 2005). The Pr/Ph ratios of the selected shale samples range from 0.64 to 1.35, which suggests that the redox conditions during the sedimentation of the organic matter are mainly dysoxic. This is supported by the cross-plots of pristane/phytane ratio versus CPI and pristane/n-C_{17} versus phytane/n-C_{18} which suggest that the organic matter in the investigated samples was derived mainly from mixed marine and terrigenous materials deposited under dysoxic conditions (Peters et al., 2005; van Koeverden et al., 2011; Figure 4 and Figure 5). Carbon preference index (CPI) of *n*-alkanes between n-C_{25} and n-C_{35} also indicates a mixed input of marine and terrigenous organic matter deposited under dysoxic conditions.

Basin Modelling

One-dimensional basin modelling was performed to reconstruct the burial/thermal maturity histories of the basin as well as predict the timing of hydrocarbon generation of the source rocks (Figure 6). Calibration of the model with measured vitrinite reflectance (Ro) and borehole temperature data indicate that the present-day heat flow in the Chad (Bornu) Basin varies from 55.0 mW/m_3 to 60 mW/m_3 and the paleo-heat flow fall range from 68–75 mW/m^3. The high heat flow might be due to the West and Central African rifting in the Cretaceous during which the basin was formed, the Maastrichtian tectonic episode (tensional deformation) which restructured the basin and which continued until the end of the Cretaceous and the Maastrichtian magmatism in which volcanic plugs intruded some of the Cretaceous sediments (Allen and Allen, 1990). The modelling results also indicate that maximum burial occurred in the late Miocene and that erosion might have been the cause of the thinning of the Tertiary sediments in the present time. Highest subsidence also occurred around 56.0 Ma. The source rocks of Gongila and Fika formations are presently at a stage of oil and dry gas generation with maturity from 0.58 to 1.79% Ro. Hydrocarbon generation in the Gongila and Fika formation sediments began from about 83.5 Ma.

Conclusions

From this study, the following conclusions can be drawn:

- The analysed samples are dominated by mixture of Type III/II and Type III kerogens
- The shales samples have fair source rock generative potential.
- The organic matter within the sediments was deposited under dysoxic environmental conditions.
- The source input of the organic matter is mainly marine algal and bacterial organic materials with significant input from terrigenous materials.
- Most of the organic matter from the Fika Formation generated low wax paraffinic naphthenic aromatic oil and gas, while the OM in the underlying Gongila Formation generated mostly gas and condensate.
- 1D basin modelling indicate that the present-day heat flow in the Chad (Bornu) Basin varies from 55.0 mW/m^3 to 60 mW/m^3 and the paleo-heat flow fall range from 68–75 mW/m^3.
- The modelling results also suggest that maximum burial occurred in the late Miocene and that erosion might have been the cause of the thinning of the Tertiary sediments in the present time.
- The source rocks of Gongila and Fika formations are presently at a stage of oil and dry gas generation with maturity from 0.58 to 1.79% Ro.
- Hydrocarbon generation in the Gongila and Fika formation sediments began from about 83.5 Ma.

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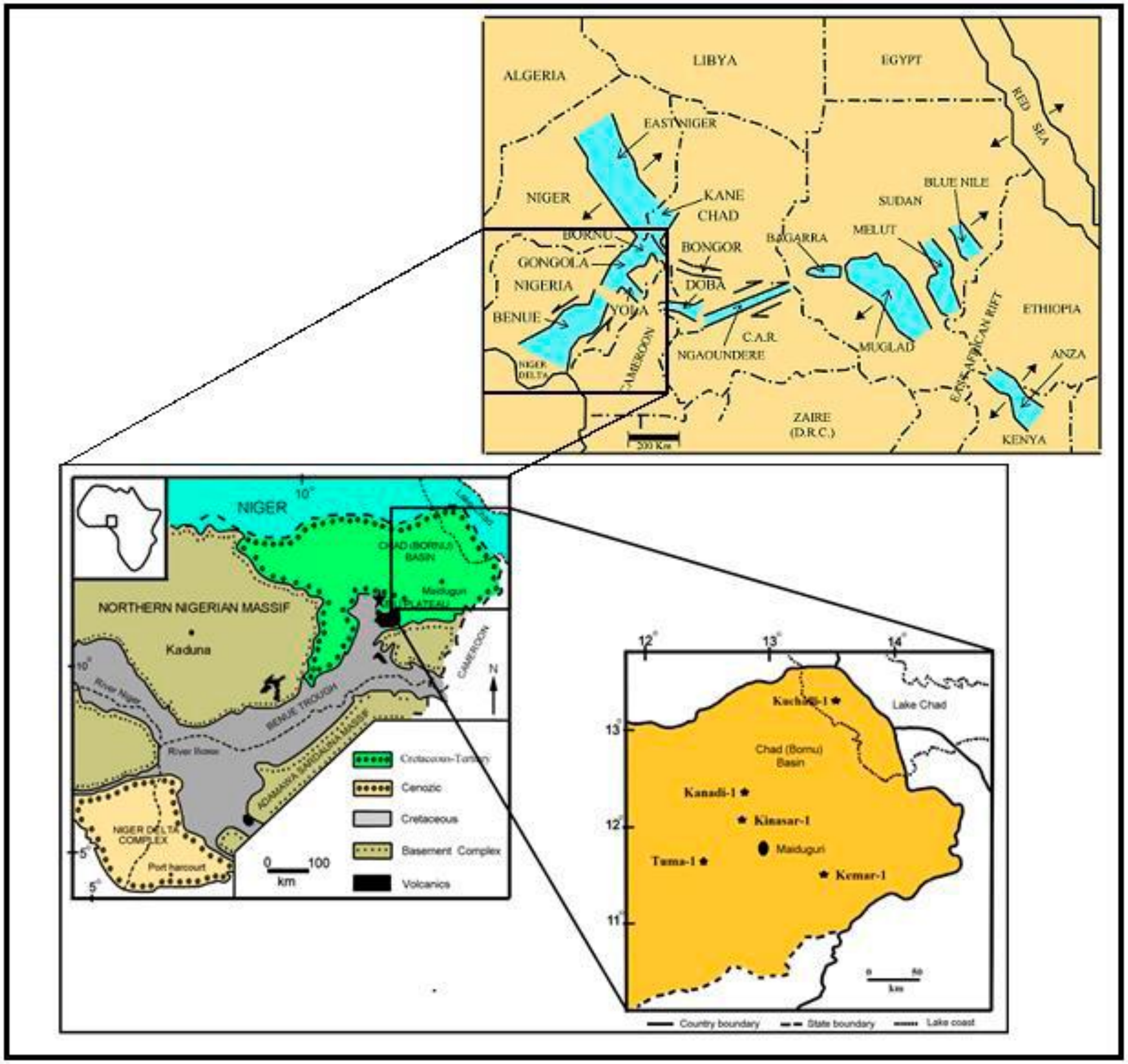

Figure 1. Regional tectonic map of western and central African rifted basins showing the Chad (Bornu) Basin and the studied exploratory wells (after Schull, 1988).

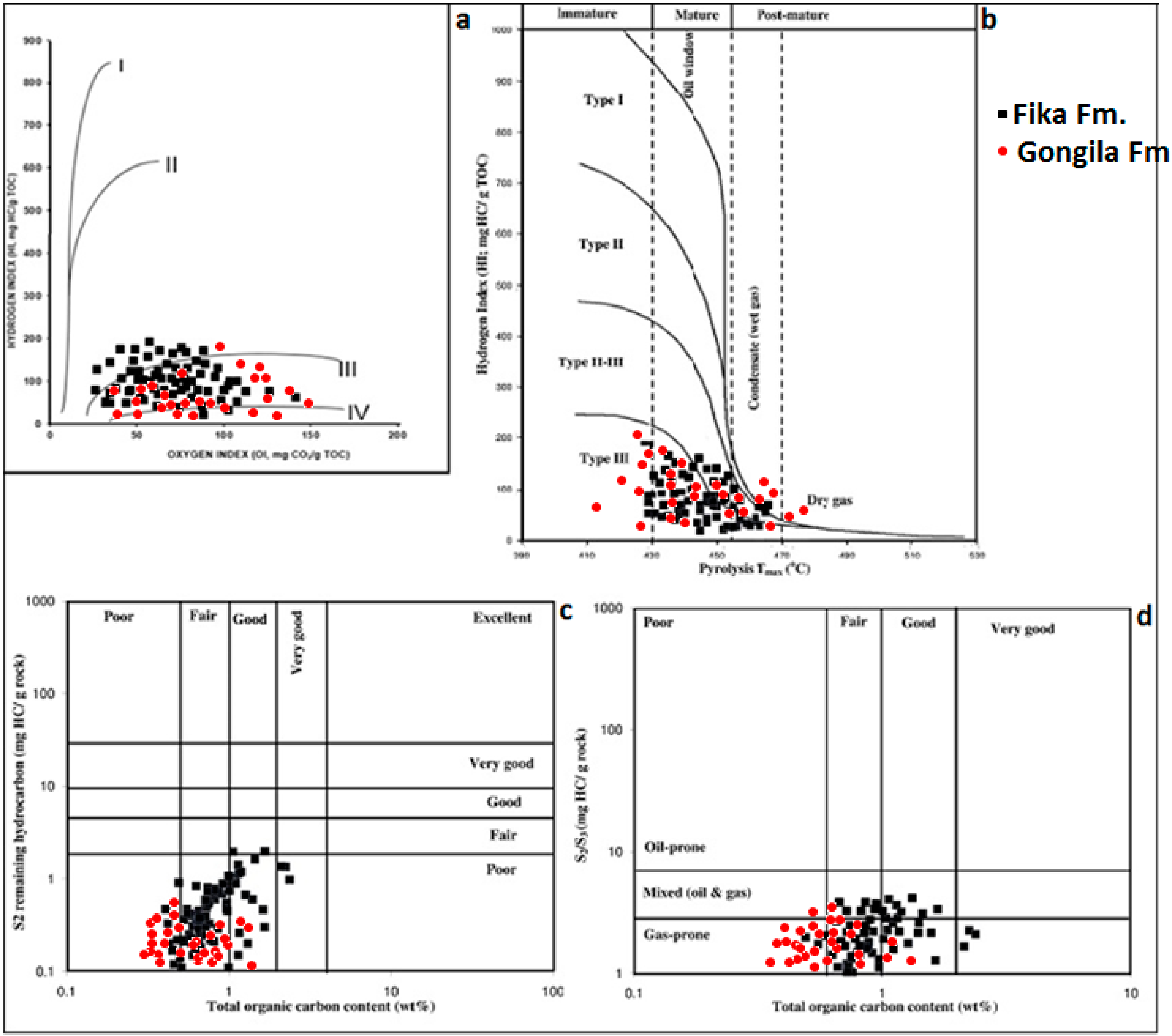

Figure 2. Plots of (a) HI versus OI; (b) HI versus Tmax; (c) S_2 versus TOC; (d) S_2/S_3 versus TOC, showing hydrocarbon generative potential and type of organic matter in Chad (Bornu) Basin sediments.

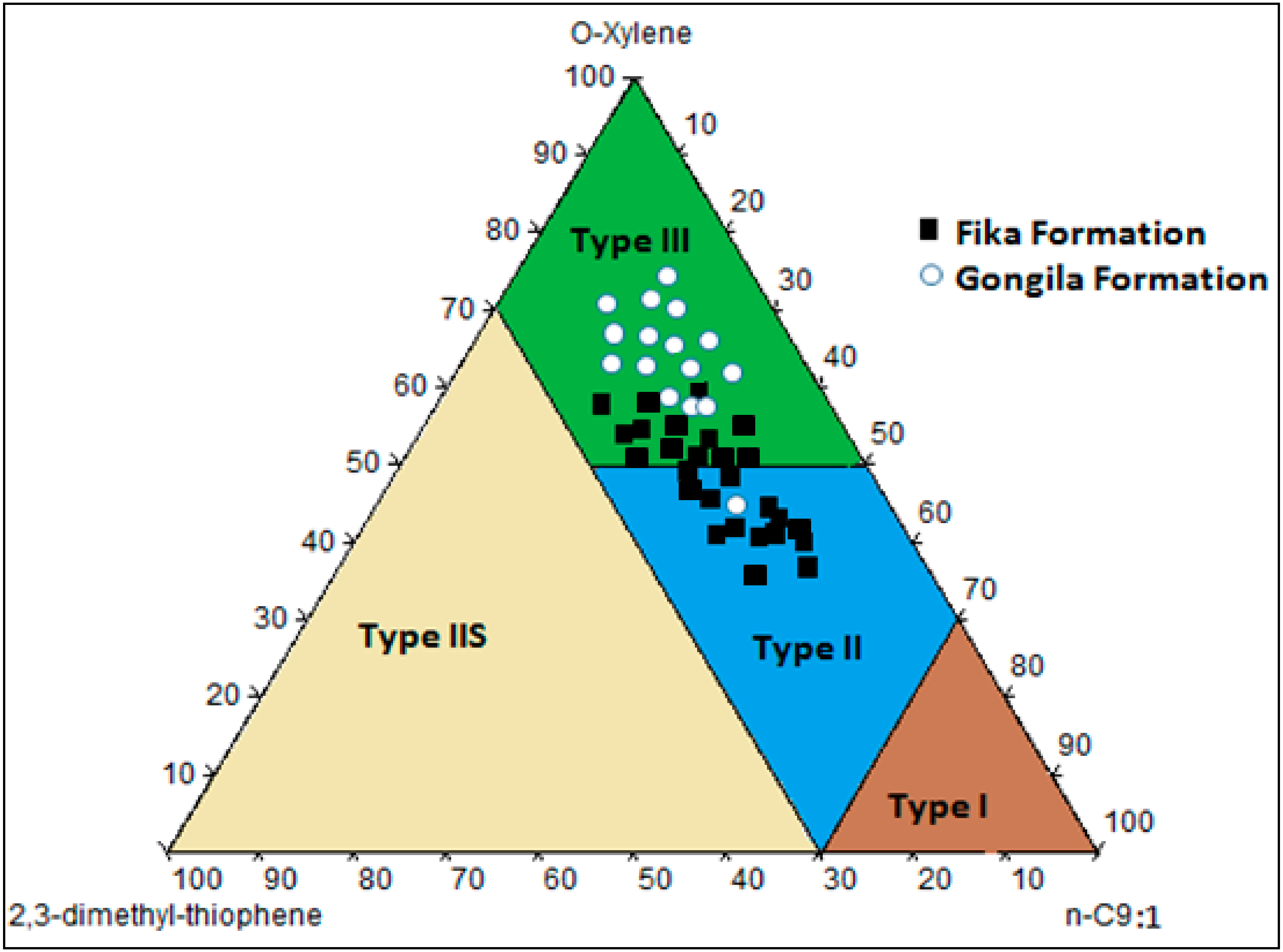

Figure 3. A ternary plot of an aromatic compound (o-xylene), an n-alkane component (C_9), and a sulphur-compound (2,3-dimethylthiophene) identified in the pyrolysates, showing kerogen type classification (adapted from Eglinton et al., 1990; Hartwig et al., 2012).

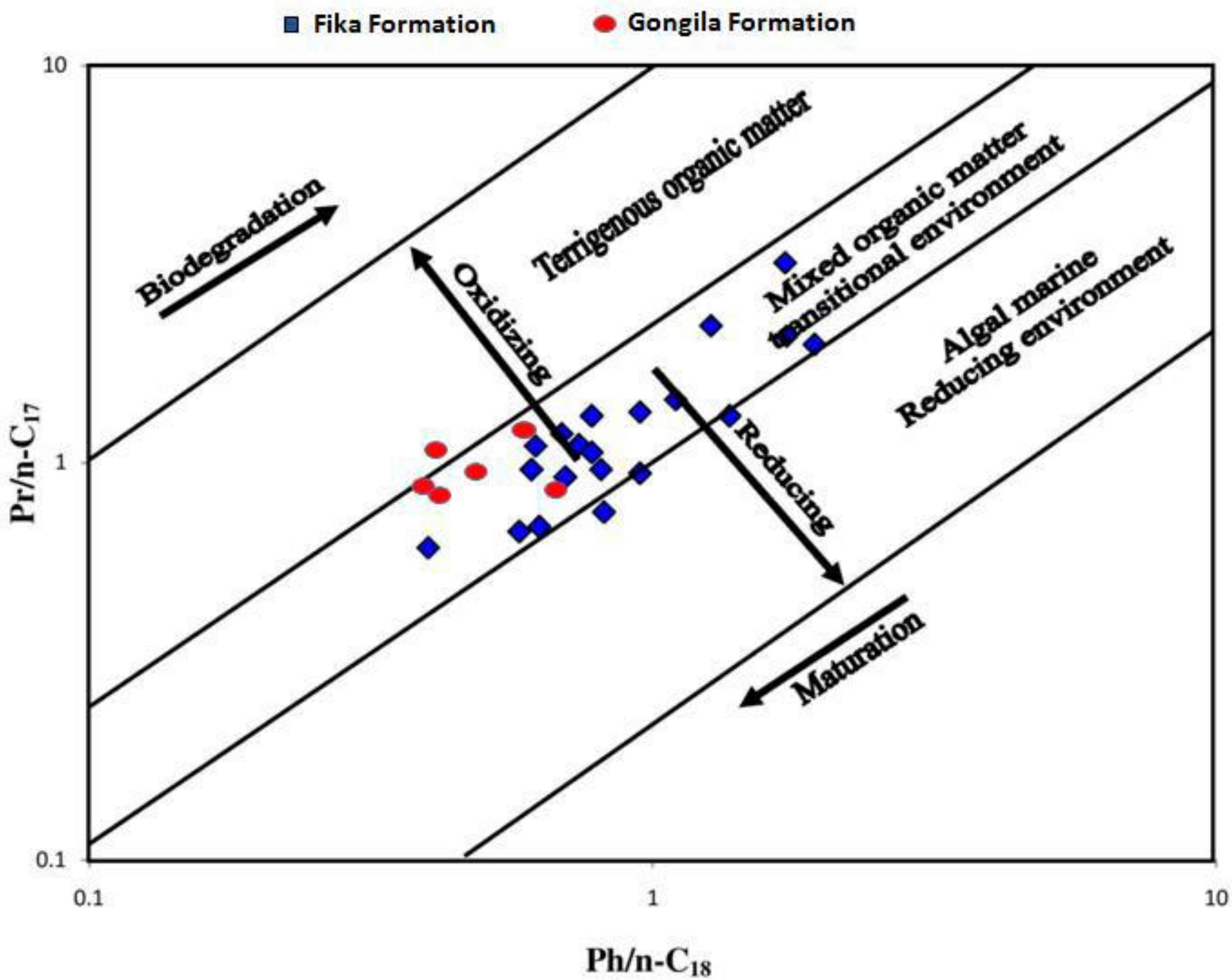

Figure 4. Phytane to n-C_{18} alkane (Ph/n-C_{18}) versus Pristane to n-C_{17} alkane (Pr/n-C_{17}) showing depositional conditions and type of organic matter of Fika and Gongila extracts. (Adapted from van Koeverden et al., 2011).

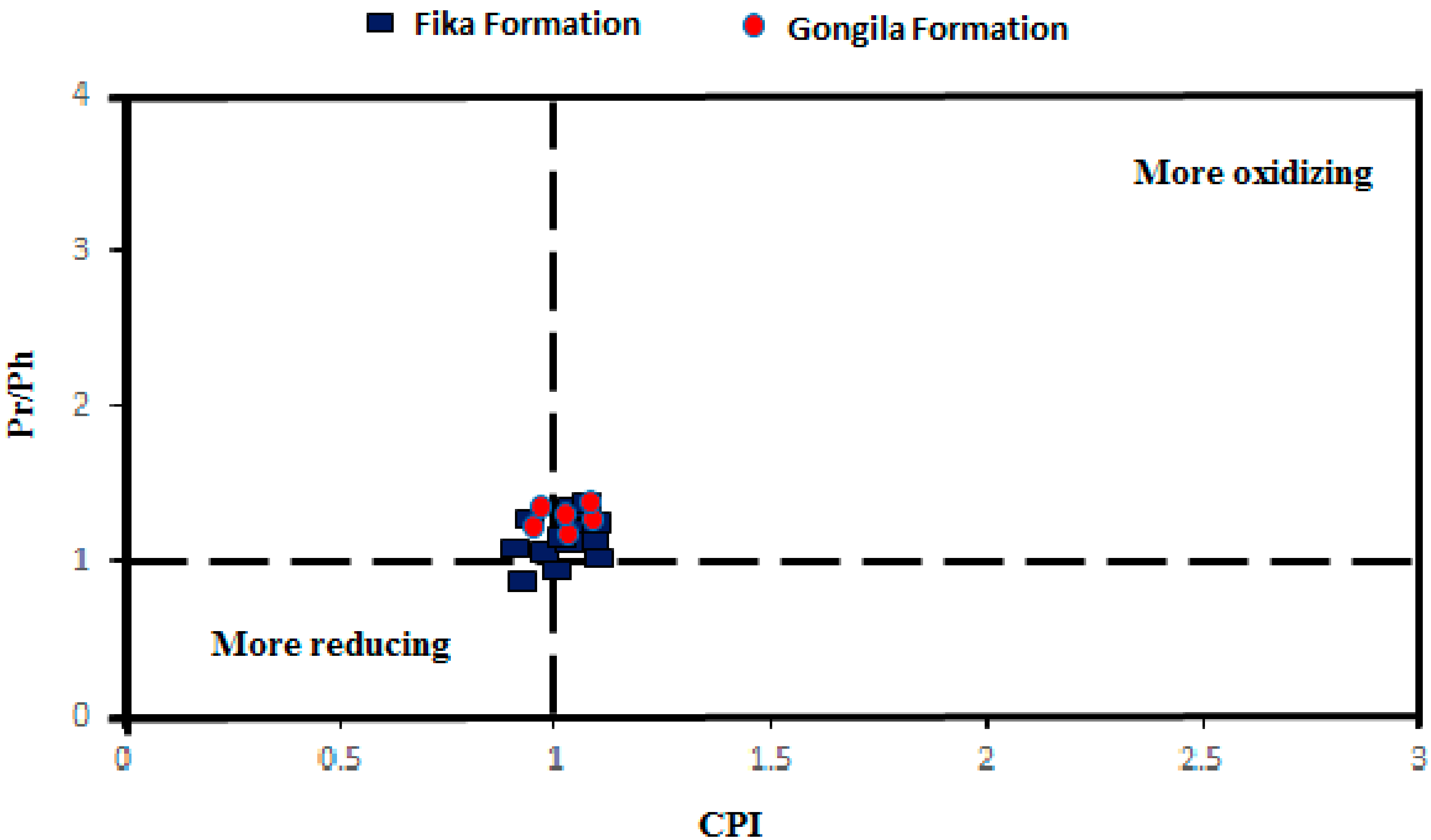

Figure 5. Pristane/phytane versus CPI, indicating the depositional environment conditions of the studied samples. (Adapted from Akinlua et al., 2007).

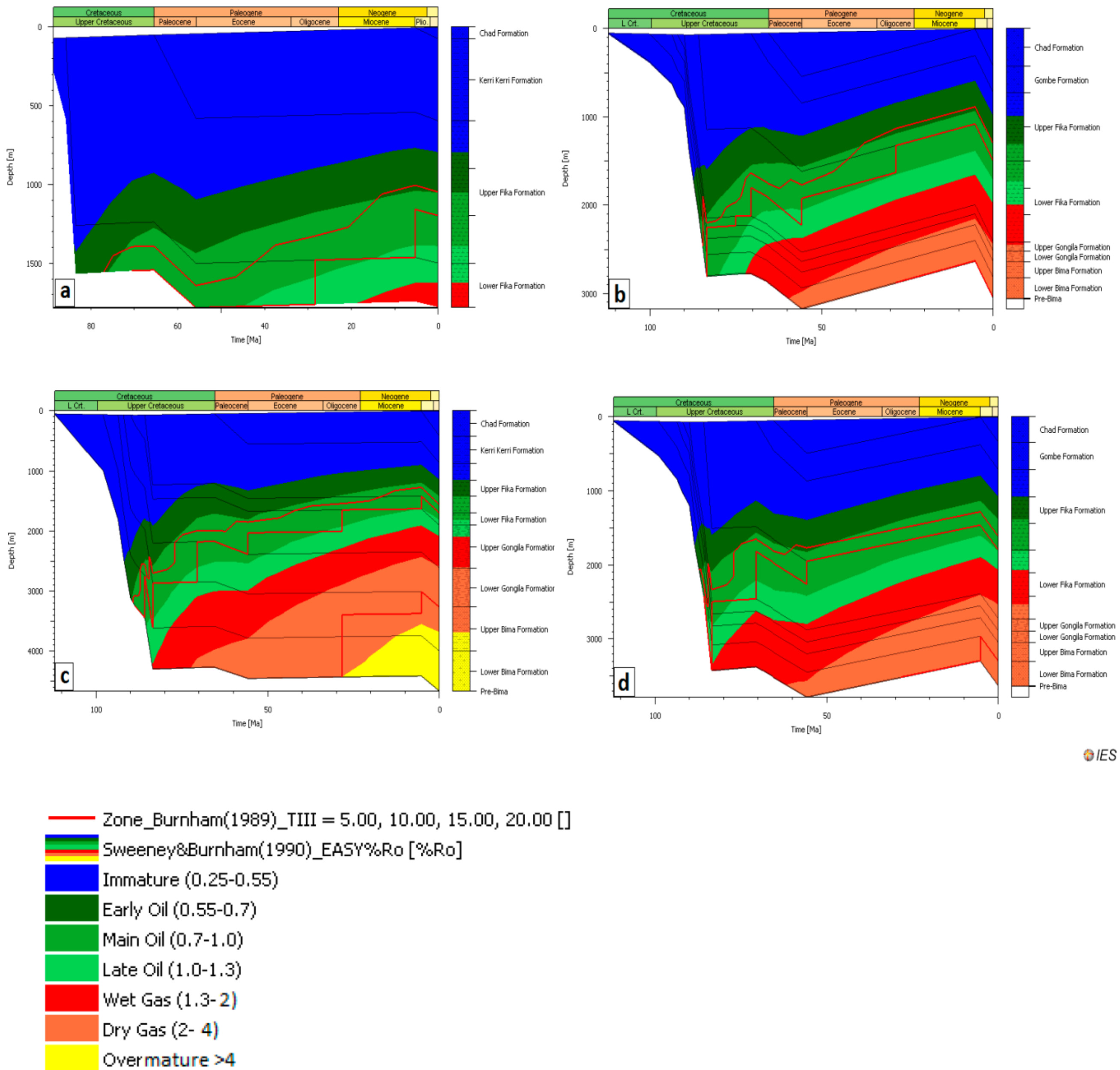

Figure 6. Thermal and maturity history curves showing the positions of the oil window in (a) Kemar-1; (b) Kanadi-1; (c) Kinasar-1; and (d) Tuma-1 wells.