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Molecular Organic Geochemistry of Crude Oils from the Albertine Graben, Uganda: Possible Implications on the Expulsion of the Oils from the Source Rocks

Joshua Lukaye[1], Godfrey Etano[1] and Geoffrey Abbott[2]

1. Directorate of Petroleum-Uganda, Plot 21-29 Johnstone Road, Entebbe 256, Uganda

2. School of Civil Engineering and Geosciences, Newcastle University, UK

Abstract: Twelve representative crude oil samples recovered from six oil fields in the Albertine Graben, Uganda were chosen for this study. The study aimed to understand the genetic relationships between the oils, the inferred depositional environment of the source rocks, maturity of the crude oils, and to gain some insight on the expulsion of the oils from source rocks. The work involved geochemical bulk analysis (asphaltene and liquid chromatographic separations), GC-FID (gas chromatography with a flame ionization detector), and GC-MS (gas chromatography-mass spectrometry) of saturate and aromatic fractions. Bulk analysis shows that the oils are dominated by saturate hydrocarbon fractions (48.7%-62.0%) and are highly waxy (35-56.2 wt%) with low sulfur content (≤ 0.1 wt%). The high saturate hydrocarbon and high wax contents are probably due to organic matter input from land plants and/or long-chain alkanes from fresh water algae in lacustrine systems. The low sulfur contents alongside the high wax abundances are consistent with clastic-dominated source rock facies deposited in a non-stratified lacustrine environment. Data from GC-FID and GC-MS analyses such as *n*-alkane distributions, pristane/phytane ratios, biomarker terpane and sterane, dibenzothiophene and phenanthrene parameters show that the oils belong to a single family and were derived from a clastic predominantly algal source rock deposited under suboxic conditions in a non-stratified freshwater to brackish water lacustrine environment. The data further show that the oils have a very narrow range of maturities and are generated in the peak oil window. The observed narrow range of maturities and inferred lacustrine depositional setting for the source rocks suggest that the kerogen responsible for the generation of the oils is likely to be predominantly type-1 known to display narrow activation energies. This in turn implies that the expulsion of the oil from the source rock occurred as a quick single event hence, the filling of reservoirs in the Albertine Graben probably did not involve late stage expulsion and multiple charges of oil.

Key words: Uganda, Albertine Graben, crude oils, *n*-alkanes, homohopanes, steranes, aromatic hydrocarbons, source facies, maturity, oil family, and oil expulsion.

1. Introduction

Understanding the petroleum systems of a basin being explored is one of the key issues in petroleum exploration. Such an understanding can be achieved through a dedicated analysis of potential source rocks penetrated by the wells alongside accurate recognition, categorization and comparison of oil accumulations. This in turn enables appreciation of the pattern and stratigraphic distribution of the source rocks contributing to the oil systems of the area hence, a key exploration tool in undrilled prospects. Thus, one of the key tools in petroleum exploration useful in establishing the source rocks responsible for the oil systems of any given area is the geochemistry of the oils and source rocks in such an area through bulk and molecular compositional studies. This is so because bulk and molecular composition of oil depends on the type and maturity of the source rock from which it was expelled while the type of source rock reflects the nature of precursor organisms and depositional conditions [1, 2]. The resultant organofacies leads to

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Corresponding author: Joshua Lukaye, B.Sc. (Geology & Chemistry), M.Sc. (Environmental & Petroleum Geochemistry), MPhil (Palynology), research fields: stratigraphy, biostratigraphy and petroleum geochemistry.

characteristic biomarkers and isotopic signals in the expelled oils which therefore provide valuable information on the nature of source rocks [3]. Thus, from bulk geochemical data and biological marker distributions of the oils, characterization and distinction of the source rocks responsible for the expulsion of the oils can be undertaken.

In the study area (the Albertine Graben; Fig. 1), intense geochemical studies on crude oils and potential source rocks are being undertaken to understand the source rocks responsible for the oil accumulations. The outcome will play an important role in the assessment of the Graben's petroleum system(s). The current study is part of these ongoing efforts and focuses on molecular organic geochemistry of crude oils collected from 6 oil fields within the Graben (Fig. 1). It aims to investigate the characterization of the oils, evaluate their geochemical relationships, and determine their source maturity and depositional environments. The ultimate goal is to characterize and distinguish the source rocks responsible for the expulsion of the accumulated hydrocarbons and also gain clues on the oil expulsion process. The outcome will in future work be correlated with similar data from source extracts to confirm the source rocks responsible for the oils and therefore get a better understanding of the pattern and stratigraphic distribution of the source rocks contributing to the Albertine Graben's oil systems.

2. Previous Work

Occurrence of natural hydrocarbons in the Albertine Graben was first documented by Wayland (1925) [4] in form of oil seeps. There are however very limited published studies on the oils and source rocks from the Graben. Dou et al. [5] are among the pioneer work on the geochemistry of oils from the Albertine Graben. The study investigated the geochemistry of oil seeps and bituminous sandstones from the Semliki, Northern Lake Albert and Pakwach basins (Fig. 1), and suggested presence of at least two mature source rocks: a terrestrial source rock for oils from the Semliki Basin, and lacustrine source rocks for oils from the Northern Lake Albert and Pakwach basins. Other unpublished studies suggest a mixed algal and terrestrial source

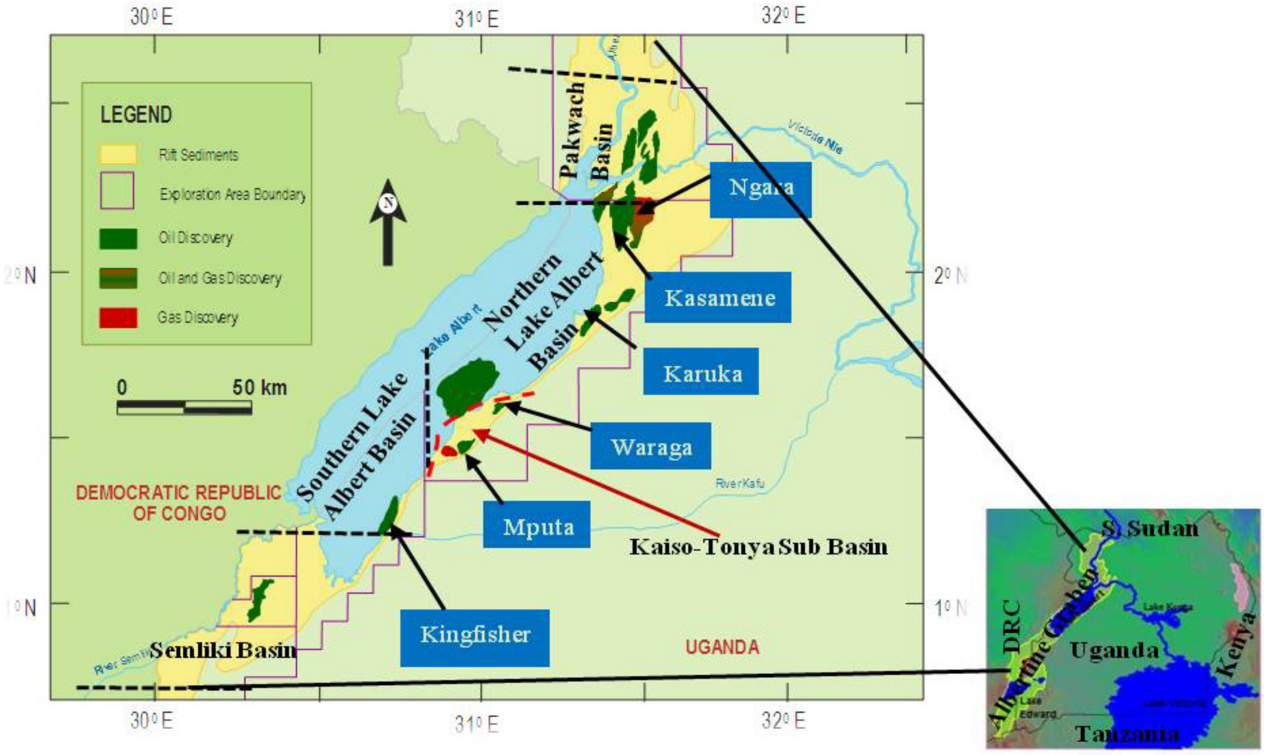

Fig. 1 Location of the Albertine Graben and the oil fields studied.

rock for oil seeps from the Semliki Basin while a fresh water lacustrine source is suggested for oil seeps from the Northern Lake Albert and Pakwach basins. Studies undertaken on crude oils collected from drilled wells are yet to be published save for Lukaye and Okello (2015) [6]. The studies show that crude oils from Northern Lake Albert and Pakwach basins (Fig. 1) are from a mature lacustrine source with limited terrestrial land plant input while crude oils from southern Lake Albert Basin are from fresh water lacustrine source rocks.

In contribution to previous studies, this paper presents a comprehensive organic geochemical study utilizing 12 representative crude oil samples from 6 oil fields within the Albertine Graben (Fig. 1).

3. Samples and Experimental Methods

The oil samples are highly viscous, solid at room temperature. The investigations performed include asphaltene precipitation, oil fractionation by liquid chromatography, GC-FID (gas chromatography with flame ionization detector), and GC-MS (gas chromatography-mass spectrometry). The analyses were conducted in the Geochemistry Laboratory of PEDPD (Petroleum Exploration Development and Production Department)-Uganda, and at the Geochemistry Laboratories of the School of Earth Sciences, Newcastle University, United Kingdom. Data on sulfur contents were acquired from an independent study earlier undertaken by PEDPD.

3.1 Asphaltenes Precipitation

The oils were first toped for 24 hours at 60 °C. Thereafter, asphaltenes were separated by adding pentane to the oil in centrifuge tubes (40:1 w/w) secured by Teflon lined caps. To promote dissolution of the oils in pentane, the bottom of centrifuge tubes were immersed in an ultrasonic bath. The solution was then transferred into a refrigerator and left for 15 hours at 10 °C to facilitate asphaltene precipitation. The tubes were thereafter removed from the refrigerator, centrifuged at 2,000 rpm (5 min) and decanted using transfer pipettes. The asphaltene precipitates were then washed by rinsing in pentane and dried at 40 °C. The deasphalted fractions of the crude oils were separated into saturate, aromatic and NSO fractions using liquid chromatography as described below.

3.2 Hydrocarbon Separation by Liquid Chromatography

Briefly, samples were separated into aliphatic, aromatic, and polar fraction (resins and asphaltenes) using liquid chromatography procedure. Silica gel (100-200 mesh activated at 100 °C overnight) was used as the stationary phase while the mobile phases were n-hexane for saturate fraction, toluene for aromatic fraction, and methanol for the NSO fraction. The saturate and aromatic hydrocarbon fractions separated were analyzed by Agilent technologies GC (gas chromatography), and GC–MS (GC–mass spectrometry).

3.3 Gas Chromatography with a GC-FID (Flame Ionization Detector)

GC was performed on the saturated hydrocarbon fractions using a Hewlett-Packard 5890 Series II GC-FID (gas chromatograph with a flame ionization detector) equipped with a fused silica capillary column (30 m × 0.25 mm i.d) coated with 0.25 um dimethyl poly-siloxane (HP-5 phase). This aimed specifically to obtain the n-alkane and isoprenoid data, and also to determine sample concentration and complexity before GC–MS analysis. The GC injector and FID temperature were set at 280 °C and 310 °C respectively. The sample (1 uL) in DCM was injected by an HP6890/Thermo AS3000 auto sampler in splitless mode. The GC oven was initially set at 50 °C for 2 min to allow the solvent peak to elute. Thereafter, a temperature ramp program was ran from 50-300 °C at 5 °C/min and held at final temperature (300 °C) for 20 minutes, using hydrogen as the carrier gas (flow 1 mL/min, pressure of 50 kPa, split at 30 mL/min). The total run time was 74 minutes. The acquired data were stored on an Atlas laboratory data system on M:\intrument drive to perform data processing and printing. In order to identify each peak from the GC analysis, the samples were later run on a GC-MS instrument in SIM mode to get the mass spectrum.

3.4 GC-MS (Gas Chromatography-Mass Spectrometry)

GC-MS analyses of the aliphatic and aromatic hydrocarbon fractions were performed on an Agilent 7890A GC split/split less injector (280 °C) linked to an Agilent 5975C MSD (electron voltage 70 eV, source temperature 230 °C, quad temperature 150 °C multiplier voltage 1,800 V, interface temperature 310 °C). The acquisition was controlled by an HP Compaq computer using a ChemStation software, initially in full scan mode (50-600 amu/sec) or in selected ion mode (30 ions 0.7 cps 35 ms dwell) for greater sensitivity. The sample (1 uL) in Hexane/DCM was injected by an Agilent 7683B auto sampler and the split opened after 1 minute. Separation was performed on an Agilent fused silica capillary column (30 m × 0.25 mm i.d) coated with 0.25 um dimethyl polysiloxane (HP-5) phase. The GC was temperature programmed from 50-310 °C at 5 °C/min and held at final temperature for 10 minutes with Helium as the carrier gas (flow rate of 1 mL/min, initial pressure of 50 kPa, split at 30 mL/min). The acquired data were stored on a DVD for later processing, integration and printing. The SIM ions monitored during the analysis were summarized in a tabula form. The ions were specifically chosen to monitor the key compounds used in maturation and facies-correlation analyses.

4. Results and Discussion

4.1 Bulk Properties of the Crude Oils

The bulk compositional data for the oils are given in Table 1. The oils display high wax and low sulfur contents (sulfur ≤ 0.1%) consistent with clastic-dominated source rock facies deposited in a non-stratified lacustrine environment [7, 8]. The oils are also characterized by high abundances of saturate and aromatic components relative to NSO components indicating lack or minimal biodegradation; ideally, biodegradation process increases NSOs components in oils [8]. The high saturate hydrocarbon (48.7-62.0 wt%) and wax (35-56.2 wt%) contents are probably indicative of organic matter input from land plant waxes and/or long chain alkanes from fresh water algae in lacustrine systems. Similar compositions are displayed by lacustrine crude oils of the Melut and Muglad Basins, Sudan [9, 10].

Table 1 Bulk organic geochemical properties of the studied crude oils from the Albertine Graben.

Oil field	Sample ID	Bulk property (wt%)					
		Saturates	Aromatics	NSO	Asph.	Est. wax	Sulfur
Kingfisher	G1	62.0	22.2	7.5	7.0	35.0	0.10
	G2	60.1	23.2	7.8	7.3	56.0	
Mputa	G3	60.2	24.0	6.1	6.8	56.2	0.07
	G4	58.2	25.0	6.0	6.6	50.0	
Waraga	G5	60.4	22.7	7.2	6.1	51.7	0.06
	G6	59.0	22.2	8.4	6.8	49.3	
Karuka	G7	54.9	29.0	9.9	3.5	48.3	0.09
	G8	56.1	29.0	8.0	2.4	51.0	
Kasemene	G9	48.7	35.5	9.4	3.8	55.1	0.09
	G10	53.0	33.1	9.0	3.1	50.3	
Ngara	G11	58.4	25.5	9.1	3.8	49.1	0.08
	G12	57.2	25.9	8.9	4.1	54.3	

Key: Asph = Asphaltenes; Est. wax = estimated waxiness = $\Sigma(n\text{-}C_{21}\text{-}nC_{31})/\Sigma(n\text{-}C_{15}\text{-}nC_{20})$.

4.2 Crude Oil Biomarker Characteristics

4.2.1 n-Alkane and Acyclic Isoprenoid Alkanes

The gas chromatograms of the saturate hydrocarbon fractions of the studied oils display predominantly unimodal n-alkanes distributions dominated by compounds in the range $n\mathrm{C}_{12}$-$n\mathrm{C}_{33}$ (Fig. 2) with moderate CPI values that range 1.09-1.19 consistent with derivation from a mixed algal and terrestrial organic matter [11, 12] due to the abundance of both the light and heavy carbon numbers. The observed slight variations in the *n*-alkane distributions in the oils could be due to minor facies variations within the source rock where near shore environments may have received slightly more terrestrial organic material relative to those in the depocenter of the lake.

The pristine/phytane (Pr/Ph) ratios of the oils range from 2.69 to 3.21 (Table 2) consistent with suboxic depositional conditions for the source rocks [12, 13]. It should however be noted that there is a possibility of multiple sources of these isoprenoids. For instance, archaebacterial lipids have been recently proposed as another source of phytane [14] while tocopherol as another source for pristine [15]. The oils also display low Pr/n-C_{17} and Ph/n-C_{18} ratios (Table 2) suggesting

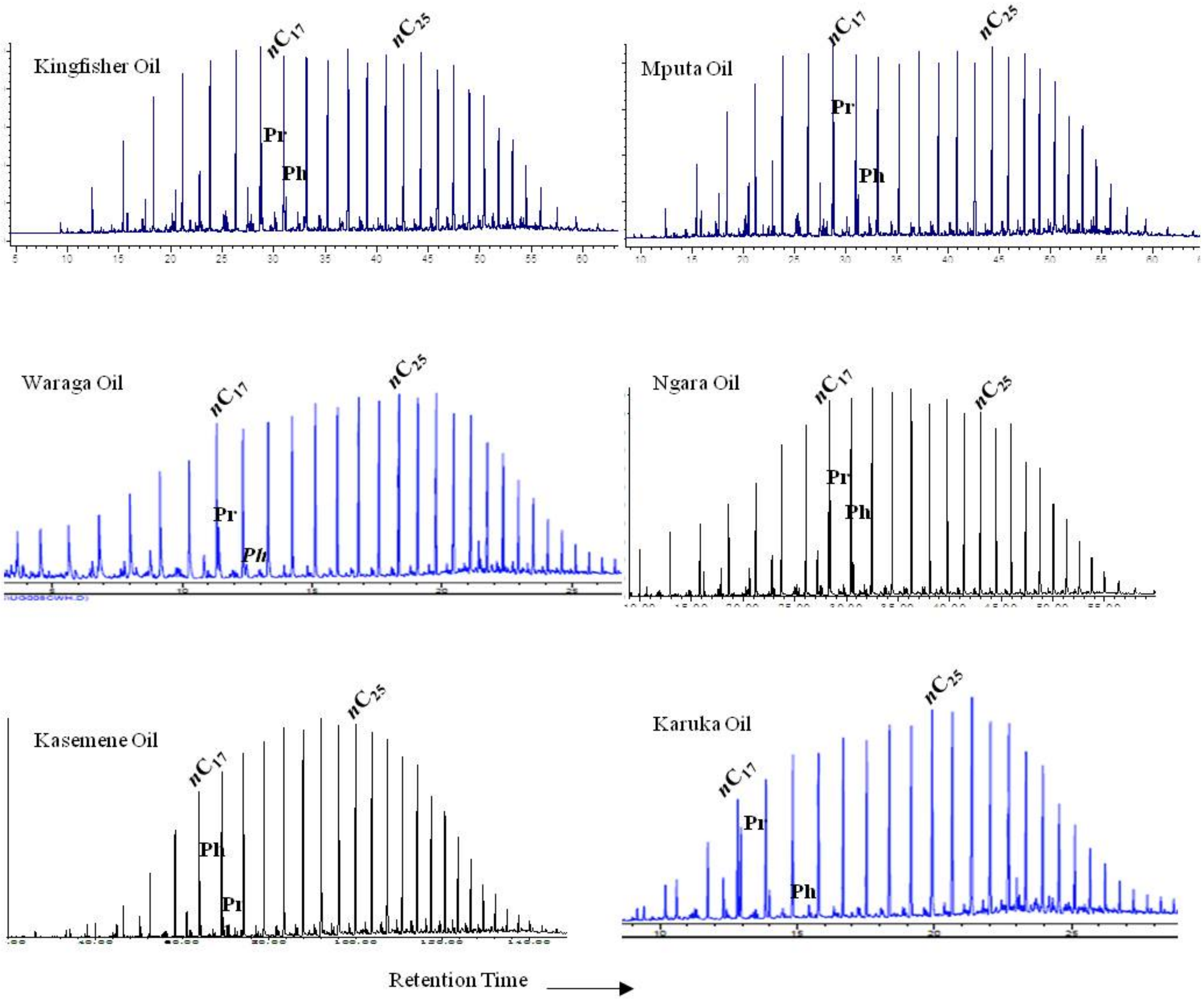

Fig. 2 Distribution of n-alkanes, pristane and phytane in crude oils from the Albertine Graben. Pr = Pristane, Ph = Phytane.

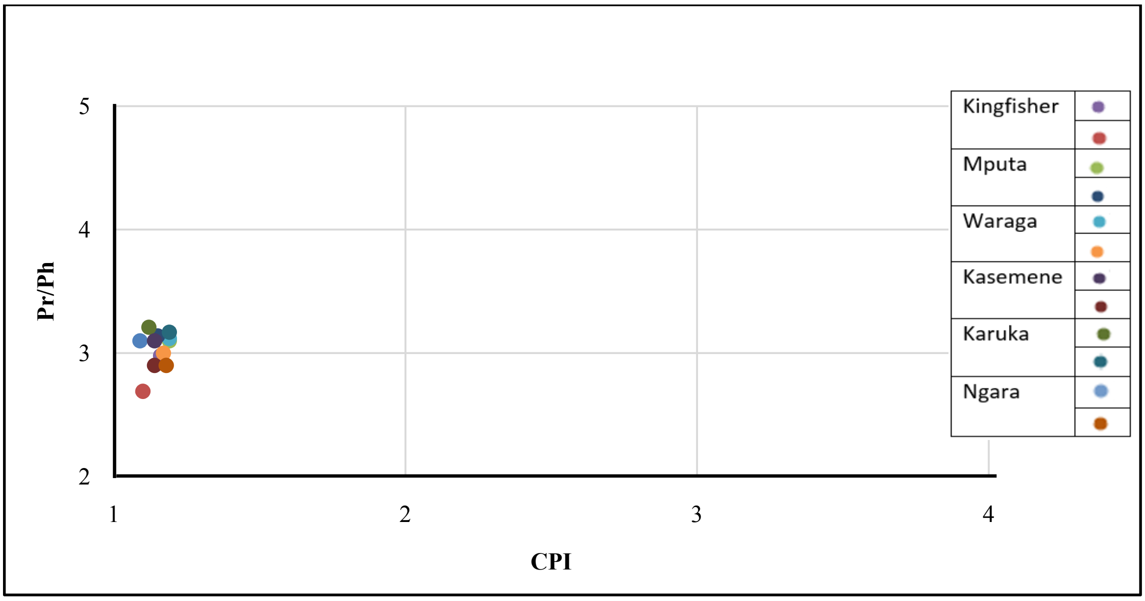

Fig. 3 **Cross-plot of Pr/Ph ratios versus CPI for the analyzed crude oils showing a similarity in the organic source facies of the oils.**

high maturity due to the shift in *n*-alkane distribution from heavy to light components in the final stage of catagenesis [16]. GC data generally show a close similarity in the oils from the 6 oil fields. A cross plot of Pr/Ph ratio and CPI in Fig. 3 indeed shows a similarity in the organic source facies of the oils. On the basis of GC data therefore, the oils have been suggested to be related and to have undergone similar histories.

4.2.2 Triterpane and Sterane Distributions

The oils were analyzed for tricyclic and tetracyclic terpanes (*m*/*z* 191), regular and rearranged hopanes (*m*/*z* 191), steranes (*m*/*z* 217, 218, 259) and other compounds such as gammacerane (*m*/*z* 191). These compounds belong to the most important petroleum hydrocarbons that retain the characteristic structure of the original biological compounds. Fig. 4 below shows the distribution and relative abundances of triterpanes in the studied oils as obtained from the *m*/*z* 191 ion chromatogram. Fig. 5 shows the hopane part of the *m*/*z* 191 ion chromatogram of the oils. Tables 2 and 3 list the parameters obtained from selected biomarker distributions.

Pentacyclic terpanes (hopanes) extend to C_{35} hopanes in all the oils and are dominated by C_{30} αβ hopanes (Figs. 4 and 5). The high abundance of C_{30} αβ hopanes relative to C_{29} norhopane, 17α (H)-trisnorhopane (Tm) suggests derivation from clastic source rocks [8, 17]. Homohopanes are dominated by the C_{31} αβ hopane and decrease regularly from the C_{31} to C_{35} αβ hopane in the order $C_{31} > C_{32} > C_{33} > C_{34} > C_{35}$ αβ hopane (Figs. 4 and 5). Such a declining pattern of homohopanes is common in clastic freshwater environments as opposed to carbonate or evaporate source rocks which often have pronounced C_{35} αβ hopane contents [18]. The oils are also characterized by high diasterane abundances (diasterane to sterane ratio 1.04-1.26) and low abundances of C_{24} tetracyclic terpanes which in conjunction with the high abundance 18α (H)-22, 29, 30-trisnorneohopane (Ts) relative to the regular 22, 29, 30-trisnorhopane provide further corroborating evidence for derivation from a clastic source rock in a sub-oxic environment [19, 20].

The oils also display low homohopane indices (0.04-0.07; Table 2) consistent with source rock deposition in an oxic to sub-oxic, low sulphur environment often encountered in non-stratified lacustrine settings [3]. These authors used C_{31}-C_{35} αβ homohopane distribution to evaluate redox conditions

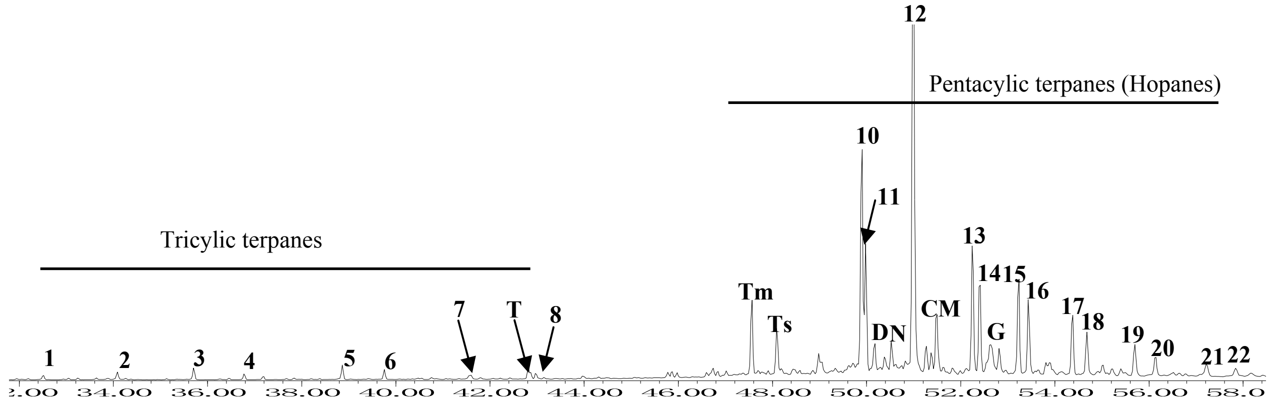

Fig. 4 Representative mass chromatograms of *m/z* 191 of the crude oils showing hopane and tricyclic terpane distributions. Note the low abundances of tricyclic terpanes compared to hopanes and the decreasing pattern of the homohopanes. Compound identifications are provided in Appendix 1.

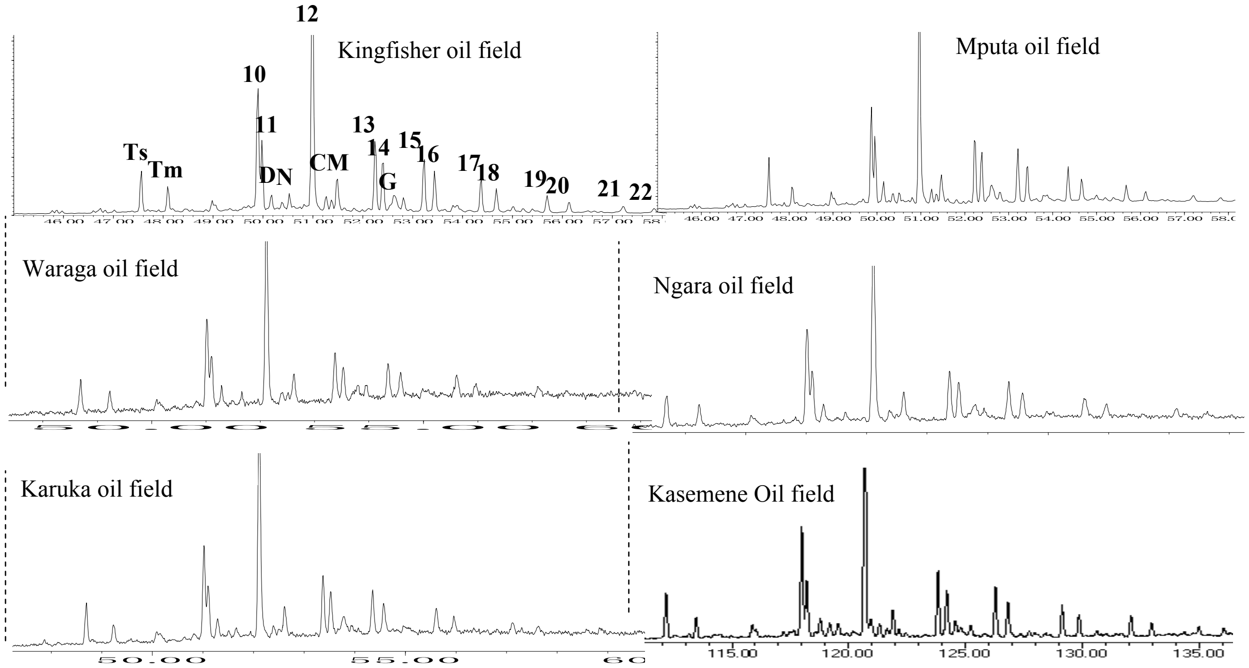

Fig. 5 Representative mass chromatogram of the hopane part of *m/z* 191 of the crude oils. Compound identifications are provided in Appendix 1.

based on homohopane index. They showed that homohopane index is ≥ 0.1 in sulfide-rich and anoxic environments while in oxic environments, it is ≤ 0.06. Collaborative evidence for non-stratified fresh water environment is provided by the low gammacerane abundances in the oils (Figs. 4 and 5) [12].

In all the oils, there are very low abundances of steranes relative to pentacylic terpanes (sterane/hopane ratios of 0.04-0.10; Table 2) consistent with a lacustrine depositional setting [8]. They are also characterized by the presence of C_{30} steranes (C_{30} 4-methyl steranes) known to be abundant in freshwater lacustrine systems [8]. Further evidence for a lacustrine depositional environment is shown by low abundance of C_{31} (22R) homohopanes relative to the C_{30} hopane and the high values of the C_{26}/C_{25} tricyclic terpane ratio (Table 2; [8, 21]). The cross plot (Fig. 6) by Hunges et al. (1995) [22] however shows that the oils straddle the line dividing Zones 3 and 4 implying possible terrestrial contributions. A dedicated comparison of geochemical data for

Table 2 Selected depositional environment and organic matter source specific molecular parameters in the studied crude oils.

Oil field	KF		MPT		WRG		KSM		KRK		NGR	
Sample	G1	G2	G3	G4	G5	G6	G7	G8	G9	G10	G11	G12
HHI	0.06	0.06	0.05	0.05	0.05	0.04	0.05	0.05	0.05	0.06	0.04	0.05
C_{31} 22R/ C_{30}αβH	0.20	0.20	0.19	0.20	0.19	0.19	0.22	0.21	0.21	0.20	0.19	0.21
HI	0.40	0.40	0.30	0.30	0.30	0.40	0.41	0.33	0.35	0.38	0.37	0.33
C_{32}MH/ C_{31}MH	0.44	0.44	0.45	0.42	0.45	0.43	0.53	0.45	0.43	0.46	0.43	0.50
Ga/C_{30}	0.05	0.05	0.04	0.04	0.04	0.03	0.05	0.03	0.05	0.04	0.05	0.03
t/H	0.05	0.05	0.07	0.05	0.06	0.04	0.06	0.07	0.05	0.06	0.06	0.04
Tri Ind	0.37	0.37	0.38	0.37	0.39	0.35	0.37	0.32	0.38	0.37	0.39	0.38
26t/25t	1.68	1.69	1.69	1.70	1.65	1.68	1.78	1.70	1.60	1.66	1.65	1.67
Tetra Ind	0.95	0.96	0.95	0.95	0.95	0.92	0.78	0.81	0.96	0.93	0.94	0.91
29Ts/29H	0.60	0.58	0.59	0.56	0.61	0.48	0.50	0.53	0.54	0.56	0.56	0.57
dH/29Ts	0.28	0.29	0.32	0.27	0.34	0.30	0.31	0.33	0.25	0.23	0.27	0.24
29H/H	0.44	0.44	0.43	0.43	0.43	0.40	0.44	0.41	0.47	0.43	0.46	0.42
Ts/Tm	1.55	1.52	1.44	1.45	1.54	1.54	1.61	1.58	1.49	1.42	1.59	1.50
Ster/Hp	0.05	0.07	0.05	0.06	0.10	0.05	0.06	0.07	0.05	0.04	0.04	0.05
Ster Ind	0.05	0.05	0.04	0.04	0.04	0.03	0.05	0.06	0.05	0.04	0.04	0.03
27βαS/ 27αααS	1.10	1.12	1.14	1.04	1.26	1.20	1.04	1.05	0.96	1.26	1.08	1.20
28αββS/ 27αββS	1.12	1.14	1.21	1.11	1.12	1.30	1.18	1.20	1.12	1.19	1.17	1.15
29αββS/ 27αββS	1.54	1.52	1.50	1.28	1.41	1.50	1.55	1.53	1.39	1.40	1.35	1.38
Pr/ph	3.10	2.69	3.10	2.98	3.12	3.00	3.14	2.90	3.21	3.10	3.17	2.90
Pr/nC_{17}	0.42	0.48	0.51	1.12	0.43	0.50	0.43	0.41	0.79	0.62	0.61	0.65
Ph/nC_{18}	0.20	0.18	0.16	0.36	0.14	0.13	0.13	0.18	0.21	0.19	0.19	0.19
CPI	1.09	1.10	1.19	1.16	1.19	1.17	1.15	1.14	1.12	1.14	1.19	1.18
DBT/Phen	0.04	0.04	0.03	0.07	0.05	0.04	0.05	0.06	0.07	0.05	0.06	0.07

Key to abbreviations: KF = Kingfisher; MPT = Mputa; wrg = Waraga; KSM = Kasemene; KRK = Karuka; NGR = Ngara; HHI = Homohopane Index, HHI = C_{35} αβ-hopanes/sum of C_{31}-C_{35} αβ-hopanes; C_{31}22R = (22R)-C_{31} αβ homohopane; C_{30}αβH = C_{30}αβ Hopane; HI = Hopane Index, HI = C_{35} αβ-hopanes/(C_{34}+C_{35}) αβ-hopanes; MH = Methyl Hopane; Ga = Gammacerane, Ga/C_{30} = Gammacerane/C_{30} αβ hopane; t/H = sum of C_{19}-C_{26} tricyclic terpane/sum of C_{29}-C_{35} αβ-hopanes; Tri Index = Tricylic terpane Index, Tri Index = sum of C_{19}-C_{20} tricyclic terpanes/sum of C_{19}-C_{20} tricyclic terpane plus the sum of C_{23}-C_{24} tricyclic terpanes; C_{26}t/C_{25}t = C_{26} tricyclic terpane/C_{25} tricyclic terpane; Tetra Index = Tetracyclic terpane Index, Tetra Index = C_{24} tetracyclic terpane/sum of C_{26} tricyclic terpane and C_{26} tetracyclic terpane; 29Ts/29H = 29Ts/C_{29} αβ hopane; dH/29Ts = C_{30} diahopane /29Ts; 29H/H = C_{29} αβ hopane/C_{30} αβHopane; Ster/Hp = Sum of C_{27} to C_{29} Steranes/Sum of C_{27} to C_{29} hopanes; Ster Ind = Sterane index = (∑C_{27}-C_{29}aaaSteranes)/(∑C_{27}-C_{29}αααsteranes)+(∑C_{29}-C_{33}αβ-hopanes); 27βαS/27αααS = C_{27}βαSteranes/27αααSteranes; 28αββS/27αββS = C_{28}αββSteranes/27αββSteranes; Pr/ph = pristane/phytane; Pr/nC_{17} = Pristane/heptadecane; Ph/nC_{18} = Phytane/octadecane; CPI = Carbon Preference Index, CPI = *n*-C_{25} + *n*-C_{27} + *n*-C_{29} + *n*-C_{31} + *n*-C_{33}/ *n*-C_{26} + *n*-C_{28} + *n*-C_{30} + *n*-C_{32} + *n*-C_{34}; DBT/Phen = Dibenzothiophene/Phenantherene.

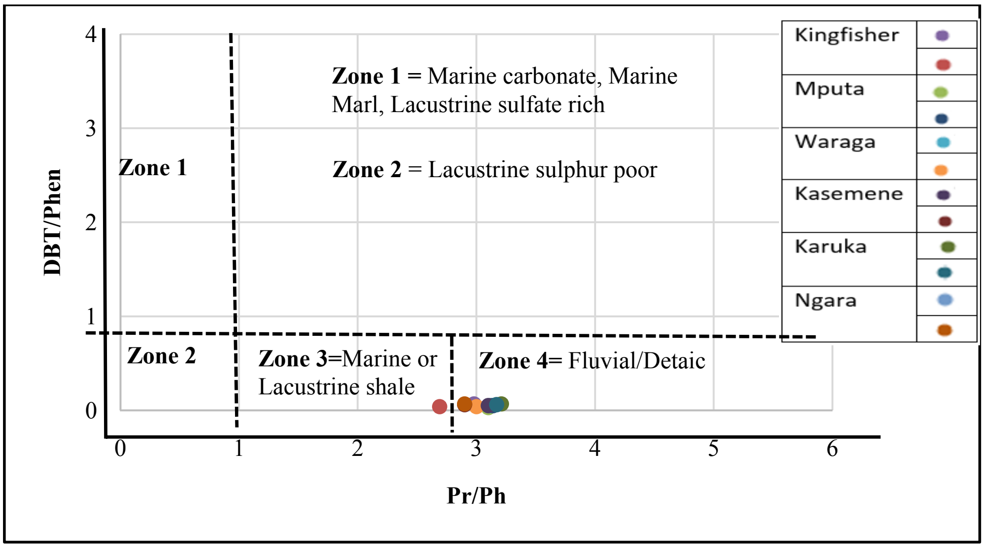

Fig. 6 **Cross plot of DBT/PHEN (dibenzothiophene/phenanthrene) vs. Pr/Ph showing oil groups according to their source rock depositional environments and lithologies (modified from Ref. [12]).**

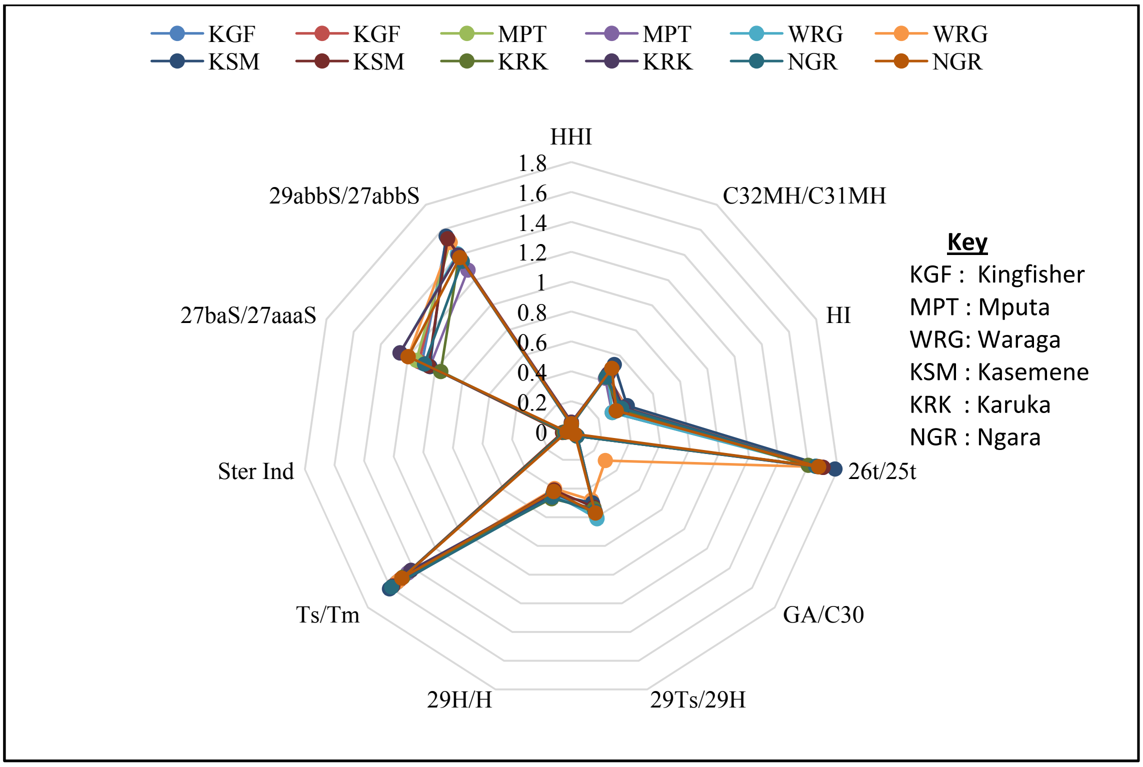

Fig. 7 **Star diagram of some of the geochemical data from the crude oils in the Albertine Graben showing a close relationship of the oils from the 6 fields. Refer to Table 2 for the key to the abbreviation.**

the oils using a star plot (Fig. 7) clearly shows a close relationship of the oils from the 6 oil fields.

The C_{31} and C_{32} αβ-hopane isomerisation values for the oils are in the range of 0.56-0.58 (Table 3) while the C_{27} and C_{29} sterane isomerisation values at the C_{20} are in the range 0.55-0.60. These values suggest explusion of the oils during the main stage of oil generation [8, 23]. Isomerisation parameters rely on the fact that with increasing maturity and/or thermal stress, organic molecules in the crude oils transform from less stable to more stable configurations and often reach equilibrium values of

0.57 to 0.62 for hopanes [8]. Corroborating evidence for expulsion during the main stage of oil generation is provided by the Ts/Ts+Tm hopane and $C_{27}\alpha\beta\beta/(\alpha\alpha\alpha + \alpha\beta\beta)$ sterane ratios (Table 3). A cross plot of the $C_{27}\alpha\alpha\alpha$ Sterane 20S/(20S+20R) ratios against $C_{27}\beta\beta/(\beta\beta + \alpha\alpha)$ ratios in Fig. 8 shows closely similar maturities of the oils.

Maturity parameters derived from aromatic compounds also suggest expulsion of the oils during the main stage of oil generation. For instance, conversion of monoaromatic steroids (TA/TA + MA) yields vitrinite reflectance equivalence values of 0.7-0.8 while methylphenantherane ratios (MPI-1) are in the range 0.62-0.67 (Table 3). Calibration of MPI-1 against measured vitrinite reflectance published by Radke & Welte (1983) [24] indicates a maturation of approximately 0.8 Veq, consistent with maturities suggested from hopane and sterane parameters. It should be noted however that ideally, MPI parameter should be calibrated against vitrinite reflectance for a given petroleum system [8]. However, because the maturity estimation provided by the MPI-1 in the studied samples is in close agreement with the maturities derived from the hopane and sterane isomerization ratios (Table 3), the acquired MPI-1 values have been considered valid/useful.

4.4 Implications on the Expulsion of the Oils by the Source Rocks

Kerogen types in petroleum source rocks can be inferred on the basis of kerogen kinetics studies in literature. Indeed several researchers (e.g. Ungerer, 1990, [25]) have used such kinetics studies in maturation modelling of kerogen and source rocks. In particular, activation energy (kcal/mol) distribution has been used extensively to calculate the degree of transformation of the kerogen to oil and gas. The underlying fact is that the distribution of activation energy varies with kerogen type [26]; marine (Type II) and terrigenous Type III kerogens have broad distributions of activation energy while Type I lacustrine kerogens have very narrow distribution of activation of energies with slightly higher maximum. Consequently, Type I kerogens expel their hydrocarbons rapidly and in a single event due to their narrow activation energies whereas Type II and Type III kerogens tend to expel their hydrocarbons over a broader range of maturation levels.

Table 3 Selected maturity parameters in the studied crude oil samples.

Sample ID	Maturity parameter							
	C_{31}S/R	C_{32}S/R	Ts/Ts+Tm	C_{27}S/R	C_{29}S/R	$C_{27}\beta a/\alpha+\beta$	MPI-1	Rc-1
G1	0.54	0.56	0.57	0.58	0.55	0.50	0.62	0.77
G2	0.56	0.56	0.57	0.60	0.57	0.50	0.62	0.77
G3	0.59	0.57	0.58	0.64	0.58	0.53	0.63	0.78
G4	0.58	0.58	0.59	0.57	0.57	0.51	0.65	0.79
G5	0.58	0.57	0.61	0.60	0.60	0.56	0.64	0.78
G6	0.58	0.57	0.62	0.67	0.60	0.51	0.67	0.80
G7	0.58	0.57	0.58	0.60	0.57	0.49	0.63	0.78
G8	0.58	0.57	0.61	0.58	0.59	0.52	0.63	0.78
G9	0.57	0.55	0.60	0.58	0.57	0.52	0.62	0.77
G10	0.57	0.57	0.60	0.57	0.56	0.52	0.63	0.78
G11	0.55	0.56	0.62	0.60	0.58	0.51	0.63	0.78
G12	0.58	0.56	0.59	0.61	0.59	0.53	0.62	0.77

Key: C_{31}S/R = $C_{31}\alpha\beta$ hopane 22S/$C_{31}\alpha\beta$ hopane (22S+22R); C_{32}S/R = $C_{32}\alpha\beta$ hopane 22S/$C_{32}\alpha\beta$ Hopane (22S+22R); C_{29}S/R = C_{29} ααα-20S sterane/C_{29} ααα-20S sterane + C_{29} ααα-20R sterane; C_{27}S/R = C_{27} ααα-20S sterane/C_{27} ααα-20S sterane + C_{27} ααα-20R sterane; $C_{27}\beta a/\ \alpha+\beta$ = $C_{27}\alpha\beta\beta$ sterane (20S + 20R)/ C_{27} αββ sterane (20S + 20R) + $C_{27}\alpha\alpha\alpha$ sterane (20S + 20R). MPI-1 = Methyl phenanthrene index (as modified by Ref. [27]); Rc-1 = calculated vitrinite reflectance = 0.6xMPI-1 + 0.4 (from Ref. [24]).

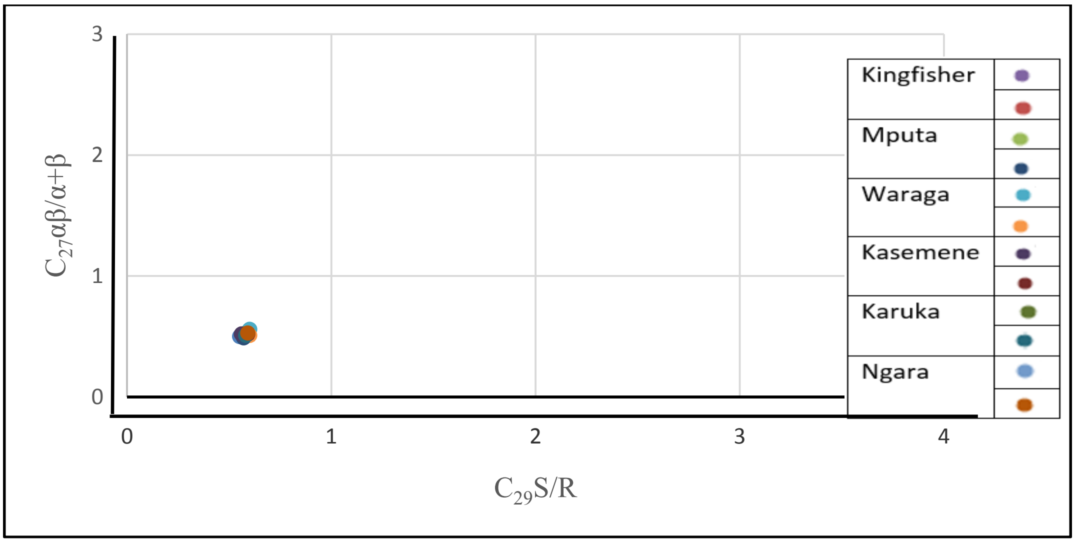

Fig. 8 Cross Plot of C_{27} ααα Sterane 20S/(20S + 20R) versus C_{27}ββ/(ββ + αα) showing that the oils are broadly of same thermal maturity. Refer to Table 3 for the key to the abbreviation in this figure.

In the studied oils therefore, the narrow range of Ro equivalence values estimated from the methyl phenantheranes (Rc-1 = 0.77 to 0.80) and the narrow range of values for all other maturation parameters (Table 3) alongside the inferred lacustrine depositional setting for the source rocks provide compelling circumstantial evidence that the kerogen responsible for the generation of the oils is predominantly of type-1 known to display narrow activation energies. This consequently implies that the source rocks expelled the oil over a narrow maturity range in a single event. Hence, chances of multiple expulsion of the oils with differing maturities from the source rocks in the Albertine Graben are very minimal. This therefore implies that the filling of reservoirs in the Albertine Graben probably did not involve late stage expulsion and multiple charges of oil.

5. Conclusions

The oils from the six fieldsdis play a striking similarity in the bulk and molecular biomarker characteristics reflecting a similarity in their source rock organic facies. They have been therefore interpreted to belong to one family, generated from a mature, clay-rich predominantly algal source rock deposited under sub-oxic conditions in a non-stratified lacustrine setting. The minor variations in biomarker characteristics as observed especially in GC finger prints are probably due to minor facies variations within the source rock where near shore environments may have received slightly more terrestrial organic material relative to those in the depocenter of the lake.

The predominance of algal organic matter in the source rocks under non-stratified lacustrine conditions and the narrow range of Ro equivalence values estimated from the methyl phenantheranes alongside the narrow range of values for all other maturation parameters indicate that the source rock is characterized by Type-I kerogen known to expel hydrocarbons rapidly and in a single event due to their narrow activation energies. It has been concluded therefore that the source rocks for the studied oils expelled the oils over a narrow maturity range in a single event. This implies that there was no multiple expulsion of the oils with differing maturities in the Albertine Graben.

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Appendix

Compound identifications for triterpanes GC-MS *m/z* 191, Figs. 6 and 7.

Peak	Compound name	Compound formula	Name used in this study
1	13β (H), 14α (H)-C19 Tricyclic terpane	$C_{19}H_{34}$	C_{19} βα Tricyclic terpane
2	13β(H), 14α(H)-C20Tricyclic terpane	$C_{20}H_{36}$	C_{20} βα Tricyclic terpane
3	13β(H), 14α(H)-C21 Tricyclic terpane	$C_{21}H_{38}$	C_{21} βα Tricyclic terpane
4	13β(H), 14α(H)-C22 Tricyclic terpane	$C_{22}H_{40}$	C_{22} βα Tricyclic terpane
5	13β(H), 14α(H)-C23 Tricyclic terpane	$C_{23}H_{42}$	C_{23} βα Tricyclic terpane
6	13β(H), 14α(H)-C24 Tricyclic terpane	$C_{24}H_{44}$	C_{24} βα Tricyclic terpane
7	13β(H), 14α(H)-C25 Tricyclic terpane	$C_{25}H_{46}$	C_{25} βα Tricyclic terpane
T	C_{24} Tetracyclic terpane$C_{24}H_{42}$	C_{24} Tetracyclic terpane	
8	13 β(H), 14α(H)-C26 Tricyclic terpane	$C_{26}H_{48}$	C_{26} βα Tricyclic terpane
9	C_{26} Tetracyclic terpane$C_{26}H_{46}$	C_{26} Tetracyclic terpane	
Ts	18 α(H)-22,29,30-trisnorneohopane	$C_{27}H_{46}$	Ts
Tm	17α(H)-22,29,30-trisnorhopane	$C_{27}H_{46}$	Tm
10	17 α(H), 21 β(H)-norhopane	$C_{29}H_{50}$	C_{29} αβ hopane
11	18 α(H),-norneohopane	$C_{29}H_{50}$	C_{29} Ts
D	17α (H)diahopane	$C_{30}H_{52}$	C_{30} diahopane
N	17β(H), 21α(H)-normoretane	$C_{29}H_{50}$	C_{29} normoretane
12	17α (H), 21β (H)-hopane	$C_{30}H_{52}$	C_{30} αβ hopane
CM	17β(H), 21α(H)-moretane	$C_{30}H_{52}$	C_{30} βα moretane
13	17α(H), 21β(H), (22S)-C31 homohopane	$C_{31}H_{54}$	C_{31} αβ hopane
14	17α(H), 21β(H), (22R)-C31 homohopane	$C_{31}H_{54}$	C_{31} αβ hopane
G	Gammacerane; pentacyclic terpane	$C_{30}H_{52}$	Gammacerane
15	17α(H), 21β(H), (22S)-C32 bishomohopane	$C_{32}H_{56}$	C_{32} αβ hopane
16	17α(H), 21β(H), (22R)-C32 bishomohopane	$C_{32}H_{56}$	C_{32} αβ hopane
17	17α(H), 21β(H), (22S)-C33 trishomohopane	$C_{33}H_{58}$	C_{33} αβ hopane
18	17α(H), 21β(H), (22R)-C33 trishomohopane	$C_{33}H_{58}$	C_{33} αβ hopane
19	17α(H), 21β(H), (22S)-C34 tetrakishomohopane	$C_{34}H_{60}$	C_{34} αβ hopane
20	17α(H), 21β(H), (22R)-C34 tetrakishomohopane	$C_{34}H_{60}$	C_{34} αβ hopane
21	17α(H), 21β(H), (22S)-C35 pentakishomohopane	$C_{35}H_{62}$	C_{35} αβ hopane
22	17α(H), 21β(H), (22R)-C35 pentakishomohopane	$C_{35}H_{62}$	C_{35} αβ hopane