

GEOCHEMICAL SIGNIFICANCE OF SEEPAGE OILS AND BITUMINOUS SANDSTONES IN THE ALBERTINE GRABEN, UGANDA

Dou Lirong^{1,2,*}, Cheng Dingsheng², Wang Jianjun², Ernest N.T. Rubondo³, Robert Kasande³, Abdul Byakagaba³ and Frank Mugisha³

Geochemical analysis of surface samples comprising three seepage oils, two bituminous sandstones and five shales collected from the Ugandan portion of the Albertine graben (a Cenozoic rift basin in Eastern Africa) indicates that the basin may have some petroleum potential. The analyses show that seepage oils from the Kibiro and Paraa localities were derived from Types I or II₁ source rocks, deposited in semi-deep or deep-water lacustrine environments containing abundant freshwater algae. However, the seepage oil from Kibuku is derived from a Type III source rock.

A comparison of the seepage oils and the bituminous sandstones suggests that there are at least two sets of mature or threshold-mature source rocks in the Albertine graben – one in the Upper Tertiary and the other in the underlying (pre-Upper Tertiary) succession. According to molecular indicators of maturity, the Kibiro seepage oil was generated during peak maturation, whereas the Paraa and Kibuku seepage oils are of lower or threshold maturity.

INTRODUCTION

Although Uganda has a long history of surface petroleum exploration, no commercial oilfields have yet been found there. The most prospective area in the country is the Albertine graben (Fig. 1); this is 570km long and about 45km wide, and extends into the Democratic Republic of Congo. Previous geological and geophysical studies have concluded that mature source rocks are present in the graben, and the presence of an active petroleum system is indicated by the occurrence of oil seeps. Wayland (1925) identified oil and gas shows at 52 locations within and around Lake Albert. At the present day,

surface seepages of petroleum occur at Paraa, Kibiro and Kibuku (see Fig. 2). The existence of these seepages indicates that not only are effective source rocks present, but also that they have generated and expelled oil and that migration has taken place.

In order to investigate the petroleum potential of the Albertine graben, CNODC geologists have recently participated in a joint research programme with PEPD Uganda. Three seepage oils, two bituminous sandstones and five shales were collected for organic geochemical analysis (Table 1). Sample locations are shown in Fig. 2.

GEOLOGICAL BACKGROUND

The Albertine graben is made up of a series of discontinuous fault-bounded segments and forms the northernmost part of the western branch of the East African Rift System (EARS) (Fig. 2). Lacking significant volcanic fill, this branch of the EARS consists of a series of narrow, deep lakes including Lakes Malawi, Rukwa, Tanganyika, Albert and Kivu, together with Lakes Edward and George. The graben, a NW-SE striking transtensional pull-apart depression (Ebinger, 1989), was formed during the Late Tertiary

¹Research Centre, China National Oil and Gas E & D Corp., CNPC, PO Box 910, Xueyuan Road 20, 100083, Beijing, P. R. China.

²Institute of Geology and Geophysics, Chinese Academy of Sciences, Beijing 100029, P. R. China.

³Petroleum Exploration and Production Department (PEPD), PO Box 9, Entebbe, The Republic of Uganda.

*corresponding author, email: dlr@petrochina.com.cn

	Sample No.	Formation	Location	Longitude/Latitude	Description
seepage oil	01-1228		Paraa	2°15'19"N; 31°29'47"E	Bubbles of oil rising to the surface of the Victoria Nile River
seepage oil	01-1229		Kibiro	1°41'66"N;31°16'83"E	Live oil shows in a stratigraphic well
seepage oil	01-1230	Kisegi	Kibuku	0°55'24"N;30°14'34"E	Oil impregnated sandstones in the Kisegi Formation
Shale	01-1239	Kaiso	Kaiso village	1°31'91"N;30°59'31"E	Grey Shale
Shale	01-1240	Kaiso	Hoima	No data	Dark grey shale
Shale	01-1241	Kaiso	Hoima	No data	Grey shale
Shale	01-1242	Kisegi	Kibuku	No data	Brownish grey shale
Shale	01-1243	Kisegi	Kibuku	No data	Dark grey shale
Bituminous sandstones	01-1237	Kisegi	Kibuku	0°55'24"N;30°14'34"E	Dark grey sandstone
	01-1238	Kaiso	Kaiso-Tonya	No data	Grey sandstone

Table 1. Samples collected from the Albertine graben, Uganda: stratigraphic and geographical location data.

due to north-south rift propagation as indicated by geomorphological observations in the Western Rift (Shackleton, 1978) where Cenozoic magmatic activity was initiated at 12Ma (or possibly later: Lezzar *et al.*, 2002). Volcanic activity in the Albertine graben is mainly limited to the area south of the Semliki Basin (location on Fig. 2). In this area, magmatic activity is generally localized in fault-bounded sub-basins, where chains of active volcanoes are aligned along the tips of border-fault segments and along oblique-slip transfer faults cross-cutting the rift valley (Morley, 1990; Ebinger, 1989). A stratigraphic column here has been established based on data from well *Butiaba Waki-1* on the NW shore of Lake Albert (Fig. 2). Drilled in 1938, *Butiaba Waki-1* reached a total depth of 1,232m and penetrated Tertiary and Mesozoic units to basement including the Kaiso, Kisegi and Waki Formations (Fig. 3). In 2003, Heritage drilled a wildcat well in Block 3 which reached a total depth of 2,487m.

EXPERIMENTAL METHODS

Samples collected from Uganda were analysed in the Key Laboratory of Petroleum Geochemistry of CNPC in Beijing. The following analytical procedures were performed: TOC evaluation (*Leco CS-400* Instrument); *Rock-Eval* pyrolysis (*Vinci 2-plus*); Soxhlet extraction with chloroform for 20 hours followed by quantification of bitumen components (*Introscan 5-new*); kerogen separation (multiple treatments by concentrated hydrochloric and hydrofluoric acids), followed by quantification of macerals and vitrinite reflectance measurements (*MPV-3* microphotometer); GC (*HP 5890*) and GC/

MS (*Fisons MD-800* quadrupole system interfaced with a *Carlo-Erba 800* gas chromatograph).

In addition to these routine analytical procedures, pyrolysis of two biodegraded seepage oils was also performed using a sealed tube at 300°C for 72 hours; each pyrolysate was then separated into four fractions, and GC and GC/MS analyses were carried out on both the saturated and aromatic fractions.

GEOCHEMICAL CHARACTERISTICS OF SHALE SAMPLES

TOC and *Rock-Eval* results are presented in Table 2. Shale samples 01-1239 and 01-1242 from the Kaiso and Kisegi Formations show low TOC values and are not considered to have source rock potential. The TOC values of shale samples 01-1240, 01-1241 and 01-1243 from the Kaiso Formation and Kisegi Formation are close to or above 1.0%; however, S_1 , S_2 and HI values are relatively low (below the normal threshold for source rocks: Hu and Huang, 1991), and therefore these rocks are interpreted to have little or no hydrocarbon potential. Based on an evaluation of non-marine source rocks in China (Hu and Huang, 1991), extracts from these shale samples were interpreted to be low grade (Table 2) ranging from 100 to 500ppm, which is indicative of a poor-quality source rock. In terms of bitumen composition, both resin and asphaltene contents are very high, while the saturated and aromatic fractions are less than 80%. In general, the analytical results show that resins and asphaltenes dominate the organic matter type, and the content of soluble organic matter is lower than that required for an effective source rock. This may be related to the

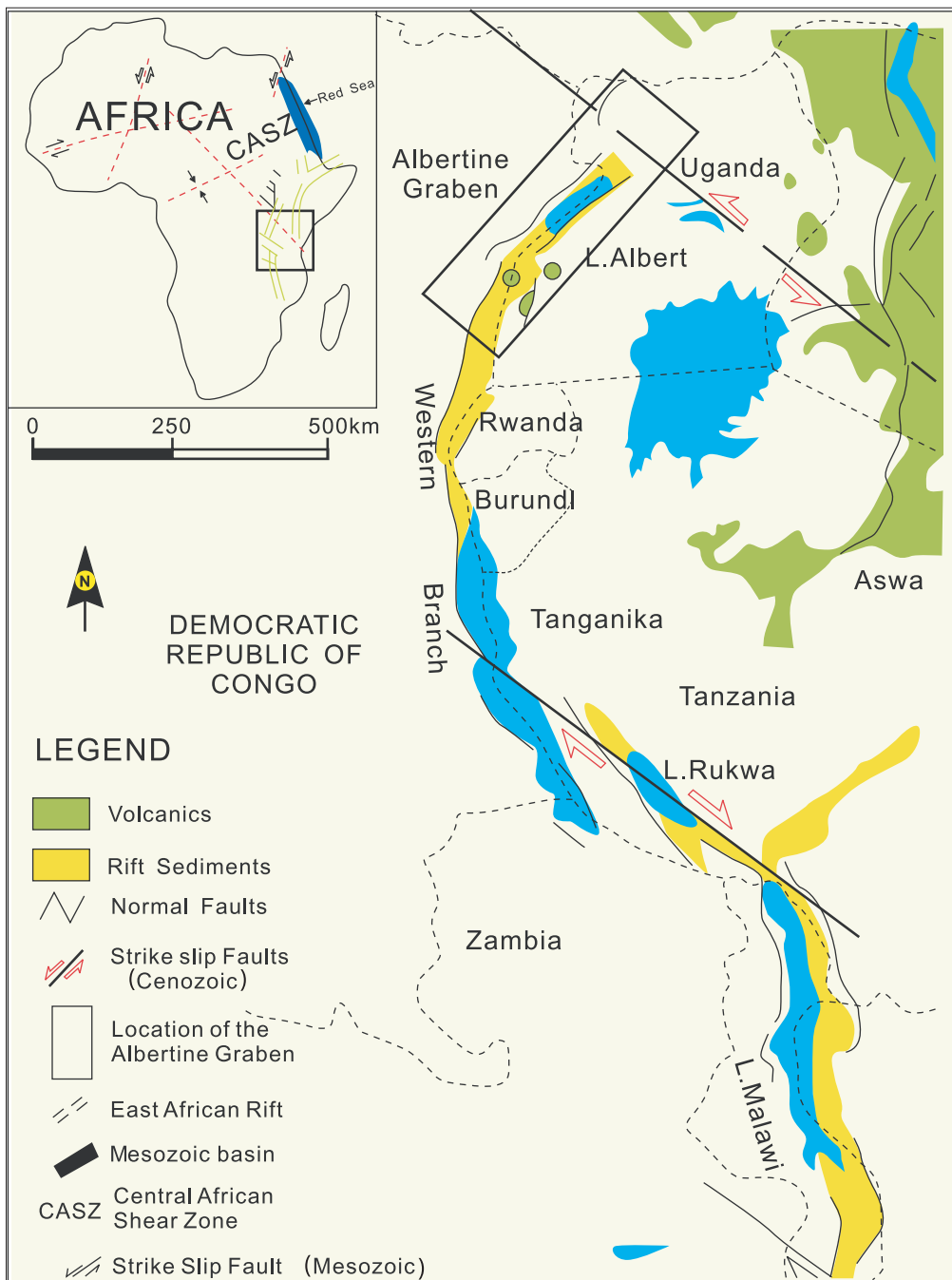


Fig. 1. Regional location of the Albertine graben in the western branch of the East African Rift System (modified from Morley, 1999).

precursor source material, the low maturation level, or the effects of weathering and oxidization.

Following Teichmüller's classification (1986), the organic macerals in the shales from the Albertine graben are mainly composed of amorphinite (both non-fluorescing and weakly-fluorescing). With the exception of sample 01-1242 which has weakly fluorescent amorphinite as a major component, the other samples are all dominated by non-fluorescent amorphinite (accounting for 60% and more) with a small quantity of inertinite, vitrinite as well as minor alginite and sporinite (see Plate 1). Except for sample

01-1243 which contains Type II₂ kerogen, the other analyzed samples contained Type III kerogen.

As shown in Table 3, GC analyses of the saturated fractions suggest that terrestrial organic matter dominates the organic source material in these five shale samples. Most of the shale samples show a unimodal *n*-alkane distribution pattern with nC_{22+} dominant, and a major peak at nC_{29} or nC_{31} . The C_{21}/C_{22+} and $(C_{21}+C_{22})/(C_{28}+C_{29})$ ratios are less than 0.35 and 0.23, respectively (Table 3). These characteristics are typical of an input of higher plant material to the precursor source rock. As an exception, however,

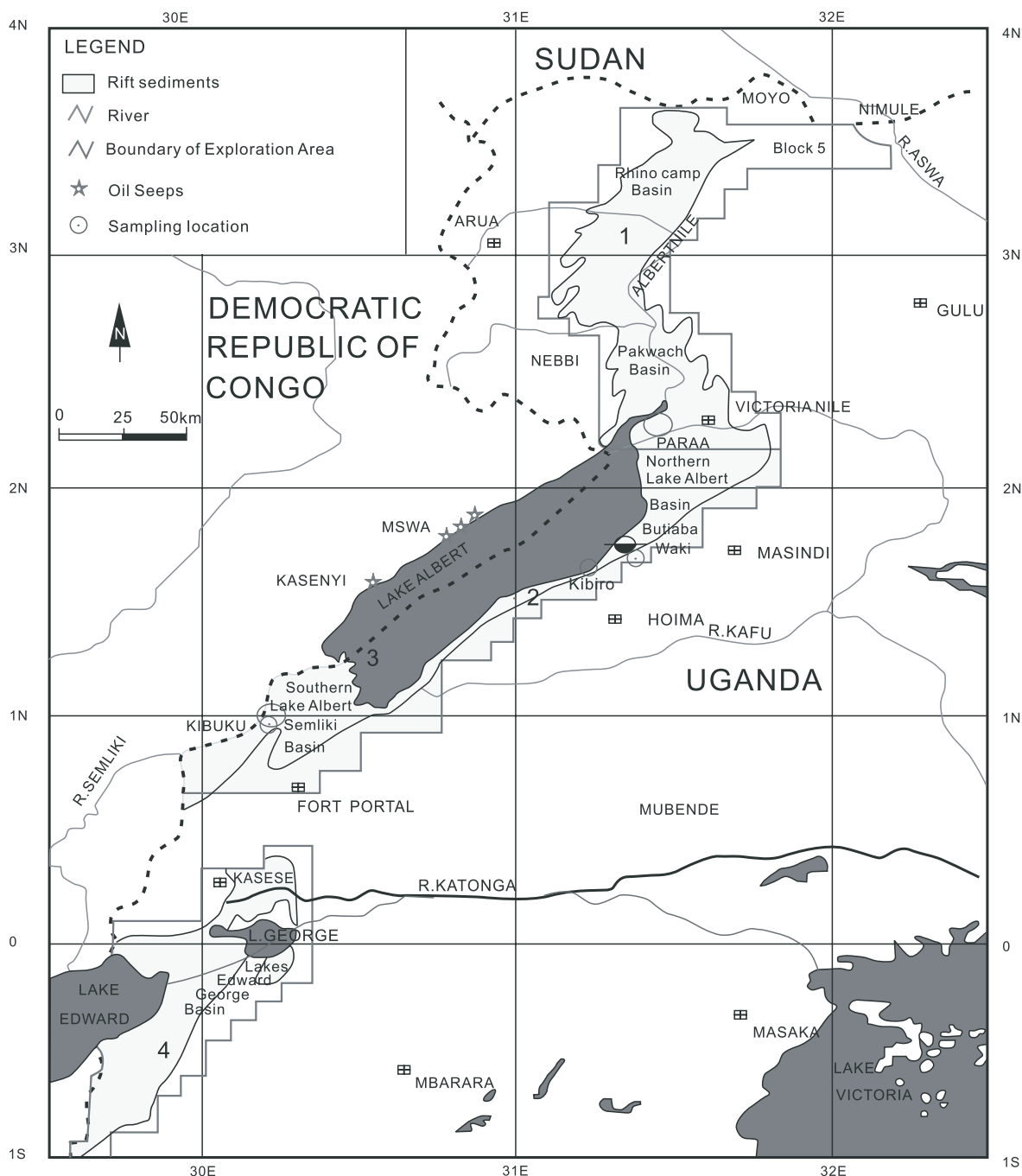


Fig. 2. Outline map of the Albertine graben, Uganda, showing exploration license areas, surface oil seepages, and sample locations.

sample 01-1241 shows a bimodal pattern in the n -alkane distribution, with a low-carbon-number peak at nC_{12} , which indicates a significant input of microbial source material. With the exception of sample 01-1240, Pr/Ph ratios of 1 or more (Table 3) indicate a non-marine, oxic depositional environment for the precursor source rocks.

Molecular maturity parameters for all the samples are presented in Table 4. They show that of the five shales samples analysed, only sample 01-1239 is mature as indicated by:

- an R_c of 0.70% (calculated from the MPI_1);
- a measured vitrinite reflectance (R_o) of 0.73%;
- a C_{29} sterane $\beta\beta/(\beta\beta + \alpha\alpha)$ ratio of 0.38;
- a C_{29} sterane $20S/(20S+20R)$ ratio of 0.49;
- a C_{31} hopane $22S/(22S+22R)$ ratio of 0.55;
- and a C_{30} moretane/hopane ratio of 0.12.

However, the sample has an odd-over-even predominance of alkanes in the GC data. The odd-over-even predominance of alkanes in the GC data and the abundance of hopanes in the other four

Sample No.	TOC	S1	S2	HI	Extracts (ppm)	Saturates %	Aromatics %	Resins %	Asphaltenes %	Saturates/Aromatics	Polars / Asphaltenes
01-1228						23.65	25.96	32.17	18.22	0.91	1.77
01-1229						18.55	38.6	26.86	15.98	0.48	1.68
01-1230					260	36.32	25.94	29.67	8.07	1.4	3.68
01-1239	0.13	0.1	0.01	8	133	16.01	2.63	32.55	48.81	2.45	0.67
01-1240	0.95	0.54	0.01	1	161	5.21	2.95	52.38	39.46	3.02	1.33
01-1241	1.35	2	0.01	1	258	5.26	4.94	45.81	43.99	6.09	1.04
01-1242	0.36	0.52	0.01	3	348	5.44	1.36	45.65	47.55	1.77	0.96
01-1243	1.15	0.52	0.09	8	424	6.65	3.36	40.72	49.27	1.06	0.83
01-1237					52	14.86	6.07	46.74	32.33	4	1.45
01-1238					55	13.52	4.48	56.48	25.52	1.98	2.21

Table 2. Summary of the bulk geochemical characteristics of samples collected from the Albertine graben.
 %TOC: weight percent total organic carbon (%); S₁: amount of free hydrocarbon (mg/g);
 S₂: amount of pyrolyzable hydrocarbon (mg/g); HI: Hydrogen index (S₁/%TOC).

Sample No	Sample type	Formation	Location	Main peak	C ₂₁₋ C ₂₂₊	C ₂₁ +C ₂₂ C ₂₈ +C ₂₉		Pr/ Ph	Pr/ nC ₁₇	Ph/ nC ₁₈
01-1228p	Pyrolyzed asphaltene		Paraa	C ₂₃	0.46	1.2	1.1	0.46	0.32	
01-1229p			Kibiro	C ₂₀	0.84	1.54	1.22	0.5	0.34	
01-1230	Oil sand	Kisege	Kibuku	C ₁₈	1.61	1.89	0.71	0.36	0.47	
01-1239	Shale	Kaiso	Kaiso	C ₃₁	0.11	0.23	1.02	0.72	0.63	
01-1240	Shale	Kaiso	Hoima	C ₂₉	0.14	0.15	0.75	0.49	0.6	
01-1241	Shale	Kaiso	Hoima	C ₂₉	0.35	0.04	1.78	0.94	0.77	
01-1242	Shale	Kisege	Kibuku	C ₃₁	0.18	0.21	1.47	0.98	0.59	
01-1243	Shale	Kisege	Kibuku	C ₃₁	0.13	0.13	1.64	1.87	1.11	
01-1237	Bituminous	Kisege	Kibuku	C ₁₇	1.39	1.25	1.67	0.92	0.62	
01-1238	Sandstones	Kaiso	Tonya	C ₁₅	1.18	0.76	2.01	0.96	0.65	

Table 3. Analytical results for saturate fractions from gas chromatography.

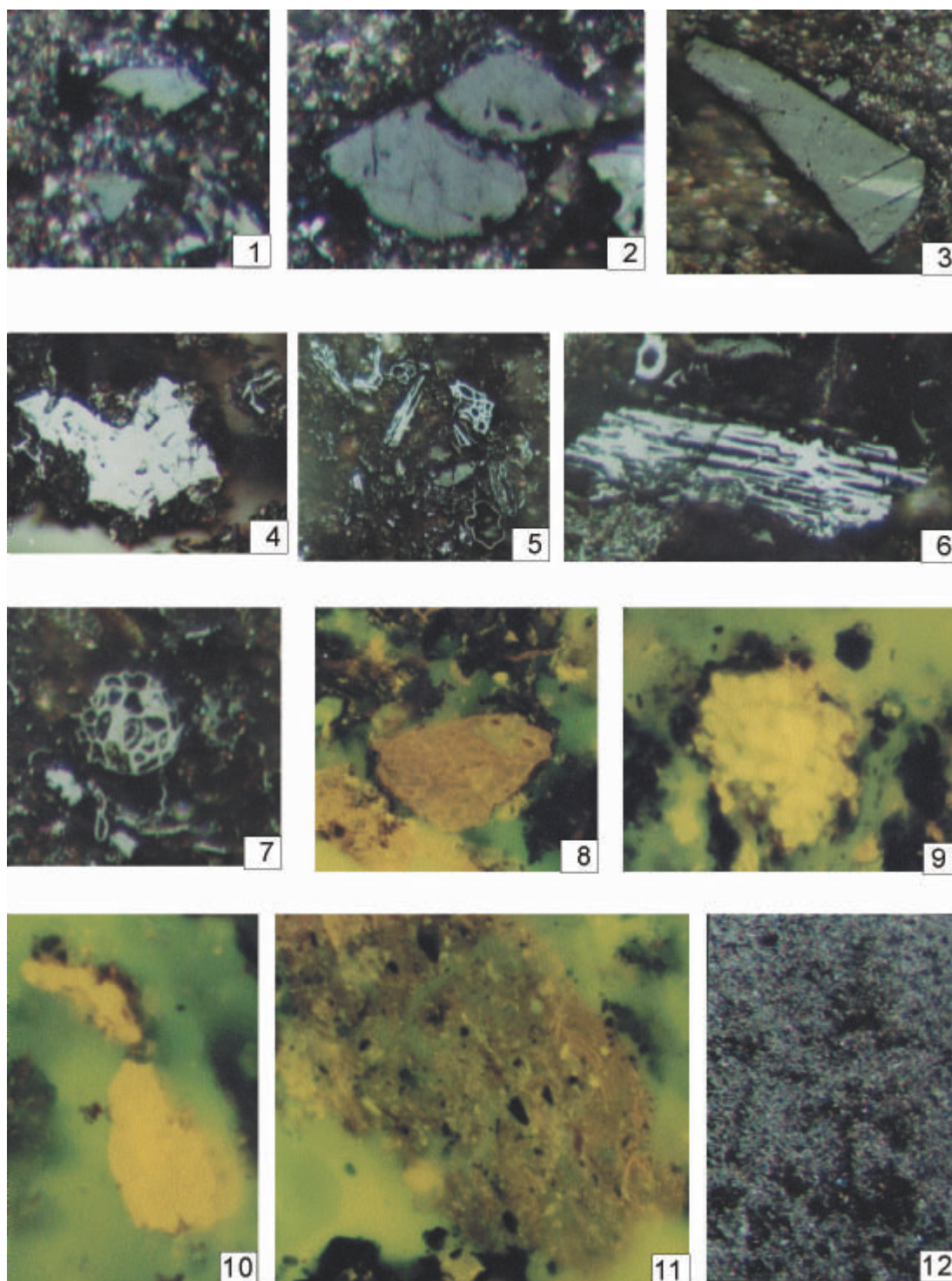


Plate 1. Photomicrographs of representative shale samples showing organic macerals.

1. Vitrodetrinite from sample 01-1239; reflected light, oil immersion, x240.
2. Vitrinite from sample 01-1239; reflected light, oil immersion, x240.
3. Desmocollinite and micrinite from sample 01-1239; reflected light, oil immersion, x480.
4. Macrinite from sample 01-1240; reflected light, oil immersion, x480.
5. Sclerotinite from sample 01-1241; reflected light, oil immersion, x480.
6. Fusinite from sample 01-1241; reflected light, oil immersion, x480.
7. Sclerotinite from sample 01-1241; reflected light, oil immersion, x480.
8. Alginite from sample 01-1240; reflected florescent light, x240.
9. Fluorescent organic matter in sclerotinite, sample 01-1239; reflected florescent light, x240.
10. Alginite and sporophyte from sample 01-1240; reflected florescent light, x240.
11. Fluorescent amorphinite from sample 01-1239; reflected florescent light, x240.
12. Humic amorphinite from sample 01-1240; reflected fluorescent light, x240.

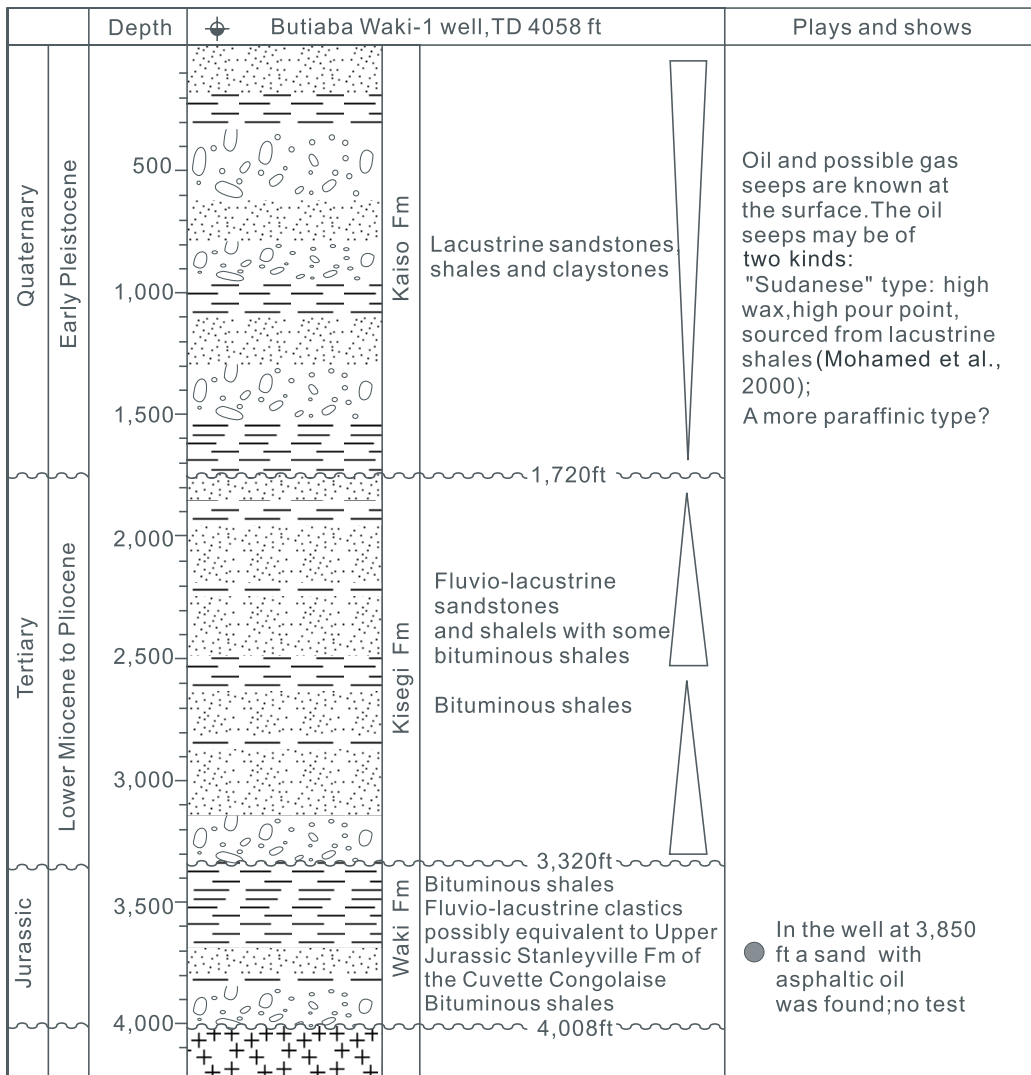


Fig. 3. Stratigraphic column for well Butiaba Waki-1 (redrawn from Patton et al., 1995). Well location in Fig. 2.

samples suggest that they are early mature (Fig. 4), and that their measured Ro values are unreliable.

GEOCHEMICAL CHARACTERISTICS OF SEEPAGE OILS AND BITUMINOUS SANDSTONES

Seepage oils

The total hydrocarbon content of the Paraa and Kibiro seepage oils accounts for 50% (resins-plus-asphaltenes make up the other 50%) and together with a saturate/aromatic ratio of <1 (Table 2) suggests that the source rock is sapropelic. The total hydrocarbon content of the Kibuku oil seepages is up to 63% (resins, 30% and asphaltenes, 8%); the saturate/aromatic ratio is >1 (Table 2), suggesting that the source rock is humic.

All the seepage oils and bituminous sandstones analyzed have high resin/asphaltene ratios (greater than 1.0) (Table 2). In this respect they resemble early mature crude oils with a low degree of polymerization

of heteroatom compounds. This is particularly pronounced in the Kibuku seepage oil and in sandstone sample 01-1238 (Table 2).

GC analytical data (Table 3) shows that alkanes and most isoprenoids are absent due to biodegradation in the Paraa and Kibiro seepage oils. Due to less intense biodegradation, some alkanes occur in the Kibuku oil and show a unimodal pattern in their n-alkane distribution with a nC₂₁ dominance; the major peak is C₁₈. The C₂₁/C₂₂₊ ratio is 1.61 while the (C₂₁+C₂₂)/(C₂₈+C₂₉) ratio is 1.89, suggesting a contribution by algae and bacteria to the precursor organic matter. The Pr/Ph ratio is 0.71, which is typical of a reducing lacustrine depositional environment for the source rocks. The odd-over-even predominance is not marked, while the CPI is 1.04 (Table 4), the OEP 0.72, and the calculated Rc is 0.68% (determined from the MPI₁). These features show that the organic matter is mature. Table 4 also presents various molecular indices of maturity including MPI₁ (Radke et al., 1986), according to which the Kibiro seepage oil is more mature than the Paraa oil.

Sample No.	Lithology	Fm.	Location	CPI	OEP	MPII*	Rc* (%)	I*	II*	III*	IV*	V*	Ro (%)
01-1228	Oil seepage		Paraa			1.11	1.07	0.36	0.5	0.64	0.59	0.18	
01-1229	Oil seepage		Kibiro			1.83	1.2	0.3	0.41	0.61	0.57	0.17	
01-1228p	Pyrolytic asphaltene		Paraa	1	1.16	1.01	1.01	0.39	0.39	0.6	0.58	0.12	
01-1229p			Kibiro		0.97	1.78	1.23	0.32	0.35	0.6	0.57	0.16	
01-1230	Oil sand	Kisegei	Kibuku	1.04	0.72	0.46	0.68	0.39	0.31	0.24	0.57	0.17	
01-1239	Shale	Kaiso	Kaiso	1.71	1.84	0.5	0.7	0.38	0.49	0.53	0.55	0.12	0.73
01-1240	Shale	Kaiso	Hoima	3.63	3.71	0.65	0.79	0.29	0.39	0.32	0.16	0.4	0.67
01-1241	Shale	Kaiso	Hoima	5.76	6.49	0.41	0.65	0.25	0.28	0.54	0.15	0.33	0.43
01-1242	Shale	Kisegei	Kibuku	3.02	4.07	0.8	0.88	0.29	0.07	0.31	0.21	0.39	0.73
01-1243	Shale	Kisegei	Kibuku	4.21	5.45	0.75	0.85	0.24	0.02	0.3	0.11	0.29	0.48
01-1237	Bituminous	Kisegei	Kibuku	1.28	1.02	0.52	0.7	0.37	0.42	0.52	0.55	0.11	
01-1238	Sandstones	Kaiso	Tonya	1.25	1.07	0.49	0.69	0.36	0.41	0.54	0.56	0.12	

Table 4. Maturity parameters for the samples analysed. MPII = 1.5(2-MP+3-MP)/(P+I-MP+9-MP) (Radke et al., 1986); %Rc = 0.6MPII + 0.4 (0.65% < Ro < 1.35%); I. C₂₉-αββ/(ααα + αββ) sterane ratio; II. C₂₉-20S/(20S+20R) sterane ratio; III. Ts/(Ts+Tm); IV. C₃₁-22S/(22S+22R) hopane ratio; V. C₃₀-moretane/hopane ratio.

Sample No	Lithology	Fm	Location	δ ¹³ C Saturates	δ ¹³ C Aromatics
01-1228	Oil seepage		Paraa	-24.9	-23.9
01-1229	Oil seepage		Kibiro	-23.7	-22.6
01-1230	Oil sand	Kisegei	Kibuku	-28.1	-27.2
01-1239	Mudstone	Kaiso	Kaiso	-26.9	-26.1
01-1240	Shale	Kaiso	Hoima	-27.9	-27.7
01-1241	Shale	Kaiso	Hoima	-27.2	-27.7
01-1242	Shale	Kisegei	Kibuku	-28.3	-25.9
01-1243	Shale	Kisegei	Kibuku	-28.6	-25
01-1237	Bituminous	Kisegei	Kibuku	-27.6	-26.3
01-1238	sandstone	Kaiso	Kaiso-Tonya	-26.2	-25.8

Table 5. δ¹³C (‰) of saturated and aromatic hydrocarbons in the samples analysed.

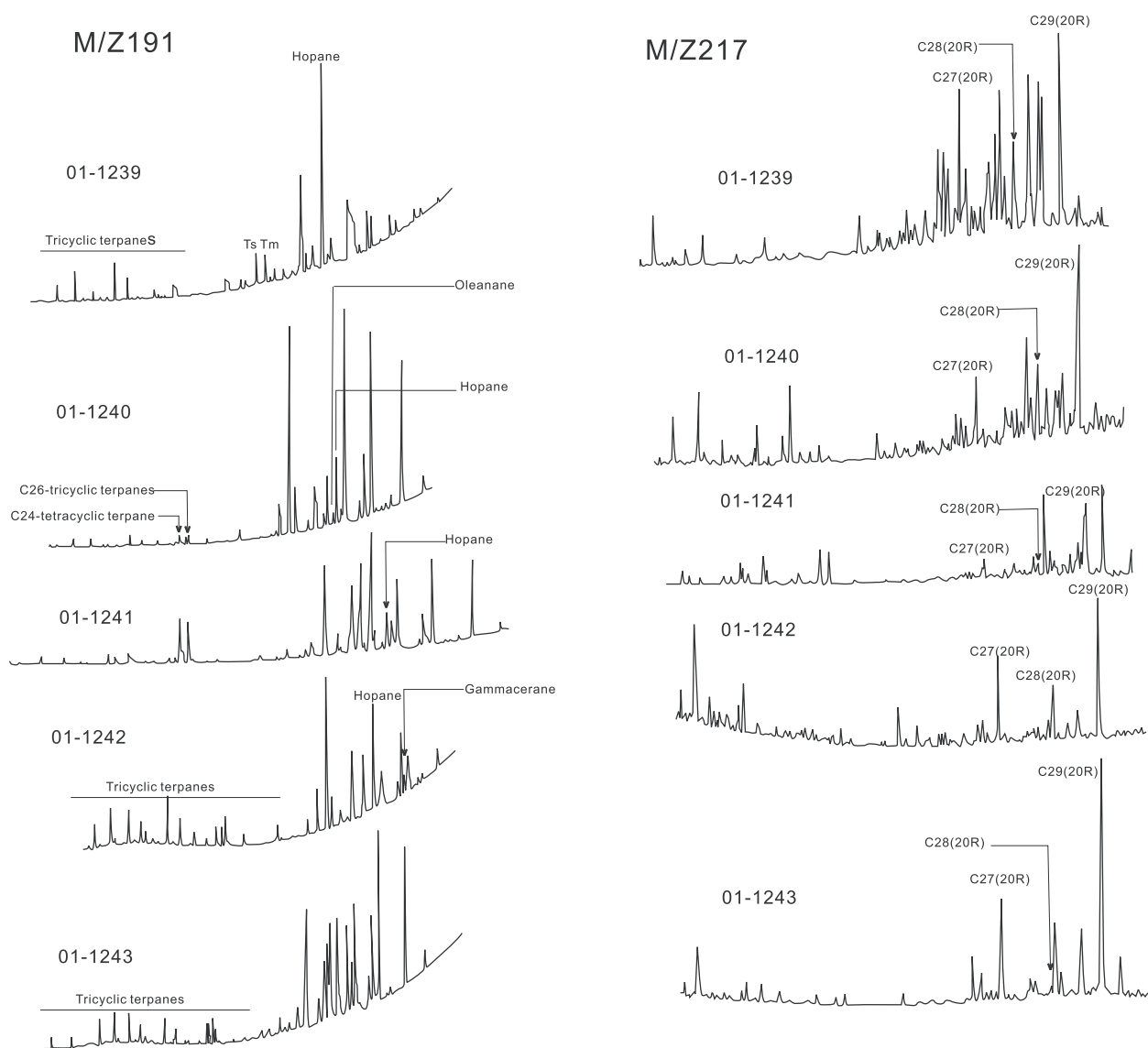


Fig. 4. m/z 191 and m/z 217 mass chromatograms for shale samples (see Table I for sample locations).

Bituminous sandstones

Extracts from weathered surface samples of bituminous sandstones were quantitatively small, <52–55ppm (Table 2). Compositional analyses indicate that the extracts' resin and asphaltene contents are high, their total hydrocarbon content is low (<21%), and that saturate/aromatic ratios are high, which indicates that their source rocks have poor organic matter type.

GC results (Table 3) indicate that the bituminous sandstone extracts have a unimodal pattern in the n -alkane distribution with nC_{21} -dominant. Major peaks occur at C_{15} or C_{17} . The C_{21}/C_{22+} ratio is greater than 1.18 and the $(C_{21}+C_{22})/(C_{28}+C_{29})$ ratio is greater than 0.76. These suggest a significant algal and bacterial contribution to the original organic matter. The Pr/Ph ratio is 1.67 or more, indicating an oxic depositional environment. An odd-over-even predominance is not

clear; the CPI is 1.28 and 1.25, respectively (Table 4); the OEP is 0.72 and 1.07; while Rc (calculated from th MPI₁) is 0.70%. These features, together with the high resin and asphaltene content, show that the organic matter is mature, and that the bituminous sandstones probably contain the remnants of immature oils.

Stable isotopes

Because liquids derived from kerogen maintain the isotopic compositions of the original source rocks, the saturate and aromatic isotope ratios can be used to identify organic facies (Rogers, 1980).

Stable carbon isotopic data for saturate and aromatic fractions of samples analysed are presented in Table 5. For all these samples, the carbon isotope ratios appear to vary little; thus for saturates, $\delta^{13}C$ varies from -28.6‰ to -23.7‰, and for aromatics from

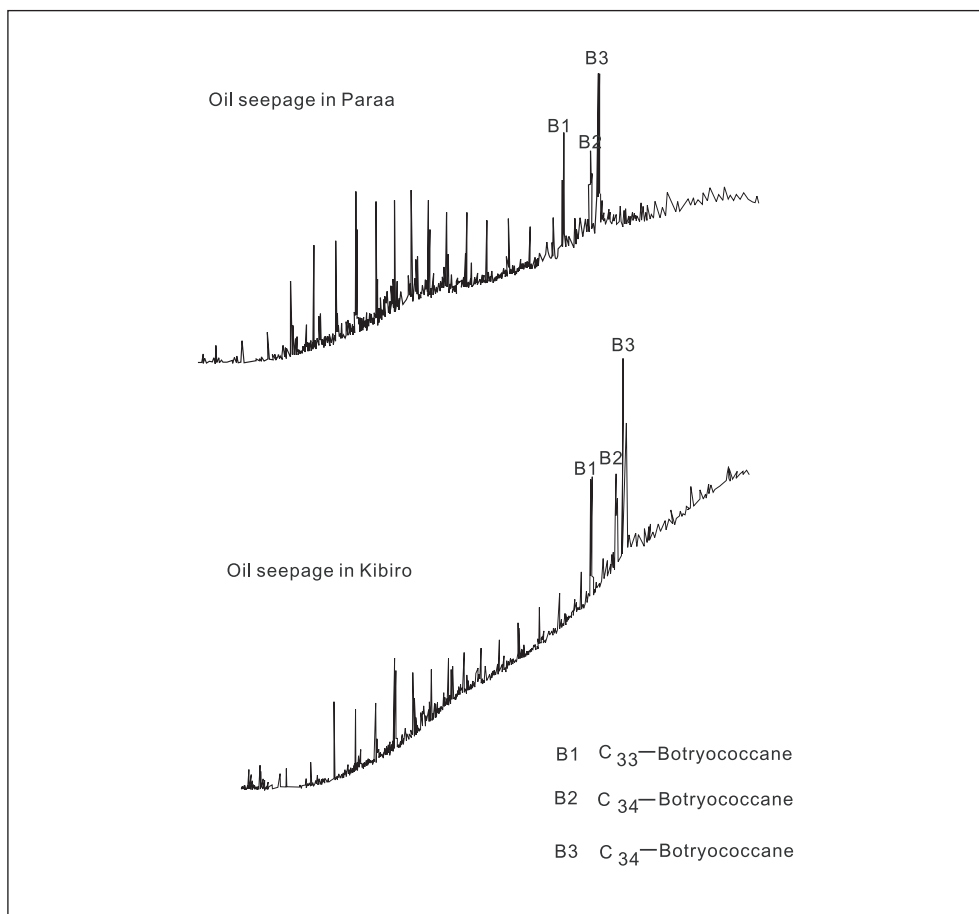


Fig. 5. m/z 183 mass chromatograms of seepage oils showing the presence of botryococcanes.

Sample No	Biomarker Parameters					
	I	II	III	IV	V	VI
1228	0.47	0.07	0.04	0.09	0.07	1.13
1229	0.62	0.06	0.03	0.08	0.06	1.18
1228p	0.53	0.08	0.04	0.06	0.07	0.99
1229p	0.62	0.1	0.04	0.05	0.09	1.02
1230	0.44	0.11	0.1		0.17	2.83
1237	0.36	0.16	0.17	0.2	0.26	0.94
1238	0.41	0.08	0.18	0.23	0.19	0.97
1239	0.24	0.04	0.19	0.25	0.14	0.7
1240	0.33	0.1	0.11	0.23	0.09	2.93
1241	0.26	0.01	0.11	0.36	0.17	2.03
1242	0.48	0.29	0.19	0.21	0.29	3.04
1243	0.19	0.1	0.28	0.24	0.18	2.77

Table 6. Biomarker parameters for the seepage oil, bituminous sandstone and shale samples analysed. See Table I for sample number identification.

Key:

- I. diasterane to regular C₂₇ sterane ratio;
- II. (C₂₁+C₂₂)/(C₂₇+C₂₈+C₂₉) sterane ratio;
- III. sterane to hopane ratio;
- IV. gammacerane to hopane ratio;
- V. tricyclic to pentacyclic terpane ratio;
- VI. ratio of C₂₄-tetracyclic to C₂₆-tricyclic terpanes.

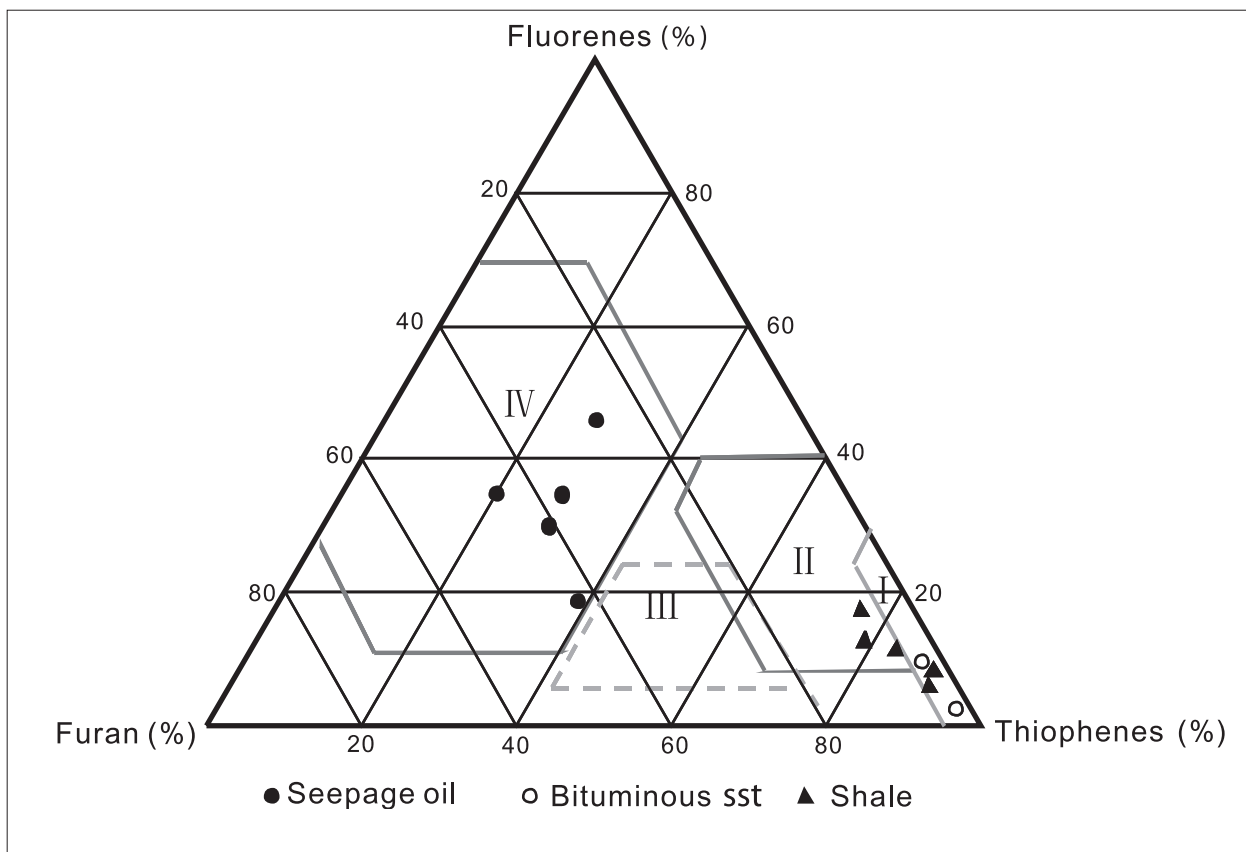


Fig. 6. Triangular plot of relative contents of furan, thiophenes and fluorenes in the samples analysed (after Ding Anna et al., 1997).

Fields are: I. marine carbonates; II. saline mudstones; III. lacustrine mudstones; IV. coaly mudstones.

-27.7‰ to -22.6‰. According to the classification of Rogers (1980), this indicates that the precursor source rock was dominated by higher land plants with a minor algal contribution.

BIOMARKERS ANALYSES

Oleanane

Source rock depositional environment and organic matter type can be interpreted according to biomarker characteristics (Peters and Moldowan, 1993). 18α (H)-oleanane is generally thought to be derived from Cretaceous or younger higher plants (Peters et al., 1993). Abundant oleanane was detected in the Kibuku seepage oil and in shale samples 01-1240, 01-1241 and 01-1243; traces of oleanane occurred in the Paraa oil and the Kibiro oil and in mudstone sample 01-1242, but no oleanane was identified in the other samples (Fig. 4). This suggests that the organic matter in the shale samples is derived from a Cretaceous or younger source rock, and the seepage oils from Cretaceous or Tertiary units.

In addition, it suggests that the source rocks generating the Kibuku seepage oil may contain more terrestrial organic matter than those supplying the Paraa and Kibiro seepage oils.

Botryococcanes

The presence of botryococcanes in the Paraa and Kibiro seepage oils is illustrated in the m/z 183 mass chromatograms in Fig. 5. As these biomarkers are only derived from *Botryococcus brannui* which is confined to mild saline or lacustrine sedimentary environments (Peters and Moldowan, 1993), the Paraa and Kibiro seepage oils are interpreted to be derived from lacustrine shales.

Biomarker ratios (Table 6)

Table 6 VI shows that the shale samples and the Kibuku seepage oil have a high abundance of C_{24} -tetraterpanes relative to C_{26} -tricyclic terpanes; this ratio is lower in the Paraa and Kibiro oils.

The presence of gammacerane generally suggests a hypersaline marine or non-marine environment (Peters and Moldowan, 1993) and the gammacerane/ C_{30} hopane ratio is thought to indicate the salinity of the depositional setting. Table 6 IV indicates that this ratio is 0.1 or lower for the Kibuku, Paraa and Kibiro oils, indicating a freshwater lacustrine setting for the respective source rocks. However, the ratio is 0.2 or above for the bituminous sandstones and the shales, indicating a hypersaline terrestrial environment for their source rocks. Palaeoclimatic analyses indicate

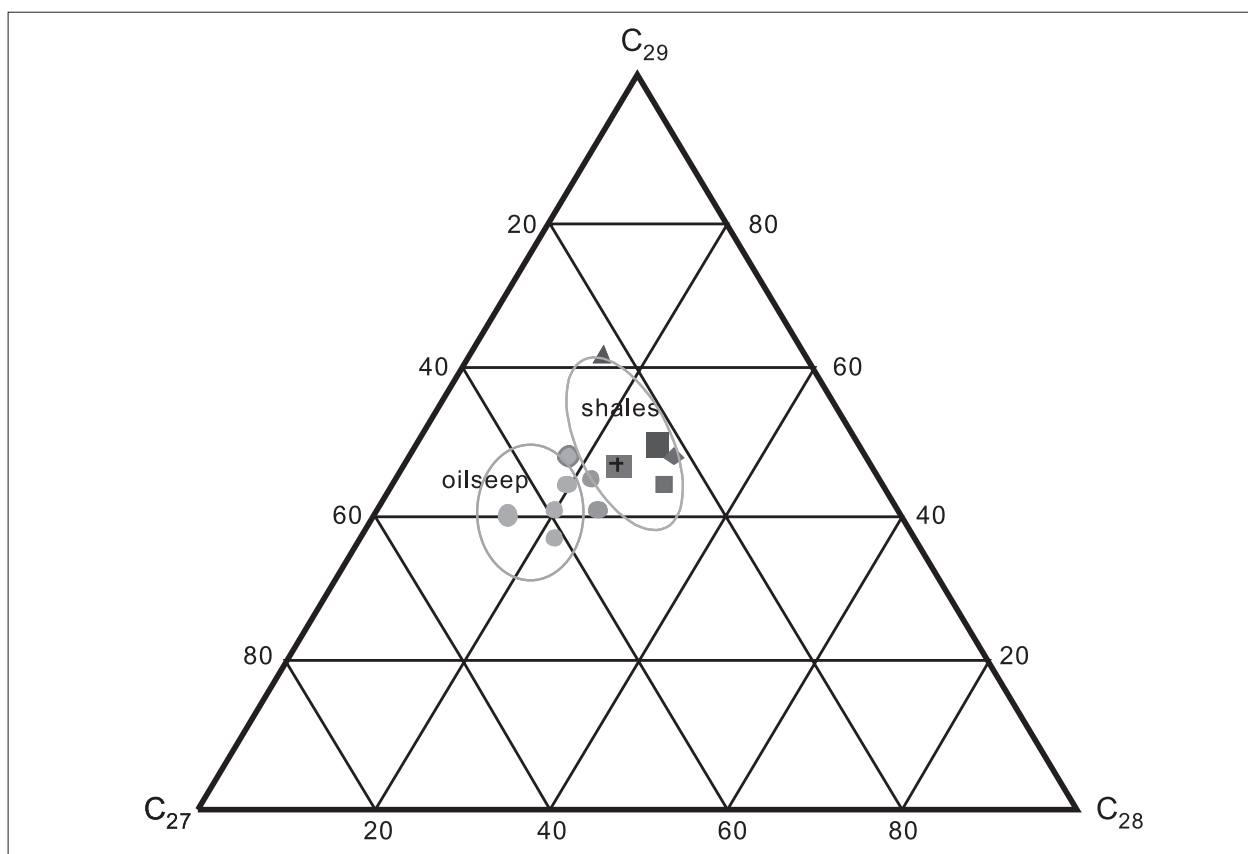


Fig. 7. Triangular plot of C_{27} , C_{28} , C_{29} regular sterane compositions for the samples analysed.

an arid climate during the late Tertiary, and that evaporation was stronger than precipitation resulting in saline waters (Pickford, 1992).

Relative proportions of furan, thiophenes and fluorenes in the samples analysed are plotted on the triangular diagram in Fig.6. The bituminous sandstones can clearly be distinguished from the seepage oils on this figure.

Tricyclic terpanes are primarily derived from bacterial and algal lipids, and hopanes are derived from various prokaryotic organisms (Peters and Moldowan, 1993). The tricyclic terpane:hopane ratio may reflect differences among precursor source rocks. In Table 6, it can be seen that the Paraa and Kibiro seepage oils have a low tricyclic terpane:hopane ratio suggesting a different source from the Kibuku oil and the bituminous sandstones. Maceral analysis indicates that only sclerotinites and a small amount of algae are present, which is consistent with the shale saturates having a high abundance of tricyclic terpanes.

The sterane distribution is frequently used to characterize the organic matter in a source rock, and to determine the genetic relationship between oils and source rocks (Peters and Moldowan, 1993). The triangular diagram of C_{27} , C_{28} , C_{29} regular steranes in Fig. 7 shows that there is little variation in sterane

distribution between the shales and the seepage oils. The shales show a slight predominance of C_{29} steranes over C_{27} steranes, more so than the bituminous sandstones and the Kibuku seepage oil; while the Paraa and Kibiro oils have similar contents of C_{27} steranes and C_{29} steranes. In terms of their tri-aromatic sterane distributions, the three seepage oils have high contents of C_{26} and C_{27} steranes, while the bituminous sandstones have a lower content.

The regular sterane:hopane ratio may represent the contribution of eukaryotes (i.e. both algae and higher plants) and prokaryotes (bacteria) to source rock OM (Peters and Moldowan, 1993). A low abundance of steranes and a low sterane:hopane ratio may point to terrestrial or biodegraded organic matter. The analysed samples have low sterane:hopane ratios (Table 6 III), especially the Paraa and Kibiro seepage oils. The shales and bituminous sandstones have slightly higher ratios. This implies that the original organic matter which generated the Paraa and Kibiro seepage oils was of the high quality, while the organic matter in the shales and bituminous sandstones was of poor quality.

Maturity parameters

Fig. 8 is a plot of regular sterane parameters $C_{29}20S/$

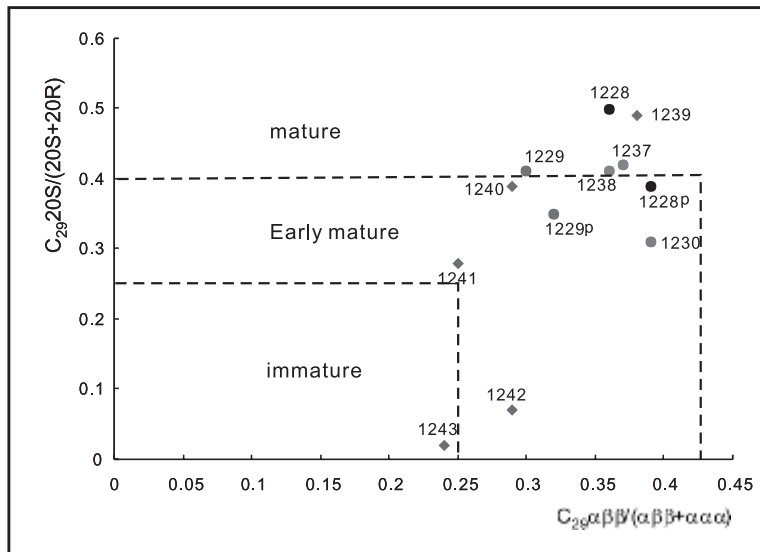


Fig. 8. Plot of regular sterane parameters $C_{29}20S/(20S+20R)$ versus $C_{29}\alpha\beta\beta/(\alpha\beta\beta+\alpha\alpha\alpha)$ for the studied samples. (After Peters and Moldowan, 1993).

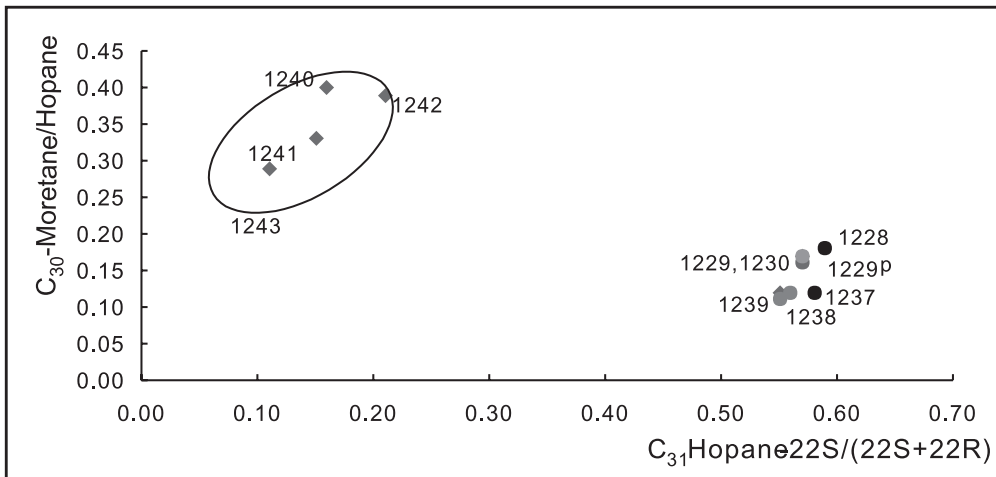


Fig. 9. Hopane maturity parameters: C_{30} moretane/hopane versus C_{31} hopane $22S/(22S+22R)$. (After Peters and Moldowan, 1993).

(20S+20R) versus $C_{29}\alpha\beta\beta/(\alpha\beta\beta+\alpha\alpha\alpha)$. The plot shows that the seepage oils, bituminous sandstones and two of the shales show similar, relatively high levels of maturation compared to that of the other three shales except sample 01-1240.

Maturity of the seepage oils, bituminous sandstones and shales can also be distinguished on a graph of C_{30} moretane/hopane versus C_{31} hopane $22S/(22S+22R)$ (Peters and Moldowan, 1993) (Fig. 9). OM in four of the shale samples is immature; that in sample 01-1239 is marginally mature; while the seepage oils and bituminous sandstones appear to be threshold mature to mature.

CONCLUSIONS

From our analyses of seepage oils, bituminous sandstones and shales in the Albertine graben, we draw the following major conclusions. Biomarker and other

data indicate that the Paraa and Kibiro seepage oils were derived from a source rock containing Type I and II_1 kerogen deposited in a fresh water lacustrine environment. The Kibuku seepage oil was derived from a source rock containing Type III kerogen. These source rocks are probably pre-Tertiary in age. Molecular maturity parameters show that the Paraa and Kibiro seepage oils are more mature than the Kibuku seepage oil.

Organic matter in the bituminous sandstones is dominated by terrestrial material, and is derived from a Tertiary source rock. Thus, at least two active source rocks are present in the Albertine graben and have generated and expelled hydrocarbons. However, the source rocks could not be correlated with the shales analyzed because the shales are immature or just entering the hydrocarbon-generating window. The shale samples analysed have a low-to-medium TOC content and a low generation potential.

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