Infilling Direction and Fluid Communication in the E2.0 Reservoir of the Kolo Creek Oil Field, Niger Delta

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ABSTRACT: A suite of oil samples from the E2.0 reservoir in the Kolo Creek oil field in Niger Delta, Nigeria were analysed to discern possible fluid communication between the wells of the reservoir and charging/infilling direction of the reservoir using geochemical tools. The study reveals a close similarity in percentage contents of the saturates, aromatics, resins and asphaltenes in all the oils. The maturity gradient clearly shows a maturation trend in the Southwest-Northeast direction which indicates that subsequent charge from the oil kitchen were more mature than the initial charges. The reservoir appears to be charged with hydrocarbons from source kitchen in the Southwest to Northeast direction. In addition, the use of the interparaffins from the GC fingerprints for correlating the oils indicates a significant degree of communication between the oils thereby ruling out any significant in-reservoir barrier. This information suggests potential ease in producing the R2.0 reservoir and the possibility of other accumulations in the periphery of the field.
Keywords: Kolo Creek, reservoir geochemistry, reservoir continuity, Niger Delta, petroleum migration, biomarkers.

INTRODUCTION

The study of hydrocarbon migration pathways is an important component of petroleum exploration particularly in discovering new plays. It shades light on the possible infilling direction and provide important information on possibility of reservoir connectivity and compartment-talisation. Furthermore, it gives information on the direction of charging petroleum fronts which is very crucial in the locating of new producing wells and injection wells (England *et al*, 1987; Holba *et al.*, 1996; Horstad & Larter, 1997).

The infilling of petroleum reservoirs is a sequential process. The advancing petro-leum front first gets into more permeable zone with lowest entry pressure and the subsequent charges of more mature petro-leum migrating into the reservoir from source kitchen displaces the less mature and earlier petroleum fronts forward (England & Mackenzie, 1989; England *et al.*, 1987; Horstad & Larter, 1997). Thus the petroleum closest to the source kitchen is always the most mature petroleum. The consequent hypothesis is that the maturation and generation of petroleum from source rock is a dynamic process involving continuous generation and expulsion of petroleum from the beginning of the oil window to the end. Thus continuously more mature oil is expelled which migrates into the reservoir. This obviously implies the possibility of detecting a lateral maturity gradient from which the reservoir infilling direction could be deduced (England & Mackenzie, 1989; Horstad & Larter, 1997).

On the other hand, the study of reservoir connectivity and compartmentalisation is based on the hypothesis that where fluid continuity in a reservoir is possible, wells within the reservoir or field may have dynamic fluid communication such that fluids from such wells will show significant similarity in physical and chemical properties (Holba *et al.*, 1996). Consequently methods and tools have been developed to help investigate this phenomenon.

The finger print method for the assessment of reservoir connectivity is well developed (Hwang *et al.*, 1994; Hunt, 1996; GeolabNor, 2004). The technique assesses fluid communication by the comparison of the relative abundances of interparaffins peaks of oils from the wells. In particular, the C_8-C_{20} molecular range has been observed to be the most diagnostic range for the reservoir connectivity/continuity assessment (GeolabNor, 2004). In this study, we examined the geochemistry of the E2 reservoir of the Kolo Creek field in the Niger Delta with the aim of assessing the reservoir's filling direction and connectivity, since studies on the field has not been in that direction (Oboh, 1993; 1995).

The Kolo Creek Oil Field

The Kolo Creek is an onshore field in the central Niger Delta. The field is about 5×10 Km in aerial extent. The main reservoir is the E2.0 which reservoir is oil bearing with depth ranging from 3580 to 3670 meters and is about 50 - 60 meters thick.

The sedimentary sequence is mainly deltaic depositional sub-environments. The lithofacies identified are rich in palynodebris, wood fragments, black debris and amorphous organic matter. The palynomorph assemblage has been used to date the reservoir to the early part of the middle Miocene (14 to 15 Ma before present), which has been identified to be deposited in parasequenece of shallow marine and deltaic plain deposits (Oboho, 1995).

SAMPLES AND METHODS

Samples used in this study were 10 Tertiary crude oils from 10 different wells ranging from 3580m – 3670m in depth of the E2.0 reservoir. The samples were collected from the wellhead and were thus representative of the bulk (Abdullah & Connan, 2002; GeolabNor, 2004; Halpern, 1995; OilTracers, 2007). The samples were stored in glass vials in refrigerator until required for analysis.

The relative proportions of aliphatic hydrocarbons, aromatic hydrocarbons, resins and asphaltenes (SARA) were determined by Iatroscan (TLC-FID) using model Iatroscan new MK-5 TLC-FID Analyser according to the method described by Karlsen & Larter (1991).

The oils in this study was fractionated with a procedure which consistent with that described in an earlier study by Abrakasa (2006) and Abrakasa and Muhammad (2007). Briefly, the oils were blended with alumina before introduced in to the chromatographic column. The samples were fractionated into aliphatics, aromatics and polar fractions by liquid column chromatography using silica (AnalaR grade supplied by BDH, England) as stationary phase. Aliphatic and aromatic fractions were eluted with petroleum ether and dichloromethane respectively. The aliphatic fraction was concentrated by first reduction by rotary evaporator to about 5mls and reduced to 1ml under a stream of nitrogen gas and analysed by GC and GC/MS.

The GC analysis of the aliphatic hydro-carbon was done on an HP5890 GC serial II. The column for the GC is a HP5 column, which 30metres long with internal diameter of 0.25mm. The film thickness is 0.25 microns. It has a split/split-less injector and hydrogen gas was used as the carrier gas at 2ml/min. The temperature program used was 50ºC for the aliphatic hydrocarbon. The temperature according to the program was held at 50ºC for 2 minutes, then run at 4ºC per minute to 300ºC, at which it was held for 20mins.

GC/MS analysis was on a Hewlett-Packard 5890 II GC with a split/split-less injector linked to a Hewlett-Packard 5972MSD with electron voltage of 70 eV, filament current of 220 µA. The temperature range for separation of the compounds is between 40˚C and 280˚C. The acquisition was controlled by an HP Vectra 48 PC ChemStation computer in both full scan mode and selected ion mode (30 ions 0.7 cps 35 ms dwell) for greater sensitivity. Integration of relevant peaks on *m/z* 217 for the steranes was done manually and peaks identification was from mass spectra. Steranes was used because it has been recommended as the most reliable maturity parameter (Tissot & Welt, 1984; Zumberge, 1987) and by comparison with standard chromatograms and matching with analysed standards (Peters *et al*, 2005).

RESULTS AND DISCUSSION

The oils generally show typical of Nigerian oils characteristics. The bulk geochemistry of the oils show that the saturated hydrocarbons were the highest fraction of the oils (*ca* 65%) followed by aromatic hydrocarbons (*ca* 30%). The asphaltenes were generally 1% or less and the resins about 3 to 4% (Table 1). This generally suggests that the oils are light crudes oils with fairly good fluidity. This is further supported by dominance of the lighter homologues in the *n*-alkane distributions as in the GC trace (Fig 1) which also shows the presence of homologues upto C_{35} (clearly showing the oils are not biodegraded).

Table 1: The bulk composition of the ten crude oils used in this study.

Wells	Saturates (%)	Aromatics (%)	Resins (%)	Asphaltenes (%)
SA02	65.0	31.0	3.0	1.0
SA03	58.0	38.0	3.0	0.5
SA15	69.0	26.0	4.0	1.0
SA16	69.0	25.0	4.0	1.0
SA19	66.0	31.0	3.0	1.0
SA20	63.0	32.0	4.0	1.0
SA22	65.0	31.0	3.0	0.4
SA23	67.0	28.0	4.0	0.6
SA25	62.0	34.0	4.0	0.7
SA29	70.0	26.0	3.0	0.5

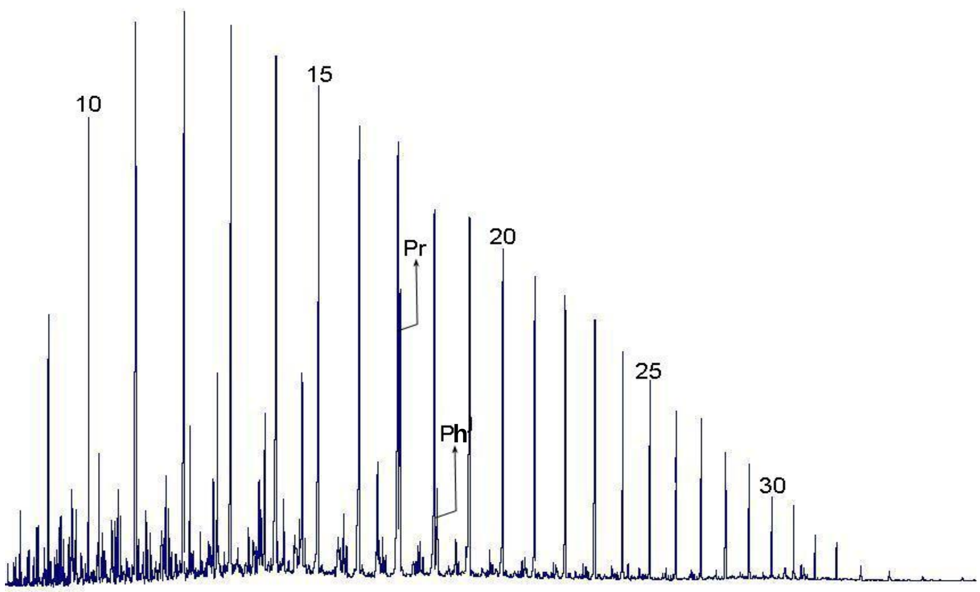

Fig 1: A representative GC fingerprint of the Kolo Creek reservoir oils showing higher lighter ends ($C_{10} – C_{15}$), the isoprenoids (pristane, Pr and phytane, Ph), *n*-alkanes homologues (up to C_{35}) and the inter-paraffins used in continuity studies.

Field Infilling direction

Table 2 shows some organic geochemical indices computed from sterane biomarker contents of the oils. In general, all the oils have very similar values of these, and other geochemical indices (e.g. %Ts/Ts+Tm, %C_{31}22S/22S+22R, Oleanane/C_{30}hopanes hopane) and molecular signatures (Abrakasa, 2004; Abrakasa, 2006; Abrakasa & Muhammad, 2007); indicative of same source rock for all the oils as they have similar characteristics for the deposition environment and source organic matter.

Despite the general similarities among the oils, there is subtle but important difference in the maturity as indicated by the ratio of the S and R isomers of the C_{29} ααα sterane in column D of Table 2. This parameter has been recommended as fairly reliable maturity index (Peters *et al.*, 2005; Peters & Moldowan, 1995; Tissot & Welte, 1984; Zumberge, 1987). The index indicates a maturity gradient varying among the wells with the highest value at well SA29. Based on the infilling hypothesis, this well bears the most recent charge from the source kitchen, given that the kitchen maturity increases with time.

Table 2: The various sterane ratios from the *m/z* 217 mass chromatogram comprising the steranes

Sample	A	B	C	D	E
SA02	41	24	35	41	38
SA03	42	24	34	37	35
SA15	42	25	34	40	34
SA16	42	24	34	40	37
SA19	41	24	35	36	36
SA20	41	25	34	34	33
SA22	40	25	35	45	35
SA23	42	23	35	39	34
SA25	42	25	33	37	35
SA29	41	24	36	45	35

Key: A=% $C_{29}/(C_{27}+C_{28}+C_{29})$ ααα steranes; B=% $C_{28}/(C_{27}+C_{28}+C_{29})$ ααα steranes; C=% $C_{27}/(C_{27}+C_{28}+C_{29})$ ααα steranes; D=% $C_{29}S/(C_{29}S+ C_{29}R)$ ααα steranes; E=% $C_{29}\alpha\beta\beta/(C_{29}\alpha\beta\beta+C_{29}\alpha\alpha\alpha)$ steranes.

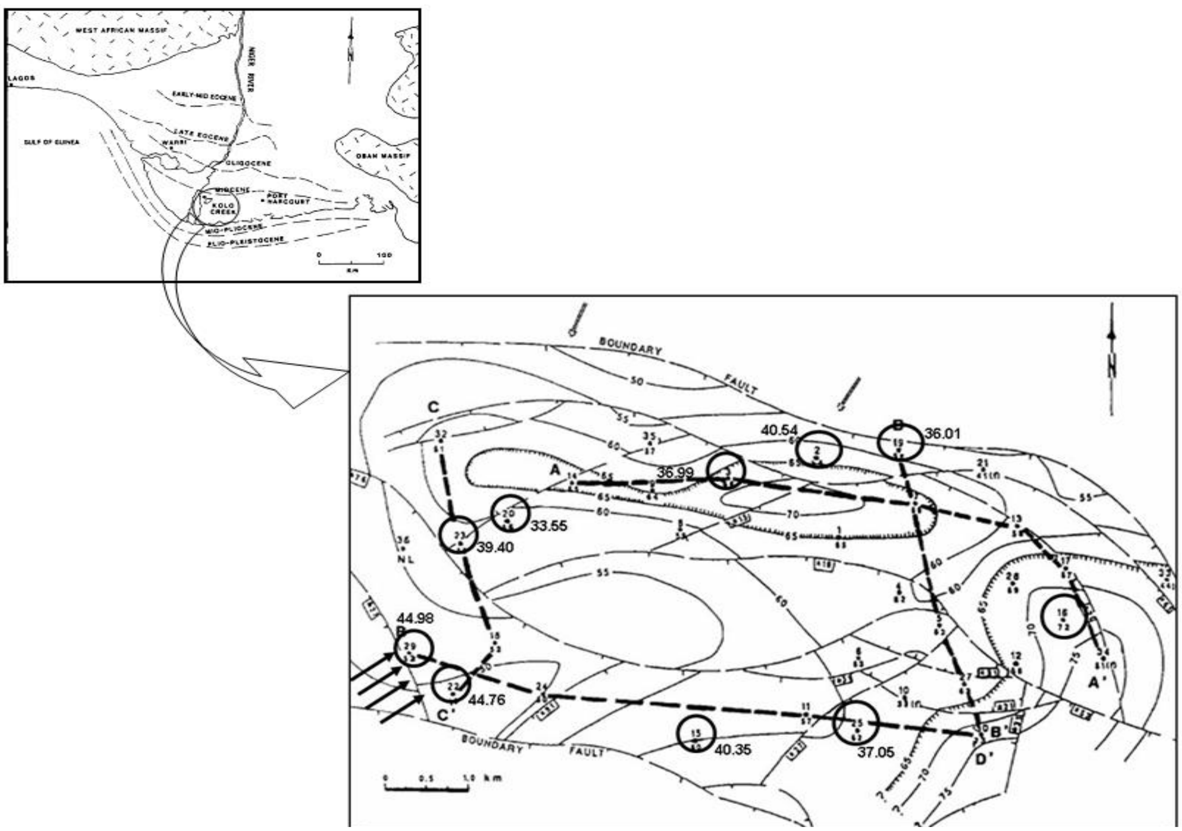

Fig 2: Map of the Niger Delta showing the Kolo Creek oil field and an isochore map of E2.0 reservoir showing trend in maturity of the oils in the northeast-southwest direction. Infilling direction is indicated by arrows. Uppermost is the map of the Niger Delta showing position of the oil field (From Oboh, 1993).

The trend in maturity across the reservoir is more evident when the values of the maturity index are plotted on the map of the reservoir as in Fig 2. A lateral maturity gradient is clearly established across the field. The maturity appears to decrease from wells in the Southwest of the field towards those in the Northeast. Thus based on petroleum generation dynamics discussed earlier, it is logical to infer that the infilling direction of the reservoir is from Southwest towards Northeast and consequently the source kitchen is somewhere in the south of the Kolo Creek field or in the Gulf of Guinea (Fig 2).

Reservoir Continuity

Absence of barriers in hydrocarbon reservoirs provides the possibility for reservoirs to communicate with each other and such situations the hydrocarbons exhibit fairly identical characteristics. In fact, it has been empirically observed that the oils from a continuous reservoir exhibit identical chromatographic fingerprints, whereas oils from separate reservoirs exhibit significantly different chromatographic fingerprints. Consequently, it is possible to discern the reservoir continuity from the GC traces of oils from different sections of the reservoir (e.g. Hwang *et al.*, 1994; Kaufman *et al.*, 1990; Slentz, 1981). One of the sensitive methods used for evaluating reservoir continuity/ connectivity used is the interparaffins (e.g. Hwang *et al*, (1994).

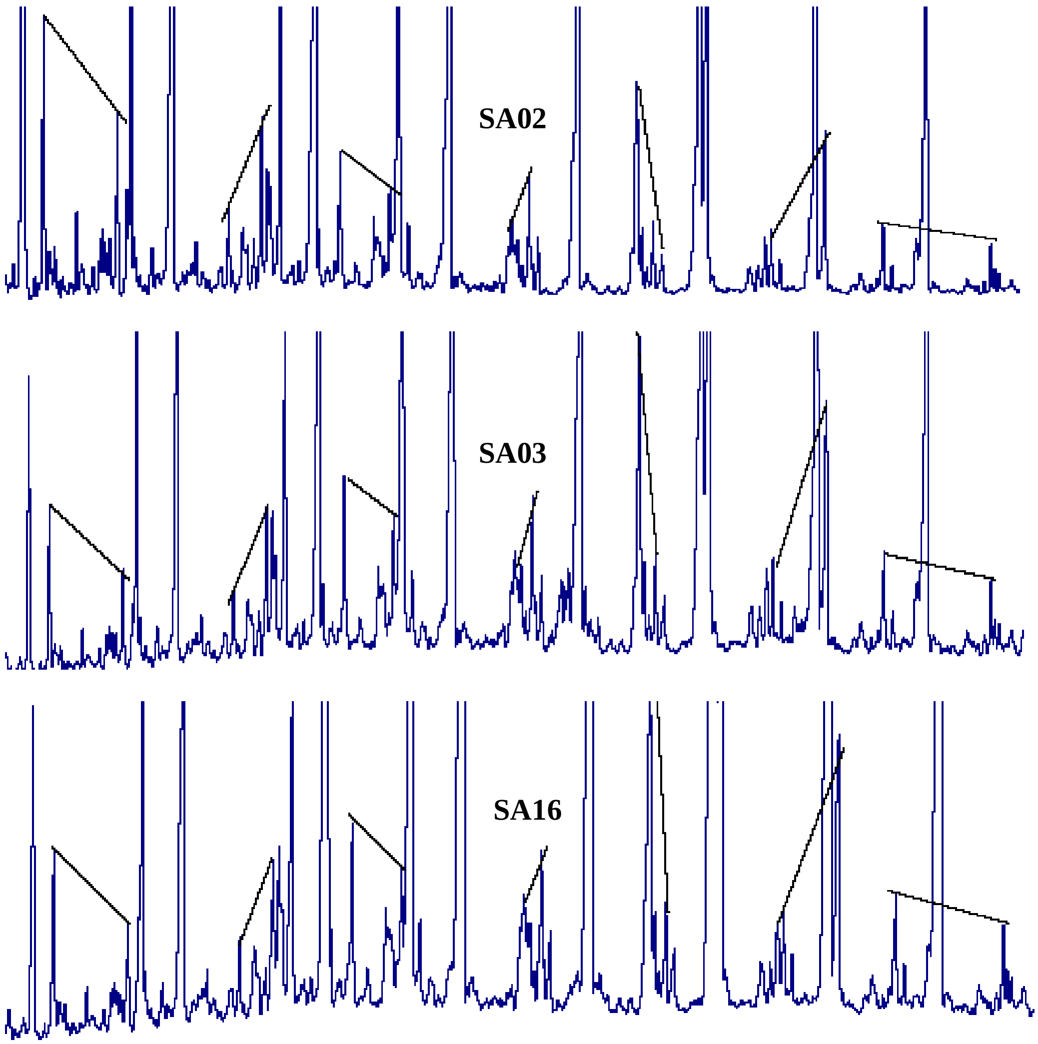

Fig 3: GC traces of 3 of the 10 oils showing the relevant inter-paraffins peaks used fingerprint ratios.

Fig 3 shows representative GC traces showing the inter-paraffins employed for correlation in this study. Same peaks, identified using retention time, were used in all the traces and the ratios were computed from the peak heights. Fig 4 shows the polar (star diagram) plot of the ratios. The plot shows same trend for all the samples and thus indicates high similarity among the oils. This means that the hydrocarbons (or fluids in general) from all the wells are similar. It further suggests that there is communication between fluids in the reservoir. In other words, the reservoir is continuous and well connected. This is supported by the work of Oboho (1995) who showed that the oil bearing horizon of the E2.0 reservoir is mainly sandstone with good porosity of 14 to 32%. and so allowing for good in-reservoir communication.

The fact that a lateral maturity gradient is established and the reservoir is well connected means that the E.2.0 reservoir has an appreciable degree of lateral homogeneity of petroleum in terms of bulk molecular composition across the field but at the same time preserves a significant lateral molecular thermal heterogeneity reflecting original petroleum generation dynamics (Slentz, 1981; Kaufman *et al.*, 1990; Hwang *et al.*, 1994).

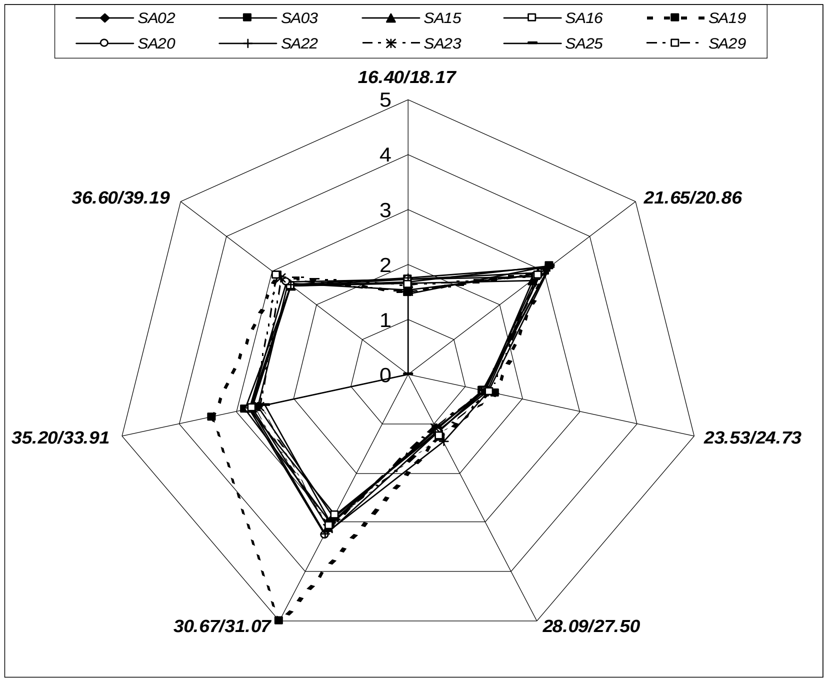

Fig 4: Polar plot showing the similarities of the Kolo Creek oils suggesting lateral continuity of the reservoir.

CONCLUSION

This study explored the reservoir organic geochemistry of the E2.0 reservoir of the Kolo Creek oil field in the Niger Delta using well developed tools to determine the possible infilling direction of the reservoir and its continuity. The biomarker-based maturity gradient shows the reservoir was charged with hydrocarbons from Southwest towards the Northeast suggesting the source kitchen to be situated somewhere in Southwest to the field. The reservoir continuity appraisal, on the other hand, shows fairly uniform oil composition in the reservoir indicative of well connected reservoir and a possible single source for the oil. The close similarity of the oils in different wells across the reservoir invariably suggests that the wells are connected and the reservoir is continuous.

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