Intra-Delta Versus Sub-Delta Sourcing of Petroleum - a Global Review*

By
Olukayode J. Samuel[1], D. Martin Jones[1], and Chris Cornford[2]

Search and Discovery Article #40243 (2007)
Posted June 25, 2007

*Adapted from extended abstract prepared for 2006 AAPG International Conference and Exhibition; November 5-8, 2006; Perth, Australia

[1]School of Civil Engineering and Geosciences, Drummond Building, University of Newcastle upon Tyne, NE1 7RU, UK (o.j.samuel@newcastle.ac.uk)
[2]Integrated Geochemical Interpretation Ltd (IGI), Hallsannery, Bideford, Devon, EX39 5HE, UK

Introduction

Petroleum occurrences in sedimentary basins are routinely described in relation to the source rock from which they have been generated. This concept of looking at petroleum occurrence in terms of the physical and temporal processes of generation in and expulsion from a single pod of mature source rock is termed a "Petroleum System" (Perrodon 1992; Magoon and Dow 1994a). By various migration pathways, a single Petroleum System may charge a number of accumulations with reservoirs at various stratigraphic levels and traps (structures + seals) of various types. By emphasizing the efficiencies of generation, expulsion, migration and entrapment, the Petroleum System concept encourages prediction of volumes and composition in undrilled prospects. Arguably this statement is least true for oil and gas exploration in river-mouth deltas.

Most of the world's major deltas with known hydrocarbon potential are shown in Figure 1. These include the Beaufort-Mackenzie, Assam-Barail, Niger, Mississippi, Mahakam, Mekong, Amur, Lema, and Baram. Oil and gas reservoired within deltaic sediments constitute a significant percentage of the world's known hydrocarbon reserves, but whether these accumulations are truly generated from source rocks within the delta remain unproven. According to Peters et al. (2005, p.752), nearly all the petroleum systems defined for Tertiary deltas have been assigned the speculative to hypothetical level of certainty. This may be because, in the thick wedge of prograding sediments that constitute a delta, organic-rich oil-prone source rocks are rarely encountered in exploration wells. With the exception of delta-top coals, typical deltaic sediments are organic lean and not particularly oil-prone. This leaves three possible models for the sourcing of oil and gas reservoired within deltaic sediments:

- That *intra-delta* source rocks exist, but, other than perhydrous coals, have yet to be reliably identified.
- That the relatively lean source rocks encountered can account for the observed volumes of oil and gas, implying exceptionally high expulsion and migration efficiencies.
- That oils are generated in *sub-delta* source rocks and migrate into deltaic reservoirs.

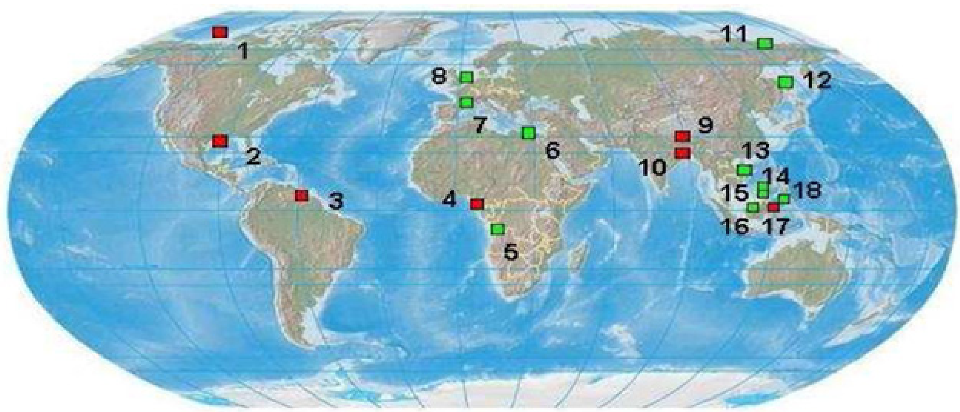
In order to discriminate between these models, we have studied the geochemistry of 250 reservoired oils at the molecular and isotopic level to reflect the source rock '*organofacies'* as it reflects the combination of organic matter type and depositional environment (Jones, 1987; Peters et al., 2000; Haack et al., 2000). This approach of drawing inference of deltaic source rock facies from the basin's regional petroleum accumulation rests on the assumption that the oil's composition has been little (or predictably) altered during the sequence of generation in, and expulsion from, the source rock, followed by migration through the carrier beds.

The delta-top sediments of tropical deltas contain shale through to perhydrous coal (e.g., Assam-Barail, Mahakam), with only the latter enriched in oil-prone macerals such as resins, cuticles, pollen, and spores. In contrast, the kerogens of intra-delta shales are generally low in oil-prone amorphous organic matter and hence constitute Type III gas-prone (vitrinitic) kerogen (Durand and Parratte, 1983; Bustin, 1988). A number of workers have carried out individual studies on both source rock characterisation and the crude oil geochemistry in these deltas; e.g., Mackenzie Delta (e.g., Snowdon and Powell, 1979; Curiale, 1991), Assam-Barail Delta (e.g., Raju and Mathur, 1995; Goswami et al; 2005), Mahakam Delta (e.g., Durand and Parratte, 1983; Peters et al., 2000), Niger Delta (e.g., Ekweozor and Okoye, 1980; Bustin, 1988; Haack et al., 2000; Eneogwe and Ekundayo, 2003). Of the studied deltas, oil-source rock correlations are highly disputatious. Arguably, the most reliable correlation is obtained from the Assam-Barail delta, which is the "fringe" Barail Delta partly buried under, and partly exposed as a result of the Naga overthrust (Goswami et al., 2005).

Common to all these studies is that significant proportions of the oils reservoired in the Tertiary sands do not share geochemical affinity with the so-called delta source rock samples. For instance, in the Niger Delta, the source rock is described as a low TOC (average ca. 1.5%) and Type III kerogen-dominated facies (Ekweozor and Okoye, 1980; Bustin, 1988), and it has been proposed that the thick source rock interval compensates for the poor source rock quality (Bustin, 1988; Demaison and Huizinga, 1994). If the huge volume of oil accumulated within the Niger Delta is to be sourced from such analysed Tertiary sediments, very high transformation, expulsion, and migration efficiencies are demanded. Thus, there is a geochemical paradox between the volumes and types of produced oil and Tertiary source rocks. In general, this appears to be a global phenomenon and raises some key questions:

- a) Do deltas act primarily as sedimentary overburden to mature the organic-rich rocks buried below them, and hence as reservoirs to accommodate oils expelled from pre-existing source rocks?
- b) How much of the oil in deltaic accumulations is truly generated by the lean and generally mixed 'gas+oil-prone' kerogens seen in deltaic source rocks?

To address this issue (and as a prelude to new analyses of a global collection of Tertiary deltaic oils), in addition to few oils from our own analyses, we have assembled from published literature a large database of bulk, molecular and isotopic properties of analysed oils.



1= Beaufort –Mackenzie (Mackenzie). 2 = Gulf of Mexico (Mississippi). 3 = Orinoco (Orinoco). 4= Niger (Niger-Benue). 5= Ogooué (Congo). 6 = Nile (Nile). 7 = Rhone (Rhone). 8 = Rhine (Rhine). 9 = Assam (Ganges-Brahmaputra). 10 = Ganges-Brahmaputra (Ganges-Brahmaputra). 11 = Lena (Lena).12 = Amur- (Amur-Darya).13 = Mekong (Mekong).14 = Sabah (Sabah).15 = Baram (Baram). 16 = Balingian (Balingian). 17 = Mahakam (Mahakam).18 =Tarakan (Tarakan).

Figure 1: Map of the world showing the distribution of the major Tertiary deltaic basins with known hydrocarbon potential. Names in brackets are the draining river while red boxes are deltas selected for further studies.

Results

The C_{27}-C_{29} sterane ternary diagram (Figure 2) provides useful visual assessment of the organic matter provenance of a large crude oil dataset. The Assam-Barail samples group closely within the regions marked as coaly and delta top source rock facies as described by Goswami et al. (2005) as the coals of the Oligocene Barail Formation and the Kopili shale. The oils from the Mahakam Delta plot nearby as expected for the first major basins where coal has been demonstrated to be volumetrically capable of sourcing commercial oil (Durand and Parratte, 1983).

However, in detail samples of oils from the Mahakam discriminate two groups; the first group as seen in Figure 2 is a coaly facies sourced oil, while the second minor group plots in the shallow marine to open marine source environment field. It is interesting to add that the oil plotting in the shallow-open marine area of the graph contains significant quantities of C_{30} sedimentary *n*-propyl cholestane (as detected by GCMS/MS), which is associated with marine chrysophyte algae precursor (Moldowan et al., 1990). In addition, these oils contain very little higher plant input as indicated by the Oleanane Index, and this distinction is further corroborated by the stable carbon isotope data plots (Figure 3), where the canonical variable discriminates between marine and terrigenous oils (Figure 4).

On the basis of the plotted bulk (isotopes) and molecular (sterane) ratios, nearly all the Niger Delta oils in the dataset are of marine aspect, while conversely the vast majority of the Mahakam delta oils are of terrigenous aspect.

These observations provide an initial method of discriminating between oils from within or from beneath the delta. While the Niger Delta oils mainly appear to derive from sub-delta sources, the Assam-Barail and most of the Mahakam oils show characteristics of intra-delta sourcing. The bimodal distribution of the Beaufort-Mackenzie oils imply sourcing from both intra- and sub delta sources: viz., from a coaly and delta top source facies and a marine arguably sub-delta source. These conclusions are supported by less complete data sets for pristane/phytane, sterane/hopane, and oleanane/hopane ratios.

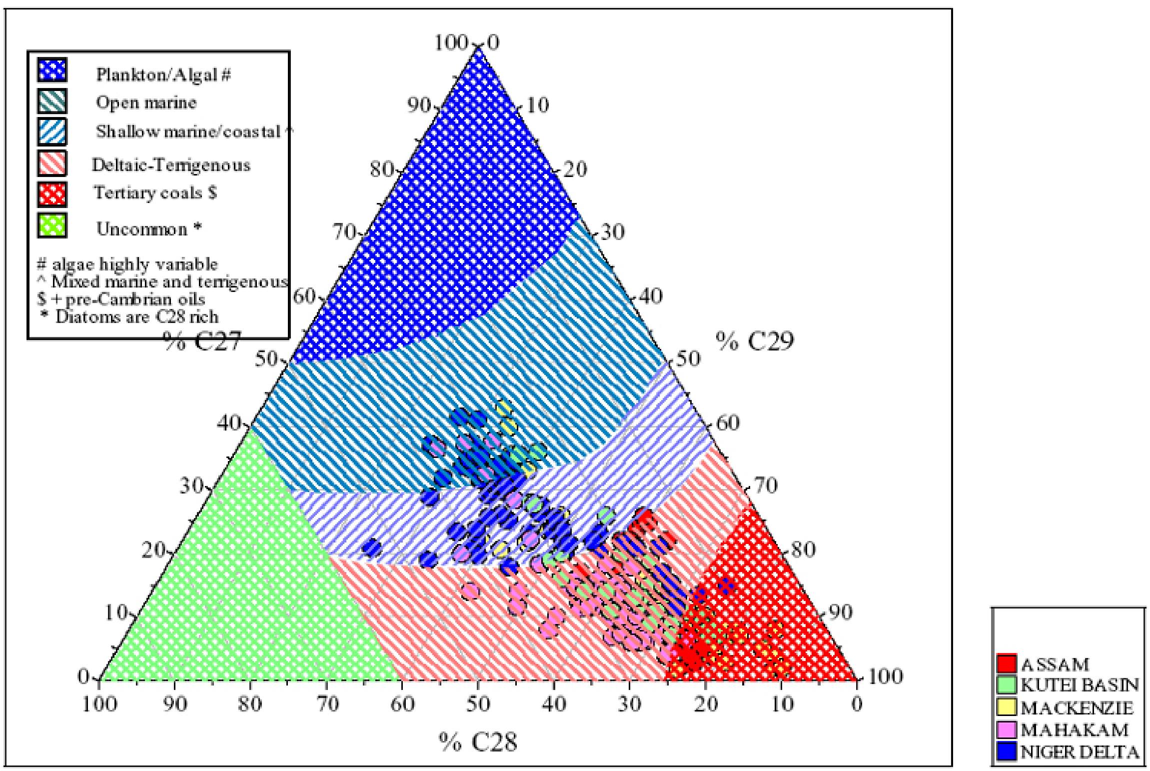


Figure 2: Ternary diagram showing the plot of C_{27} C_{28} and C_{29} steranes. The overlay fields defined are based on large global database of source rock sterane data of known origin modified after Huang and Meinschein (1979).

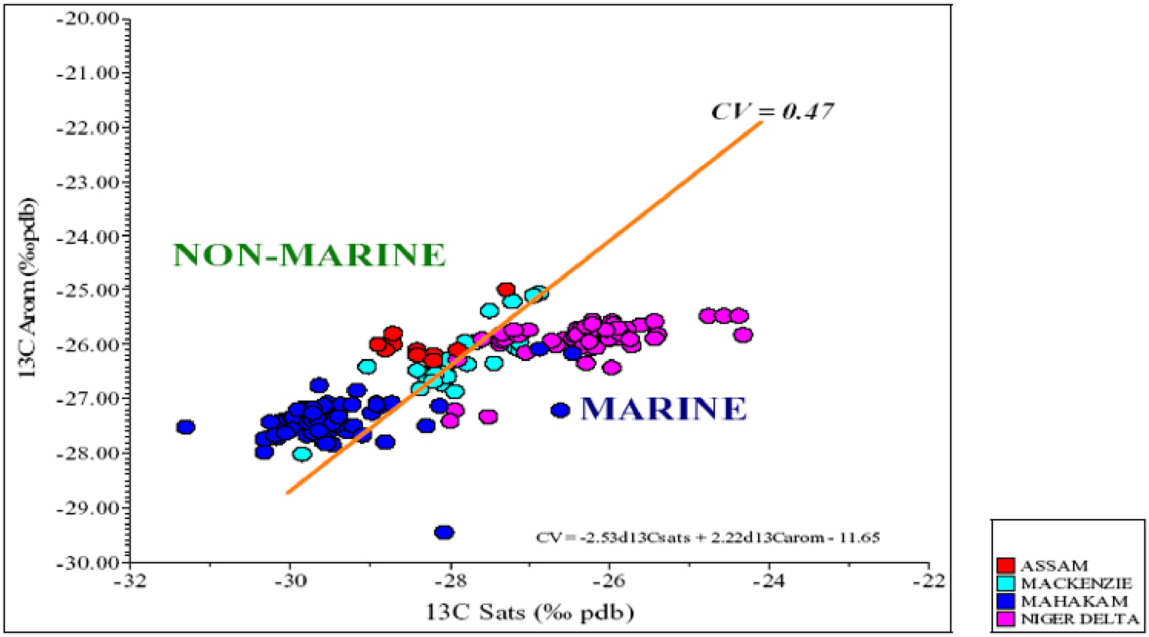


Figure 3: Plot of the $\delta^{13}C$ of saturated and aromatic hydrocarbon fractions to recognise marine and terrigenous sourced oils. CV (canonical variable), is based on Sofer (1984), = -2.53 ($\delta^{13}C$ sat) +2.22 ($\delta^{13}C$ arom) -11.65.

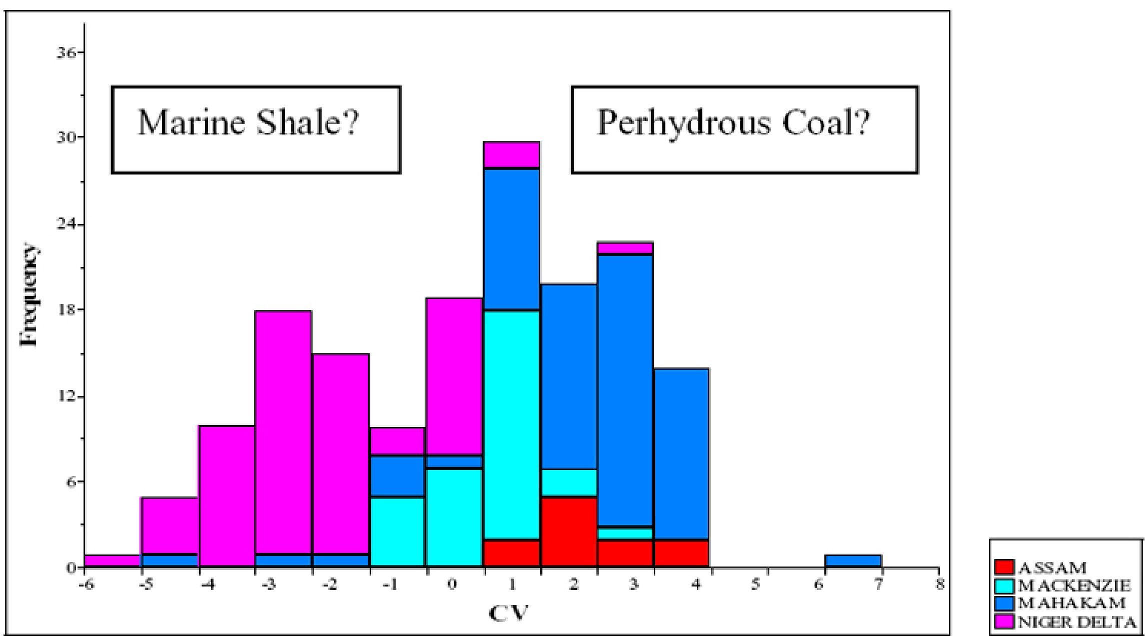


Figure 4: A histogram of canonical variable (CV) separates samples into land plant dominated coal and associated delta top carbonaceous shale sourced oils and marine organic matter sourced oils.

Discussion and Conclusion

The molecular and isotopic evidence presented above suggests that oil accumulations within Tertiary deltas (Figure 5) can contain:

i. oils of a marine aspect arguably expelled from *sub-delta* source rocks
ii. oils of a more terrigenous aspect expelled from *intra-delta source rocks*
iii. logically, mixes of intra- and sub-delta oils.

We believe that the source rocks for the *sub-delta* oils are marine shales which have become overstepped by the prograding delta. In the case of the Mackenzie and Niger deltas, these marine shales contain high TOC values and Type II algal-bacterial kerogens. The lateral equivalents of these sub-delta deposits may be seen as low-maturity outcrops on the delta flanks, with examples being the Upper Cretaceous Smoking Hills and Cenomanian-Turonian Nara (lower Benue trough) formations for the Mackenzie and Niger deltas, respectively. The timing of oil generation from the *sub-delta* source rock is controlled by prograding delta, it being earlier in the proximal and later in the distal locations. Buoyancy- and pressure-driven oil migration fills deltaic reservoirs via a 3-D network of sub-vertical listric fault and sub-horizontal interbeds of mud and sand.

It is acknowledged that shales within deltas may be marine in organic character and contain a variable mix of land-derived and planktonic biomass. Typically these shales are lean, due to the combination of oxic depositional conditions and high sedimentation rates. The leanness of the shales is compensated by efficient expulsion, promoted by the intimate interbedding of silt and sand beds. As the locus of deposition moves seaward, the prodelta shales become buried beneath the delta, potentially providing an additional source of 'marine' type oil.

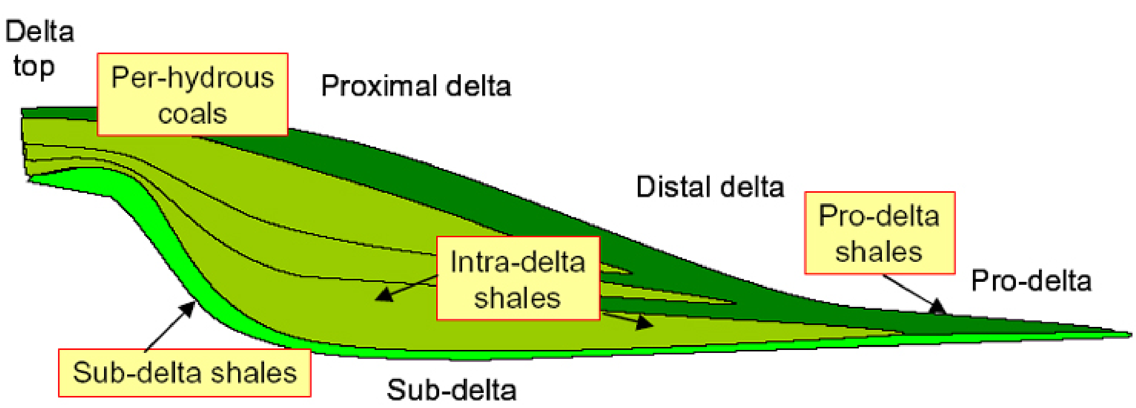


Figure 5: Section through a delta showing source rocks indicated by oil properties.

References

Bustin, R.M., 1988, Sedimentology and characteristics of dispersed organic matter in Tertiary Niger Delta: origin of source rocks in deltaic environments: AAPG Bulletin, v. 72, p. 277-298.

Curiale, J.A., 1991, The petroleum geochemistry of Canadian Beaufort Tertiary "non-marine" oils: Chemical Geology, v. 93, p. 21-45.

Demaison, G.J., and B.J. Huizinga, 1994, Genetic classification of petroleum systems using three factors: charge, migration, and entrapment, *in* The Petroleum System - from Source to Trap, L.B. Magoon and W.G. Dow, eds.: AAPG Memoir 60, p. 73-89.

Durand, B., and M. Paratte, 1983, Oil potential of coals: a geochemical approach, i*n* J. Brooks, ed.: Petroleum Geochemistry and Exploration of Europe: Blackwell Scientific Publishing, Boston, MA, p 255-265.

Ekweozor C.M., and N.V. Okoye, 1980, Petroleum source-bed evaluation of the Tertiary Niger Delta: AAPG Bulletin, v. 64, p. 1251-1259.

Eneogwe, C., and O. Ekundayo, 2003, Geochemical correlation of crude oils in the NW Niger Delta, Nigeria: Journal of Petroleum Geology, v. 26, p. 95-103.

Goswami, B.G., R.S. Bisht, A.K. Bhatnagar, D. Kumar, K.L. Pangtey, A.K. Mittal, G.C. Datta, and N.J. Thomas, N.J., 2005, Geochemical characterization and source investigation of oils discovered in Khoraghat-Nambar structures of the Assam-Barail-Arakan basin, India: Organic Geochemistry, v. 36, p. 161-181.

Haack, R. C., P. Sundararaman, J.O. Diedjomahor, H. Xiao, N.J. Gant, E.D. May, E.D., and K. Kelsch, 2000, Niger Delta petroleum systems, Nigeria, *in* M.R. Mello and B.J. Katz, eds., Petroleum Systems of the South Atlantic Margins: AAPG Memoir, v. 73, p. 213-231.

Huang, W.Y., And W.G. Meinschein, W.G., 1979, Sterols as ecological indicators: Geochimica et Cosmochimica Acta, v. 43, p. 739-745.

Jones, R.W., 1987, Organic facies, *in* J. Brooks and D. Welte, eds., eds., Advances in Petroleum Geochemistry: Academic Press Inc., London, p. 1-90.

Magoon, L.B., and W.G. Dow, 1994a, The petroleum system, *in* The Petroleum System - from Source to Trap, L.B. Magoon and W.G. Dow, eds.: AAPG Memoir 60, p. 3-24.

Moldowan, J.M., F. Fago, C.Y. Lee, *et al*., 1990, Sedimentary 24-*n*propylcholestanes,

molecular fossils diagnostic of marine algae. Science, v. 247, p. 309-312

Peters, K.E., J.W. Snedden, A. Sulaeman, J.F. Sarg, and R.J. Enrico, 2000, A new geochemical sequence Stratigraphic model for Mahakam Delta and Makasssar slope, Kalimantan, Indonesia: AAPG Bulletin, v. 84, p. 12-44.

Peters, K.E., C.C. Walters, J.M. Moldowan, 2005, The Biomarker Guide, 2nd edition: Cambridge University Press, Cambridge, 1155 p.

Perrodon, A., 1992, Petroleum systems: models and applications: Journal of Petroleum Geology, v. 15, p. 319-326.

Raju, S.V., and N. Mathur, 1995, The Petroleum geochemistry of a part of upper Assam-Barail basin, India: Brief overview: Organic Geochemistry, v. 23, p. 55-70.

Snowdon, L.R., and T.G. Powell, 1979, Families of crude oils and condensates in the Beaufort –Mackenzie Basin: Bulletin of Canadian Petroleum Geology, v. 27, p. 139-162.

Sofer, Z., 1984, Stable carbon isotopic compositions of crude oils: Aplication to source depositional environments and petroleum alteration: AAPG Bulletin, vo. 68, p. 31-49.