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Thermal Maturity Evaluation of Albian Shales from Offshore Benin Basin (Benin - West Africa)

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Abstract

The hydrocarbon maturity level of Albian shales intervals from four (04) wells drilled in the Offshore Benin Basin was assessed. The unnamed "Albian Formation" consists of marine sandstones and shales with some organic-rich black shales and minor limestone. The shale contains increase seaward and reaches 300m in deep water. For maturity assessment, traditional parameters such as Spore Coloration Index (SCI), Vitrinite Reflectance (R_o) and Rock-Eval pyrolysis T_{max} data were appreciated. The kerogen identified in studied samples is of both types II/III and III. Spore Coloration Index (SCI) data range from 7.0 to 8.5 while Vitrinite Reflectance (R_o) data are comprise between 0.69 and 1.10. The Rock-Eval pyrolysis T_{max} data show values in the range 434°C to 465°C. Obtained maturity data suggest that Albian shales are partially at the peak of oil generation zone (optimal mature) and partially within the lower part of the oil window (late mature). Moreover, the deepest shale interval (sequence 1) of R23, G20 and G21 wells have reached the upper part of the gas window. Similar maturity results were obtained after modeling burial history of the basin using Petrel software. To broaden the available thermal maturity information of Albian shales and attempt an oil-source rocks correlation, data from more wells and analyzes via GC-MS for a biomarker approach are require.

Keywords: Offshore Benin Basin; Albian shales; maturity level; hydrocarbon.

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1. Introduction

The Benin coastal basin belongs to the Dahomey Embayment figure (1) an extensive basin delimited in its offshore area by the Romanche and Chain fractures zones and formed during the opening of Equatorial Atlantic starting in the Late Jurassic and continuing into the Cretaceous [1,2,3]. The history of the region is divided into four tectono-sedimentary stages: pre-rift (up to Late Jurassic), syn-rift (Neocomian to Albian), transitional (Cenomanian - Santonian) and post-rift (Maastrichtian - Holocene). Petrographic analyses of cores samples confirm that rocks within the Embayment are almost exclusively clastics and, in a gross sense, mirror the increasing separation of the continents representing a graduation from terrestrial at the base, through shallow marine, deep marine (with restrictive bottom circulation) to open deep marine. In the Offshore Benin Basin (OBB), the stratigraphic succession has been increasingly defined by various workers [4,5,6,7,8,9,10] and the oldest syn-rift rocks are represented by the Neocomian Ise formation consisting of sandstone, shale, and conglomerate deposited in fluvial, lacustrine, and deltaic environments. The deposition of Albian shales units coincides in time with the anoxic conditions and black shale deposition that took place in Southern Atlantic basins during Mid-Cretaceous time [9]. Shales in such settings tend to be organic rich and oil prone [11]. The lithology of this unit consists of marine sandstones and shales with some organic-rich black shales, coarse sandstones and minor limestone. Seismic data indicate that Albian and Aptian source rocks may be more present in deep water but are mainly sandstones on the basin shelf [10]. As shown on figure (1), in narrow sediments belts along the coast, pre-Turonian (mainly Neocomian-Albian) marine sub-oxic active source rocks with good oil source potential appear to have regional distribution and are identified in Tano (Ivory Coast), Saltpond (Ghana) and Dahomey Embayment basins [12]. Oil from Lower Cretaceous reservoirs has been tested in all basins of the region. In OBB, Albian sandstones have produced in well test over 1,000 BOPD of different quality (28° to 42° API).

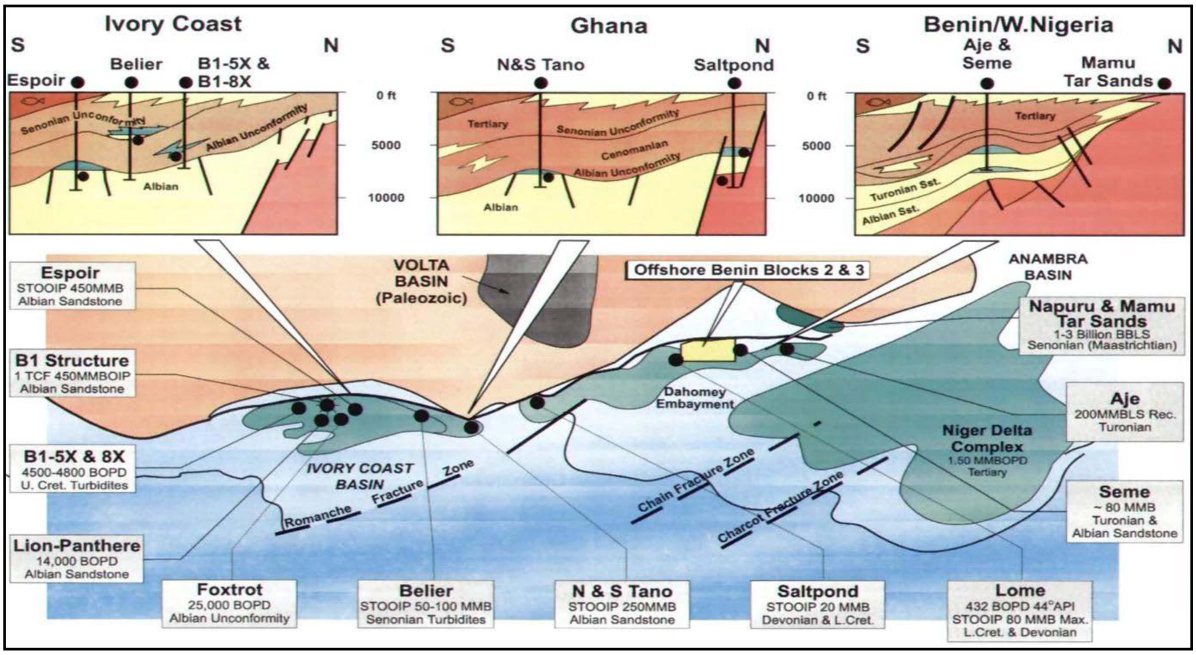


Figure 1: Regional Albian reservoir rocks occurrence and productivity

Currently it is assumed that upper Albian reservoirs in Seme and Aje fields are sourced from Ise Formation shales, but seismic and borehole data suggest that Albian shales can be potential source rock for Albian oil. Recent studies, carried out on a very limited number of Albian shale samples from the OBB, put forward that these shales include organic matter of both terrestrial and marine planktonic origin and may ranges from mature to late mature in terms of oil generation [10,12]. Therefore, to precise the Petroleum Systems of the Offshore Benin Basin, it is important to clear-cut the true maturity level of these shales intervals which thick can separately reach 180m and globally exceed 375m in deep water area (bathymetry of 2000m).

In this study, we combine Spore Coloration Index (SCI), Vitrinite Reflectance (%R_o) and Rock-Eval pyrolysis T_{max} data from Albian shales intervals of four wells supplemented by a burial history and hydrocarbon generation model of the basin in order.

2. Material and methods

2.1. Material

Various numbers of shale samples, in form of cuttings and side wall cores, were recovered for maturation analyses from a range of unaltered black colored, bituminous Albian intervals (sequences) of four (04) selected wells figure (2).

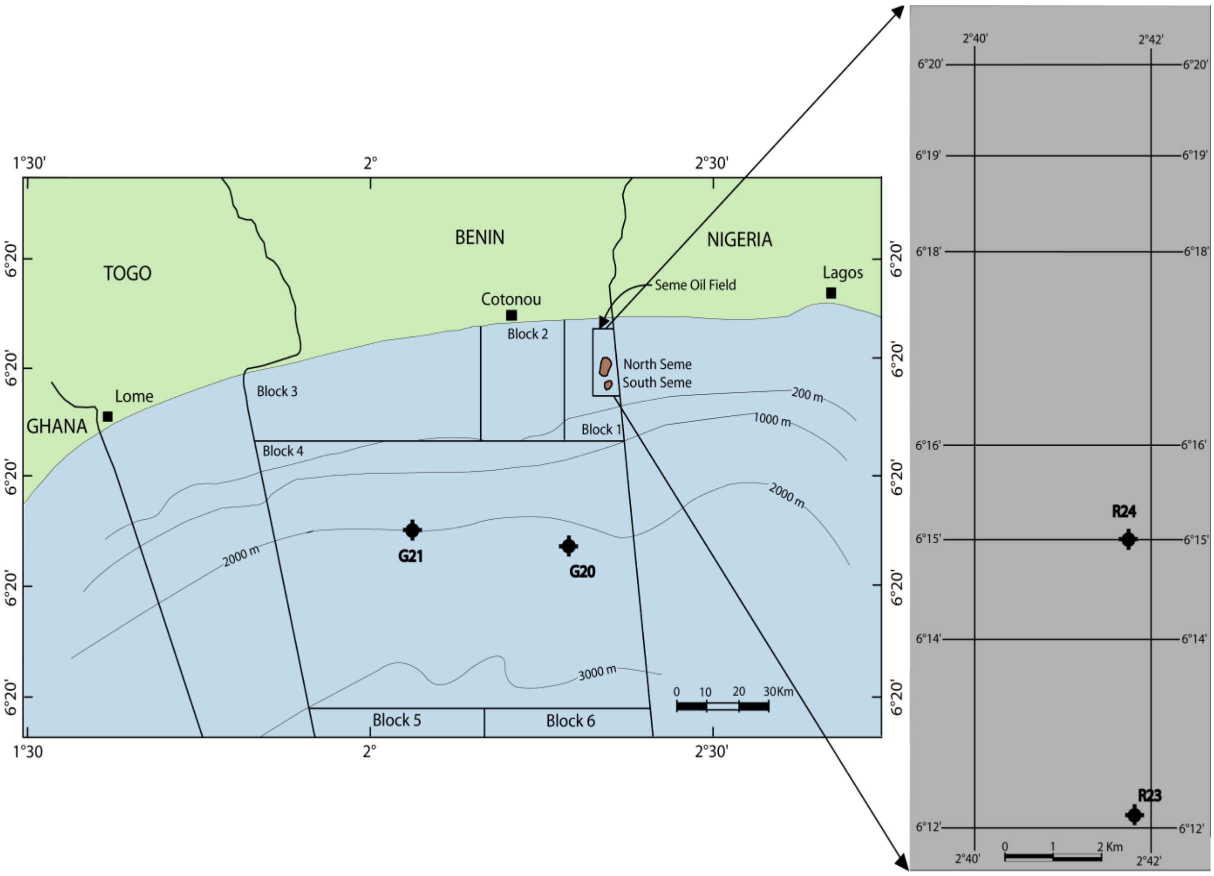
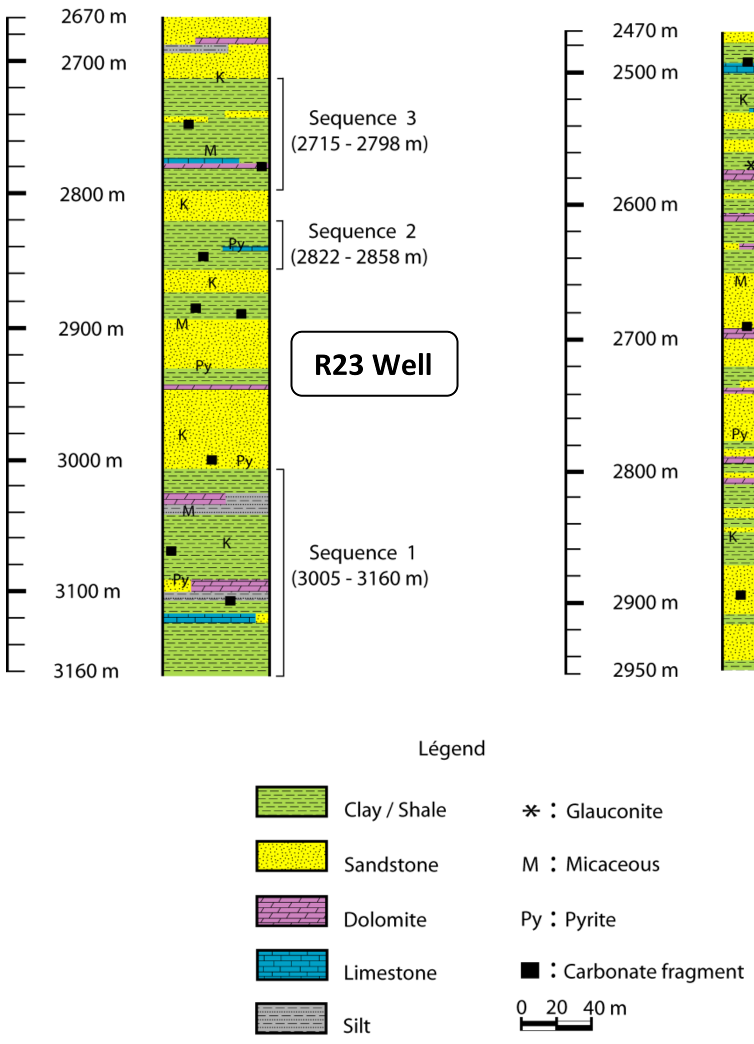


Figure 2: Position of Offshore Benin Basin within the Dahomey Embayment

Because of lack of sufficient boreholes, the study was limited to a little offshore area. Depths quoted in this study are based on the measured depths (MD) and True Vertical Depth (TVD). Details of the samples are given in table (1) and considered sampling intervals (sequences) are shown on figure (3).

Table 1: Samples details

Well	Well Depth	Formation	Sampling interval	Sample Type	Number of samples
R23	3160m (MD)	Albian	2720m – 3130m	Cuttings & Sidewall Cores	164
R24	2973m (TVD)	Albian	2510m – 2870m	-	204
G20	4800m (MD)	Albian	4220m – 4780m	-	174
G21	4025m (MD)	Albian	3360m – 3710m	-	80



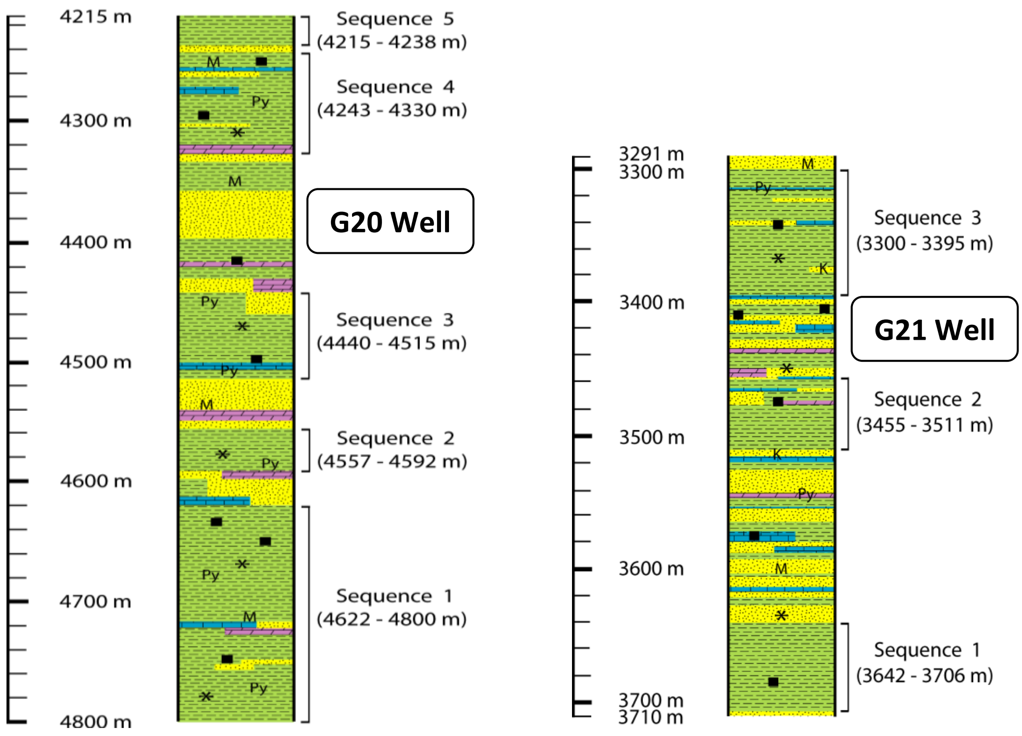


Figure 3: Simplified lithological representation of the four Albian sections covered in this study

2.2. Methods

Only continuous sequences of more than 20 m thick were retained for sampling. Thus, the number of considered sequences was variable from one well to another. For each well, the deepest sampling interval is represented by Sequence (1). Samples were prepared and analyzed in two prominent petroleum geochemistry Laboratories. Samples from R23 and R24 wells, drilled in shallow water deep, were analyzed in Robertson Research International Ltd. Laboratory in England [14] while samples from G20 and G21 wells, drilled in deep water, were analyzed in Humble Geochemical Services Laboratory in USA [15,16]. Organic petrography(spore coloration and vitrinite reflectivity measurements) supplemented by T_{max} data obtained from Rock Eval pyrolysis and burial history modeling graph of the basin were employed for interpreting maturity levels of Albian shales. The basic optical and screening geochemical techniques applied, have been described in detail by [11,17,18,19,20,21,22,23,24,25]. In the present paper these analytical procedures are briefly presented:

Spore Color Indices (SCI)

Sporomorph color is assessed using a >20µ sieved kerogen fraction viewed in transmitted light on a standard palynological microscope. Unusual hues are checked using incident blue/UV light fluorescence. The colour determination of suitable spores is made by eye with reference to a standard set of slides provided by Robertson Research International table (2).

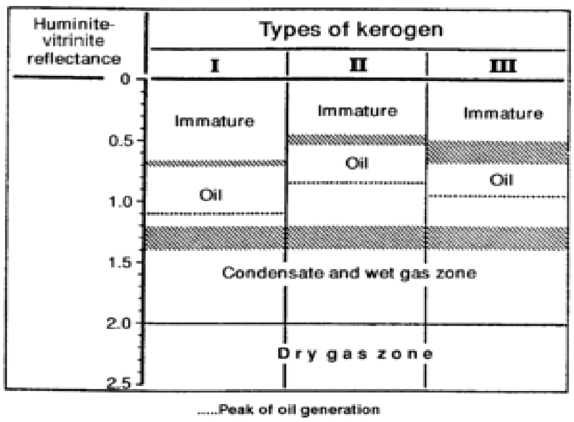
Table 2: Spore color conversion table [14]

SCI	Palynomorph Color	Maturity Degree
1	Colorless - Pale Yellow	Immature
2	Pale Yellow - Yellow	Immature
3	Lemon Yellow - Golden Yellow	Transition to mature
4	Golden Yellow - Deep Yellow	Transition to mature
5	Yellow Orange - Light Orange	Early mature
6	Mid to Dark Orange	Mature (oil generation)
7	Orange Brown - Light Brown	Mature (Optimum oil generation)
8	Mid to Dark Brown	Late mature, gas condensate
9	Very Dark Brown - Black	Over mature, dry gas
10	Black	Over mature, dry gas (traces)

Vitrinite Reflectivity (%R_o)

Vitrinite random reflectance (%Ro) measures the reflection capacity in incident light in relation to the increase of the paleo-temperature [11] and is reliable only when at least 20 unaltered vitrinite particles can be measured. The intensity of light reflected from a sample is measured as hundreds of points along a microscopic sampling area, and then a statistical analysis determines the amount of vitrinite in the sample and its thermal maturity. A Zeiss Universal microscope system was used for analysis. The relationship between %R_o and hydrocarbon generation is dependent on vitrinite chemistry as well as kerogen chemistry. Ranges for thermal maturity are typically as shown in table (3). Time-temperature relationships and mixing of various sources of organic matter may alter these boundaries.

Table 3: The %R_o, kerogen and hydrocarbon generation relationship [11]



Pyrolysis (Rock Eval)

This screening technique provides parameters which are both measures of maturity and kerogen type. Small amounts (~100 mg) of crushed or whole Albian shale sample are heated conforming to Rock Eval pyrolysis technique in order to determinate, for each retained sequences, the temperature (T_{max}) at which the maximum rate of hydrocarbon generation occurs in a kerogen sample during pyrolysis analysis. T_{max} provides a good indication of thermal maturity for Type III (gas prone) and usually Type II (oil prone) kerogens. T_{max} values can be converted to equivalent vitrinite reflectance values using the formula of Jarvie [26]. For analysis, a Source Rock Analyzer (SRA) and the general guideline for maturation levels given below table (4) were used although in practice, greater variation than these ideal temperatures ranges may be seen.

Table 4: Guideline for maturation levels for Rock-Eval pyrolysis T_{max} [27]

Hydrocarbon generation zone	Rock-Eval pyrolysis T_{max} (°C)
Immature	< 435
Oil (from type II kerogen)	435–450
Oil (from type III kerogen)	440–460
Gas (from type II kerogen)	> 450
Gas (from type III kerogen)	> 460

3. Results

The results of Albian shales maturity evaluation are presented in tables (5) to (8). The deepest sampling interval for each well is represented by the Sequence 1. Spore coloration data (SCI) are presented in table (5), while Vitrinite Reflectance values (%R_o) are showed in table (6) and Rock-Eval pyrolysis T_{max} data are presented in table (7). The maturity summary of Albian shales sequences is presented in table (8).

3.1. Spore Color Data

SCI measurements were undertaken on 50 selected samples. Albian samples contain few to sufficient sporomorph populations and data quality ranged from fair to very good. Selected samples give Spore Color Indices ranging from 7.0 to 8.5 as indicated in table (5).

Table 5: Albian shales spore coloration data and their maturity conversion

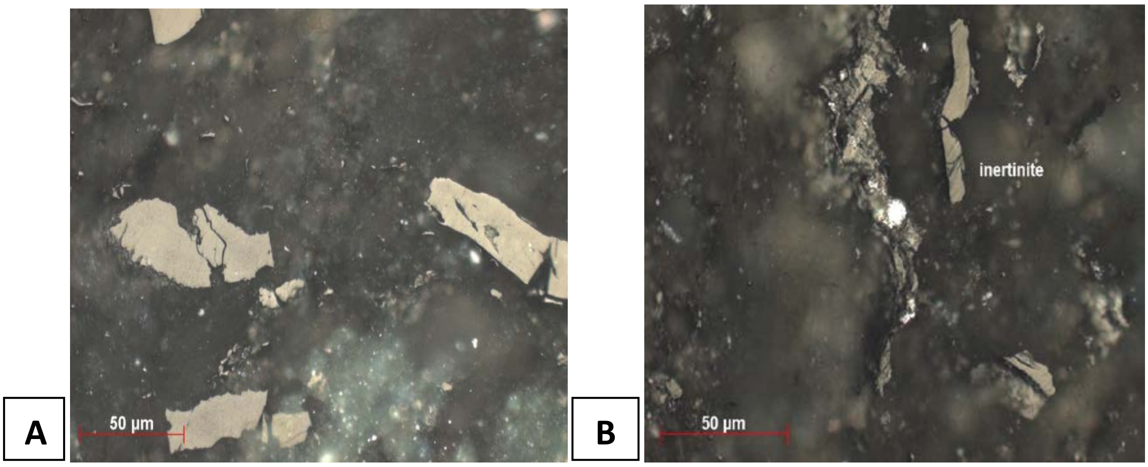
	Albian shales spore coloration data and their maturity conversion				
Well	Sequence 1	Sequence 2	Sequence 3	Sequence 4	Sequence 5
R23	7.5 - 8.5	7.0 - 8.0	7.5 - 8.5	-	-
		(Late mature)		-	-
R24	8.0 – 8.5	7.5 – 8.0	7.5 – 8.0	7.5 – 8.0	
		(Late mature)			-
G20	7.5 – 8.0	7.0 - 7.5	7.0 - 7.5	7.0 - 7.5	7.0 - 7.5
	(Late mature)		(Optimal mature)		
G21	7.0 - 7.5	7.0 - 7.5	7.0 - 7.5	-	-
		(Optimal mature)		-	-

For R23 well, obtained values range from 7.0 to 8.5. The measured values of 7.5 - 8.5 sequence (3), which is based on very few spores could be obtained from caved lithologies within the cuttings samples since well data are not reliable with depth. Sequence (1) has better sporomorph populations and values from these shales are consistent, ranging from 7.5 to 8.5 and more reliable for the sediments of this interval. For R24 well, sporomorph content ranged from poor to very poor and the measured SCIs are consequently of poor reliability. A small variation in the measured values is noted, ranging from 7.5 to 8.5 over all the sequences, with no reliability and apparent consistent variation with depth sequence (4). This may also be a function of the occurrence of caved lithologies especially within the cuttings samples of sequence (4). Nevertheless, using table (2) guidelines, data suggest that shales of R23 and R24 wells are all within the late mature zone with regard to oil generation. Moreover, sequence (1) of R24 well may be have reaches the over-mature zone at the base of the analyzed interval. For G20 well, the deepest interval sequence (1) is within the late mature zone, but probably reaches the over-mature zone at the base of the analyzed interval. The values from the Albian samples from G20 and G21 wells are consistent, ranging from 7.0 to 8.0 over the intervals with reliability or particular trend of increasing values with depth. Thus, obtained data suggest that sequence (2) of R23 well; sequences (2) to (5) of G20 well and the three sequences of G21 well are all at the peak oil generation. The bulk of the SCI data from Albian intervals of the (04) wells places swallow deep water sediments in late mature zone with regard to oil generation and deep water sediments in both optimal mature zone (i.e. at the peak of the oil window) and late mature zone with regard to oil generation table (5).

3.2. Vitrinite Reflectivity (R_o)

Samples on which SCI determinations are made are also examined, in transmitted white and incident blue/U.V. light, for kerogen composition (source material identification). Visual assessments of kerogen samples from microscopy reveal that they contain organic matter of various sources. Kerogen from R23 and R24 wells contain massive amounts of humic material associated with very little amorphous debris (Inertites: 0-20%; Vitrinite: 80-90%; Sapropel: 0-5% for R23 well and Inertites: 5-30%; Vitrinite: 60-80%; Sapropel: 0-20% for R24 well). They are more structured non fluorescents with good preservation of the vitrinite population. Visual assessments of kerogen samples from G20 and G21 wells show that they are slightly fluorescents and contain 70-95% of amorphous debris and 5-20% of coaly fragments. In some intervals, the coaly fragments content reach 50%. The preservation is poor and it is difficult to distinguish vitrinite from sapropel at such elevated levels of maturity. It is thus feasible that much of this amorphous kerogen may be sapropelic in nature. Herbal plant debris and woody plant debris are none seen. Kerogen of these two last wells is dominantly algal amorphinite type but some intervals contain predominantly coaly herbaceous types of kerogen. Kerogen of the studied wells intervals are of mixed types (both Types II/III and III) and can generally be characterized as kerogen of terrestrial-dominated macerals (vitrinite, inertite) with deltaic or marine influence board (1).

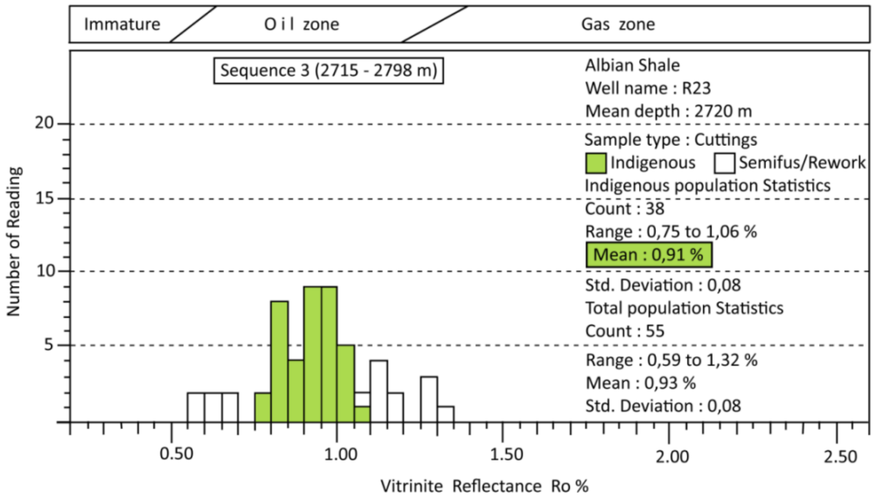
According to vitrinite populations enclose, samples yielded very poor to good quality data. An excellent way to recognize high-quality vitrinite reflectance data is to plot it in a histogram. Histograms of wells sequences are presented in figures 4 to 7, in an increasing depth order. The colored assemblages represent the indigenous population statistics and the colorless, the caved or reworked vitrinite. We can have high confidence in the data when a single mode in the distribution curve is tightly clustered about a mean value.



Board 1: Representative photos in incident white light of kerogen slides showing terrestrial-dominated macerals (vitrinite, inertite) with deltaic or marine influence.

(A) Sample from Albian deposits in shallow deep water; (B) Sample from Albian deposits in deep water.

Of 164 samples analyzed from R23 well intervals, 133 were identified as indigenous to the sequences from which they derived. For the three sequences, data qualities obtained from the populations of vitrinite range from 1.06% sequence (3) to 0.68% sequence (1). Three vitrinite reflectance maturity histograms are presented with statistics in figure (4). Caved and reworked vitrinite are frequent in sequence (3). Only the clustered data about a single mode in distribution on the histograms of sequence (1) and (2) can give us high confidence for obtained data.



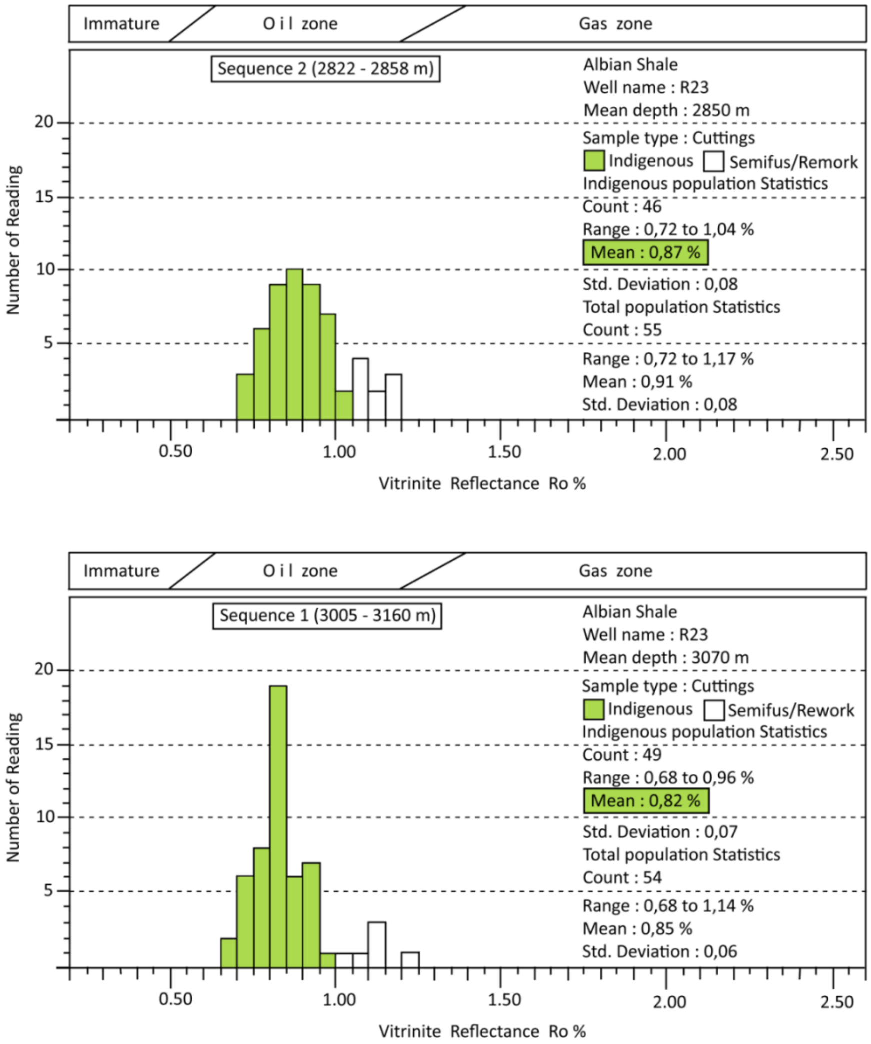
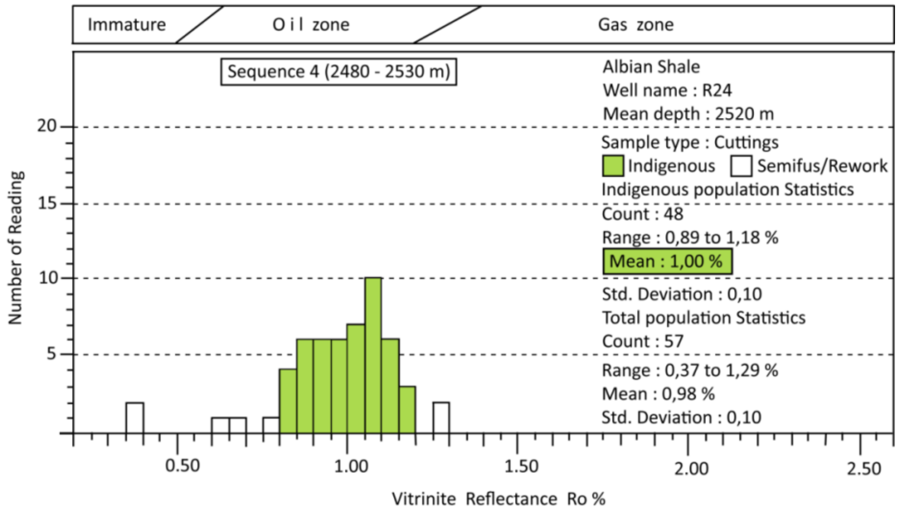
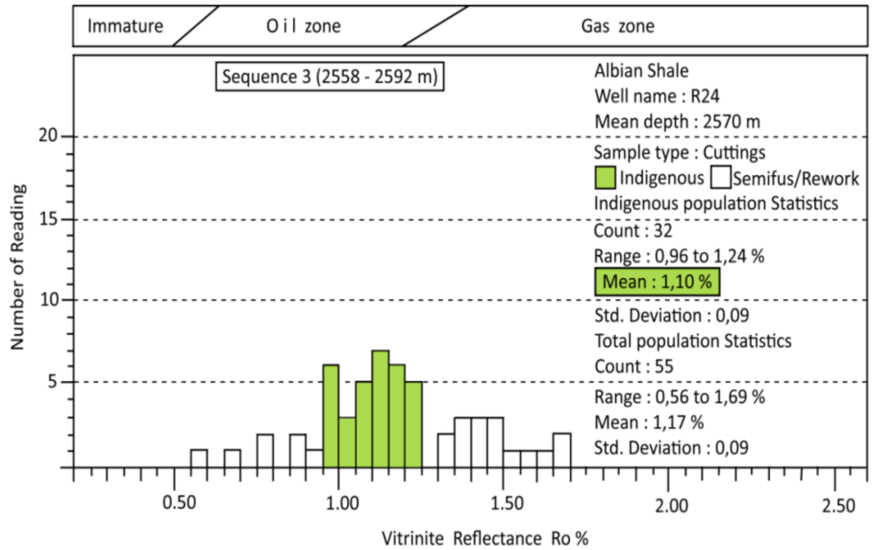


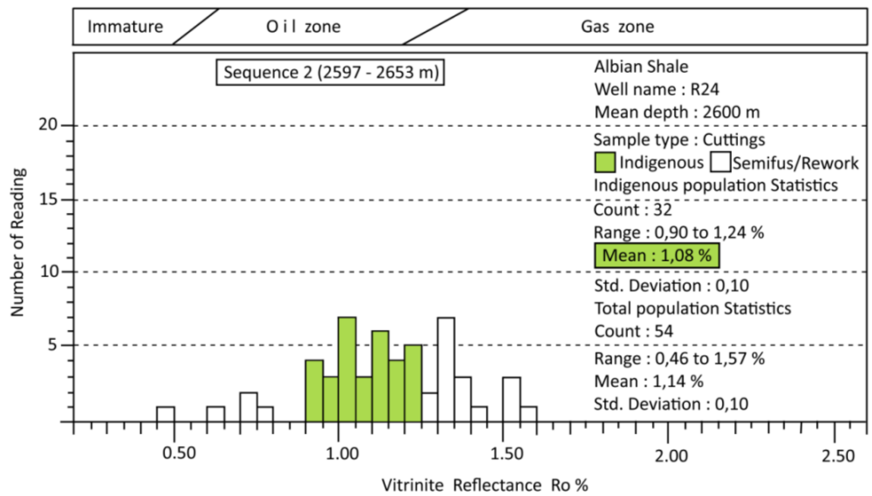
Figure 4: Histograms showing R_o measurements and statistics for R23 well

Of 204 samples analyzed from R24 well intervals, 144 were identified as indigenous to the sequences from which they derived. For all sequences, data qualities obtained from the populations of vitrinite are unusually highs. They range from 0.88% to 1.27% and related reflectance maturity histograms are presented with statistics in figure (5). Caved and reworked or oxidized vitrinite are present in each sample. The large spread in the range of measured values does not truly represent the maturity of samples especially from sequences (2) and (3). Only the distribution observable on the histogram of the sequences (1) and (4) can produce a mean R_o that could represent the maturity of these sequences.

Of 174 samples analyzed from G20 well intervals, 165 were identified as indigenous to the sequences from which they derived. For the five sequences, data qualities obtained from the populations of vitrinite range from 0.92% sequence (2) to 0.67% sequence (4). Five vitrinite reflectance maturity histograms are presented with statistics in figure (6). Only few particles of reworked vitrinite were identified in sequences (1) and (4). For all the sequences the histogram profile of vitrinite reflectance used to estimate the maturity level of samples show a single mode in the distribution curve tightly clustered about a mean value. With an approximation, the interpretation of the mean value for each sequence can be considered as the true reflectance of the indigenous vitrinite in the studied samples.







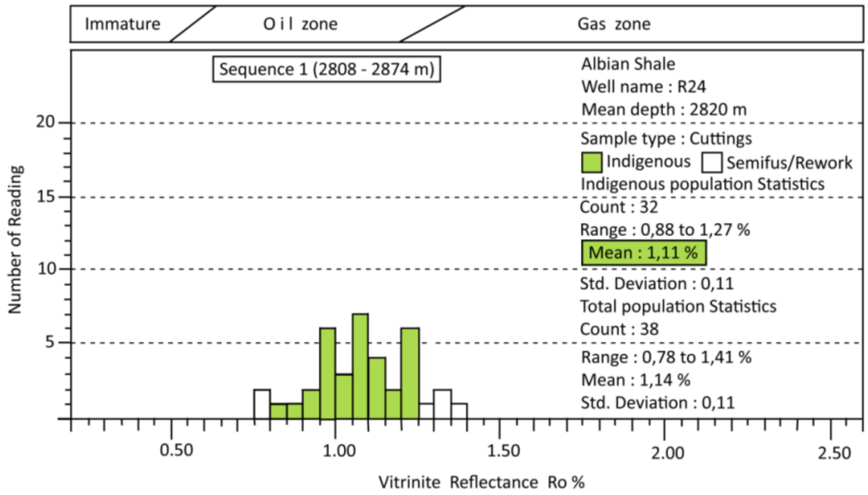
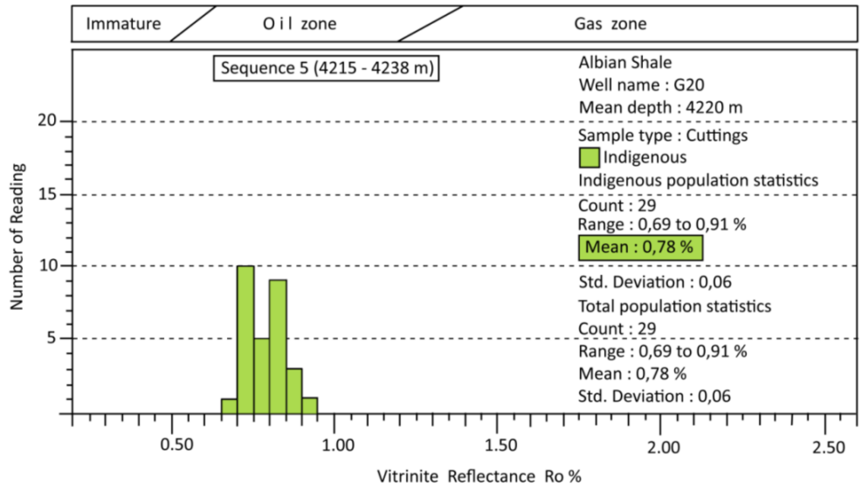
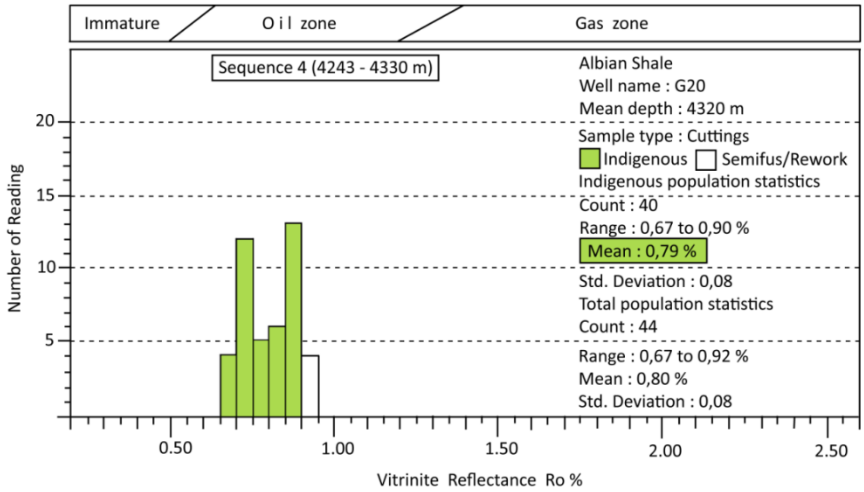


Figure 5: Histograms showing R_o measurements and statistics for R24 well





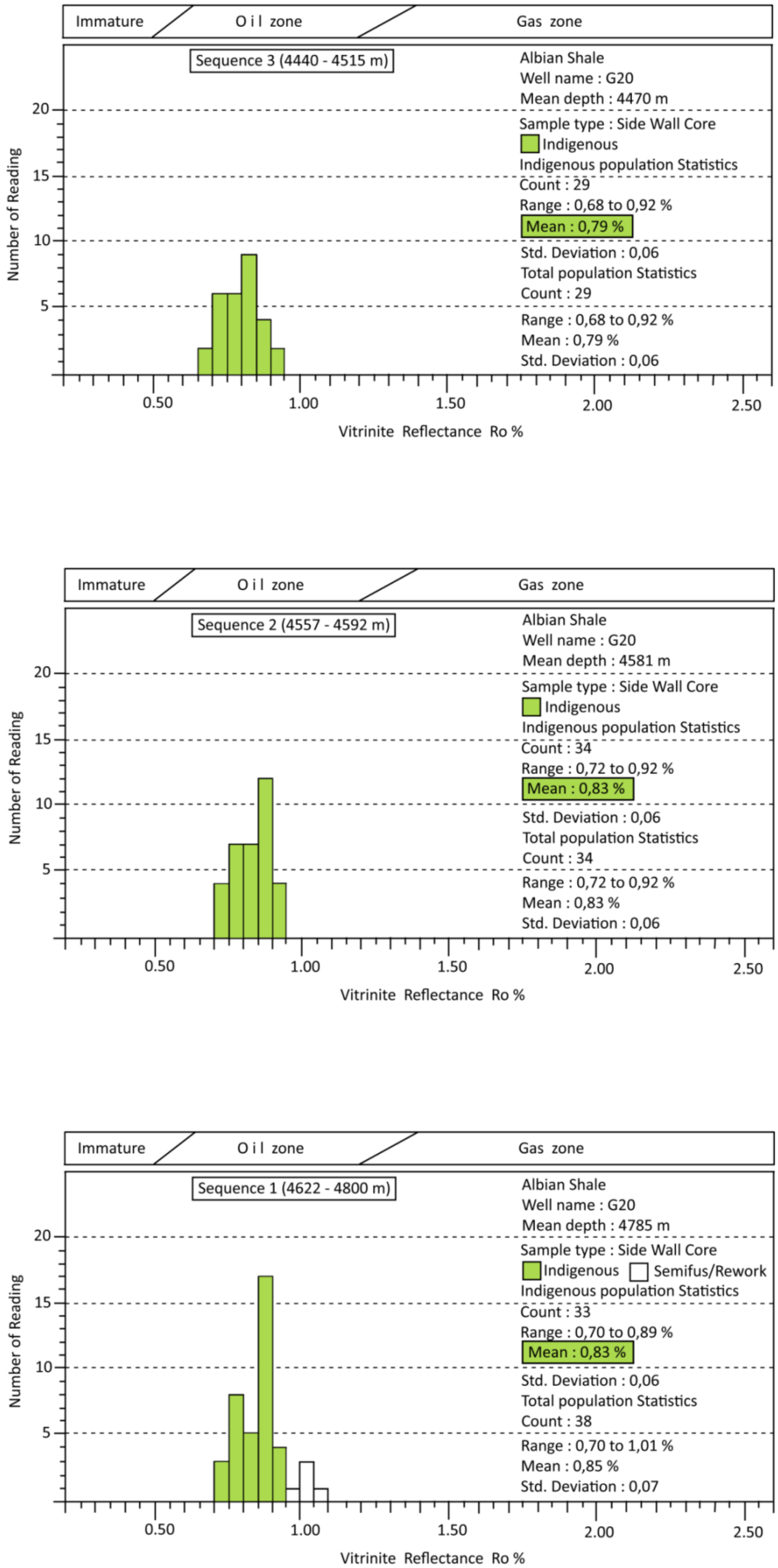


Figure 6: Histograms showing R_o measurements and statistics for G20 well

Of the 80 samples analyzed from G21 well intervals, 74 were identified as indigenous to the sequences from which they derived. For the three sequences, data qualities obtained from the populations of vitrinite range from 0.89% sequence (2) to 0.58% sequence (3). Three vitrinite reflectance maturity histograms are presented with statistics in figure (7). For sequence (1) the mean value is 0.69% while for sequence (2), a poor histogram profile is obtained due to a lack of data but with a mean value of 0.89%. However, the single mode in the distribution curve tightly clustered about a mean value obtained for sequences (1) and (3) samples allow, despite the existence of few reworked vitrinite, to consider the mean reported value of sequence (3) 0.72% as a constant value of indigenous vitrinite present in these three sequences.

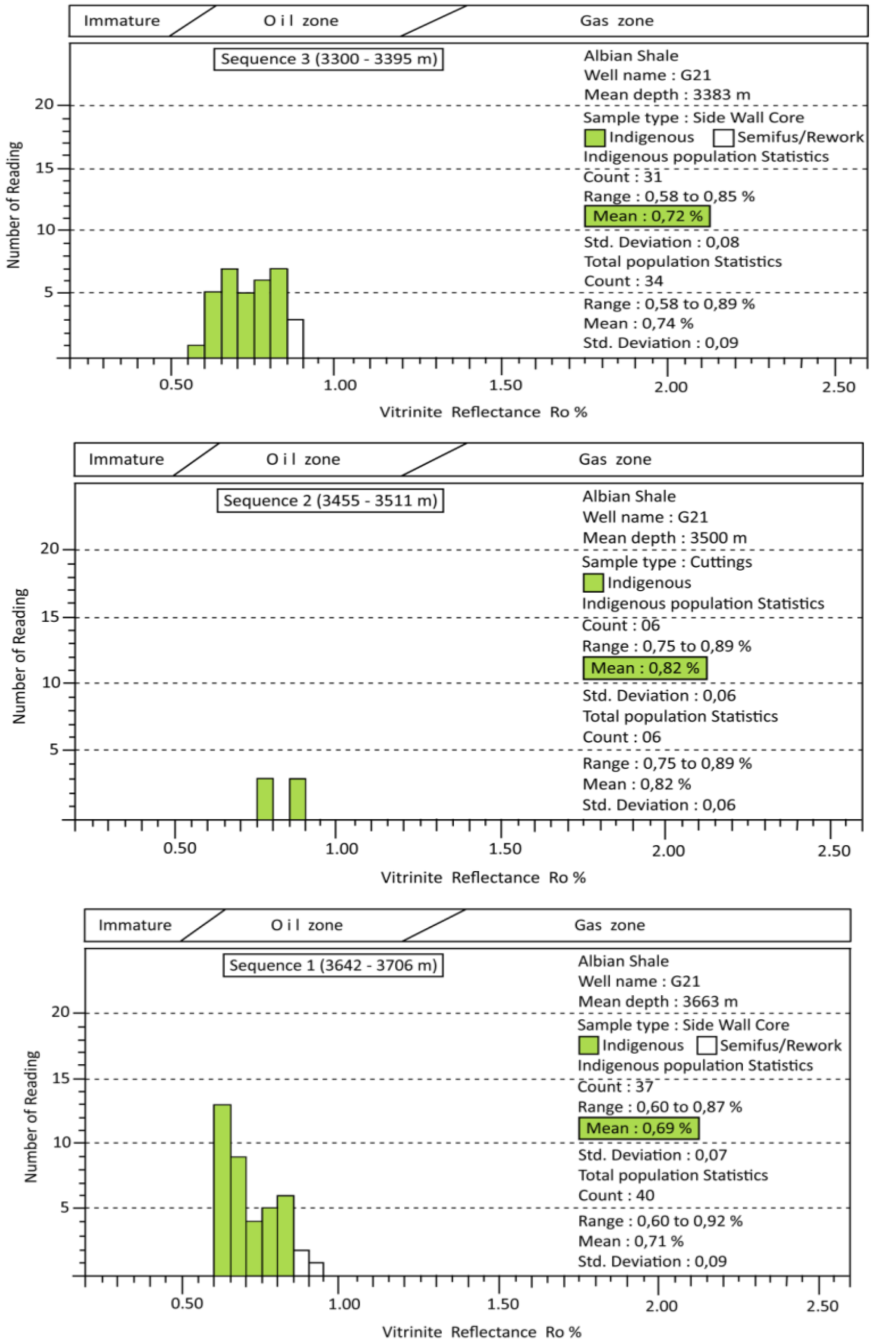


Figure 7: Histograms showing R_o measurements and statistics for G21 well

The mean R_o values obtained for sequences of each well are presented in table (6). This table summarizes, with approximation, the wide data variation of all histograms presented above figures (4) to (7).

Table 6: Vitrinite Reflectance Values of measured Sequences

Well name	Mean (%Ro) Values for measured Sequences				
	Sequence 1	Sequence 2	Sequence 3	Sequence 4	Sequence 5
R23	(3005 – 3160 m) 0,82	(2822 – 2858 m) 0,87	(2715 – 2798 m) 0,91	-	-
R24	(2808 – 2874m) 1,11	(2597 – 2653 m) 1,08	(2558 – 2592 m) 1,10	(2480 – 2530 m) 1,00	-
G20	(4622–4800 m) 0,83	(4557–4592 m) 0,83	(4440 – 4515 m) 0,79	(4243 –4330 m) 0,79	(4215 –4238 m) 0,78
G21	(3640 - 3710 m) 0.69	(3455 – 3511 m) 0,82	(3300–3395m) 0,72	-	-

Samples analyzed from R23 well, yielded good to very good vitrinite populations and the reflectivities from these samples range from 0.91% at 2720 m, dropping to 0.82% at 3130 m with the sample at 3100 m being higher at 0.90%. The data from these intervals are unusual since no discernible trend towards the increasing maturity with depth is clear. The sediments of the upper most sequences apparently show a higher (R_o> 0.85%) reflectivity than the underlying sediments of sequence (1) (with 0.80 < R_o < 0.85%). Observation of the particles suggests that oxidation of some of the vitrinite may have occurred. A very small population, assigned as the indigenous, is apparent at 1.05%, although this assignment must be tentative. If this interpretation is correct, then this places the sequence (1) in the late mature zone. Nevertheless, the data as they stand clearly place both sequence (2) and (3) within the late mature zone with regard to oil generation zone and sequence (1) at the peak of oil generation.

Samples analyzed from R24 well, yielded very good vitrinite populations and the reflectivities from these samples range from 1.00% at 2490 m to 1.11% at 2850 m. Thus, from samples of this well, highest maturities were recorded with no apparent consistent variation with depth. This clear difference in vitrinite reflectance data in contrast with R23 well may be caused by the kerogen composition or associated with a higher geothermal gradient in this area. Using the vitrinite maturity range of table (3), and considering that the kerogen is mostly gas-prone (type III), the reflectivity of all the samples are above 0.85% and thus, place the sediments of R24 well within the late mature zone with regard to oil generation zone and may at the beginning of the early mature zone with regard to gas generation for sequence (1).

Samples analyzed from G20 well, yielded fair to good vitrinite populations and the reflectivities from these samples range from 0.78% at 4220 m to 0.83% at 4780 m. The vitrinite reflectance data are usual and can be considered like high for this dominantly algal amorphinite type of kerogen were the preservation of vitrinite particles is poor. Here, a recognizable increasing of vitrinite reflectance data with depth can be noted. Using the vitrinite maturity range of table (3), and considering that the kerogen is oil-prone or mixed oil/gas-prone (type II), we can place the sediments of sequences (1) and (2) within the late mature zone with regard to oil generation zone (R_o> 0.80%) and may at the beginning of the early mature zone with regard to gas generation. Obtained data concur to place the other Albian shales sequences at the peak of oil generation zone (0.70 < R_o < 0.80%).

Samples analyzed from G21 well, yielded poor to fair vitrinite populations and the reflectivities from these samples range from 0.58% at 3663 m to 0.72% at 3320 m. For sequence (1), values range from 0.60% to 0.87% with a mean value of 0.69% which is not reliable with the obtained mean value of 0.82% of the next upper sequence. Using the vitrinite maturity range of table (3), we can place sequence (2) within the late mature zone (R_o> 0.80%), and the sequences (1) and (3) at the peak of oil generation zone (0.70 < R_o < 0.80%).

3.3. Rock-Eval pyrolysis T_{max}

Supplementary data were gained from Rock-Eval pyrolysis T_{max} data. Samples on which SCI determinations and visual assessment of kerogens compositions were made, were also analyzed, by Rock-Eval pyrolysis, for T_{max} determination. Most of the samples appeared to have been successfully extracted (with reliable S_2 parameters) and give T_{max} values in the range 434°C to 465°C as shown in table (7).

Table 7: Rock-Eval pyrolysis T_{max} data

Rock-Eval pyrolysis T_{max} data for Albian shales intervals					
Well	Sequence 1	Sequence 2	Sequence 3	Sequence 4	Sequence 5
R23	465°-449°C	458°-454°C	458°-454°C	-	-
	(Late mature)	(Optimal mature)		-	-
R24	453°-456°C	434°-426°C	441°-434°C	441°-434°C	
		(Optimal mature)			-
G20	460°-454°C	454°-451°C	451°-450°C	446°-443°C	443°-438°C
	(Late mature)	(Optimal mature)		(Optimal mature)	
G21	440°- 434°C	438°- 423°C	432°- 422°C	-	-
		(Optimal mature)		-	-

Obtained values suggest that the samples contained kerogen with different stages of thermal maturity. The T_{max} data obtained from sediments of R24 well are slightly reliable with depth, and are in range from 426°C to 456°C, except values obtained from sequence (2) of R24 well (434°-426°C) which are unusually low and not reliable with the upper sequences of this well. For all others wells, T_{max}values obtained from each well interval are reliable with depth. Values obtained from sequence (1) of this well, would place the interval in the late mature zone, although at a slightly lower level of maturity. Examination of the programs reveals that several samples from R24 well display signs of residual contamination arising from OBM.

Thermal maturity as assessed by T_{max}, shows that sediments within the lowest part of sequence (1) in R23 well and those within sequences (1) to (3) in G20 well have reach the late mature zone of oil generation and may be are at the beginning of the over-mature zone (generation of condensate). For the others sequences, the bulk of T_{max} values, place sediments in optimal oil generation zone or transitional to late mature zone.

In summary, after performing the analyses, the contrast of data from the three used techniques of maturity show globally good consistency between optical data of each sequence. Nevertheless, for each sequence, these data are not constantly reliable with obtained T_{max} values especially in case of R23 and R24 wells table (8). Organic matter contained in samples of these wells show no systematic variation with depth. It is probably due to some minor residual effects of the OBM, although variations in the constituent kerogens in the samples cannot be ruled out.

Table 8: Correlation of maturity parameters with hydrocarbon zone

Well name	Method	kerogen type	Maturity level				
			Sequence 1	Sequence 2	Sequence 3	Sequence 4	Sequence 5
R23	SCI	III	Late Mature			-	-
	R_o		Mature	Late Mature		-	-
	T_{max}		Late Mature	Mature		-	-
R24	SCI	III	Late Mature				-
	R_o		Late Mature				-
	T_{max}		Mature				-
G20	SCI	II/III	Late Mature	Mature	Mature		
	R_o		Late Mature		Mature		
	T_{max}		Late Mature			Mature	
G21	SCI	II/III	Mature			-	-
	R_o		Mature	Late Mature	Mature	-	-
	T_{max}		Mature			-	-

In addition, maturation model utilizing Lopatin Time Temperature Index (denoted TTI) was used to calculate theoretical thermal maturity of source rocks of a well in the Seme field. This model which describes quantitavely the relationship between thermal history and organic maturity, account only for the burial history, and assume a background constant geothermal gradient [28][29] [30].The model therefore neglects the feedback effect of the sedimentary process itself on the local thermal gradient. Thus, a global burial history model of the OBB on which maturity level of the formations are shown [10]is presented on figure (8). On this plot, realized with Petrel Software, vitrinite reflectance values are matched to indicate the progressive maturity level of containing source rocks intervals. The results, expressed by definition of equal-reflectance lines, point out that the upper part of the Ise formation is in the gas window while the lower part is now over-mature (R_o>3%).

For the unnamed Albian formation consisting mainly of sandstones (Events 5 to 7), the lower part is in transition zone and early mature with regard to gas generation. The upper part is presently at the peak of oil generation.

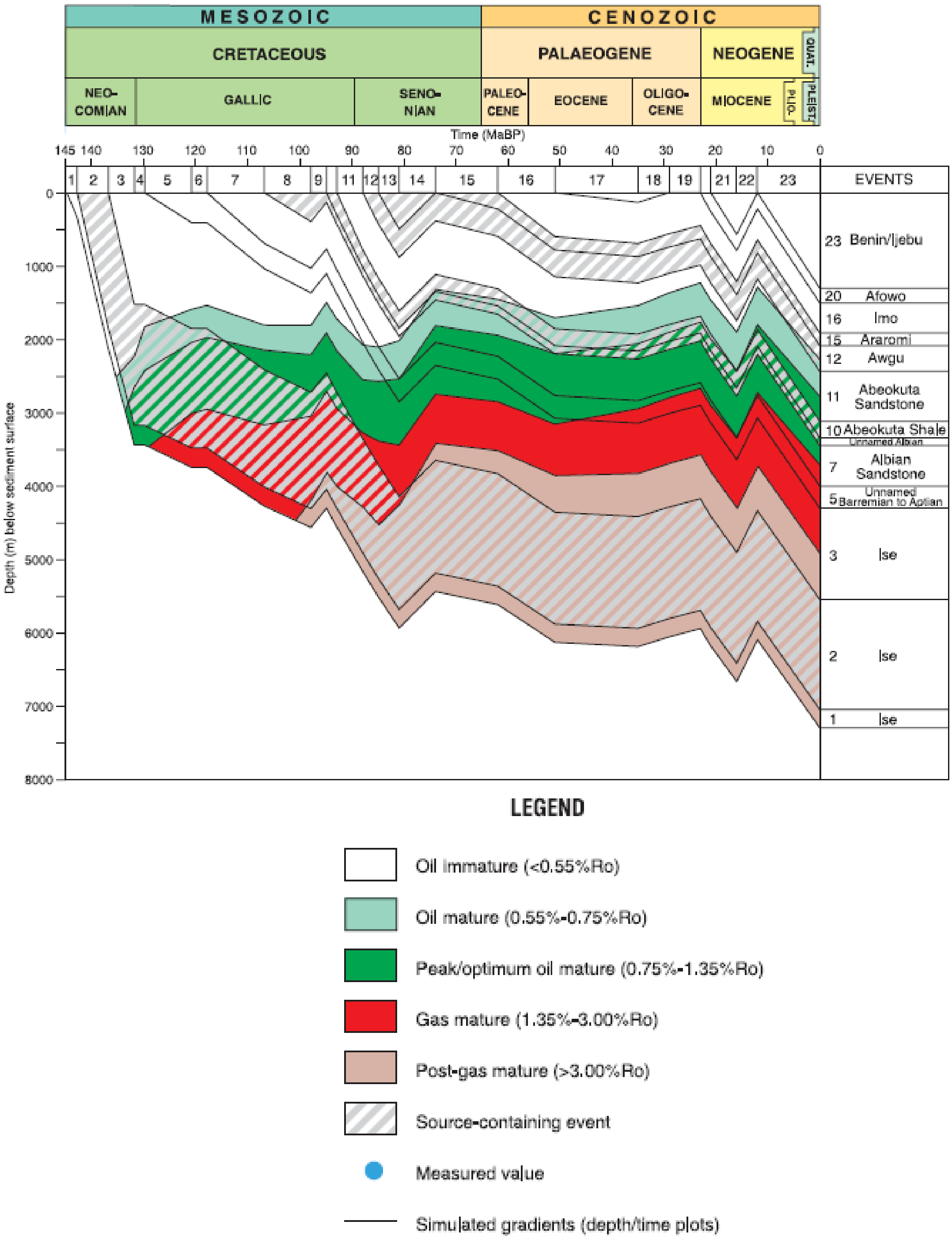


Figure 8: Burial history of Offshore Benin Basin with indication of time-depth maturity level of source rocks intervals [10]

4. Discussion

Owing to limited number of boreholes covering a small part of the offshore area, our results are not yet representative considered for the entire Offshore Benin Basin. The mixing of all obtained maturity analyses data suggests that Albian shales present within the study area are all mature with regard to oil generation; but have reach different level of maturity depending of OM content and sequence depth. As indicated before, visual kerogens typing suggest that the OM of samples issued from R23 and R24 wells is composed mostly of vitrinite; while for samples from G20 and G21 wells, the OM content is composed mostly of amorphous amorphinite material with little vitrinite. It is well known that in rock with little vitrinite (or containing mainly other organic matter type) the obtained R_o values could be not reliable to the true maturity level of the rock. This may explain the values obtained for G20 and G21 wells sequences although these values, like T_{max} data, place the lowest sequences of these wells in late mature zone with regard to oil generation or in the early-mature zone with regard to gas generation.

Taking into account the general reliability of the T_{max} values with depth, and the various or mixed type of kerogen present within studied intervals, an alternative approach was used to precise the true reflectance values of the OM within samples from different wells. Thus, we have tested the usefulness of a widely-used vitrinite conversion formula [26] that was established in the Barnett Shale (USA), with measured reflectance values and T_{max} data for some Albian shales intervals of the OBB. The conversion formula of Jarvie: (calculated $R_o = 0.0180 \times T_{max} - 7.16$) is based on a large data set of measured maturity parameters and has been used extensively in basins around the world with various ages and lithologies. Hence, for some intervals with sediments containing few vitrinite particles, calculated R_o data could highlight the approximate true degree of maturation of the OM.

Comparison between the T_{max} and calculated R_o data showed significant relations between the two parameters:

- For sediments of R23 well, T_{max} data ranges between 465-449°C across sequence (1) and 458-454°C across sequences (2) and (3) samples. Their converted values according to the formula of Jarvie range between 1.21-0.92%R_o and 1.01-1.08 %R_o respectively. The calculated values are reliable with depth and are in good agreement with the measured SCI within each sequence and vitrinite reflectance of the two upper sequences. The arrangement of all data including calculated R_o values places all Albian shale intervals of this well in the late mature zone with regard to oil generation but the base of sequence (1) may reaches the beginning of the over-mature zone (generation of condensate) (R_o> 1.20%).
- For sediments of R24 well, T_{max} data ranges between 456-450°C across samples of the deepest sequence (1) and 441-426°C across the overlying sequences (2) to (4). Their converted values range between 0.99-1.04 %R_o and 0.71-0.77 %R_o respectively. These values are reliable with depth but are in good agreement only with the measured SCI (8.0-8.5) and 1.1% R_o obtained in sequence (1). Considering T_{max} and calculated R_o values gained from sequences (2) to (4); we can conclude that data obtained within these sequences by microscopy methods (SCI and R_o) indicate residual contamination arising from Oil Based Mud used to drill this well. Thus, the bulk of all data including calculated R_o values places the sequence (1) in late mature zone and the overlying sequences in optimum oil generation zone (the peak oil generation maturity).
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- For sediments of G20 well, T_{max} data ranges between 460-450°C across samples of the deepest 1 to 3 sequences and 446-438°C across the overlying (4) and (5) sequences. Their converted values range between 1.12-0.95 %R_o and 0.87-0.72 %R_o respectively. Although the measured R_o values were low (0.83-0.78% R_o) due to the poor contain of vitrinite particles and kerogen type; calculated values are reliable with depth but are in good agreement only with the SCI (8.0-7.5) data obtained in sequence (1). Calculated R_o are reliable to the true maturity level of the rock in this interval. Thus, the bulk of all data places sequence (1) in the transition zone from late mature to over-mature zone (generation of light oil and condensate); sequence (2) and (3) in late mature zone and the overlying sequences (4) and (5) in optimum oil generation zone (the peak oil generation maturity).
- For sediments of G21 well, T_{max} data across samples of the deepest sequence (1) range between 440-434°C. Their converted values range between 0.76-0.65% R_o with an average of 0.69% R_o. According to the type II kerogen, the bulk of data concur in placing this interval in mature to optimal mature zone (mature to peak oil generation maturity).

In general, calculated Ro values suggest that conversion formula [26] can be, with caution, potentially applied to determinate the maturity level of Albian Shales of the Offshore Benin Basin. Although the conversion line is not presented here, we can note that the conversion formula was established for organic maturity of Albian shales at all maturity stages. Except for Albian sediments of G20, it is difficult to draw a gradient through the maturity data obtained in the Albian intervals of the other three studied wells. The measured values from R23 and R24 wells appears to be highs, very little in variation and often non reliable with depth. Finally, it is important to point out that discrepancies in maturity level of Albian shales from the Offshore Benin Basin could also be controlled by local palaeogeographic and structural features.

As shown in figure (1), in narrow sediments belts along the coast, pre-Turonian (mainly Albian) marine sub-oxic active source rocks with good oil source potential appear to have regional distribution and are identified in Tano (Ivory Coast), Saltpond (Ghana) and in all basins of the Dahomey Embayment. In this context, the maturity/analytical data obtained from the prospective OBB area point to the existence of a Lower Cretaceous (Neocomian to Albian) Petroleum System (PS), including both Albian source rocks (shale intervals) and reservoir rocks (sandstones sequences), in the Offshore Benin Basin.

The Lower Cretaceous PS was defined because lacustrine and nearshore marine source rocks and sandstones reservoirs deposited in early grabens have been recognized in the entire Dahomey Embayment (from Aje oilfield westwards). Oils from Albian sandstones Formation has been tested in the OBB (in Seme field oil is of 28° API while in deep water oils tested from wells G21 and G20 are of 35° and 42° API respectively). The maximum extent of this system coincides with the boundaries of the offshore basins of Equatorial Africa and the minimum extent of the system is defined by the area extent of fields of the Dahomey Embayment. Events chart for potential Lower Cretaceous PS, graphically portray the ages of source rocks, reservoir rocks, and seal, as well as the timing of generation, migration, trap development, preservation of hydrocarbons, and the critical moment are showed in figure (9). In the OBB, this petroleum system is few documented in reports and not yet assessed because of very limited boreholes data.

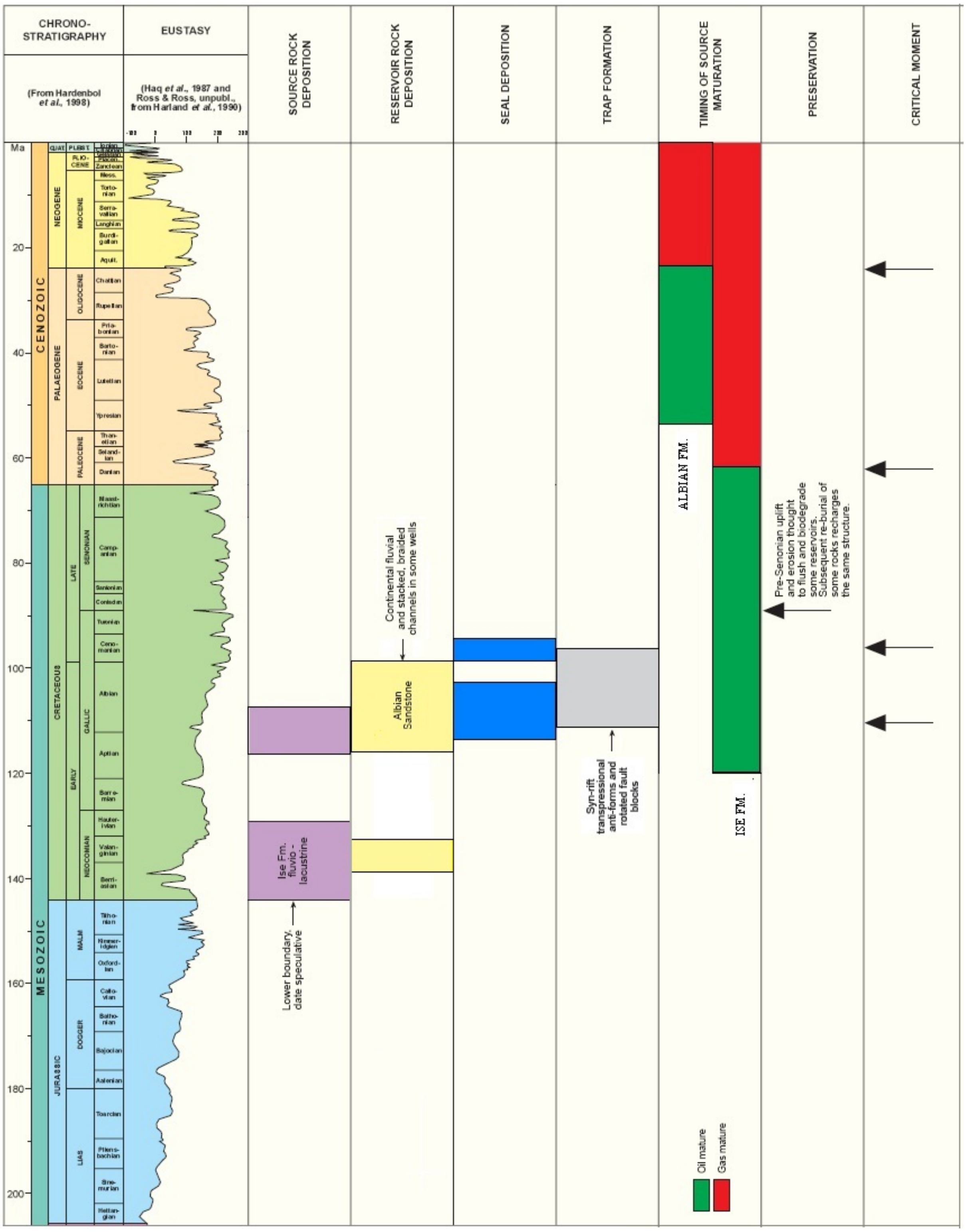

Figure 9: Lower Cretaceous Petroleum System of the Offshore Benin Basin

5. Conclusion

This study has focused on assessment of the maturity levels of Albian shales from four (04) wells drilled within the Offshore Benin Basin using SCI, R_o and T_{max} data. Several interesting observations resulted from our study:

1) Maturity evaluations of Albian shales intervals indicate a fluctuation of the organic matter content and the occurrence of different source material. samples from shallow water wells (R23 and R24 wells) are composed mostly of vitrinite (Type III kerogen); while those from deep water (G20 and G21 wells) are composed mostly of amorphous amorphinite material with little vitrinite (Types II or II/III kerogens).
2) The microscopy (SCI, Ro) and screening geochemical (T_{max}) data concur in placing the Albian shales intervals in optimum mature and late mature zone with regard to oil generation for wells drilled in shallow deep water zone (shallow diagenetic areas). Furthermore, sequence (1) sediments from R23 well may be placed at the beginning of gas generation zone. In deep water, sediments of deepest sequences (1) and (2) intervals of G20 well, and sequence (1) of G21 well are wholly in late mature zone with regard to oil generation and early mature with respect to gas generation.
3) Calculated R_o values from T_{max} data specify that the highest maturities recorded in sequences (2) and (3) of R23 well as well as in sequences (2) to (4) of R24 well are due to the presence of OBM supplemented somewhere, by a higher geothermal gradient.

The data gathered for this study cover a very limited part of the offshore area and at this stage, the obtained results cannot be generalized to the entire OBB. The integration of obtained maturity results with data from recently drilled wells should attract the main interest for further research related to petroleum exploration of Lower Cretaceous sediments from the Offshore Benin Basin. Therefore, for a more rigorous thermal maturity determination, selection of additional samples from other wells and analyzes via GC-MS for a biomarker approach is recommended. This is paramount to comprehend the Petroleum Systems of the basin as thermal maturity is one of the most critical factors in hydrocarbon exploration.

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