

Geochemical Characterization and 1D Basin Modelling of Afowo Shale: Implications for its Potential Hydrocarbon Source Rock in the Dahomey Basin, Southwestern Nigeria

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Abstract

This study presents an integrated assessment of the Cretaceous Afowo Formation shales in the Dahomey Basin, focusing on geochemical characterization and 1D basin modelling to accurately determine their hydrocarbon generation potential and thermal evolution. Geochemical analyses, including Total Organic Carbon (TOC) and Rock-Eval pyrolysis (Tmax, Hydrogen Index), confirmed the shales as a viable, organically rich source rock (TOC up to 2.50wt.%) dominated by gas-prone Type III kerogen. Subsequent 1D burial and thermal modelling, performed using PetroMod software, was critically constrained by measured vitrinite reflectance (%Ro) values, which served as the primary thermal calibration points. The simulation results conclusively indicate that the Afowo source rock unit at the studied shallow depths is thermally immature (Tmax 410–431°C), demonstrating low kerogen transformation ratios and suggesting that the unit has not entered the main oil or gas window. Palynomorphs and foraminifera were used to establish the age and paleoenvironmental framework essential for model construction. A key finding was the poor fit between the default Mckenzie heat flow model and the measured (%Ro) profile, highlighting a significant heterogeneity in the basin's thermal regime. This critical discrepancy underscores the necessity of developing a customized, high-resolution heat flow history for the area. The overall implication is that the Afowo Formation's vast, gas-generating potential remains fully preserved and untapped in shallow sequences. This study provides necessary, constrained input data for the Dahomey Basin's petroleum system, strongly recommending that future exploration efforts be strategically redirected toward deeper structural targets where the required thermal conditions for commercial gas conversion have been reached.

1. INTRODUCTION

The Eastern Dahomey Basin in southwestern Nigeria represents a critical frontier in West African petroleum exploration, characterized by a complex petroleum system that hosts both significant onshore bitumen deposits and major recent offshore oil discoveries (Opatola et., 2023). Despite these prolific indicators, the basin remains fundamentally underexplored. As global energy demands shift toward cleaner-burning fossil fuels, the Dahomey Basin's potential, specifically its capacity for natural gas requires a more rigorous, data-driven assessment to move beyond historical surface-level observations.

Central to the basin's architecture is the Cretaceous Afowo Formation, a primary candidate for hydrocarbon generation. However, the scientific community remains divided regarding its paleoenvironmental origins and its ultimate source potential. Previous studies have presented a paradox: while the presence of massive tar sands suggests a highly active past generation, recent geochemical assessments (reporting Genetic Potential (GP) values below 1 mg HC/g rock) often classify the formation as having low potential or being dominated by inert Type IV kerogen (Adeoye et. al, 2020; Oluwajana et.al 2019; Elueze and Nton, 2004; Elueze and Olade 1996). This discrepancy highlights a critical knowledge gap and most existing studies lack the integrated thermal modelling necessary to explain how depth and heat flow influence these geochemical signatures.

This research addresses these uncertainties by employing an integrated multi-proxy approach, combining rock-eval pyrolysis for quantitative organic matter assessment with biostratigraphic analyses (using foraminifera and palynomorphs), a robust age and paleoenvironmental framework is established which are used to calibrate a 1D basin model, allowing for a quantitative reconstruction of the burial and thermal history. This methodology provides a comprehensive framework to resolve the "immaturity vs. potential" debate and offers a predictive tool for identifying deeper, thermally mature targets for hydrocarbon exploration in the region.

2. GEOLOGY OF DAHOMEY BASIN

The study area for this research is in Ondo State within the Eastern Dahomey Basin between latitudes 6°34'36"N and 6°41'21"N and longitudes 4°50'59"E and 4°56'51"E. The Dahomey Basin is a coastal sedimentary basin located along the Gulf of Guinea (Fig. 1). It stretches from southeastern Ghana through Togo and the Republic of Benin and extends eastward to the western margin of the Niger Delta in Nigeria. Geologically, it is part of the West African Atlantic Margin basins, which formed during the Late Jurassic–Early Cretaceous, when separation of the African and South American plates initiated the opening of the Gulf of Guinea. The resulting rifting, together with block faulting and crustal subsidence, created space that was gradually filled with sediments (Kaki et al., 2013).

The basin remains active, with erosion occurring in its subaerial sections and sediment deposition taking place in its distal, submarine regions. Structurally, the basin displays horst and graben systems that developed through prolonged rifting and sediment accumulation.

The stratigraphic succession of the Eastern Dahomey Basin comprises Cretaceous to Tertiary sedimentary units. The Cretaceous sequence includes the Ise, Afowo, and Araromi Formations (Fig. 2), deposited during the Maastrichtian–Neocomian interval. The Afowo Formation, which is the focus of this study, consists of sandstones, siltstones, claystones, and shales. Above these lie Tertiary formations such as Ewekoro, Akinbo, Oshosun, Ilaro, and the Benin (Coastal Plain Sands), which together provide a wider context for the basin's depositional and evolutionary history (Omatsola and Adegoke, 1981).

3. MATERIALS AND METHODS

Eight wells were selected to provide representative stratigraphic coverage of the basin (Fig. 3). Thirteen samples were selected for Rock Eval, EOM (Extractable Organic Matter) for its close relationship to ascertaining S1 in Rock Eval. Whole-core samples were selected for geochemical analyses (Table 1), whereas ditch cuttings were used for palynological and foraminiferal studies. Sample selection was guided by lithological characteristics.

3.1 EXPERIMENTAL PROCEDURE

Total Organic Carbon (TOC) and Rock-Eval pyrolysis were conducted, utilizing the Hydrocarbon Analyzer with Kinetics (HAWK). This involved treating 200 mg of ground rock with HCl to remove carbonates before combustion, while pyrolysis measured free hydrocarbons (S₁), kerogen-derived hydrocarbons (S₂), and CO₂ (S₃) under a controlled temperature ramp. The resulting Tmax and calculated indices including Hydrogen Index (HI) and Genetic Potential (GP) provided the basis for evaluating kerogen type and thermal maturity. The EOM analysis was done by Soxhlet Extraction of Organic Matter (Peter, 1986).

Palynological analysis was performed using HCl/HF acid maceration to isolate organic matter for the microscopic identification of pollen and spores. Simultaneously, foraminiferal analysis involved disaggregating 21 g samples in kerosene and sieving to extract the > 63 µm fraction for micropaleontological examination (Poulsen et al., 1990). These biostratigraphic data were used to determine chronostratigraphic age and reconstruct paleoenvironmental conditions.

To bridge laboratory data with regional potential, these datasets were integrated into 1D basin modeling using PetroMod software. This involved reconstructing burial and thermal histories based on stratigraphic and lithological inputs, followed by thermal calibration against measured vitrinite reflectance (%Ro) and Tmax data using the EASY%Ro kinetic algorithm. This integrated approach allowed for the quantitative determination of the timing and extent of hydrocarbon generation and expulsion within the Afowo Formation.

4. RESULTS AND DISCUSSION

4.1 TOC Analysis

The TOC, with the results presented in Table 1, represent various lithologies including mudstone, shelly mudstone, and shale. The TOC values of the Afowo mudstone and shale range between 0.69 and 2.50 wt%, reflecting a fair to very good concentration of organic matter (Fig. 4). The average TOC of 1.55 wt.% indicating fair to very good source rock quality (Bacon et al., 2000; Sweeney and Burnham 1999)

The values of peak indicating the free light, and thermally extractable hydrocarbons in the rock sample (S₁) range from 0.02 mg HC/g rock to 3.99 mg HC/g rock, with an average of 0.54 mg HC/g rock. This range indicates poor to very good generative potential, with eight of the thirteen samples ranging between 0.02 mg HC/g to 0.08 mg HC/g and the last sample reading 3.99 mg HC/g and the values of hydrocarbons generated through the thermal conversion of the kerogen (S₂) range from 0.16 mg HC/g to 11.30 mg HC/g, with an average of 2.11 mg HC/g, six of the thirteen samples had S₂ values less than 1 mg HC/g, indicative of poor generative potential.

4.2 Thermal Maturity

Thermal maturity, as indicated by Tmax values varied between from 410 to 431°C, calculated Ro (0.22 to 0.60%), and PI ranging from 0.02 to 0.65, shows that the Afowo Formation samples are predominantly immature, with some samples indicating early maturity. These findings suggest that significant hydrocarbon generation is unlikely under present conditions (Yalçın et al., 1997).

Also, the ratio of free hydrocarbons (S₁) to total organic carbon (TOC) is useful for identifying reservoir rocks and assessing the thermal maturity of tight source rocks. Mature source rocks typically exhibit higher S₁/TOC ratios compared to immature ones. According to [15], the interpretation of S₁ * 100/TOC values is as follows:

- 0–50: Lean source rock
- 50–100: Possible staining, indicating mature, tight source rock
- >100: Reservoirs or contamination

In this study, S₁*100/TOC ratios ranged from 2 to 160, with an average of 23.21. Notably, sample 8, 9, 10, 11, 12, 13 exhibited ratios greater than 100, suggesting the possibility of migrated hydrocarbons (bitumen) or other forms of contamination affecting their organic richness. The remaining samples showed ratios below 50, indicating they are lean source rocks.

The S₂/S₃ ratio, along with cross plots of HI versus OI and HI versus Tmax, reveals that the mudstone/shale samples of the Afowo Formation contain organic matter predominantly of Type III and Type IV, with some presence of Type II. This indicates that the organic matter in these samples is mainly gas-prone (Type III) and inert (Type IV), with a smaller proportion being oil-prone (Type II) (Vandenbroucke, 1999).

Table 1
Rock-Eval pyrolysis and total organic carbon (TOC) results of the analyzed samples.

Sample no	Well	Lithology	Depth (m)	TOC (wt%)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	Tmax	H1	OI	PI	S1/TOC (OSI)	GP (S1 + S2) (mg/g)	Calc. Vitrinite reflectance
S1	A	Mudstone	41.71–42.27	0.7	0.02	0.16	1.14	431	23	164	0.11	3	0.18	0.6
S5	B	Mudstone	62.15–63.48	1.36	0.06	0.68	0.75	425	50	55	0.08	4	0.74	0.49
S8	B	Shelly Mudstone	72.33–72.51	2.5	3.99	11.3	0.91	424	452	36	0.26	160	15.29	0.47
S6	B	Mudstone	72.51–73.51	0.69	0.03	0.26	0.65	424	38	94	0.1	4	0.29	0.47
S7	B	Mudstone	85.00–85.58	2.2	0.04	0.42	1.05	418	19	48	0.09	2	0.46	0.36
S3	C	Mudstone	76.00–79.03	1.83	0.08	0.37	0.8	410	20	44	0.18	4	0.45	0.22
S2	C	Shale	85.43–87.43	0.81	0.05	0.41	0.73	422	51	90	0.11	6	0.46	0.44
S4	D	Shaly Mudstone	68.38–71.48	2.31	0.07	3.28	1	423	142	43	0.02	3	3.35	0.45
S9	E	Fossiliferous Shale	31–34	0.95	1.1	1.12	0.97	397	39	87	0.50	116	2.22	-0.014
S10	E	Oil Sand	35–36	1.37	5.9	3.85	1.26	403	53	37	0.61	431	9.75	0.094
S11	F	Bituminous Shale; Fossiliferous	38–39	2.35	4.3	4.69	0.96	399	57	31	0.48	183	8.99	0.022
S12	F	Bituminous Shale	45–47	1.43	9.9	5.31	1.13	406	59	42	0.65	692	15.21	0.148
S13	F	Indurated Shale	47–49	1.91	1.7	1.37	0.91	400	40	66	0.55	89	3.07	0.04

The plot of S2 against TOC (Fig. 5) shows the relationship between the organic richness and the hydrocarbon potential of the samples. A positive correlation typically indicates that higher organic carbon content in the rock is associated with greater hydrocarbon generation potential. This analysis further complements the S2/S3 ratio interpretation, offering a more comprehensive assessment of the source rock quality and its potential to generate hydrocarbons.

4.3 Palynology

The palynological analysis revealed a diverse assemblage dominated by terrestrial species such as *Longapertites marginatus*, *Cingulatisporites ornatus*, *Monocolpites marginatus*, *Cyathidites minor*, and *Zlivisporites blanensis* (Fig. 6).

Less abundant components included dinoflagellate cysts (*Paleocystodinium australinum* and *Spiniferites* sp.), the alga *Botryococcus braunii*, and diatom frustules.

A total of 34 palynomorph species, comprising 20 pollen, 9 spores, 3 dinoflagellate cysts, 1 freshwater algae, 1 diatom frustule, and 1 charred gramineae cuticle were recorded. The dominance of terrestrial species indicates significant land-derived input, while the presence of freshwater elements such as *Botryococcus braunii* and diatom frustules suggests a lacustrine or freshwater influence, possibly indicating proximity to freshwater bodies. (Taiwo et al., 2020; Aturamu and Akinmosin, 2024)

4.4 Foraminifera

Foraminiferal assemblages include abundant calcareous benthic, planktic, and agglutinated species, with accessory elements such as ostracod and echinoid spines.

- **Benthic Foraminifera:** *Afrolivina afra*, *Cibicides succedens*, *Anomalinoides umbonifera*, *Anomalinoides midwayensis*, *Gavellinella guineana*, *Eponides pseudoelevatus*, *Lenticulina midwayensis*, *Epistominella minuta*, *Fursenkoina wilcoxensis*, and *Dentalina* spp.
- **Planktic Foraminifera:** *Archeoglobigerina blowi*, *Rugoglobigerina macrocephala*, *Rugoglobigerina scotti*, *Heterohelix globulosa*, and *Heterohelix navaroensis*.
- **Agglutinated Foraminifera:** *Textularia*, *Ammobaculites*, and *Haplophragmoides*.

Benthic species, including *Anomalinoides midwayensis* and *Afrobolivina afra*, indicate depositional settings ranging from inner to middle neritic zones (up to ~ 100 meters in depth) (Gebhardt et al., 2010; Okosun and Alkali 2012)

1. *Polypodiaceisporites* sp., 2. *Sapotaceae*, 3. *Zlivisporites blanensis*, 4. *Botryococcus braunii*, 1. *Cingulatisporites ornatus*, 6. *Cyathidites minor*, 4. *Distaverrusporites simplex*, 8. *Ephedripites* sp., 9. *Monocolpites marginatus*, 10. *Longapertites marginatus*, 11. *Proteacidites cursus*, 12. *Echitriporites trianguliformis*.

4.5 1D BURIAL HISTORY

The burial history and thermal maturity were modelled using the PetroMod 1D software, to analyse the thermal maturity evolution and hydrocarbon generation histories of the Afowo Formation, measured vitrinite reflectance values were used for calibration of models. The combination of source rock, reservoir rock, seal rock and boundary conditions form the model (Wygrala, 1989). The simulated model was thermally calibrated against the measured vitrinite reflectance values. 1D burial history profile of the simulated model shows that the source rocks from Maastrichtian to Paleocene show no sign of maturity (Fig. 7) due to burial depth which implies low transformation ratios of kerogen to hydrocarbon (Fig. 8). At present day all the source rocks in the shallow source sequences do not have the potential to be converted into hydrocarbons.

The Mckenzie heat flow model was used to calibrate the measured vitrinite reflectance values in the studied well but unfortunately did not give a good fit. The results of the burial and thermal modelling indicate that the Afowo source rock unit is immature in all the wells and has not entered the mature oil window stage for hydrocarbon generation.

4.6 Comparative Analysis with Regional Studies

Total Organic Carbon (TOC) and Organic Richness

The current study recorded TOC values that largely align with the ranges reported by Akinmosin et al. (2015), confirming that the shales and clays of the Afowo and Araromi Formations possess the fundamental "richness" required to be classified as potential source rocks. However, Mohammed et al. (2020) reported a significantly broader TOC range. This divergence suggests that while the basin has a baseline of organic richness, there are localized "sweet spots"—likely distal or deeper facies—where preservation conditions were superior, potentially leading to higher hydrocarbon generation capacity in specific stratigraphic intervals.

Thermal Maturity and Kinetic Evolution

A pivotal point of discussion is the disparity in thermal maturity. The current study, alongside Akinmosin et al. (2011), identifies the organic matter as being in the early mature to immature stage (typically indicated by Tmax values < 435°C). This suggests that in the sampled locations, the sediments have not yet reached the "oil window."

In contrast, Mohammed et al. (2020) indicates the presence of mature organic matter. This variation is likely a function of burial depth and geothermal gradient differences across the basin; it implies that while the shallow eastern fringes remain immature, the deeper offshore or down-dip equivalents have likely entered the main stage of hydrocarbon generation.

Hydrogen and Oxygen Indices (HI & OI): Kerogen Quality

Both current and past studies exhibit a strong clustering of data points in the Type III and Type IV regions of the Van Krevelen pseudo-diagram. High Oxygen Indices (OI) and relatively low Hydrogen Indices (HI) substantiate the prevalence of terrestrial, woody organic matter. These indices reflect a depositional environment dominated by higher plant input with significant oxidation during transport. The consistency across these studies confirms that the Eastern Dahomey Basin is primarily a gas-prone province.

Kerogen Type and Generative Bias

While the predominant signature is Type III (gas-prone) and Type IV (inert/recycled), the "occasional presence" of Type II kerogen noted in this study and by Mohammed et al. (2020) is highly significant. Type II kerogen typically originates from marine algae and suggests brief periods of marine transgression or restricted marine conditions within the basin. These intervals represent the only legitimate oil-prone potential in the sequence. The identification of these Type II signatures provides a more optimistic outlook for liquid hydrocarbon exploration than a purely terrestrial model would suggest.

Hydrocarbon Generative Potential (S2)

The overall generative potential (represented by the S2 peak in Rock-Eval pyrolysis) varies across the literature. The current study shows a broader range and higher potential in certain samples compared to earlier assessments. This suggests that the Afowo Formation is not geochemically homogenous; rather, it contains high-quality organic facies capable of significant expulsion if subjected to sufficient thermal stress. This "broader range" indicates that previous studies may have underestimated the basin's total capacity due to limited sampling density.

Table : Table showing comparison with other studies.

Parameter	Current Study	Akinmosin et al. (2011)	Mohammed et al. (2020)
Richness (TOC)	Moderate to Good	Moderate	Highly Variable (Poor to Excellent)
Maturity	Immature to Early Mature	Immature	Mature
Primary Product	Gas	Gas	Gas and some Oil
Kerogen Type	III > IV > II	III & IV	III > II

5 CONCLUSIONS

The integrated geochemical and 1D basin modelling assessment confirms the Afowo Formation as a high-potential petroleum system characterized by organically rich, gas-prone Type III kerogen. Thermal maturity data reveals that shallow-depth sequences remain immature, indicating that their hydrocarbon potential is exceptionally preserved and untapped.

By successfully constraining the 1D model with measured vitrinite reflectance (%Ro), this research provides a calibrated predictive framework that resolves regional thermal complexities. Ultimately, these findings shift the exploration focus toward deep structural depocenters, where optimal thermal conditions for commercial gas generation are realized, establishing the Afowo Formation as a high-value target for future energy needs.

Declarations

Author Contribution

A. O. design the concept , partake in the laboratory analysis and jointly write the manuscriptT. interpret the palynological and forams dataW. O. developed the 1D model with Petromod and jointly write the manuscriptA.O join in the laboratory analysis work

Declaration of Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. However, Southwest Bitumen Limited, Nigeria provides the samples used for this study

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Figures

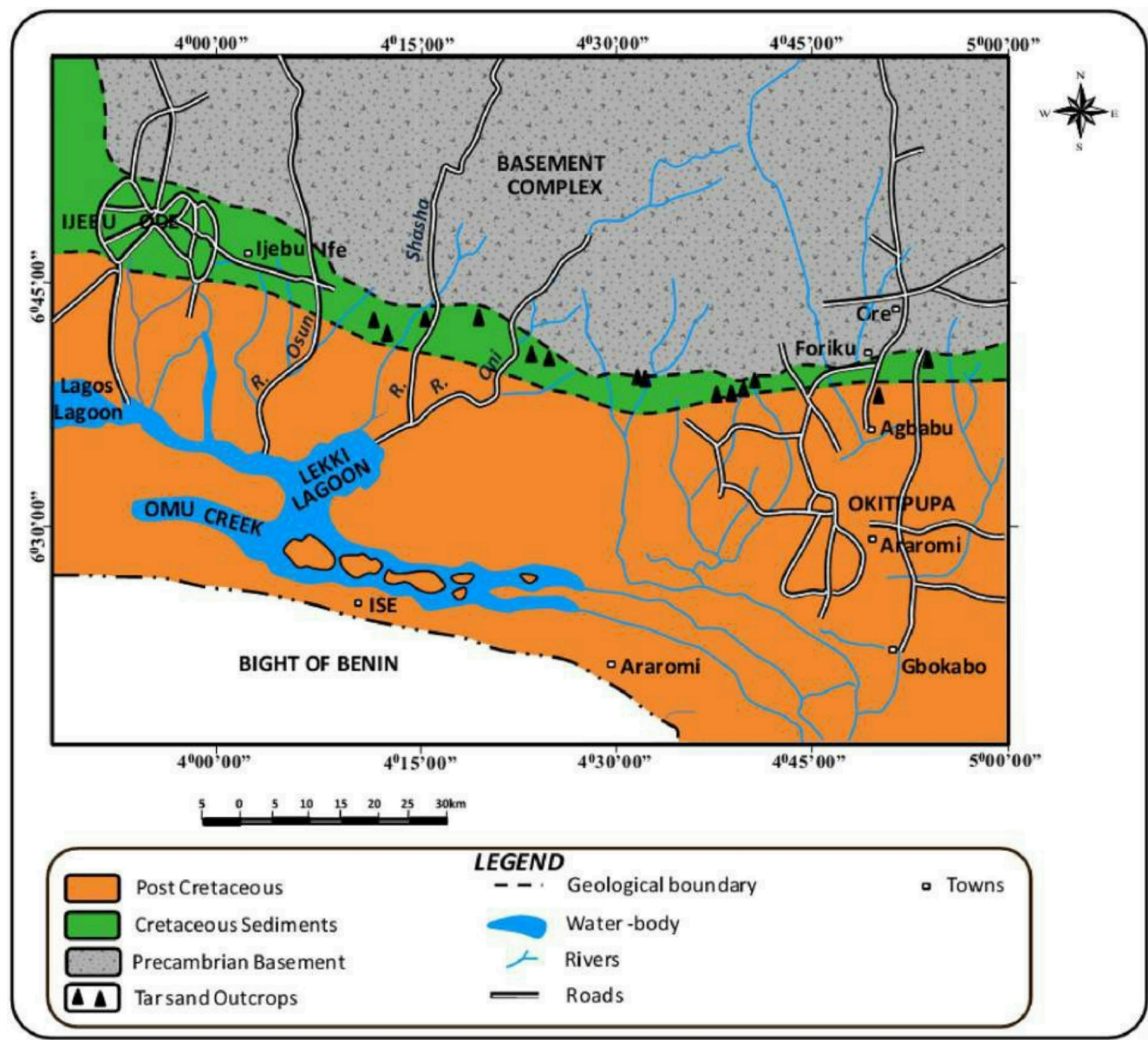


Figure 1

Generalized geological map of the eastern Dahomey Basin showing Area Extent of the tar sand deposits (modified after Enu, 1985).

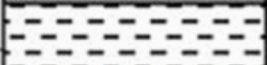
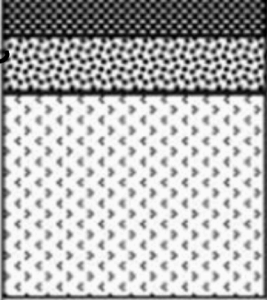
Age	Formation	Lithology
Pleistocene-Oligocene	Coastal Plain Sands	
Eocene	Ilaro	
	Oshosun	
Palaeocene	Akinbo	
	Ewekoro	
Maastrichtian-Neocomian	Araromi	
	Afowo	
Precambrian	Crystalline Basement	

Figure 2

Stratigraphic overview of the Eastern Dahomey Basin (modified from Omatsola and Adegoke, 1981).

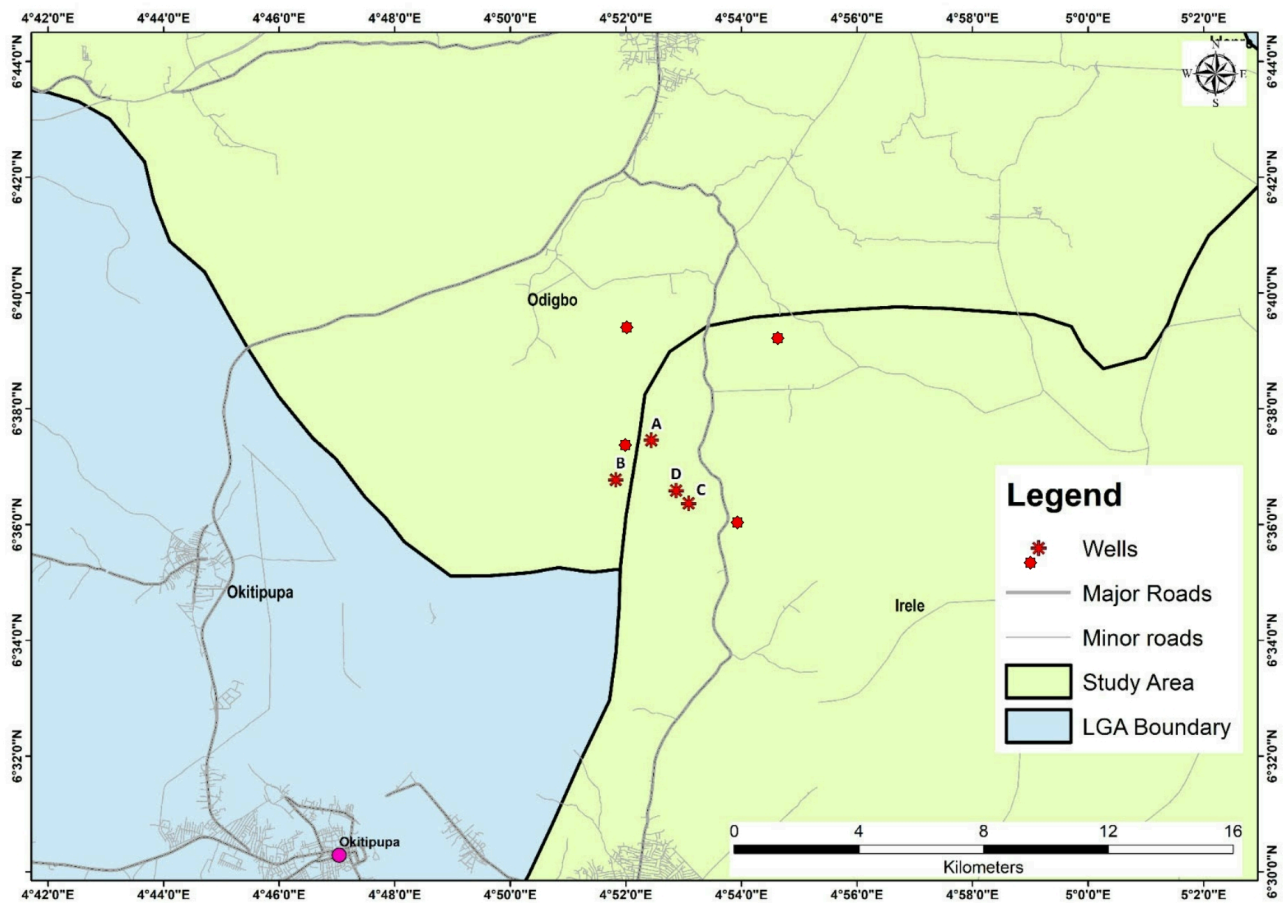


Figure 3

Map of the study area showing the locations of the eight wells used for sample collection in this study.

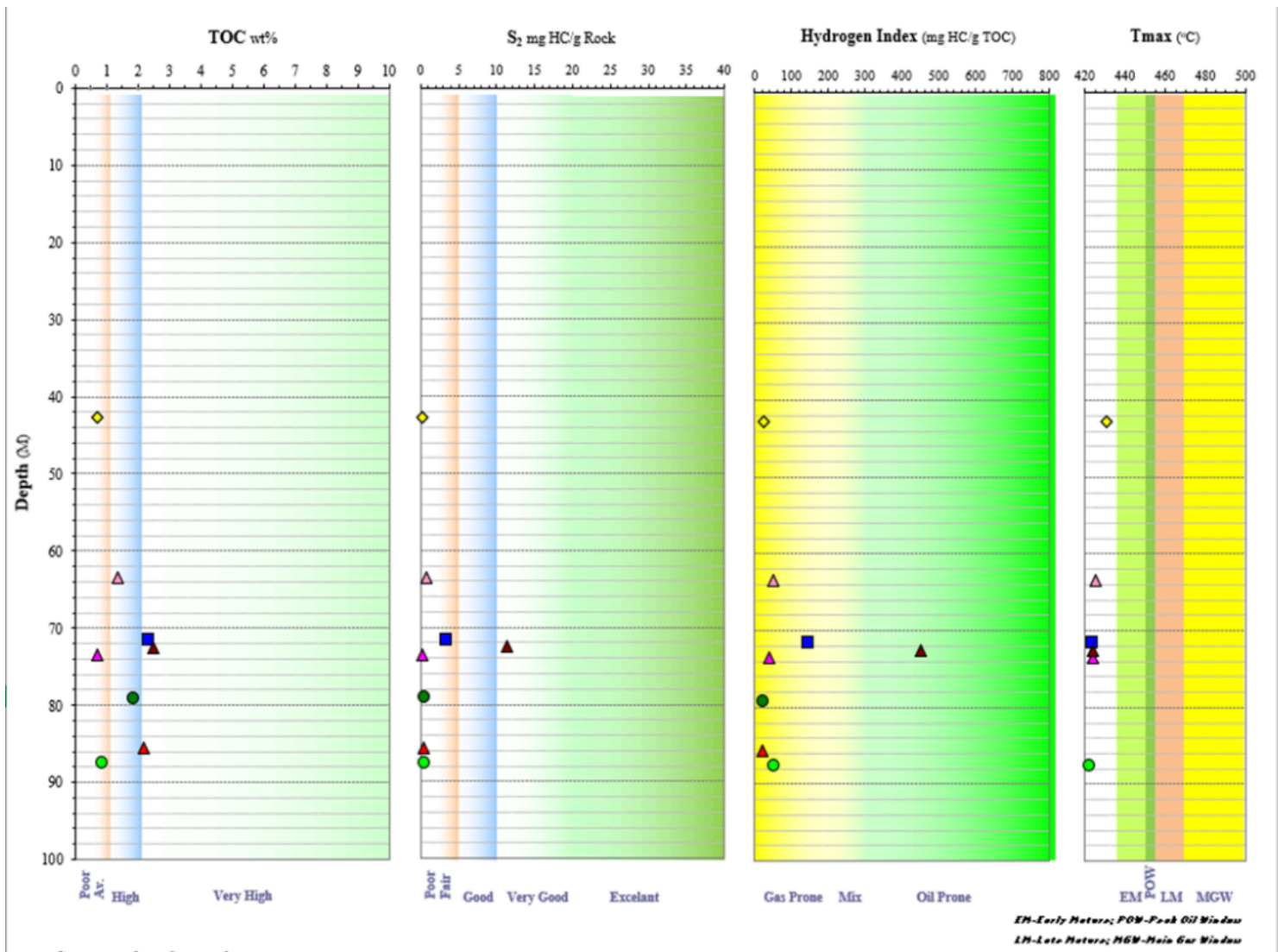


Figure 4

Geochemical log of the well shows the distribution of organic matter as it increases down the well.

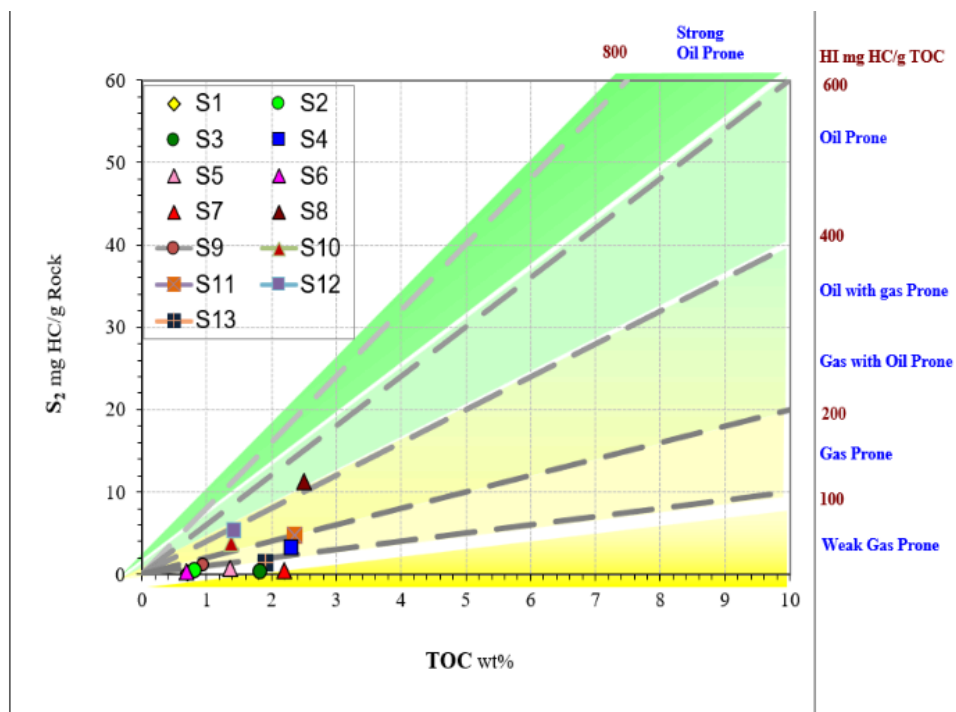


Figure 5

Graphical presentation of remaining hydrocarbon potential (S2) versus total organic carbon (TOC) (*The graph Substantiates the kerogen types*).

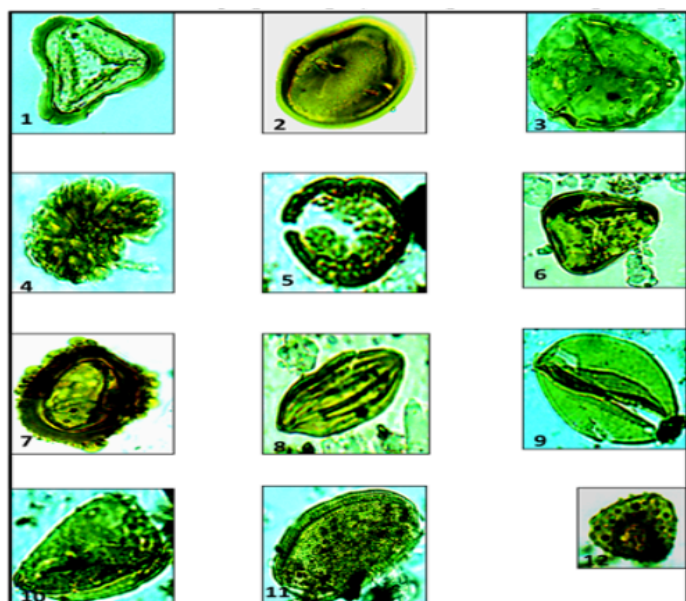


Figure 6

Representative palynomorphs identified from the samples studied (X400 magnification).

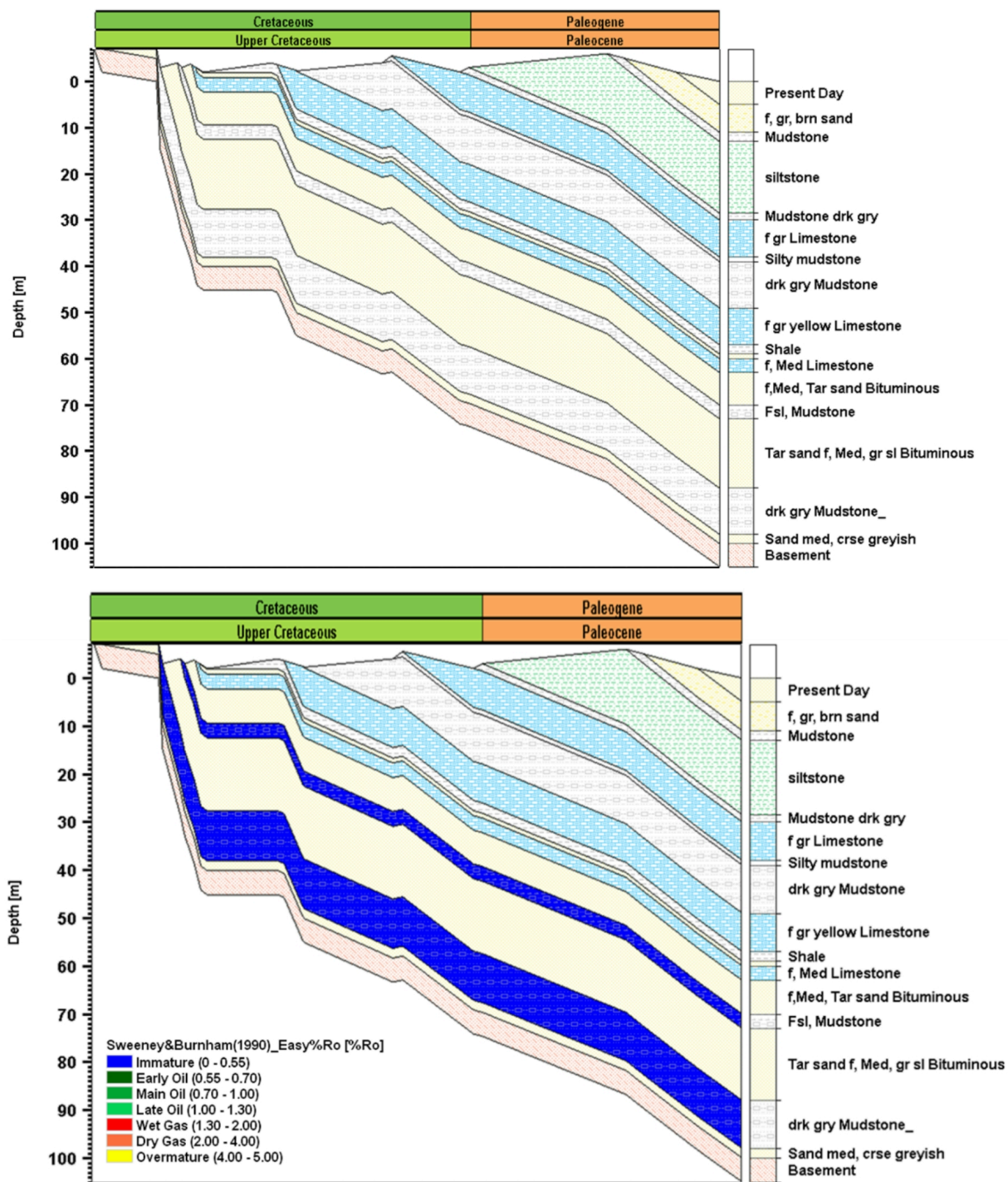


Figure 7

Burial and Maturity Plots of the modelled well

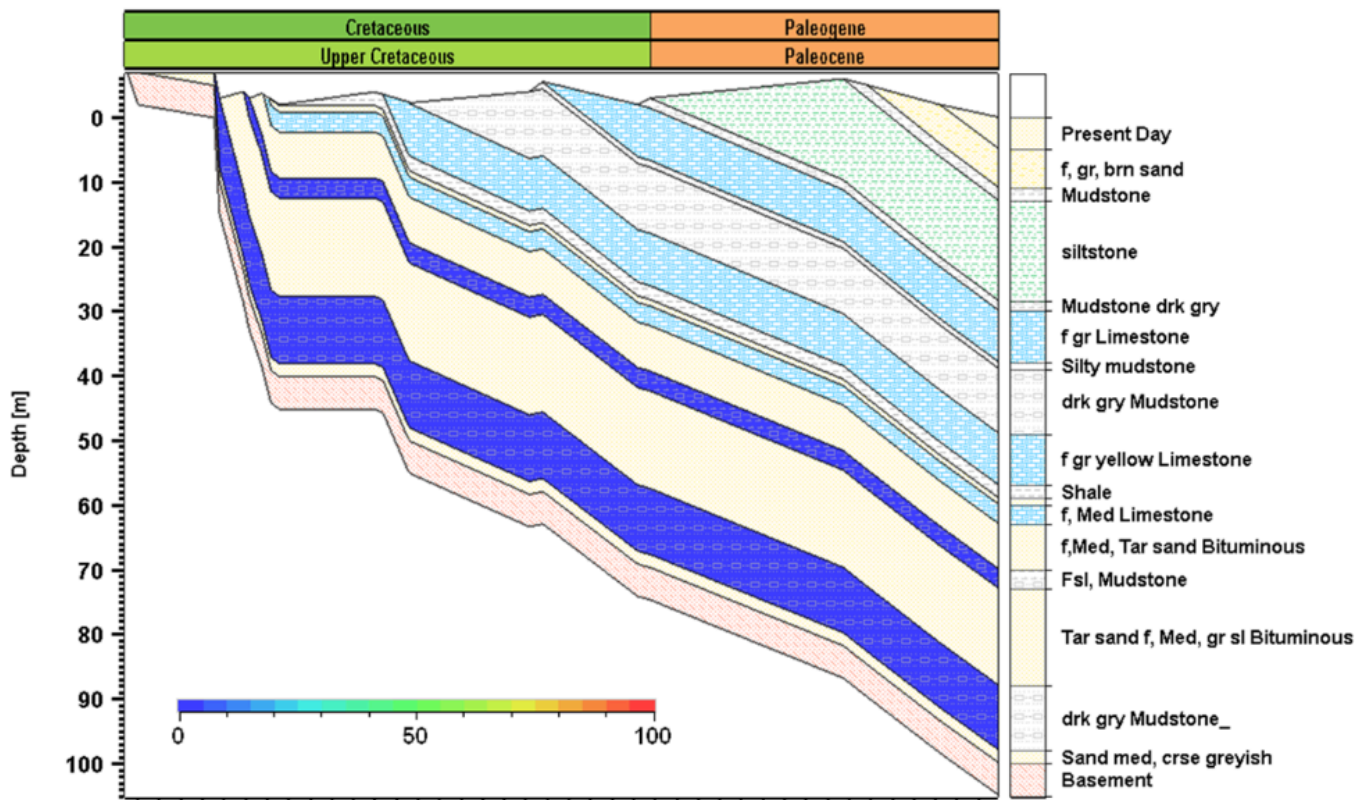


Figure 8

Burial history of the modelled well showing transformation ratio of source rock zones