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# Maturity modelling and Source rock evaluation of upper Oligocene source rocks (within Agbada Formation), Greater Ughelli Depobelt, Niger Delta Basin

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**Abstract**

Greater Ughelli depobelt of Niger Delta basin is an important petroleum province in Nigeria. Data/information on hydrocarbon generation potentials of Oligocene source rocks in the depobelt is limited. This present study utilized results of Rock-Eval pyrolysis and 1-D basin modelling of two wells to infer the timing of hydrocarbon generation and evaluate the deeply buried upper Oligocene source rocks within Agbada Formation. Total Organic Carbon contents of the shale samples within the studied wells range between 1.7 to 31.8 wt. % and suggest that the upper Oligocene source rocks could be considered as potential source rocks for hydrocarbon generation. The vitrinite kerogen composition of the upper Oligocene source rocks is the main organic matter with fewer component of exinite/vitrinite kerogen. The shale samples have poor to excellent source generative potential. Maturity models assumed that the deeply buried upper Oligocene source interval began hydrocarbon generation during Miocene and continue till date. The modelled present-day transformation ratios for upper Oligocene source rocks are low for enough hydrocarbons to be significantly expelled from the upper Oligocene source rocks. The results of this study provide basic information that improves understanding of the viability of the Oligocene-sourced play in the Greater Ughelli depobelt.

***Keywords:*** Niger Delta Basin; generation; Oligocene; hydrocarbon; basin modelling.

## 1. Introduction

The study field lies in the Greater Ughelli depobelt (Figure 1) and one of the productive fields in the Niger Delta Basin. Greater Ughelli depobelt of the Niger Delta Basin has significant hydrocarbon potentials with oil and gas discoveries [1]. Quite a few studies had been undertaken on the source rocks of the Niger Delta basin [1-10].

Nwachukwu *et al.* [4] and Ekweozor *et al.* [6] have shown that the Agbada shale units have intervals that contain organic carbon contents sufficient to be considered good source rocks. However, published works particularly related to source rock characteristics, maturity histories and the timing of hydrocarbon generation of upper Oligocene source rocks within the Agbada Formation are limited. Oligocene source rocks have contributed to petroleum systems of some oil and gas fields in other parts of the world, as noted in offshore Sarawak Basin in Malaysia [11] and Yayu Basin, southwestern Ethiopia [12]. Source rocks of upper Oligocene age within the Agbada formation have not been considered to have contributed to oil and gas fields in the Greater Ughelli Depobelt.

This study presents the results of Rock-Eval pyrolysis and 1-D basin modelling study of *Giri* field in the Greater Ughelli depobelt using vitrinite reflectance data, rock-eval data and stratigraphic well data to evaluate the source rock characteristics of upper Oligocene source rocks and infer the maturity histories and time of hydrocarbon generation of the deeply buried upper Oligocene shale intervals. The evaluation of sedimentary rocks as effective source rocks of petroleum requires the determination of the amount and type of organic matter and the degree of conversion of the organic matter to petroleum hydrocarbons [13]. The outcome of this study provides information on the quantity, quality of the organic matter and hydrocarbon generation potentials of upper Oligocene shale intervals in the Greater Ughelli depobelt of Niger Delta Basin.

## 2. Geological settings

The Niger Delta continental margin (Figure 1) is one of the largest deltaic systems in the world [9]. The sub-aerial part of the delta covers about 75,000 km$^2$ and extends more than 300 kilometers from apex to mouth [14]. The total sedimentary sequence was deposited in a series of mega-sedimentary belts (depobelts or mega-structures) in a succession temporally and spatially with southward progradation of the Delta [9]. The sedimentary fill is usually divided into three diachronous formations (Eocene-Recent); namely the undercompacted, overpressured marine Akata Formation, paralic Agbada Formation and continental fluviatile Benin Formation. The Akata Formation is typically overpressured and made up of prodelta shales with occasional turbidite sands. The Akata Formation represents muddy continental slope and rise environments and is the core unit in which shale diapirs form offshore [14].

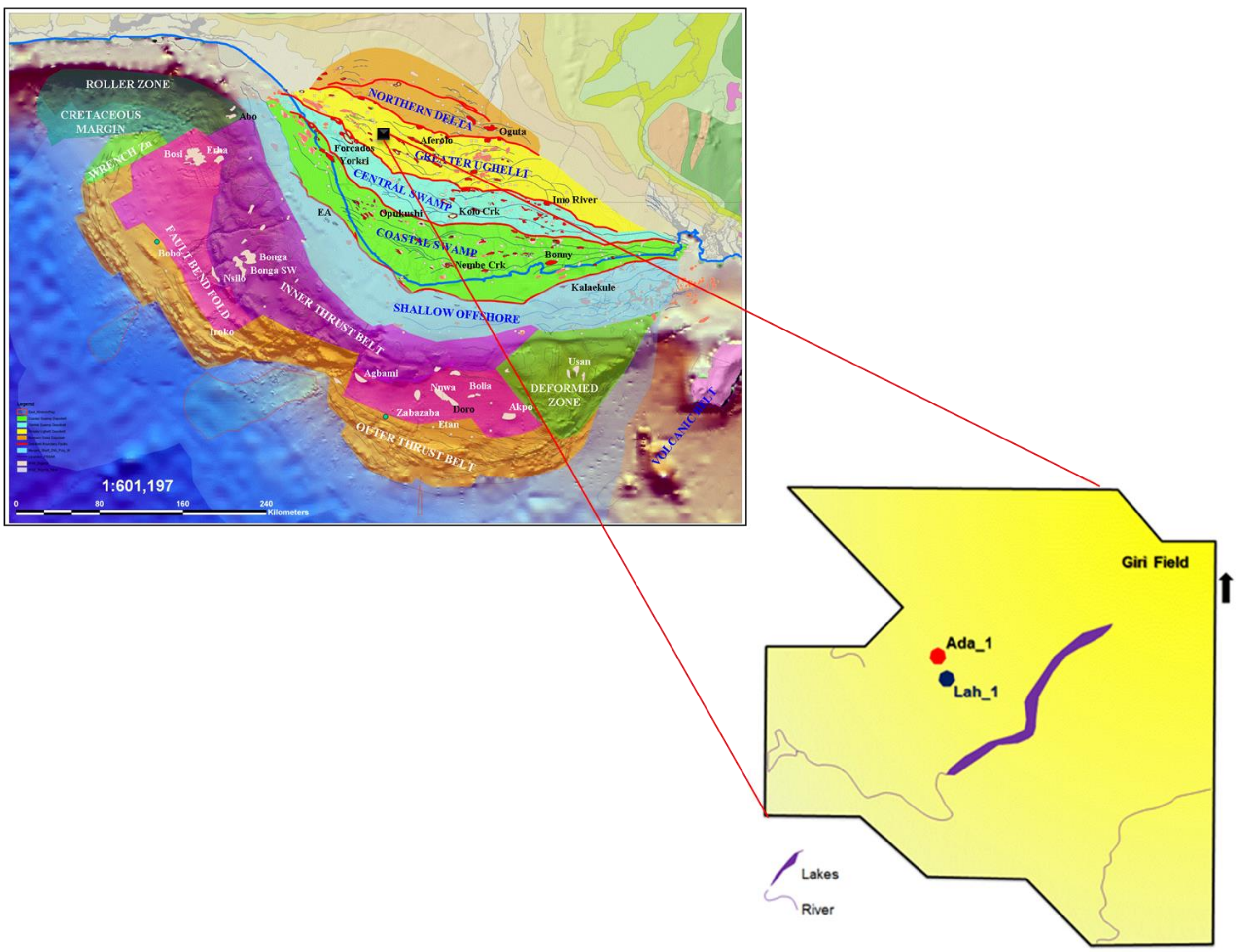


Figure 1. Location map of depobelts in the Niger Delta; showing the field where subsurface data were collected (Ada_1 and Lah_1 wells) (map modified from [15])

The Agbada Formation consists of paralic, mainly shelf deposits of alternating sands, shales and mudstone. The Benin Formation is predominantly non-marine upper delta plain sandstone (Figure 2). The Benin Formation is up to 2,000 m thick in the central onshore part of the delta and thins toward the delta margins [8]. The undercompacted, overpressured marine Akata Formation and paralic Agbada Formation are thought to have charged to varying degrees oil

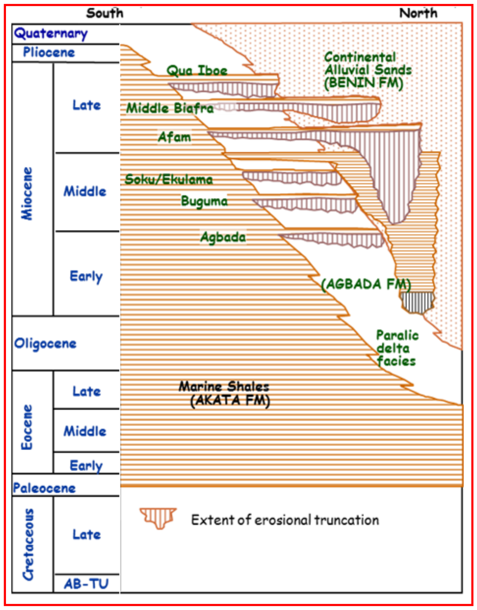


Figure 2. Regional stratigraphy of the Niger Delta showing different formations (*modified from* [19])

and gas in the Niger Delta [2]. Short *et al.* [16] defined the contact between the Agbada and Benin Formations as the highest shale bearing marine fauna in the Agbada Formation. However, the contact is more practically defined at the base of the massive sandstones typical of the Benin Formation and generally corresponds to the base of freshwater-bearing strata [8].

The progradation of the delta has been accompanied by formation of growth faults, associated rollover anticlines and mud diapirism [8]. Most hydrocarbon-bearing structures are along proximal margins of sub-basins where growth strata accumulated on blocks down-dropped across major syn-depositional faults and onlap adjacent anticlinal (rollover) closures [9]. Major growth faults exhibit throws of several hundred meters are arcuate in plain view, concave basinward and are generally several tens of kilometers in length [17]. All major oil and gas discoveries in the Niger Delta occur in Eocene to Pliocene sandstones of the Agbada Formation [8].

## 3. Materials and methods

Forty (40) ditch-cutting and sidewall samples from two wells in Greater Ughelli depobelt were analyzed by Shell Petroleum Development Company of Nigeria (SPDC). The two wells for proprietary reason were named as Ada_1 and Lah_1 wells. This study utilized Rock-Eval pyrolysis results and stratigraphic well data of the upper Oligocene source rocks within Agbada Formation. The results of the Total Organic Carbon (TOC) and Rock-Eval pyrolysis were presented in Table 1 and 2.

The sedimentation history of the basin is subdivided into a series of events of specified age and duration [18]. 1-D basin modelling was carried out using Schlumberger Petromod 2011 to basically infer the maturation and timing of hydrocarbon generation of the deeply buried upper Oligocene source rocks. The input data for the stratigraphic modelling included age, and thicknesses, lithology of different sedimentary layers, duration of deposition. Thickness and depth values of different sedimentary units are based on proprietary stratigraphic (well) penetration data from Shell Petroleum Development Company of Nigeria.

Paleobathymetry data are used in the reconstruction of the total subsidence that occurred within the basin [18]. Paleobathymetric values for the Niger Delta Basin used in this study were obtained from the proprietary Shell Petroleum Development Company chart and published reports [20-21]. Heat flow is considered to be an input parameter but it is challenging to define the heat flow values for the past. Therefore, the reconstruction of thermal histories of sedimentary basins is always simplified and calibrated against maturity profiles such as vitrinite reflectance [22]. The heat flow values were determined based on the tectonic history of the basins and were defined by streaming modelled and measured vitrinite reflectance data. Modelled vitrinite reflectance (calculated after Easy%$R_o$ Sweeney and Burnham, 1990) has been related to measured data (Table 3) in order to calibrate the hydrocarbon generation levels. The hydrocarbon generation stages were calculated using reaction kinetics data based on [23].

The source rock parameters i.e. Total Organic Carbon content (TOC) and Hydrogen Index (HI) used in the construction of 1-D models were obtained from available well reports. Present-day TOC of 5.59 wt. % TOC and Hydrogen Index (HI) of 146mgHC/gTOC were applied during the modelling of Ada_1 well. TOC content of 3.66 wt. % TOC and Hydrogen Index (HI) of 128 mgHC/gTOC were applied during the development of Lah_1 well models.

Basin modelling, numerical simulation and calibration stages were the stages involved in the 1-D basin modeling. The basin modelling simulations were performed by applying forward modelling method. After calibration stage was achieved, the 1-D models of the two wells were simulated. Modelling results were presented visually.

## 4. Results and discussion

### 4.1. Organic matter richness

The Rock-eval pyrolysis results (Table 1 and 2) indicate that the Total Organic Carbon (TOC) contents of upper Oligocene shale samples in Ada_1 and Lah_1 wells range from 1.7 to 31.8 wt. % (average value of 5.59 wt. %) and 2.0 wt. % to 12.9 wt. % (an average value of 3.66 wt.%) respectively indicating good to very good source rocks (Figure 3).

Table 1. Geochemical results of Rock-Eval/TOC analysis of upper Oligocene shale samples in Ada_1 well

| Well | Depth (m) | TOC (wt. %) | Rock-Eval pyrolysis | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | $S_1$ (mg HC/g Rock) | $S_2$ (mg HC/g rock) | $S_1$+$S_2$ (mg HC/g Rock) | $T_{max}$ | OI (mg HC/g Rock) | HI (mg HC/g rock) | PI (mg HC/g rock) |
| Ada_1 | 3093 | 13.9 | 1.22 | 26.35 | 27.57 | 412 | 45 | 190 | 0.04 |
| Ada_1 | 3120 | 14.3 | 0.81 | 35.21 | 36.02 | 423 | 49 | 246 | 0.02 |
| Ada_1 | 3235 | 31.8 | 2.46 | 69.9 | 72.36 | 414 | 35 | 220 | 0.03 |
| Ada_1 | 3253 | 11.4 | 0.73 | 18.58 | 19.31 | 421 | 41 | 163 | 0.04 |
| Ada_1 | 3267 | 15.8 | 0.8 | 29.96 | 30.76 | 422 | 42 | 190 | 0.03 |
| Ada_1 | 3276 | 5 | 0.3 | 6.69 | 6.99 | 412 | 42 | 134 | 0.04 |
| Ada_1 | 3285 | 2.5 | 0.28 | 3.37 | 3.65 | 418 | 52 | 135 | 0.07 |
| Ada_1 | 3294 | 2.9 | 0.22 | 3.7 | 3.92 | 420 | 51 | 128 | 0.06 |
| Ada_1 | 3331 | 8.1 | 0.58 | 12.73 | 13.31 | 415 | 42 | 157 | 0.04 |
| Ada_1 | 3345 | 3.8 | 1.34 | 4.45 | 5.79 | 415 | 51 | 117 | 0.23 |
| Ada_1 | 3358 | 19.7 | 2.52 | 66.69 | 69.21 | 415 | 38 | 338 | 0.04 |
| Ada_1 | 3372 | 4.8 | 0.27 | 6.45 | 6.72 | 415 | 38 | 134 | 0.04 |
| Ada_1 | 3450 | 3.4 | 7.08 | 12.25 | 19.33 | 415 | 65 | 360 | 0.37 |
| Ada_1 | 3454 | 2.8 | 0.32 | 2.74 | 3.06 | 423 | 60 | 98 | 0.1 |
| Ada_1 | 3596 | 2.2 | 0.1 | 1.3 | 1.4 | 422 | 66 | 59 | 0.07 |
| Ada_1 | 3633 | 1.7 | 0.16 | 1.46 | 1.62 | 427 | 71 | 96 | 0.1 |
| Ada_1 | 3637 | 1.7 | 0.32 | 2.04 | 2.36 | 425 | 82 | 120 | 0.14 |
| Ada_1 | 3665 | 2.4 | 0 | 0 | 0 | 428 | 18 | 0 | 0 |
| Ada_1 | 3683 | 2.4 | 0.2 | 1.36 | 1.56 | 424 | 35 | 57 | 0.13 |
| Ada_1 | 3683 | 2.1 | 0.27 | 1.71 | 1.98 | 430 | 50 | 81 | 0.14 |
| Ada_1 | 3701 | 2.6 | 0.38 | 2.07 | 2.45 | 421 | 49 | 83 | 0.16 |
| Ada_1 | 3719 | 2.2 | 1.34 | 2.62 | 3.96 | 423 | 77 | 119 | 0.34 |
| Ada_1 | 3747 | 2 | 1.15 | 2.212 | 3.36 | 426 | 95 | 106 | 0.36 |
| Ada_1 | 3761 | 2.7 | 0.93 | 0.63 | 1.56 | 428 | 69 | 134 | 0.2 |
| Ada_1 | 3779 | 2.3 | 1 | 3.72 | 4.72 | 428 | 82 | 162 | 0.21 |
| Ada_1 | 3784 | 2 | 0.97 | 3.42 | 4.39 | 429 | 89 | 171 | 0.22 |
| Ada_1 | 3793 | 2.1 | 0.83 | 4.34 | 5.17 | 428 | 70 | 207 | 0.18 |
| Ada_1 | 3806 | 2.2 | 0.7 | 1.84 | 2.54 | 424 | 80 | 84 | 0.28 |
| Ada_1 | 3851 | 2.1 | 1.42 | 3.37 | 4.79 | 427 | 105 | 160 | 0.3 |
| Ada_1 | 3869 | 1.9 | 1.01 | 2.65 | 3.66 | 429 | 100 | 139 | 0.28 |
| Ada_1 | 3870 | 2 | 1.21 | 2.61 | 3.82 | 427 | 87 | 131 | 0.32 |
| Ada_1 | 3912 | 2.2 | 1.32 | 3.01 | 4.33 | 429 | 90 | 137 | 0.3 |

All the shale samples have TOC values exceeding 0.5 wt. % minimum thresholds required for potential source rock [24]. Organic matter richness of Agbada Shale as reported by [4] and [6] ranges from 0.2 to 6.5 wt. % and 0.4 to 4.4 wt. % respectively. Bustin [8] regarded upper Eocene to Oligocene as the richest source rock strata with the Agbada Formation.

The hydrogen index (HI) values of Ada_1 well and Lah_1 well ranged from 0 to 360 mg HC/g TOC and 41 to 255 mg HC/g TOC (Table 1 and 2), and are comparable to HI values of Agbada Shales obtained by [4] and [25].

Table 2. Geochemical results of Rock-Eval/TOC analysis of upper Oligocene shale samples in Lah_1 well

| Well | Depth (m) | TOC (wt. %) | Rock-Eval pyrolysis | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | $S_1$ (mg HC/g Rock) | $S_2$ (mg HC/g Rock) | $S_1+S_2$ (mg HC/g Rock | $T_{max}$ | OI (mg HC/g rock) | HI (mg HC/g rock) | PI (mg HC/g rock) |
| Lah_1 | 2872 | 2.3 | 0.35 | 1.46 | 1.81 | 427 | 26 | 63 | 0.19 |
| Lah_1 | 2989 | 1.7 | 0.45 | 2.23 | 2.68 | 427 | 34 | 131 | 0.17 |
| Lah_1 | 3068 | 12.9 | 1.64 | 34.2 | 35.84 | 426 | 10 | 255 | 0.05 |
| Lah_1 | 3132 | 3 | 0.64 | 3.2 | 3.84 | 424 | 11 | 107 | 0.17 |
| Lah_1 | 3195 | 2 | 0.28 | 1.29 | 1.57 | 430 | 29 | 65 | 0.18 |
| Lah_1 | 3304 | 2 | 2.27 | 3.19 | 5.46 | 429 | 38 | 160 | 0.42 |
| Lah_1 | 3393 | 2.8 | 0.64 | 5.55 | 6.19 | 431 | 28 | 198 | 0.1 |
| Lah_1 | 3397 | 2.6 | 0.31 | 1.07 | 1.38 | 425 | 14 | 41 | 0.22 |

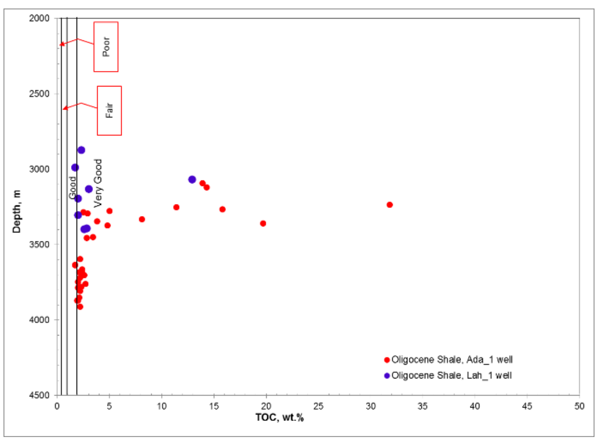


Figure 3. Organic richness of upper Oligocene source rocks in Ada_1 and Lah_1 wells

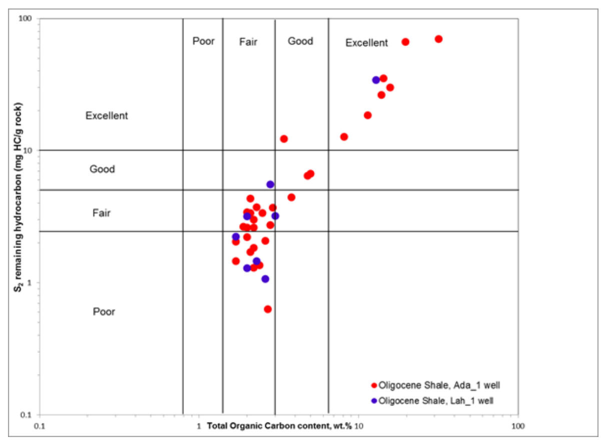


Figure 4. Crossplot of Total Organic Carbon (TOC) against Rock-Eval S2 (generative hydrocarbons of the sample) values for the potential source rocks in the Agbada Formation

The plot of TOC content and $S_2$-generative hydrocarbons of the sample [28] showed that the upper Oligocene samples meet the accepted standards of a source with poor to excellent generative potential as classified by [26] (Figure 4).

## 4.2. Generating potentialities

The sum of the values $S_1$ (free hydrocarbons present in the sample) + $S_2$ (generative hydrocarbons of the sample) is regarded as generative potential. The generative potential of upper Oligocene shale samples in Ada_1 well ranges from 0 to 72.36 mg HC/g rock with average of 11.61 mg HC/g rock while ($S_1$+ $S_2$) values for Lah_1 well range from 1.38 to 35.84 mg HC/g rock (an average of 7.35 mg HC/g rock). The relationship between ($S_1$+$S_2$) and TOC [27] suggests that the upper Oligocene shale samples in the two wells are considered as fair to excellent source potential (Figure 5). All Niger Delta source rocks have, or had, little or no oil-generating potential [8].

### 4.3. Type of organic matter

Petroleum is a generative product of organic matter disseminated in sediments; therefore the quality of hydrocarbon is directly related to the type of organic matter contained in any potential source rock [24]. The initial genetic type of organic matter of a particular source rock is essential for the prediction of oil and gas potential [28]. The kerogen type of the upper Oligocene shale samples in Ada_1 well and Lah_1 well were determined by using Rock-eval pyrolysis kerogen classification diagram constructed using crossplot of Hydrogen Index (HI) against $T_{max}$ values [29]. The type of organic matter identified from the plot of Hydrogen Index (HI) against $T_{max}$ (°C) indicate the presence of mainly vitrinite kerogen composition of gas-prone Type III in shale samples recovered from Ada_1 well and Lah_1 well whereas few samples in the two wells are within the kerogen type II/III capable of generating mixed gas and oil but mainly gas (Figure 6). Van Krevelen-type diagram of the three pyrolyzed Agbada shales as reported by [4], indicates that they contain essentially Type III organic matter. The abundance of terrestrial organic matter in deltaic sediments has been documented [30].

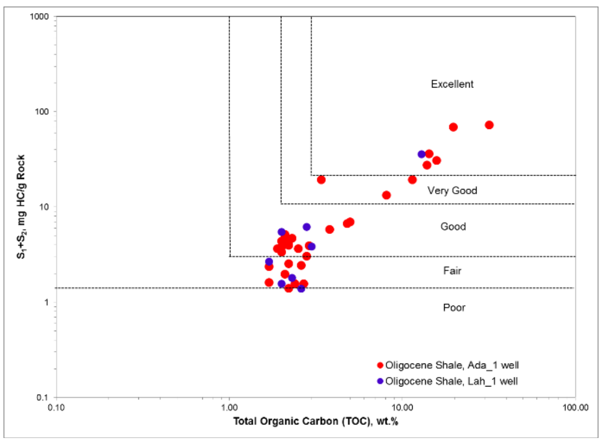


Figure 5. Plot of TOC against Rock-Eval $S_1$ (free hydrocarbons present in the sample) + $S_2$ (generative hydrocarbons of the sample) values for the potential source rocks in the two studied wells

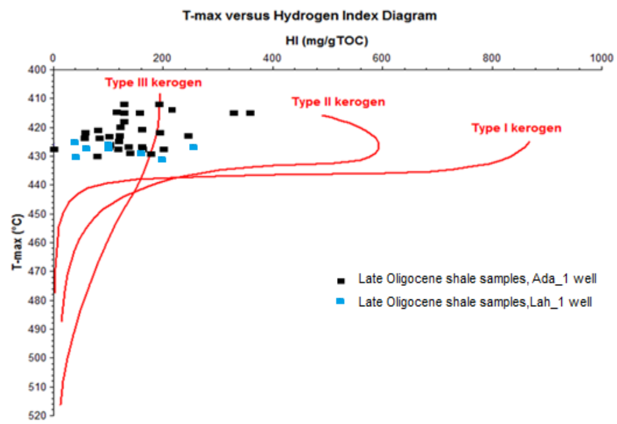


Figure 6. Diagram showing plot of Hydrogen Index (HI) against $T_{max}$ (°C) for selected upper Oligocene shale samples in Ada_1 well and Lah_1 well

### 4.4. Thermal maturity

$T_{max}$ variation is a function of its thermal evolution [31]. The maturity windows represent an approximate range [36] as shown in figure 7. The thermal maturity of the upper Oligocene source rocks has been assessed by the plot of $T_{max}$ against depth [31] (Figure 7) indicates that the upper Oligocene source samples are immature to marginally mature source rocks. This result is consistent with the work of [4].

Thermogenic oil is thought to be generated from marine and lacustrine source rocks at vitrinite reflectance values between 0.5 %$R_o$ and 1.3%$R_o$, suggest oil generation window, while samples with values less than 0.5 %$R_o$ are considered thermally immature [31-32]. Vitrinite reflectance greater than 1.3 %$R_o$ indicates gas window maturity [32]. Vitrinite reflectance values of Ada_1 well range from 0.5 %$R_o$ to 0.70 %$R_o$ while vitrinite reflectance values of Lah_1 well range from 0.53 %$R_o$ to 0.60 %$R_o$. The plot of vitrinite reflectance data (%$R_o$) versus depths [31] indicates that the vitrinite reflectance values of the two wells correspond to earliest part of the mature window (Figure 8). Nwachukwu *et al.* [4] identified mature Agbada shales in some wells in the western part of the Niger Delta basin.

Table 3. Vitrinite reflectance measurements of Eocene stratigraphic levels in the Ada_1 well and Lah_1 well

| Well(s) | Depth (m) | Measured vitrinite reflectance values | Well(s) | Depth (m) | Measured vitrinite reflectance values |
|---|---|---|---|---|---|
| Ada_1 | 3253 | 0.5 | Lah_1 | 2872 | 0.46 |
| | 3597 | 0.52 | | 3068 | 0.5 |
| | 3858 | 0.7 | | 3393 | 0.6 |

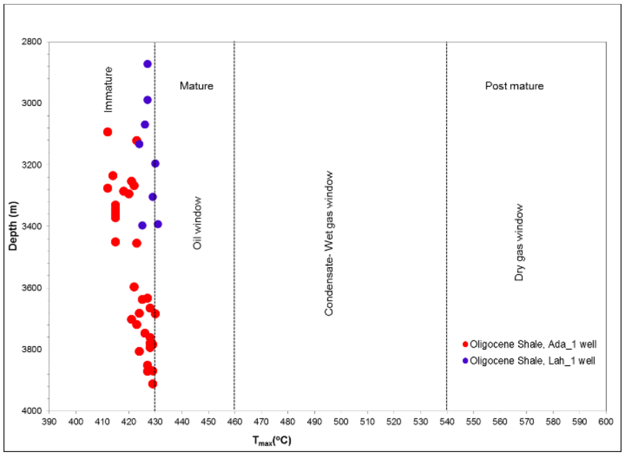


Figure 7. Plot of Depth versus pyrolysis $T_{max}$ showing thermal maturity windows

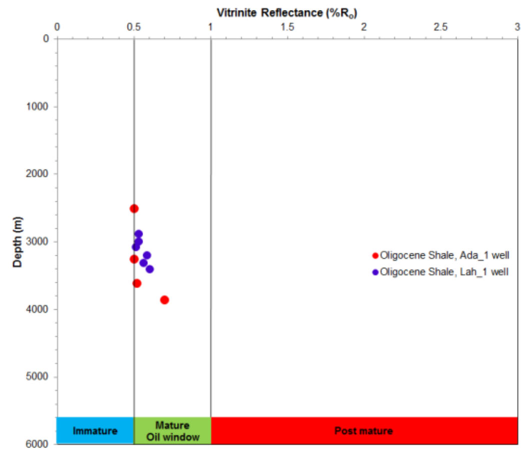


Figure 8. Plot of vitrinite reflectance data (%Ro) versus depth showing thermal maturity stages of the upper Oligocene source rocks in the Ada_1 and Lah_1 wells

## 4.5. 1-D reconstructions using Schlumberger Petromod 2011

### *4.5.1. Heat flow history*

Heat flow value ranging from 66 $mWm^{-2}$ in the Aptian-Albian times to 88 $mWm^{-2}$ during the Coniacian to early Santonian was calibrated for the 1-D models (Figure 9).

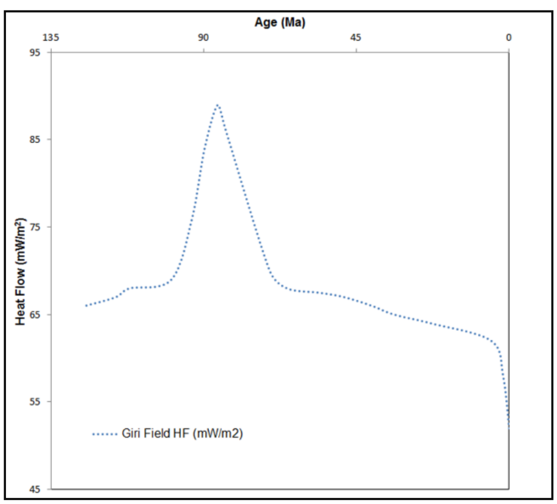


Figure 9. Heat-flow history used to model the most probable scenario for hydrocarbon generation in the Greater Ughelli (Niger Delta Basin)

Elevated heat flow value of 90 $mWm^{-2}$ was assigned to the early Santonian phase of intense volcanic activity [10]. Late Turonian to Santonian times were marked by indication of active tectonic phase of folding, faulting, and uplifting [33]. This event was followed by gradual loss of thermal momentum associated with final cessation of mantle upwelling. Heat flow value of 45 $mWm^{-2}$ was modelled as the present day values for the two wells. Heat flow values less than 80 $mWm^{-2}$ observed during the Cenozoic, thus, suggest that the field located in Greater Ughelli depobelt is not geothermally active area. Rapid sedimentation may cause reduction in heat flow and thermal maturity [34]. Reduction in the values of heat flow during Cenozoic may be associated with rapid sedimentation in the Greater Ughelli depobelt.

### 4.5.2. Hydrocarbon generation phases

Kinetic models of [23] and [35] were used to establish the burial history and hydrocarbon generation potential of upper Oligocene Shale samples through 1-D charge modelling of Ada_1 and Lah_2 wells. Figure 10 shows a good and reasonable correlation between measured and calculated vitrinite reflectance values for the two wells. Maturity (vitrinite reflectance) values of the upper Oligocene source rock are low. The burial models showed that sedimentation rates were rapid in the two wells (Figure 11 and Figure 12).

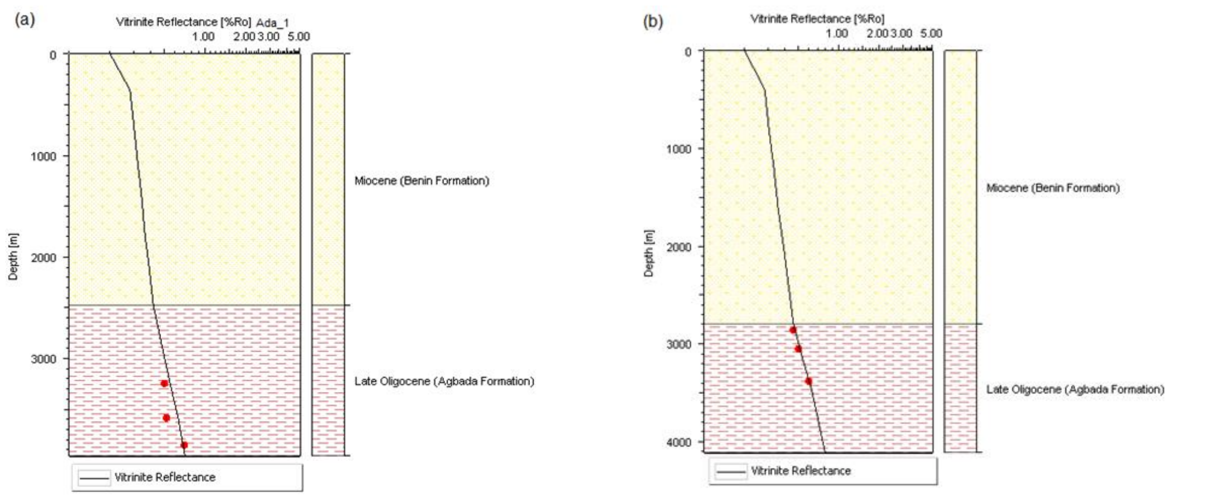


Figure 10. Correlation of measured and modeled vitrinite reflectance data for (a) Ada_1 well and (b) Lah_1 well

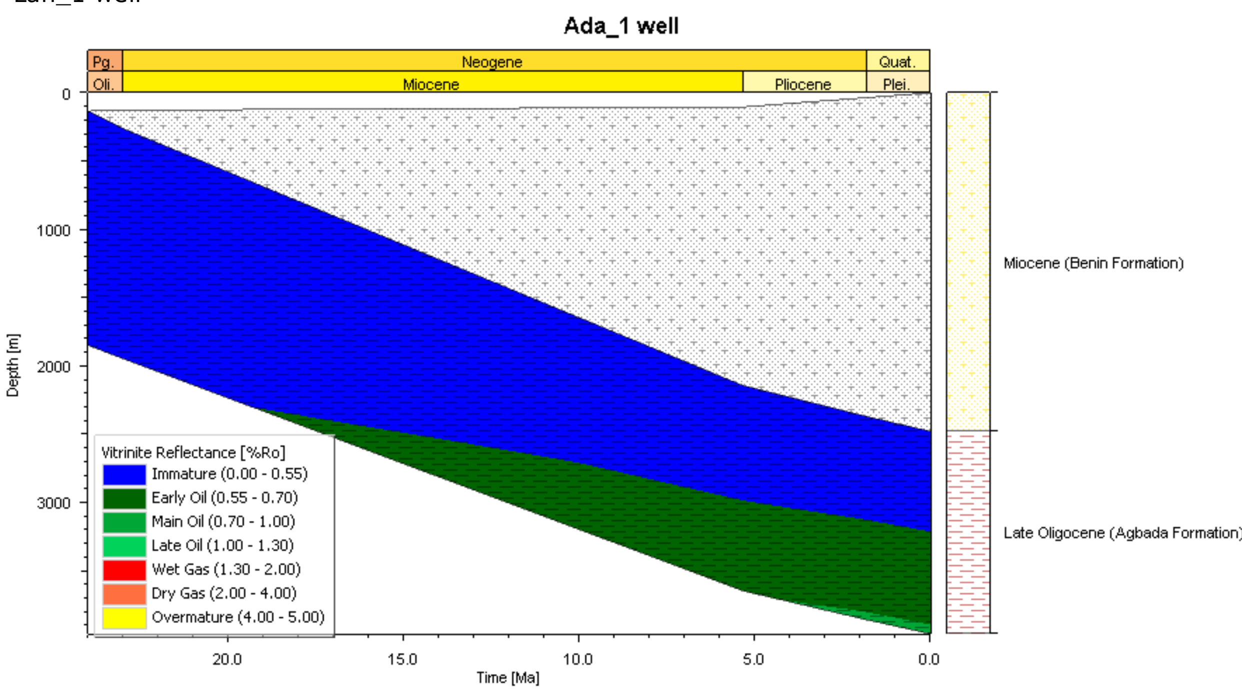


Figure 11. Burial history of the well Ada_1 showing the maturity overlay

Hydrocarbon generation from the upper Oligocene source rocks started during the Miocene (about 19.26 Ma). The top of the liquid hydrocarbon window in Ada_1 well was identified at 2,307 m and suggest that the upper Oligocene shale intervals in Ada_1 well are presently within immature to main oil window (Figure 11). The maturity model of Lah_1 well predicts that the hydrocarbon generation from the upper Oligocene source rocks occurred during the

Miocene (about 21.46 Ma) at present depth of 1,962 m. Upper Oligocene source rocks in Lah_1 well are currently within immature to main oil window (Figure 12).

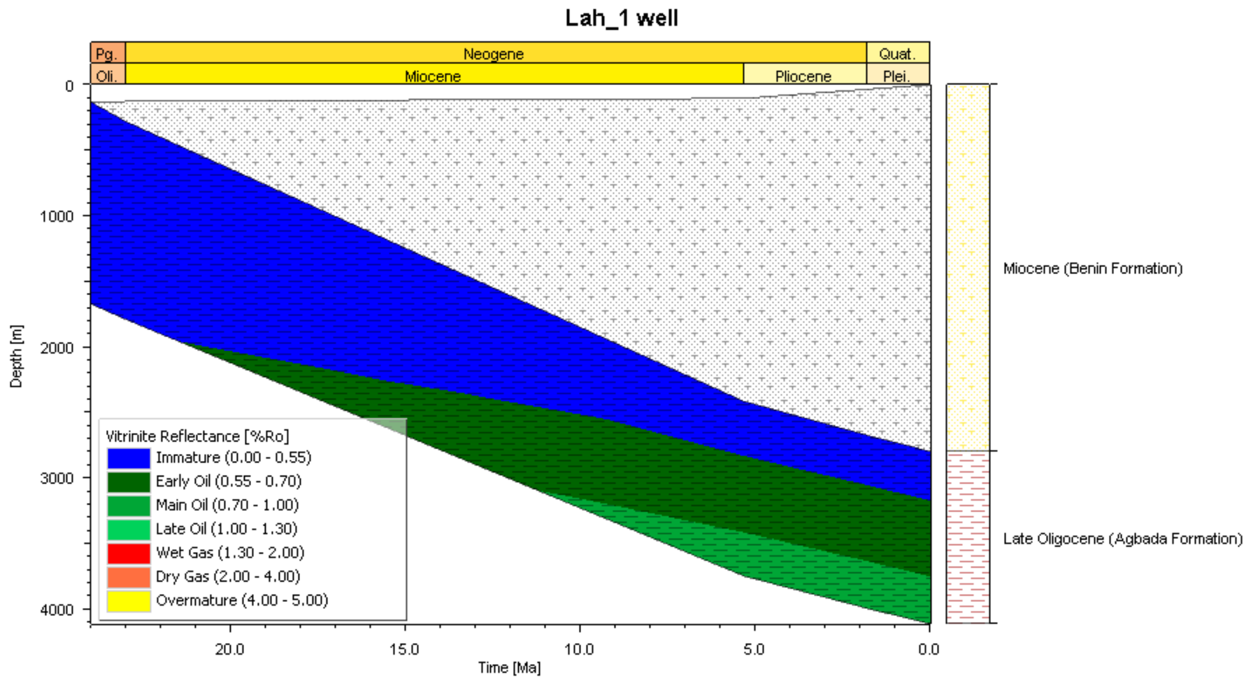


Figure 12. Burial history of the well Lah_1 showing the maturity overlay

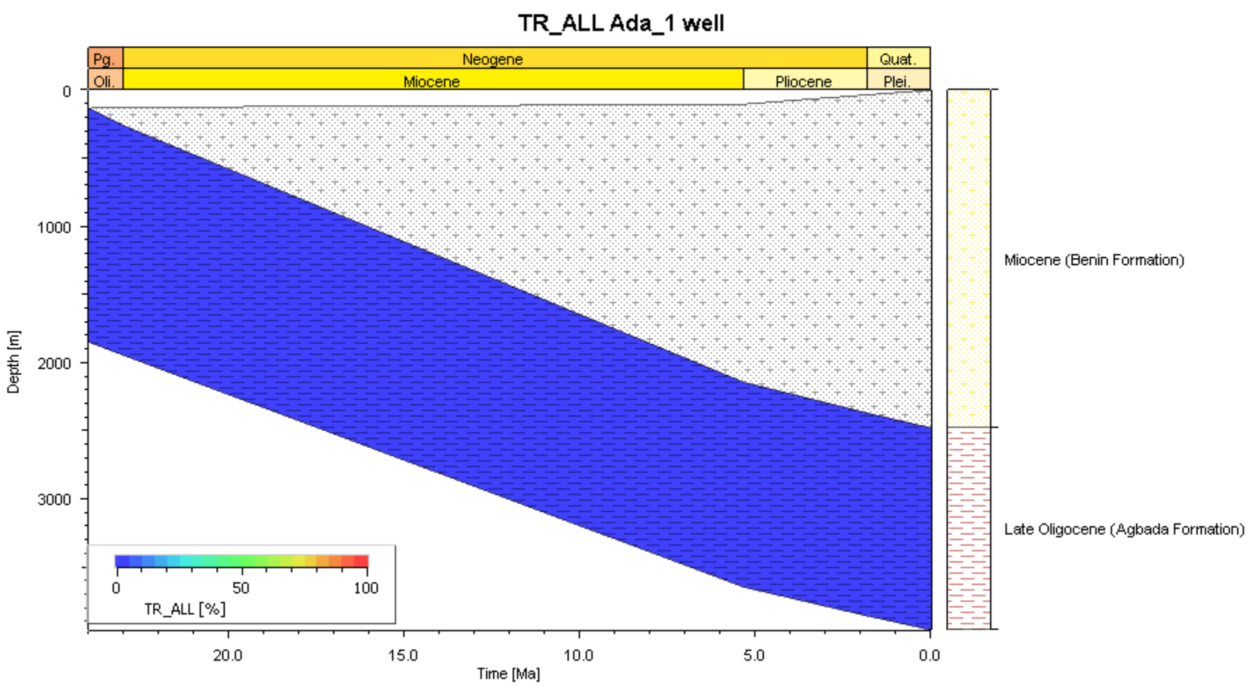


Figure 13. Transformation ratio (TR) distribution using burial history model of Ada_1 well

Oligocene source rock interval in Ada_1 well and Lah_1 well currently has transformation ratio of 0.12 % and 0.93 % respectively (Figure 13 and 14). The values of modelled present-day transformation ratio of deeply buried upper Oligocene source rocks in the two wells are less than 1%. Only small percent (<1%) of the organic material within upper Oligocene source rocks has been transformed. This transformation ratio is low for enough hydrocarbons to be significantly expelled. The source rock intervals may have contributed to the charging of Miocene sandstone and unconsolidated sands of the Agbada Formation. Nwachukwu *et al.* [4] and Doust *et al.* [4] attributed the distribution of the top of the oil window to the thickness and sand/shale ratios of the overburden rock (Benin Formation and variable proportions of the Agbada Formation).

## 5. Hydrocarbon prospectivity

Thermal maturity of the deeply buried upper Oligocene source rocks in *Giri* Field is low ranging from immature to early mature. The studied Oligocene source rocks may have contributed to the hydrocarbon base of the Greater Ughelli depobelt of the Niger Delta. Hydrocarbon charge from Eocene source rocks, marine shales of the Akata Formation and underlying Cretaceous shales are also expected. Lambert-Aikhionbare *et al.* [7] derived a thermal maturity profile, showing that the shale within the Agbada Formation is mature enough to generate hydrocarbons. Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. Interbedded shale within the Agbada Formation is expected to serve as the seal rock in the Niger Delta.

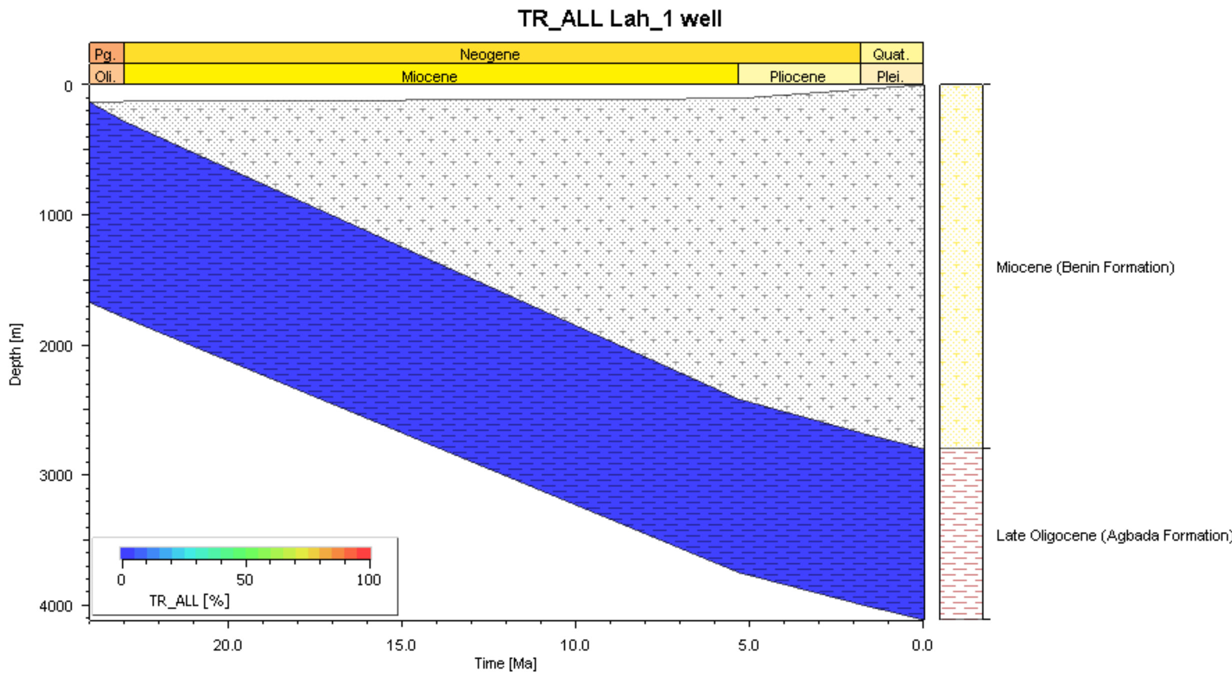


Figure 14. Transformation ratio (TR) distribution using burial history model of Lah_1 well

## 6. Conclusion

This study has established the importance of source rock evaluation and basin modeling in petroleum generation potential of a field within Greater Ughelli depobelt of Niger Delta Basin. The Total Organic Carbon (TOC) contents of upper Oligocene shale samples in the studied wells range from 1.7 to 31.8 wt.% indicating good to very good source rocks and could be considered as potential source rocks. The relationship between ($S_1+S_2$) and TOC suggest that the upper Oligocene source rocks in the two wells can be regarded as poor to excellent source potential. The plot of Hydrogen Index (HI) against $T_{max}$ (°C) showed that the upper Oligocene source rocks are capable of generating mainly gas and mixed hydrocarbon. Thermal maturity (vitrinite reflectance, $\%R_o$) data indicates that the deeply buried upper Oligocene source rocks in the two wells are within immature to earliest part of the mature window.

1-D modelling of two wells in the Greater Ughelli depobelt assumed that the deeply buried upper Oligocene source rocks entered main oil (mature stage) window of hydrocarbon generation during Neogene. The transformation ratios of the deeply buried upper Oligocene source rocks are low (<1%), thus, suggest that small amount of the organic material within upper Oligocene source rocks has been transformed. Upper Oligocene source rocks within the Greater Ughelli have not generated enough hydrocarbons for significant expulsion to occur.

The results of this study have shown that upper Oligocene source rocks are potential source rocks in the Greater Ughelli depobelt and may have contributed some hydrocarbon to the interbedded Agbada sandstones of Greater Ughelli Depobelt.

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