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The link to this publication is https://ajoeer.org.ng/otn/ajoeer/2022/qtr-2/03.pdf

MODELING HYDROCARBON GENERATION IN ANAMBRA BASIN, SOUTHEASTERN NIGERIA: IMPLICATIONS ON HYDROCARBON PROSPECTIVITY.

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ABSTRACT

The Anambra Basin contains oil and gas producing reservoirs in the southeastern part of Nigeria. Two-dimensional (2-D) modeling, using data from three (3) exploration wells has been carried out to assess the maturity, timing, and distribution of hydrocarbon generation in the Anambra Basin. This current study focuses on two sources in Anambra Basin namely; Coniacian Agwu and Nkporo source rocks. The results of models generated indicate that the onset of hydrocarbon generation from Awgu source rock started in the area of deepest subsidence during the late Campanian (77.30Ma). Awgu source rock in the model has a present-day transformation ratio of about 60-65%. This range indicates that the Awgu source rock has sufficient generation for hydrocarbon expulsion to occur. Nkporo source rock was equally observed to have capacity for hydrocarbon generation, but the generation was insufficient for expulsion because it has lower transformation ratio (<10%). Migrated hydrocarbon from the Coniacian Awgu source rock must have accumulated as oil and gas pools within the Coniacian Agbani and upper Campanian Owelli Sandstone. The discovery of gas in the Coniacian Agbani sandstone of Amansiodo-1, Akukwa-2, and Nzam-1 wells indicates the existence of petroleum traps in Cretaceous beds of the Anambra Basin.

Keywords: Two dimensional modelling, Hydrocarbon generation and expulsion, Anambra basin, Transformation ratio, Awgu and Nkporo shales ,

1.0 Introduction

The Anambra Basin has been identified as one of the major inland sedimentary basins in Nigeria (Fig. 1). It is bounded on the east by the Abakaliki Anticlinorium and on a south-westerly direction by the Benin Hinge-line, while the southern extreme is marked by the upper limits of the Eocene growth faults of the Niger Delta [1]. Some wells drilled in the Anambra Syncline penetrated the upper Cenomanian-lower Turonian marine and continental facies [2]. These bituminous upper Cenomanian-lower Turonian marine facies contain Type II kerogen [3], [4], [5] characterized as a remarkably good petroleum source interval and must have charged shallow stratigraphic units [1]. The efforts to expand exploration activities have led to the re-evaluation of the hydrocarbon generation potential of the Anambra Basin.

The one dimensional (1-D) modeling of some drilled wells in the Anambra Basin has established the aspects of the burial histories and hydrocarbon charge of the Cretaceous source rock units in Anambra Basin [2], [6], [7], [8], [9]. This study utilized a two-dimensional (2-D), sketch-based modeling approach to understand the maturity, timing, and distribution of hydrocarbon generation in the Anambra Basin, using available well data and reports, and calibration (maturity) data of three (3) exploration wells. The 2-D model is expected to provide the basis for petroleum exploration in the Cretaceous strata of Anambra Basin.

2.0 Geology Setting

Anambra Basin is a roughly triangular basin in the southeastern Nigeria that covers about 40,000 km. The southern boundary of the basin coincides with the northern boundary of the Niger-Delta basin. Anambra Basin (Fig. 2) is located in the southern part of the regionally extensive northeast-southwest trending Benue Trough [2]. It is a synclinal structure representing the third phase of marine sedimentation in the Benue Trough [12]. During the Albian-Santonian times, the proto-Anambra Basin area was sparsely covered by older sediments [13]. A very high rate of subsidence in the Turonian was thought to be the actual time of initiation of the Anambra Basin creation [13]. During the Santonian deformation, the axial part of the adjacent Benue basin was uplifted into a major anticlinorium, and the Anambra platform was flexed into a syncline that became the main depositional axis after an intervening period of erosion [14].

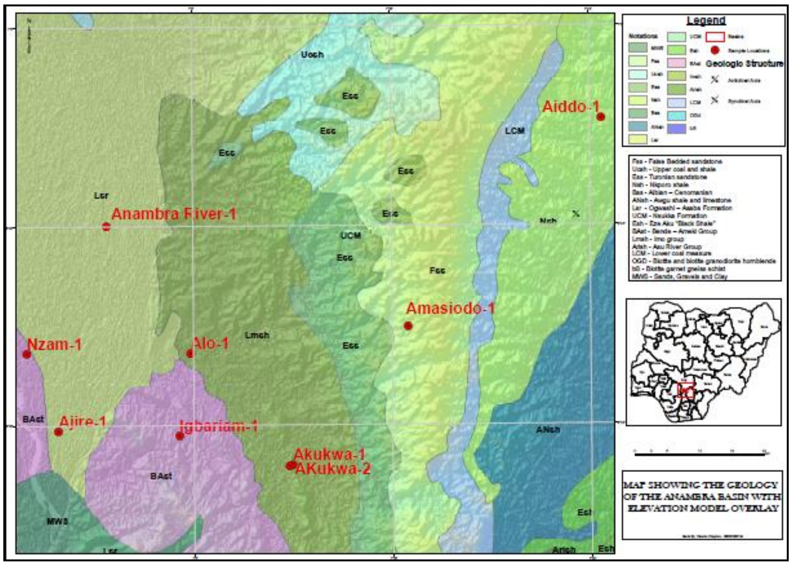

Figure 1. Geological map of Anambra syncline with elevation model overlay showing the exploration wells [2]

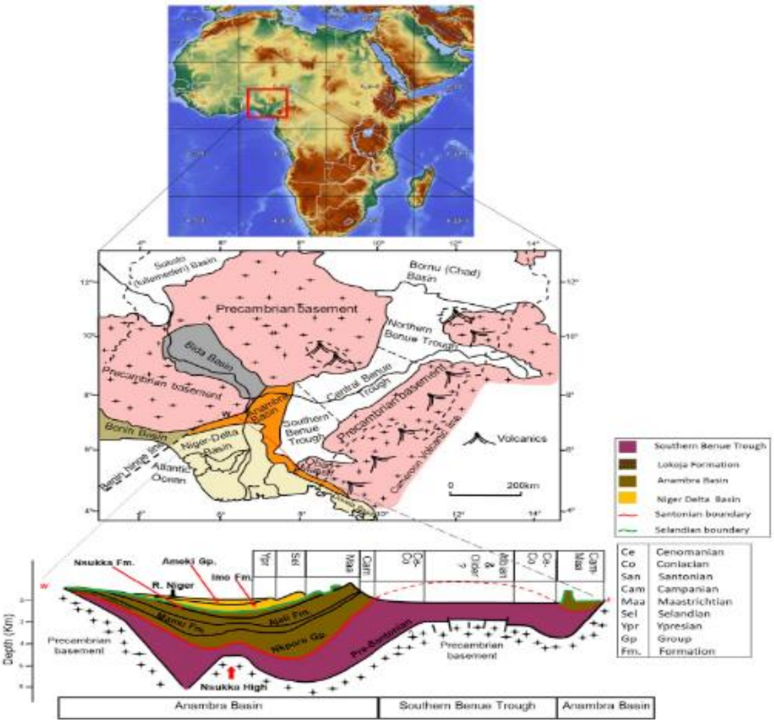

Figure 2. Map of Nigeria showing areas underlain by sedimentary and Basement rocks. Below a W-E cross-section of the Anambra Basin showing lithostratigraphic packages [Modified from 10, 11].

Anambra Basin became clearly defined after the Campano-Santonian folding episode that resulted in the uplift of the Benue-Abakaliki Anticlinorium and consequent downwarping of the Anambra Platform which resulted in the Anambra Basin. Sediment deposition started in the Anambra Basin with short marine transgression trailed by regression [1]. Nkporo Shale and the lateral equivalents (Enugu Shales and Owelli Sandstones) were deposited during the Campanian and formed the basal sediments of the Anambra Basin [12]. Gradual subsidence during the Maastrichtian causes the shallow sea to gradually become shallower resulting in a regressive phase that deposited the distributary/estuarine channels, shoreface, swamp, tidal flats, and storm-generated beds of the Mamu Formation (lower coal measures) and overlies the Nkporo Shale [15].

Onlapping onto the Mamu Formation is the medium to coarse-grained, moderately sorted quartz arenite called Ajali (false-bedded) Sandstone [16]. Overlying the Ajali Sandstone is the regressive flood plain facies of the Nsukka Formation (upper coal measures), the last of the Cretaceous sediments to be laid down before the major transgressive phase of the early Paleogene, which resulted in the massive, deep marine "Imo Shale" facies being deposited over the entire basin [15]. Subsequently, the main depositional axis shifted southwards to form Niger Delta [14].

3.0 Materials and Methods

The input data for the stratigraphic modeling include lithology of different layers, duration of deposition and erosion, age, and thickness (Table 1). Available data from three (3) wells including Nzam-1, Akukwa-2, and Amasiodo-1 (Fig. 3) were uploaded into PetroMod™ 2019.1, developed by Schlumberger. The modeling approach adopted requires input data that describe the present-day geological situation as a result of past events. The geological history is simulated from the oldest to the most recent. The pre-grid faults and horizon lines were digitized manually, this process ensures that each node of the digitized horizon intersects on a grid point and extends to the model boundary. The gridded horizon lines were defined in the property definition table, while assigned ages, facies, and layers were defined in the age assignment table.

The gridded stratigraphic events include nine (9) horizons namely Eze-Aku, Awgu, Agbani, Ogugu, Owelli, Nkporo, Mamu, Ajali, Nsukka, and Ameki formations. Information on each stratigraphic event of each well was compiled based on well data and reports of Shell Petroleum

Table 1: Generalized lithostratigraphy and input parameters of the model.

Layer Name	Age (Ma)	Water Depth (m)	Surface Water Interface (°C)	Heat flow (mW/m^2)
Ameki Shale	33.9	93	30	72.58
Imo Shale	56	201	30	70
Nsukka Formation	65	200	30	68.66
Ajali Sandstone	67	220	30	69.54
Mamu Formation	70	238	30	70.45
Nkporo Formation	72.1	241	30	71.32
Owelli Sandstone	77.3	240	30	72.41
Santonian event	80	227	30	71.22
Ogugu Shale	86	222	30	71.22
Agbani Sandstone	86.3	225	30	71.1
Awgu Shale	87	237	30	72
Eze-Aku Shale	89.8	240	30	75

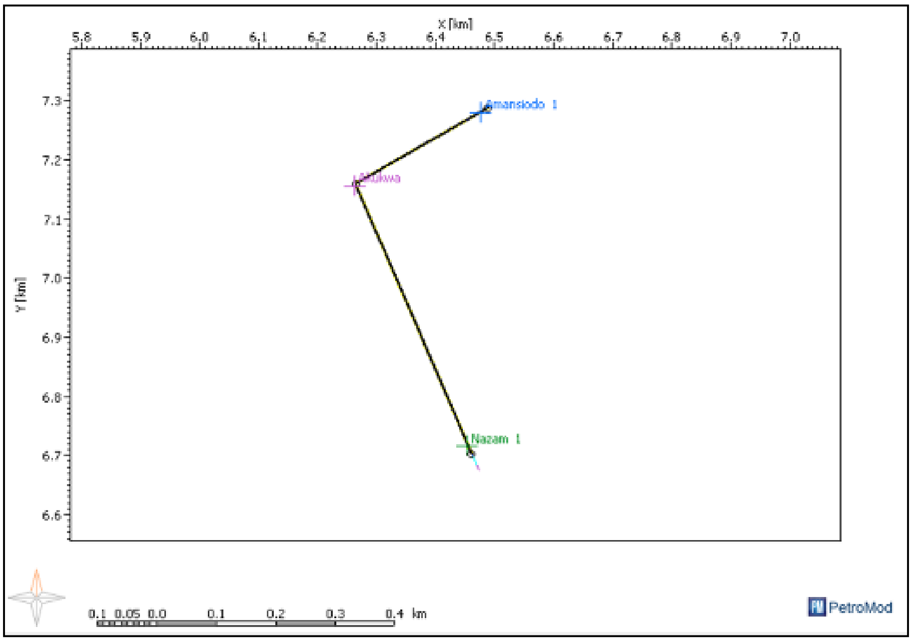

Figure 3. 2-D cross-section location map of the studied exploration wells in the Anambra Basin.

Development Company (SPDC) of Nigeria. Well locations, geological maps, and production data also serve as input for the stratigraphic modeling.

Paleo-water depth values were used to define the paleogeometry while heat flow and sediment-water interface temperature are the main boundary conditions defined during modeling [2]. The paleo-water depth was assigned based on Hardenbol et al. [17] and varies from 200 to 240 meters. The present-day sediment-water interface temperature of 30°C was assumed suitable for the boundary condition for the model.

The hydrocarbon generation modeling was based on the total organic carbon (TOC) and hydrogen index (HI) of the Agwu and Nkporo source rocks in the Anambra Basin. The maturity modeling was calculated using the EASY% Ro model of Sweeney and Burnham [18]. The TOC and Rock-eval pyrolysis data (Table 2) on Coniacian Awgu source rocks in Akukwa-2 well, Campanian Nkporo shales, and Coniacian Agwu shales in Nzam-1 well are from published reports [19], [20], [21], [22]. Vandenbroucke *et al*. [23] kinetic model was used for the modeling. The model was simulated using the hybrid migration method.

4.0 Results and Discussions

4.1 Hydrocarbon generation potential

The 2-D simulated model of the Anambra Basin is overlaid with Sweeney and Burnham [18] easy% Ro vitrinite reflectance model. The results of the modeling suggest that the onset generation of hydrocarbon from the Awgu source rock started in the area of deepest subsidence during the late Campanian (77.30Ma; Fig. 4). By the late Eocene (33.90 Ma), the Awgu source rock entered the main oil to wet gas window (Fig. 5). The majority of hydrocarbon expulsion within the Awgu Formation occurred during the Paleocene. The source rock maturity of both the Awgu and the Nkporo formations has the capability of generating oil (early-late oil window), however, the Awgu Formation has reached the wet gas-generating phase (Fig. 6).

4.2 Transformation window

The results of the 2-D simulation indicate that the Awgu source rock in the three models has a present-day transformation ratio of about 60-65%, this range indicates that the Awgu source rock

Table 2: Summary of the acquired geochemical data for Coniacian Awgu and Upper Campanian Nkporo Shales for the studied wells [19, 21, 22].

Well	**Source Rock**	**TOC (wt. %)**	**HI (mg HC/g TOC)**	**T_{max} (°C)**	**Production Index (PI)**	**Cal. vitrinite reflectance (% R_o)**
Nzam-1	Awgu Shales	0.07 -1.78 (av. 1.4)	1 – 25	451 -568 (av. 491)	0-0.49 (av. 0.42)	0.96-3.06 (av. 1.69)
	Nkporo Shales	0.08 -1.45 (av. 1.2)	14 - 37	439-516 (av. 454)	0.35-0.42 (av. 0.38)	0.74-2.13 (av. 1.01)
Akukwa-2	Nkporo Shales	0.81- 3.02 (av. 1.38)	35 – 179	428– 441 (av. 432)	0.05-0.25 (av. 0.11)	0.53-0.71 (av. 0.61)

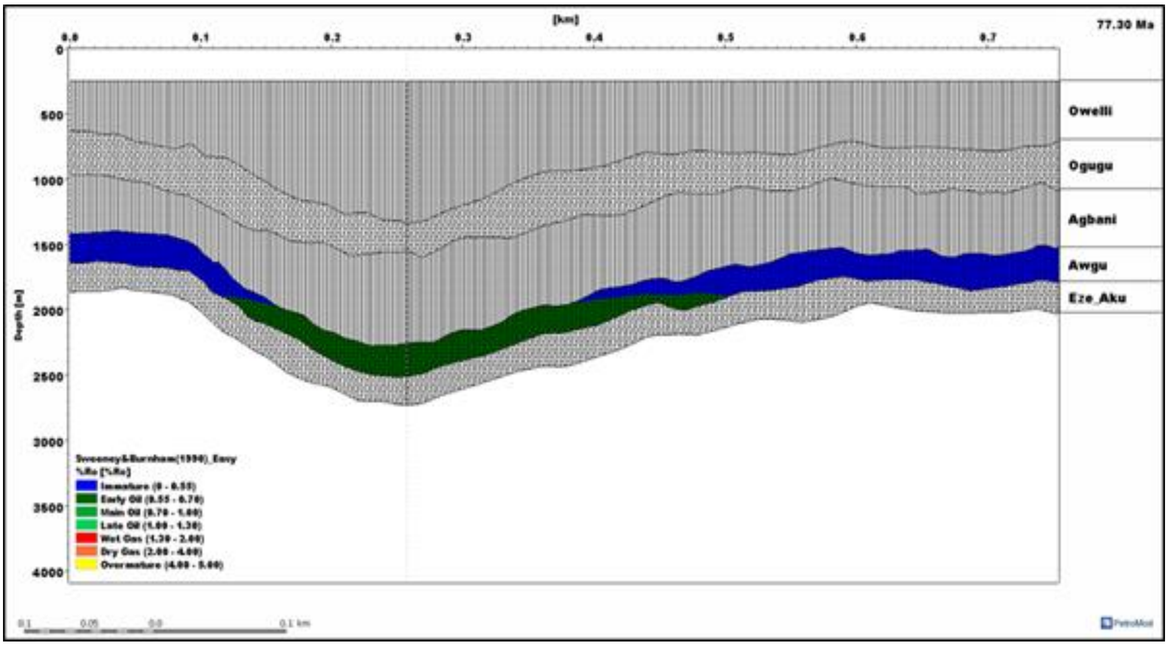

Figure 4: Selected maturity model for the Anambra Basin at 77.30 Ma. The onset of hydrocarbon generation in the Awgu source rock occurred during the late Campanian (77.30Ma).

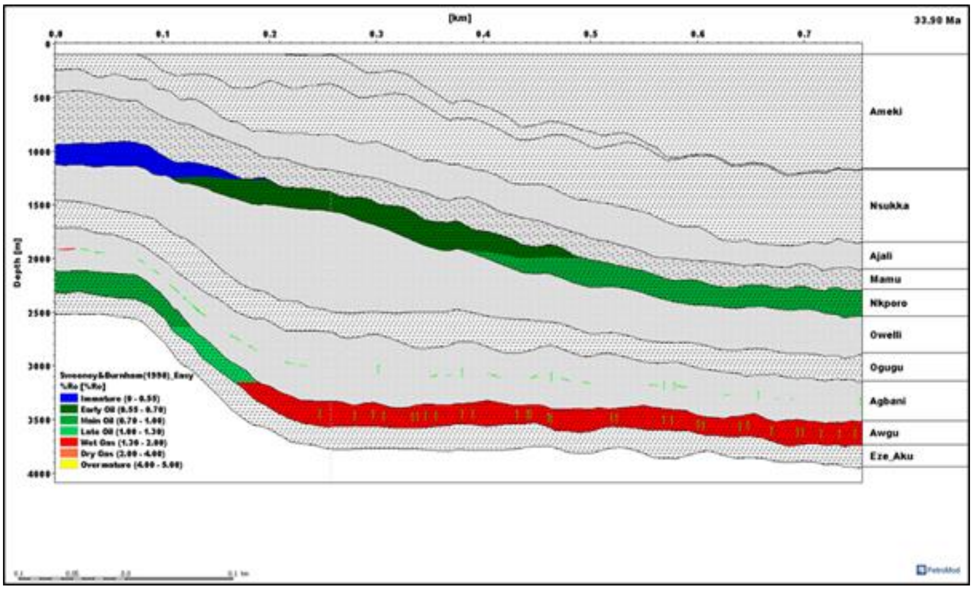

Figure 5: Source rock maturity for Awgu source rock for the Anambra Basin in the Late Eocene (33.90Ma).

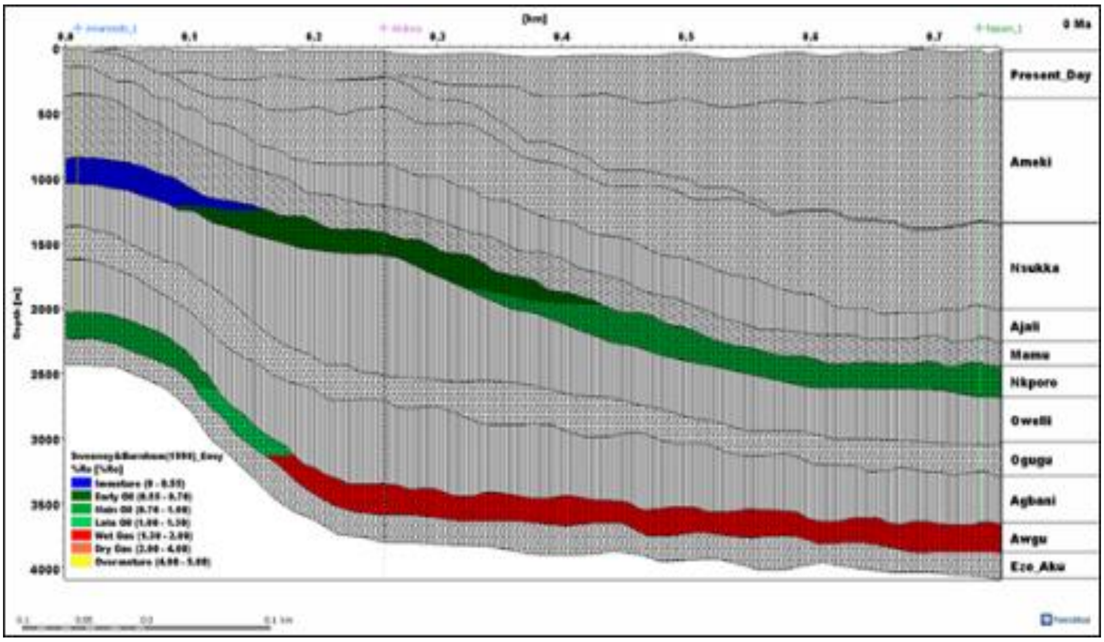

Figure 6: Selected maturity model for the Anambra Basin at the present day. The model suggests that both source rock units can generate both oil and wet gas.

has sufficient generation for expulsion to occur (Fig. 7). Although the Nkporo source rock enters the oil window, there is an insufficient generation for hydrocarbon expulsion to occur because the Transformation ratio of Nkporo source rock is less than 10%.

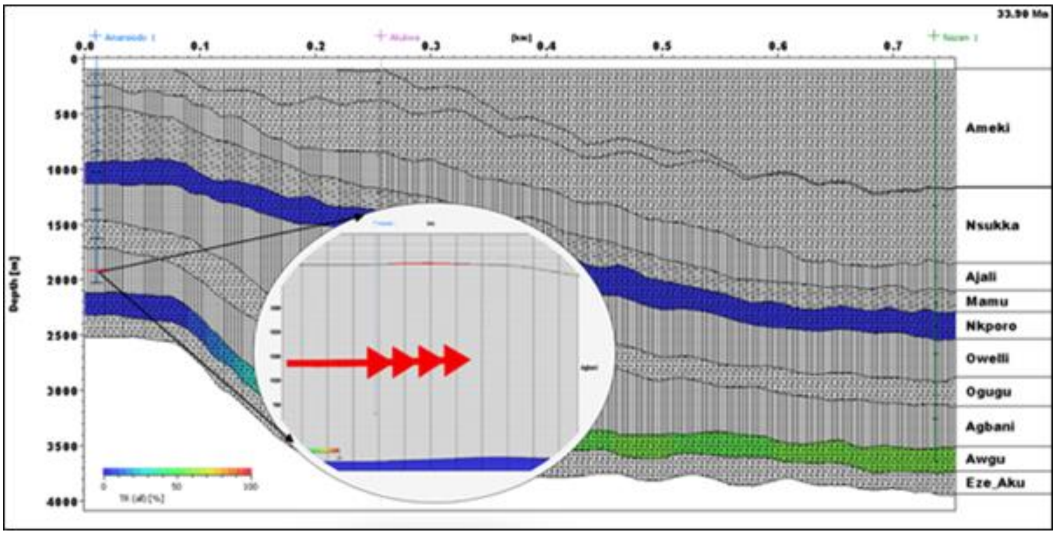

Figure 7. The hydrocarbon transformation ratio of 60-65% in the simulated model corroborates with the hydrocarbon encountered in Amansiodo-1 well.

4.3 Hydrocarbon in Reservoirs (Source, Reservoir, and Seal)

Hydrocarbon accumulation depends on the configuration of hydrocarbon generation as well as the migration, formation, and evolution of the reservoir and its sealing conditions [24]. The effects of uplift and erosion show that both the sub-Santonian marine shales of the Awgu Formation and the super-Santonian Nkporo Formation are mature [25], [26]. The current study has shown that Coniacian Awgu source rocks are mature and capable of generating hydrocarbon still at present. Hydrocarbon generated is expected to migrate to relatively shallower stratigraphic levels. Oil and gas accumulation is expected in Coniacian Agbani and upper Campanian Owelli sandstone members, with the Imo shale serving as a regional seal rock.

5.0 Prospectivity of the Anambra Basin

A variety of authors have published and presented data on the source rocks within the Anambra Basin [26], [27], [28]. It has been established that the Agwu and Nkporo formations constitute the source rocks of the sub-Santonian and super-Santonian shale deposits with both having the capacity to generate hydrocarbon. Based on the simulated models, only the Awgu source rock has expelled hydrocarbon with several sub-commercial hydrocarbon discoveries made at different horizons in the Anambra Basin in addition to the heavy crude seepages recorded within the Owelli sandstone [20], which confirms hydrocarbon generation in the basin. The combination of water-washing and bacteria biodegradation has been suggested to have converted a large amount of light oil into heavy bitumen [29]. The Nkporo source rock appears to be mature in areas of deeper subsidence but has not expelled any hydrocarbon-based on the Transformation ratio which is less than 10%.

The reservoirs units within the simulated model results are Coniacian Agbani and upper Campanian Owelli Sandstone members. Migrated hydrocarbon from the Coniacian Awgu shale through stratigraphic traps are expected to charge these younger Cretaceous reservoir units.

However, according to the simulated model, the Coniacian Agbani sandstone unit appears to be the only reservoir with accumulated hydrocarbon.

6.0 Conclusion

1. The two-dimensional (2-D) stratigraphic modeling, used data from four (3) exploration wells namely; Nzam-1 well, Akukwa-2 well, and Amasiodo-1 well to determine the maturity, timing, and distribution of hydrocarbon generation in the Anambra Basin.
2. The onset of hydrocarbon generation from Awgu source rock started in the area of deepest subsidence during the late Campanian (77.30Ma), and peaked during the late Eocene (33.90Ma), Awgu source rock in the three models has a present-day Transformation ratio of about 60-65%, this range indicates that the Awgu source rock has sufficient generation for expulsion to occur.
3. Nkporo Formation was observed to be matured with the capability of generating oil, but the hydrocarbon generation is insufficient for expulsion to occur because the Transformation ratio of Nkporo source rock is less than 10%.
4. Migrated hydrocarbon from the Coniacian Awgu source rock must have accumulated as oil and gas pools within the Coniacian Agbani and upper Campanian Owelli Sandstone.

5. The discovery of gas in the Coniacian Agbani sandstone of Amansiodo-1, Akukwa-2, and Nzam-1 wells indicates the existence of petroleum traps in Cretaceous beds of the Anambra Basin.

Declaration of interests

None

Acknowledgements

The authors are grateful to the Department of Geology, University of Ibadan and Schlumberger Company for providing the research facilities. The anonymous reviewers are also appreciated for their constructive critiques.

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