Evaluating Petroleum Systems in the Anambra Basin: 1D and 3D Modeling Insights and the Prospectivity of the Basin

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ABSTRACT

This study offers an in-depth evaluation of the petroleum systems within the Anambra Basin through the application of 1D and 3D basin modeling techniques. Limited seismic and well data, along with outcrop data and regional aeromagnetic data, were used to constrain the tectonic-stratigraphic history of the basin. This enabled the assignment of chronological ages to formations within the basin, facilitating the evaluation and modeling of key petroleum system elements and processes. The modeling exercise focused on critical factors such as source rock maturity and distribution, hydrocarbon generation and expulsion, pressure regimes, temperature history, and current geothermal gradients.By integrating a diverse array of datasets, the study provides a clearer view of the Anambra Basin's geological history, shedding light on its complex stratigraphy and tectonics. The results reveal significant variations in thermal maturity across the basin, highlighting areas with hydrocarbon generation potential. This comprehensive modeling study enhances the understanding of the basin's hydrocarbon prospectivity and the uncertainties/risks associated with it. It delivers crucial insights for guiding and optimizing future exploration activities, offering a valuable contribution to the broader field of petroleum geology, particularly regarding the inland Cretaceous sedimentary basins in Nigeria.

Keywords: Tectonic-Stratigraphic, Modelling, Thermal Maturity, Chronological Ages, Aeromagnetic.

INTRODUCTION

Petroleum system modeling helps to properly understand, model, and track source rock burial/maturity, hydrocarbon generation, expulsion, migration, and accumulation processes throughout a basin's evolution cycle. It requires a thorough understanding of the regional geologic processes prevalent in the basin and how they are best represented within the area the dataset covers. An integrated basin model helps optimize exploration within frontier basins and evaluate the possibility of new plays in already explored basins (Schneider *et al.,* 2000; Telnaes *et al.,* 2000; Zhi-Yuan *et al.,* 2022).

Generally, 1D models aid in reconstructing a basin's thermal history and monitoring organic matter maturation using data from a single well (Hadad *et al.,* 2017; Radkovets *et al.,* 2018). In contrast, a 3D model accurately establishes basin strata structure and petroleum system elements, and allows for the simulation of thermal history, pressure evolution, hydrocarbon entrapment, and migration (Hantschel and Kauuerauf, 2009). This modeling involved the use of mapped depth surfaces generated from seismic volume interpretation, information on petroleum system events and processes, timing of tectonism, and the relative ages of stratigraphic surfaces, along with calibration data. The combination of these datasets aids in constructing a model of the basin's evolution across the study area (3D model) and at specific points within the study area (1D model).

This paper aims to use 1D and 3D models to reduce the uncertainties and risks associated with exploration and provide a clearer picture of the evolution of petroleum system elements and processes throughout the Anambra Basin's history.

BACKGROUND GEOLOGY

The Anambra Basin is a significant geological province characterized by its rich hydrocarbon potential. This basin is primarily composed of post-deformational sediments ranging from the Campanian to the Eocene periods, with a

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total sediment thickness of about 9 km. Its structural evolution is closely linked to the Santonian tectonics associated with the Abakaliki-Benue Trough, which initiated significant sediment folding and displacement of the depositional axis. Sedimentation in the Anambra Basin began with a marine transgression during the Campanian, leading to the accumulation of sediments primarily shed from adjacent tectonic features (Murat, 1972; Nwachukwu, 1972; Benkhelil, 1982; Amogu *et al.,* 2010). The basin's geological history is marked by three major tectonic phases that influenced sedimentation patterns and resulted in three successive depocenters: the Abakaliki-Benue phase, the Anambra Basin phase, and the Niger Delta phase (Benkhelil, 1989; Kogbe, 1979).

The basin's lithostratigraphy includes several post-Santonian formations: the Late Campanian Nkporo Group, consisting of carbonaceous shales and sandstones; the Late Campanian to Early Maastrichtian Mamu Formation, associated with coal deposits; and the Ajali Formation, characterized by poorly cemented sandstones (Figure 1). The Nsukka Formation overlies the Ajali Formation, with a lithology comprising dark shales and sandy shales that serve as cap rocks (Akande *et al.,* 2011; Ola-Buraimo et al., 2012, 2013; Nwajide, 1990).

Tectonically, the Anambra Basin has experienced multiple phases of subsidence and uplift, which have influenced sedimentation patterns and the maturation of source rocks (Ladipo *et al.,* 1992). These processes have created diverse depositional environments, enhancing the basin's hydrocarbon prospectivity. The Anambra Basin exhibits significant variations in thermal maturity across its regions, which are crucial for hydrocarbon generation.

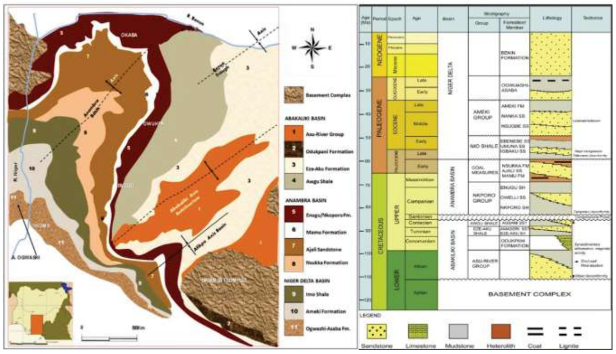

Figure 1a: Map of southeastern Nigeria sedimentary basins showing surface geologic formations in Abakaliki Basin, Anambra Basin and Up-dip Niger Delta Basin (after Akande *et al.* 2007; Dim *et al.* 2017). 1b: Stratigraphic succession in the Anambra Basin and Niger Delta (redrawn and modified from Short and Stauble, 1967; Nwajide, 2005).

METHODOLOGY

Different surfaces representing several geologic timelines were loaded. They included a surface layer marking surface elevations from well data and Google Earth, nine depths generated from regional seismic mapping, and a depth-basement derived from a combination of magnetic and gravity data, which was used to constrain the variation in sediment thickness within the basin.

Sixteen layers were created from eight surfaces to establish thickness trends for each stratigraphic interval, with facies and petroleum system elements assigned to the layers using information from regional geology, gross depositional maps, and sediment provenance constrained to facies. The reservoir and source layers were constrained by the gross depositional environment, while the source rock layers (shales in the Nkporo, Asu-River, and Eze-Aku Groups) were modeled with their geochemical properties (TOC and HI) and organic matter kinetic models, reflecting their properties as stated in published literature.

Four 1D models were extracted from the 3D model to capture the variations in tectonic history across three sub-basins (Onitsha, Ankpa, and Lafia) as revealed by the aeromagnetic data. These served as control/selection areas for the model, with their subsidence curves, stretching factors, and paleo-water depths unique to each sub-basin. Four pseudo wells were extracted and calibrated with measured vitrinite reflectance (VR) to model the basin's geothermal history. Boundary conditions (basal heat flow, paleo-water depth, and sediment-water interface temperature) were used to define and control basic thermal energy conditions affecting source rock maturation throughout the basin's evolution. Given that the basin is currently located onshore and was the precursor to the prograding Niger Delta Basin, paleo-water depths (PWD) were modeled to reflect the basin's evolution. Information from the wells indicates a reduction in water depth, characterized by a change from marine to continental environments. Sediment-water interface temperature (SWIT) served as the upper boundary condition for heat transfer within the basin, functioning as a product of the paleo-water depth and paleo-surface temperature, aiding in constraining the geothermal gradient through geologic time for the basin.

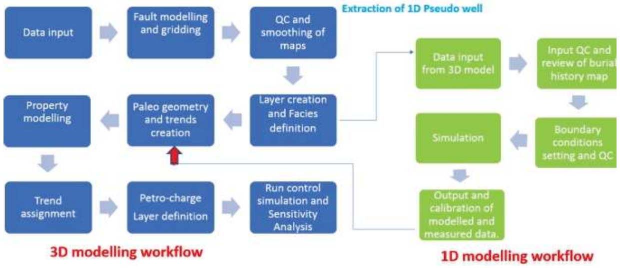

Figure 2: Basin modeling workflow for the 1D and 3D modeling.

RESULT AND DISCUSSION

The heat flow trend is based on the subsidence trend, which shows a good match between modeled and tectonic subsidence. The McKenzie stretching model was adopted, which examines the factor by which the crust is thinned during rifting relative to its original thickness. The thickness of the surrounding basement complexes around the basin from the CRUST 2.0 model was used to assign a pre-rift thickness of 115,000 ft for the Anambra Basin, and a McKenzie stretching factor of 1.6 was modeled for the basin based on these inputs. Granitic crustal lithology was used to constrain heat transmission from the mantle to overlying sediments.

Maximum water depths were attained in the basin during the Mid-Early Cretaceous. Present-day water depths were constrained and correspond to present-day onshore elevation values. Maximum heat flow values are 54 mW/m² and correspond to the end of rifting. The drop in heat flow during the post-rift phase was due to the thermal subsidence of the upwelled mantle, with present-day modeled heat flow values being about 41 mW/m² (Figure 3).

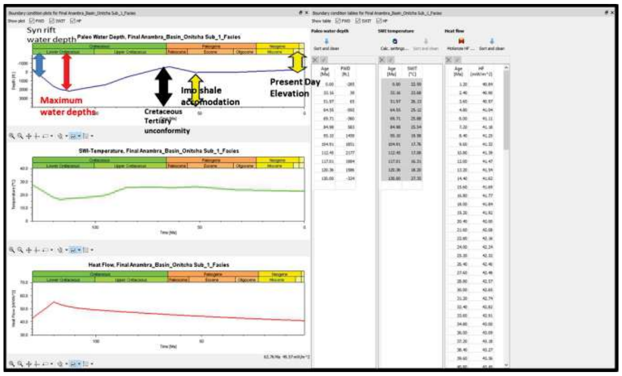

Figure 3: Boundary conditions tables.

Generation and Expulsion

The geohistory plot reflecting the basin's evolution and sedimentary processes is the initial product of a 1D model. It reveals two major depositional episodes: Early to mid-Cretaceous, characterized by low sediment accumulation rates (SAR), and mid to late Cretaceous, characterized by high SAR. It further indicates a significant change in accommodation space due to basin opening, with water depths decreasing rapidly from 3,500 ft to above sea level (Figure 4).

Source rock maturity and hydrocarbon generation were also modeled using Sweeney and Burnham's (1990) Easy Ro model and calibrated with vitrinite reflectance (VR) data for better correlation with measured VR profiles. The models highlight the occurrence of multiple petroleum systems within the basin and place the current oil window

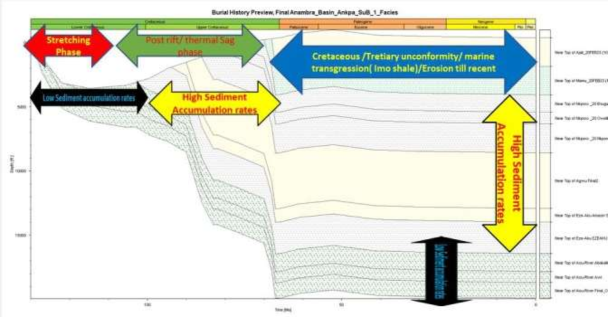

Figure 4: Primary Geo-history plot capturing modeled Paleo water depth.

between 6,400 and 16,000 ft across the basin (Figure 5). Within the Onitsha and Ankpa sub-basins, the modeled Campanian Nkporo source layers and Santonian Agwu source layer maturities range from immature to early gas window. The modeled pre-Santonian source maturities (Eze-Aku and Agwu) across the basin range from mid-oil to mid-gas window. Moreover, the Onitsha sub-basin has the highest maturities for all modeled source layers. In the Lafia sub-basin, the modeled pre-Santonian source layers are within the mid-oil to late-oil window. Generally, it can be inferred that the generated and expelled hydrocarbon is from a small source kitchen.

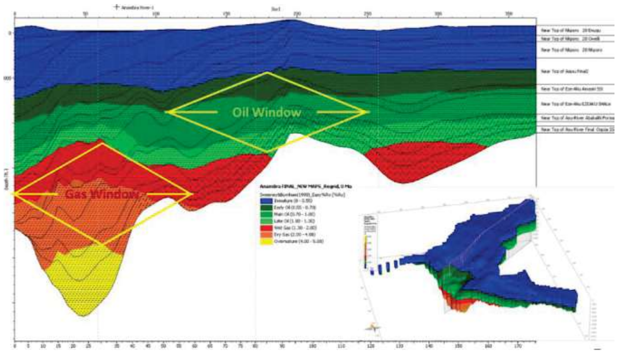

Figure 5: Present-day modeled vitrine reflectance maturities for source rock layers in Anambra basin.

Moreover, the source layers exhibit varying maturities. The Asu-River Group has the highest maturity across all sub-basins and is in the oil to early gas window, even in the Lafia sub-basin, which has the least sediment thickness. Furthermore, the transformation ratio (TR) models indicate that the Asu-River Group source rocks in all the sub-basins have completely converted organic content to hydrocarbons, while other source rocks have experienced varying degrees of transformation (≥60%) across the sub-basins (Figure 6).

The modeling exercise revealed two possible plays (pre-Santonian and post-Santonian). Hydrocarbon generation in most source layers (pre-Santonian source rocks) began in the Late Cretaceous, primarily within the Onitsha and Ankpa sub-basins, with very little generation in the Lafia

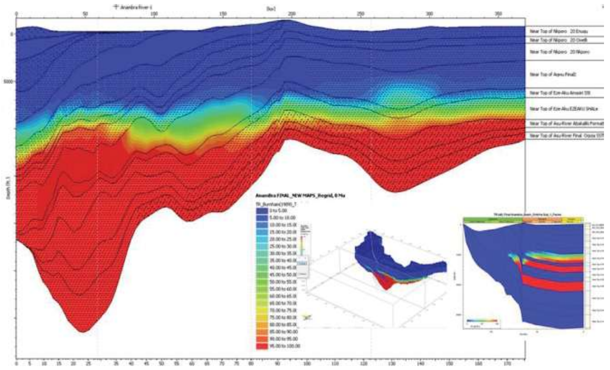

Figure 6: Present-day modeled transformation ratio for source rock layers.

sub-basin (Figure 7). However, the Late Cretaceous Nkporo Shale does not make a significant contribution to the modeled expelled and migrating hydrocarbons within the basin. The generation from modeled source layers is consistent with the maturity and transformation ratio values observed within all the sub-basins.

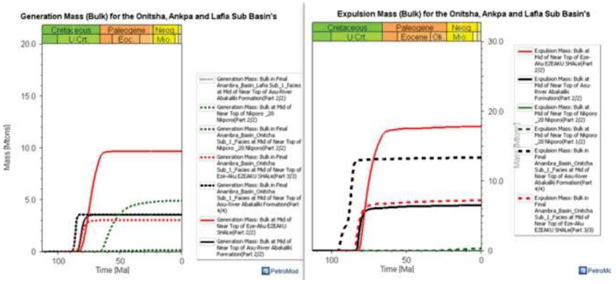

Figure 7: Bulk Generation and Expulsion from Modeled Source Layers.

Optimal accumulation zones for hydrocarbons are identified using the Golden Zone concept (60–120°C isotherm). This was calibrated to available vitrinite reflectance data and revealed that most of the available wells within the basin penetrated the top of the Golden Zone. Therefore, there is potential for deeper prospects in the basin.

The biodegradation risk zone in all sub-basins occurs at depths shallower than 5,000 ft, indicating the possibility of poor seal integrity. This suggests that seals shallower than this depth might not sufficiently support large column heights for hydrocarbon accumulation (Figure 8).

Migration and Trapping

The knowledge of hydrocarbon trapping mechanisms in the sub-basins was limited due to sparse subsurface data. Faults were not incorporated into the model due to the inability to interpret faults as a result of the nature and orientation of available 2D seismic lines. Structuration associated with hydrocarbon trapping in the sub-basins may be more related to growth faulting rather than tectonics, as seen in the Onitsha sub-basin. This structural style has yet to be determined in the Ankpa and Lafia sub-basins due to the absence of subsurface data (seismic).

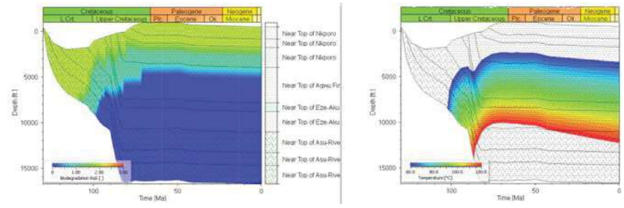

Figure 8: Biodegradation Trend distribution map obtained from 1-D model.

The maps and layering utilized in the 3D model were constrained by the available seismic data, well data, outcrop data, and regional geologic information (Figure 9). The absence of fault information ensured that trapping within the model was limited to folding, changes in the dip of modeled layers, and lateral facies changes associated with changes in depositional environments. A hybrid migration model utilizing both Darcy flow and flow-path models was employed.

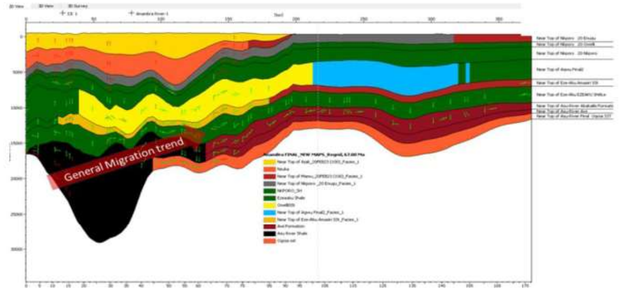

Figure 9: Modelled migration vectors for oil (green) and gas (red) along a NE/SW cross section across the Anambra basin showing possible phase separation and migration direction.

Hydrocarbon accumulation and preservation within the basin were determined using seal and reservoir assessments, as well as the Golden Zone concept. Diverse reservoirs (Awi, Amasiri, Agbani, Owelli, Otobi, and Ajali sandstones) were modeled based on available information about their locations within the basin. Hydrocarbon accumulations were primarily within the Ankpa sub-basin and areas bordering the Lafia sub-basin, with most modeled hydrocarbons migrating from the Onitsha sub-basin (Figure 10).

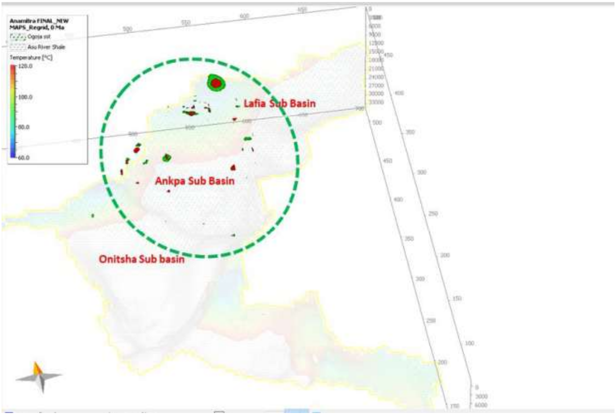

Figure 10: Modelled migration vectors for oil (green) and gas (red) along a NE/SW cross section across the Anambra basin at 0 Ma and 67Ma showing possible phase separation and migration direction.

CONCLUSION

A 3D model, which is crucial for reducing exploration risks and uncertainties, was built to provide a comprehensive understanding of the Anambra Basin. Data integration and modeling have identified two possible petroleum systems within the basin. Preliminary modeling results show hydrocarbon migration from the Onitsha sub-basin to the Ankpa sub-basin and areas around the Lafia sub-basin. The study also defined the extent of the "Golden Zone," an 8,000 ft subsurface region with varying upper and lower depth limits across the basin. The established post- and pre-Santonian source kitchens provide sufficient hydrocarbon charges to fill all available traps. However, this study shows the trapping efficiency to be low due to the timing of the charge relative to the deposition of the reservoirs and seals. Although stratigraphic opportunities exist, their uncertainties can only be reduced with further work, such as additional 2D and 3D data acquisition, data reprocessing, and Amplitude Versus Offset (AVO) studies. Further seismic data acquisition and visualization techniques are recommended to capture subtle geologic features, such as sand and shale distribution.

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