Available online at www.elixirpublishers.com (Elixir International Journal)

Earth Science

Elixir Earth Science 155(2021) 55441-55446

ISSN: 2229-712X

A Comparative Study on Shale Gas Exploration Opportunity in the Eastern Dahomey Basin, Nigeria

Amodu O.I., Ehinola O.A., Adeigbe O.C and Unomah G.I.

ARTICLE INFO

Article history:

Received: 14 April 2021;

Received in revised form: 03 June 2021;

Accepted: 15 June 2021;

Keywords

Unconventional Resources,
Shale Gas,
Cretaceous.

ABSTRACT

The Eastern Dahomey Basin is a rift basin located in the Southwestern part of Nigeria with formations spanning from the Cretaceous to Tertiary ages which are well defined in their lithology types ranging from sand, silt, carbonates, and shale. Shale is now considered as a reservoir rock in the unconventional petroleum system unlike its previous characterisation as only a source rock and/or seal in the conventional petroleum play. The hydrocarbon field operators in the Dahomey basin have reported higher percentage of gas production up to 20% LPG and 52% gas and also identified the syn-rift to contain light oil and condensate-rich gas. The increasing demand of natural gas as a cleaner energy compared to other fossil fuels and the several commercialization strategies of the Federal Government of Nigeria has necessitated the exploration possibility of more gas, even unconventional gas. This paper reviewed the geological and geochemical properties of the Cretaceous shales in Dahomey basin from previous authors and selected some producing shale plays in the USA as possible analogues for its shale gas potential.

Introduction

1.0 Background

Dahomey basin spans from southeastern Ghana through to Togo, Benin and southwestern Nigeria (Fig. 1) (Adegoke, 1969). The Nigeria section of the basin is referred to as the Eastern Dahomey Basin. It is separated from the Niger Delta basin by a faulted hinge line called Okitipupa ridge (Adediran&Adegoke, 1987). Over many decades, many propositions have be made concerning the stratigraphy, structural, mineral potential including the hydrocarbon evaluation of the basin. While limited data are available for the offshore section of the basin, the onshore and coastal parts are being constantly updated and studied.

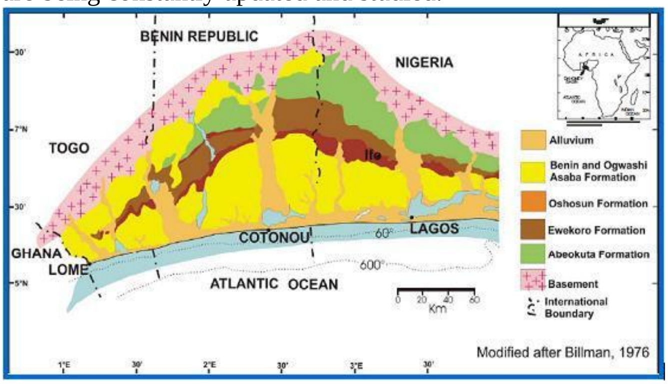

Fig 1 . Outcrop Geology of the Dahomey Basin.

During the Mesozoic era, the Dahomey basin was initiated along with other West African sedimentary basins. The major tectonic event of the separation of the South America and the Africa continental mass led to a rift-generated basement subsidence and the opening of the Atlantic Ocean. The eventual depression gave rise to the deposition of continental grits and pebbles along the fault during the early Cretaceous (Leaner & Ruiter, 1977). Another episode of tectonic event during the late cretaceous led to the folding of the basin, where the basement and the sediments experienced a tilting and fault-blocking that resulted in the horst and graben series across the basin. This was followed by an erosional activity that cleared the lower cretaceous sediments from the horsts (Omatsola & Adegoke 1981).

The stratigraphy composition of the basin has been well defined, accepted and established in the works of several authors (Billman, 1976; Petters, 1978; Omatsola & Adegoke 1981; Okosun, 1990). Through the assessments and studies of the several borehole drilled to ascertain the components of the stratigraphy of the basin, it has been established that the Abeokuta group is the oldest sediments in the basin (Omatsola & Adegoke 1981) dated to be Cretaceous (Fig. 2). The Abeokuta group are divided into three, namely Ise, Afowo and Araromi formations (Jan du Chene, 1977a, b; Adegoke *et al.*, 1980). The other formations comprise of the Ewekoro, Akinbo, Oshosun, Ilaro and the coastal plain sands (fig. 2).

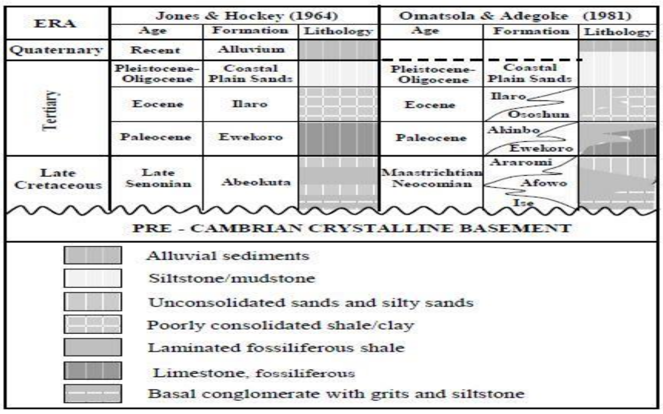

Fig 2. The Stratigraphy of Dahomey Basin

Tele:
E-mail address: amodu.omowunmi@paulesi.org.ng

The hydrocarbon potential of the Dahomey basin has been evaluated and many conclusions have been resolved to the Afowo formation being the viable formation for hydrocarbon generation (Nton and Elueze, 2005; Adekeye and Akande, 2010; Akinmosin e al., 2015). Several other discoveries about the oil sand (tar sand) bitumen has been explored and quantified among other conventional hydrocarbon resources. For instance the first indigenous oil company to successfully explore and exploit the hydrocarbon potential of the Dahomey basin is the Yinka Folawiyo Petroleum, who is the major operator of the OML 113, AJE field, which is located on the offshore Eastern Dahomey basin and is the first field to be producing outside of the Niger Delta. The field has been reported to have estimated gross contingent resources of 380 million boe of which 28% is oil and condensate, 20% is LPG and 52% is gas. Additionally, according to the operators of the OPL 310, light oil and condensate-rich gas are expected within the syn-rift of the Dahomey basin.

It has been speculated that gas will represent more than 25% of the world energy demand by 2035, amounting to about 50% of the global energy mix (International Energy Agency 2011). An estimated increase of 4.6% gas consumption was recorded in 2018, the highest since 2010, when a new high of 3 937 Billion cubic metres (Bcm) global production of natural gas was reached, a 4.0% increase compared to 2017 (International Energy Agency (IEA), 2019). Moreover, the carbon footprints and emission of the natural gas is low compared to other fossil fuels.

The Federal Government of Nigeria has recently launched a strategy for the commercialisation of her gas resources to reduce flaring and generate more revenue. The visions of the Federal Government of Nigeria concerning the high level review of the National Gas Policy 2017 are to diversify from oil to gas, increase gas supply to the domestic market and facilitate the use of gas for her power generation and industrial uses. This is in the hope to maximally harness the potential in the gas resources and remain a top player in the world energy market. Based on the 2018 Annual Report from the Department of Petroleum Resources (DPR, 2018), gas reserves have increased since 2013 and it is projected to continue at 1% rate annually. The development plans for the nation's natural gas increased from two to six within a year. This proves the government is committed to gas projects as they also seek to improve the performance of the domestic supply obligation which is on the average 1.3bscf/d (DPR, 2018).

2.0 Shale Gas

The shale revolution in the USA unlocked many potential basins across the world. The era of unconventional resources sprung into limelight with improved technology and economics. The USA became almost totally dependent on its hydrocarbon production especially the shale gas. Around the globe, as conventional hydrocarbon exploitation are becoming mature, the petroleum industry are exploring the unconventional options to continue in business and also renew their reserves (Euzen, 2011).

Unlike the conventional resources found in the porous and permeable formations, unconventional resources can be classified as those that will normally not yield their maximum volume, unless specific technologies are applied to extract and/or exploit because they are found in low porosity and permeability formations including shale. The unconventional hydrocarbon resources include, coal bed methane (CBM), oil sand and oil shale, tight gas/oil, heavy oil (bitumen), shale oil and shale gas (Fig. 3).

Shale is an extensive (both laterally and vertically) and is the mostly available sedimentary rock in the world which not only source these hydrocarbon resources but has become a potential reservoir. Bustin (2006) referred simply to shale gas as gas in a fine-grained rock that is rich in organic matter. Shale gas reservoir does not strictly mean 'shale' but a range of fine-grained lithology from siltstone to mudstone which may contain silica or carbonates, as seen in the American shale reservoirs and the West Canada Sedimentary Basins (WCSB).

Consequently, not all shales can play. Some are identified as seal, and are probably very inefficient to release any hydrocarbon. Also, laminations in shales serve as textural compliment to store free gas and help with conduit to the well bore. Shale gas is being exploited by a method popularly known as hydraulic fracturing which has become less challenging with technological advancement.

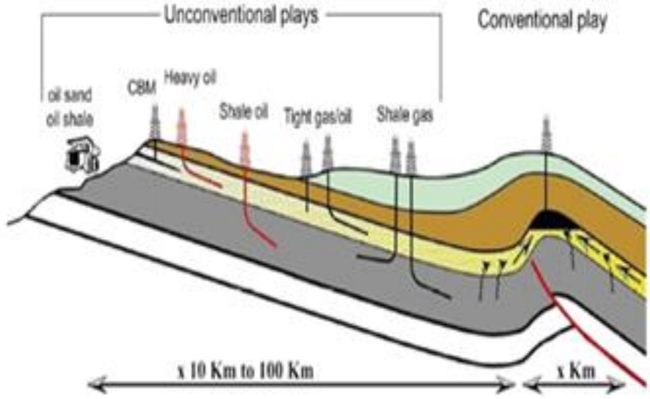

Fig 3. Conventional and Unconventional Plays (Euzen, 2011).

Just like the required conventional petroleum play system, there are fundamental characteristics that make unconventional resources play. Although these characteristics vary from basin to basin and even within the shale formations, there are basic key considerations to note. While there are many other considerations such as characteristics of the shale system, adsorption capacity, mechanical properties, kerogen type, brittleness, texture, mineralogy, fracability, porosity, natural fractures and gas content, throughout the cycle of exploration and development of shale gas, the basic geochemical and geological requirements include;

Total Organic Carbon, TOC (wt %): the organic richness of a shale is a key criteria in the determination of a source material for hydrocarbon.

Thermal Maturity (%R0): a mature source rock should have transform its organic content into hydrocarbon. Hence, a highly mature source rock would generate more gas resources, all other factors being equal.

Type of Gas: a gas can be biogenic or thermogenic in origin. While thermogenic gas forms at great depth signifying degree of maturation, biogenic gas can be produced from immature source rocks usually from microbial activities. An example is the Antrim shale gas field in Michigan basin, USA which is more of biogenic than thermogenic source (Martini *et al*., 2004).

Permeability: this regards to the flow rate of a reservoir. Shale is typical of low porosity and permeability, and its hydrocarbon content will not flow unless induced.

Table1. Basic shale gas characteristics/conditions (Zhang *et al.*, 2018)

Criteria	TOC	Ro	Depth	Thickness	Brittle mineral	Permeability	Porosity
	(wt %)	(%)	(m)	(m)	(%)	(nd)	(%)
Value	>1.0	>0.5	<4000	>15	>30	>100	>2

Shale exhibits multiple storage mechanisms. It can be stored in the micropores and macropores as free gas, on the surface of the organic matter as adsorbed gas and as dissolved/solution gas in the nanopores of the bitumen (Bustin, 2006; Wang *et. al*, 2016). Hence, the careful development and management of the potential of shale reservoirs can boost energy security.

Therefore, this paper aims to identify the opportunity for shale gas exploration and development in the eastern Dahomey basin by reviewing the geochemical and geological properties of the basin reported by previous authors and comparing with other producing shales in the USA as a complimentary standard.

3.0 Shale Gas Potential of the Eastern Dahomey Basin

In the Dahomey basin, several estimates has been reported of its heavy oil otherwise known as bitumen within the Afowo formation (Enu, 1990; Falebita et al. 2014; Akinmosin et al,. 2011, 2015; Olayinka et al., 2016; Bata et al., 2016; Emmanuel et al., 2019; Muhammed et al., 2019; Ogala et al., 2019). The basin has proven to be a store house for these unconventional hydrocarbon resources as with several other basin like the Lokpanta oil shale within the Benue trough in Nigeria (Ekweozor & Unomah, 1990; Ehinola et al., 2004) and the Mamu formation in Anambra basin (Ogungbesan and Adedosun, 2019).

Yohannah (2015) evaluated the unconventional resources of the shales within the Benue Trough basin. Using the Rock Eval pyrolysis method, he reported maturity (VR0) of 0.89-1.34% and 0.83-1.13% for Awe and Agwu formations respectively. He also compared the Awgu TOC result of 0.83-6.54% with that of the Barnett shales of Fort Worth basin in the USA which has TOC value of 1-4.5%. He concluded the range of values are sufficient for shale gas prospect.

In their assessment of the global unconventional resources, Wang et al., (2016), outlined the types of basin and formation that are rich in unconventional gas resources, fig. 4&5.

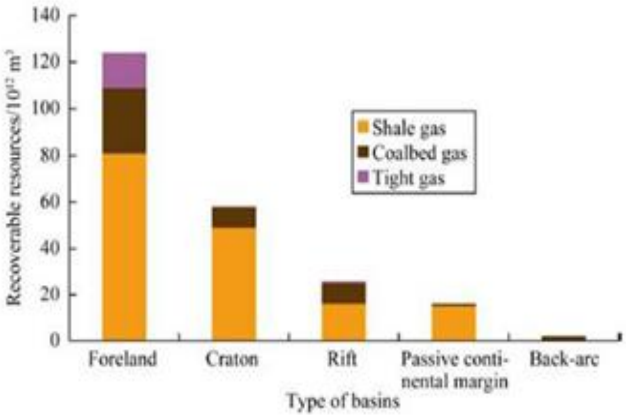

Fig 4. Types of Basins and their Estimated Recoverable resources (Wang *et al.*, 2016).

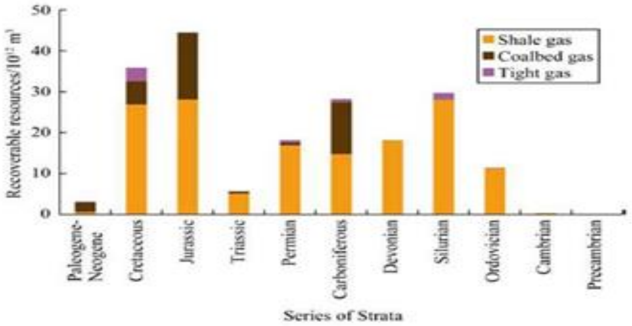

Fig 5. Recoverable unconventional gas potential in the formations (Wang et al., 2016).

This assessment, regarding a rift basin in the cretaceous era, pose a qualifying potential for the Dahomey basin as a play in the world of unconventional gas resources.

Okosun (1990) reviewed the stratigraphy of the cretaceous sediments of the eastern Dahomey basin giving a neostratotype and hypostratotype of these sediments by using the Ojo-1 well. He established a thickness of ~320m for the Araromi formation and ~850m for the Abeokuta group.

Adeigbe and Amodu (2015) highlighted the pollens and spores found in the Araromi-1 well to determine the paleo environment and age. The studied sediments of the Araromi-1 well (128-571.8m) as inferred from the diagnostic markers such as *zonocortites ramonae (fresh water swamps), homotryblium oceanicum (deep marine)* were deposited within the brackish-deep marine environment and during the late Maastrichtian to late Paleocene period.

There have been recent geochemical studies of the shales in the eastern Dahomey basin from several exploratory wells using the usual Rock-Eval pyrolysis by different authors (tab. 2). Akande et al. (2018) highlighted their results to indicate a mature source rock for the Afowo formation (tab. 2) and also generated a 1D model of the thermal history and transformation ratio from well X (offshore), Orimedu-1 and Ise-2 wells.

Adekeye et al., (2019) also examined the comprehensive geochemical analyses and source potential of the Araromi formation. He reported an immature and marginally mature (0.51-0.68 VR0%) source rock from two exploratory wells, Gbekebo and Araromi-1 wells. He highlighted the maceral compositions with abundance vitrine of 38.1%, inertinite of 35.9% and liptinite of 26.0% indicating terrestrial sources that have been reworked with marine-algae components. He also differentiated some oil stains that were identified in the upper part of the wells from the potential source rock.

Adeoye et al. (2020) in their report on the characteristics of the cenomanian, turonian and coinamia ages of the Afowo shales, gave the organic matter maturity and kerogen types of the shales from X (offshore), Orimedu-1 and Ise-2 exploratory wells. He also examined the provenance and paleo environment of the shale. He reported some mineral oxides of the shales ranging from SiO2, Al2O3, TiO2 and phosphates. The high value of 57% of SiO2 and 19.2 value for the Al2O3/TiO2 align with terrigenous and intermediate igneous rock source of the sediments.

Muhammed et al., (2020) examined five outcrop samples of the Afowo claystone for source rock evaluation using three different measurements; Rock Eval pyrolysis, Loss on Ignition (LOI) and thermogravimetry. The claystone was about 2.44m thick and the range of sampling was between

8.7-9.9m intervals. The TOC evaluated from LOI was 9.410-38.750 wt% and 0.81-18.46 wt% from rock eval. The Tmax from the thermogravimetric analysis range from 417–424 °C which indicates the samples are thermally immature. This occurrence is similar to the immature outcrop samples of the Barnett shales with very high TOC (13%) compared to the matured producing samples with TOC range of 1-5% as a result of deposition and diagenesis (Euzen, 2011).

A peep into the SEM image studies of the Afowo oil sand by Akinmosin et al., (2011) identified kaolinite as the dominate clay minerals including k-feldspar, pyrite crystals and corrosion quartz. These minerals are classified safe for textural and reservoir characteristics during hydrocarbon production. The images from the SEM revealed micro pores of 2-4 µm and 2-5µm fractures.

4.0 Results and Discussions

The Late Cretaceous sediments (Abeokuta group) has been identified as the producing and potential hydrocarbon-bearing interval of the Dahomey Basin. The Afowo shales dated Cenomanian-Coniacian looks more promising than the Araromi shales (Maastrichtian-Paleocene). The geochemical

Table 2. Geochemical Analyses by Previous Authors.

	Araromi Shale			Afowo Shale			
	Okosun	Adekeye et al. (2019)		Akande et al., 2018			Okosun
	(1990)			Adeoye et al., 2020			(1990)
wells	Ojo-1	Ar-1	Gbekebo	Orimedu-1	Ise-2	X(offshore)	Ojo-1
Depth (m)	756-1075	405-572	834- 1028	700-1700	2300-	2000-3000	1076-1923
					4000		
TOC (wt.%)	-	0.61-2.75	0.5-4.8	0.8-1.9	0.7-1.1	0.6-2.3	-
				1.3-1.9	-	0.9-1.3	
Thickness (m)	319	167	194	1000	1700	1000	847
VR0 (%)	-	0.5-0.66	0.5-0.68	0.4-0.74	0.58-0.72	0.6-0.95	-
						0.95	
Tmax (^{0}C)	-	403-428	422-437	418-439	430-438	-	-
SP (kgHC/ton of	-	0.03-5.46	0.01-14.56	-	-	-	-
rock)							
HI	-	1-202	1-327	99-225	180-250	331-707	-
(mgHC/gTOC)				179-357		214-560	
kerogen type	-	II/III, III	II/III	II/III	II/III	I, II	-

Table 3. A Comparison of Some of the Producing Shale Gas Basins in USA and the Cretaceous shales of Dahomey Basin (Zhang *et al.*, 2018).

Basin	Age	Shale name	TOC, %	Kerogen type	Vitrinite reflectance, %	Single-layer shale thickness, m	Brittleness index, %	Porosity, %	Burial depth, m	Gas content, m^3/tonne
Fort Worth	Carboniferous	Barnett	1–7	II	1–2.1	30.48–182.88	30–50	4–5	1981.2–2591	8.5–9.9
San Juan	Late Cretaceous	Lewis	0.45–2.5	II, II/III	1.6–1.88	60.9–570	50–75	3–5.5	914.4–1828.8	0.42–1.27
Arkema	Carboniferous	Fayetteville	4.0–9.8	I, II/III	1.2–3.0	6.10–60.96	40–70	2–8	305–2133	1.70–6.23
Arkema	Late Devonian	Woodford	3–7	I, II/III	0.37–4.89	36.57–60.06	50–75	3–9	1828.8–3352.8	5.66–8.5
Michigan	Late Devonian	Antrim	3–8	I	0.4–0.6	21.34-36	20–41	9	182.88–670.56	1.14–4.53
Illinois	Late Devonian	New Albany	2–6	II/III	0.4–1.0	15.24 30.48	50	10–14	152.4–609.6	1.14–2.27
Abba La Cilla	Late Devonian	Ohio	0.5–23	II/III	0.4–4	91–610	45–60	2–11	610–1524	1.70–2.83
Abba La Cilla	Devonian	Marcellus	3–12	II/III	0.6–3.0	15.24–60.96	30–60	6	1219–2591	1.70–2.83
Louisiana	Late Jurassic	Haynesville	0.5–4.0	I, II/III	2.2–3.0	60.9–91.446	35–65	8–9	3200–4115	2.83–9.35
Dahomey	Late	Araromi	0.5-4.8	III	0.5-0.68	167-443	?	?	400-834	?
	Cretaceous	Afowo	0.6-2.3	I, II, II/III	0.6-0.95	847-1700	?	?	700-2300	?

Similar range of comparison

analyses from the exploratory wells and outcrop has proven that the basin can generate oil and gas, but more importantly, gas (tab. 2).

The organic matter are marginally mature to mature, comparing with the Antrim and New Albany shales (tab. 3), the R0 recorded (0.5-1%) in the Dahomey basin (tab. 2) are substantial and even higher. The shales are thick enough to accommodate volumes of hydrocarbon comparing the depth threshold of >15m required.

The Late Cretaceous age and burial history of the Lewis shale align with the Afowo shale of the Dahomey basin including the low TOC (0.45-2.5%) value (tab. 3). Additionally, the Antrim shale gas has been reported to be predominantly biogenic, the Araromi and Afowo shales might just share similarity in this type of gas content considering a factor of their kerogen type.

No direct research has focused on the porosity or brittleness index of the shales of the Dahomey basin (?) because the shales have been studied for its source rock properties and not as a reservoir. The brittleness index denotes the fracability of a reservoir which is a function of its mineral and associated clay compositions resulting from the provenance and diagenesis of the basin. If the shales are found to be easily fractured, then more pores can be created and a sustainable production might be guaranteed.

5.0 Conclusion

The many other information required to establish if the Cretaceous shales of the Dahomey basin can indeed be considered as unconventional reservoirs for commercial gas exploration and exploitation are still unknown. Therefore, further studies are recommended for more detailed reservoir characteristics in geochemistry, mineralogy, porosity, permeability, brittleness index, mechanical properties and quantification of the shale gas resources in Dahomey Basin.

As shale gas characteristics vary from basin to basin, and technology still advancing, many difficulties and parameters are bound to change and become easier and economical. Hence, exploring for future opportunities and possibilities is paramount to keep up with the demand of energy across the globe.

References

Adediran S. A. and Adegoke O. S. (1987): Evolution of the Sedimentary Basins of The Gulf Of Guinea. In: Current Research in Africa Earth Sciences, *Matheis and Schandeimeier (eds). Balkema, Rotterdam*, pp. 283-286.

Adegoke O.S. (1969): Eocene Stratigraphy of Southern Nigeria. *Bureaude Recherches Geologiques et Minières Memoir*, 69, 23-48.

Adekeye O. A., Akande S. O. and Adeoye J. A. (2019): The Assessment of Potential Source Rocks of Maastrichtian Araromi formation in Araromi and Gbekebo wells Dahomey Basin, southwestern Nigeria, *Heliyon*, 5, e01561 https://doi.org/10.1016/j.heliyon.2019.e01561

Adekeye O.A. and Akande S.O. (2010): The Principal Source Rocks For Petroleum Generation In The Dahomey Basin, Southwestern Nigeria, *Continental Journal Earth Sciences*, vol. 5 (1), pp. 42 – 55.

Adeoye J. A., Akande S. O., Adekeye O. A., Sonibare W. A., Ondrak R., Dominik W., Erdtmann B. D., and Neeka J. (2020): Source Rock Maturity And Petroleum Generation In The Dahomey Basin SW Nigeria: Insights From Geologic And Geochemical Modelling, *Journal of Petroleum Science andEngineering*,195,107844.https://doi.org/10.1016/j.petrol.2020.107844.

Adeoye J. A., Akande S.O., Adekeye O., Abikoye V.T. and Ojo O.J. (2020): Geochemistry And Paleoecology Of Shales From The Cenomanian-Turonian Afowo Formation Dahomey Basin, Nigeria: Implication for Provenance And Paleoenvironments, *Journal Of African Earth Sciences*, 169,103887.https://doi.org/10.1016/j.jafrearsci.2020.103887.

Akande S.O., Adekeye O., Adeoye J. A. and Ojo O.J.(2019): Burial and Thermal History of Cretaceous Sediments In The Dahomey, Anambra And Gongola Rift Basins: Implications For Coal Facies Distribution And Petroleum Potential. *FUOYE Journal of Pure and Applied Sciences* 3(1). https://www.researchgate.net/publication/333812459

Akinmosin A., Omosanya, K. O. and Olawale, A. O. (2015): Hydrocarbon Potential of Some Afowo Shale Deposits in Part of South Western Nigeria. *International Journal of African and Asian Studies* 2409-6938 (11)

Akinmosin, A., Adeigbe, O.C., and Oyemakinde, O.O. (2011): Scanning Electron Microscope Description of the Afowo Oil Sand Deposits In South-Western Nigeria. *Earth Sci. Res. J.* 15(1)

Akinmosin, A., Omosanya, K. O. and Olawole, A. O. (2015): Hydrocarbon Potential of Some Afowo Shale Deposits in Part of South Western Nigeria. *Int. J. Afr. Asian Stud.* 11, 1–22

Akinmosin, A., Omosanya, K.O, Folorunsho, A.F, Ariyo, S.O and Aiyeola, S.O., (2011):
Structural Control for Bitumen Seepages in Imeri, Southwestern, Nigeria. *International Journal of Basic and Applied Sciences*, Vol. 11(1): 93-103

Amodu O.I. and Adeigbe O.C. (2015): Palyno-Environmental Studies Of The Araromi-1 Well, Eastern Dahomey Basin, Southwestern Nigeria, 2nd International Conference on Scientific Research and Innovation in Nigeria, Faculty of Science, University Of Ibadan. Journal of Science Research, vol. 14, pp. 1-8.

Bata T., Parnell J., Bowden S., Boyce A. (2016): Origin of Heavy Oil in Cretaceous Petroleum Reservoirs. *Bulletin of Canadian Petroleum Geology*, 64 (2), 106–118. https://doi.org/10.2113/gscpgbull.64.2.106

Billman,H.G.(1976).Offshore Stratigraphy and Palaeontology of the Dahomey Embayment.*Proc. 7th Afri. Micropal. Coll.* Ile-Ife, pp. 27-42.

Bustin, M.R. (2006): Geology Report: Where Are The High-Potential Regions Expected To Be In Canada And The U.S.? Capturing Opportunities In Canadian Shale Gas; The Canadian Institute's 2nd Annual Shale Gas Conference, Calgary, January 31–February 1, 2006.

Ehinola, G. A., Badejoko, T. A., Ekweozor, C. M. and Adebowale, K. O., (2004): Organic Facies Variations In The Middle Cretaceous Black Shales Of The Abakaliki Fold Belt, Southeastern, Nigeria, *NAFTA* 55, pp. 505 - 515.

Ekweozor, C. M., and Unomah, G. I., (1990): First Discovery of Oil Shale in the Benue Trough, Nigeria, Fuel, 69, pp. 502 - 508.

Enu, E.I. (1990): Nature and occurrence of tar sands in Nigeria. In Occurrence, Utilization and Economics of Tar Sands (eds Ako, B.D. & Enu, E.I.) Nigeria Mining and Geosciences Society, Anglo-Jos

Euzen T. (2011): Shale Gas: An Overview.
DOI: 10.13140/RG.2.1.2236.6242

Falebita D. E., Oyebanjo O. M., and Ajayi T. R. (2014): A Geostatistical Review Of The Bitumen Reserves Of The Upper Cretaceous Afowo Formation Agbabu Area, Ondo State, Eastern Dahomey Basin, Nigeria. *Petroleum & Coal* 56(5) 572-581, 2014

International Energy Agency (2011): World Energy Outlook 2011, IEA, Paris. https://www.iea.org/reports/world-energy-outlook-2011
International Energy Agency (2018).Oil Market Report; 13 April2018https://www.iea.org/media/omrreports/fullissues/2018-04-13
International Energy Agency (2019): African Energy Outlook.www.iea.org/africa2019
Jan du Chene, R. (1979). Some New Pollen Species of the Upper Maastrichtian Tar Sand,Southern Nigeria, Rev. Esp. Micropal., 9, pp. 109-201.
Lehner P. and Ruiter P. A. (1977): Structural History of the Atlantic Margin of Africa. *AAPG Bull.* v. 61, pp. 961-981.
Martini, A.M., Nüsslein, K. and Petsch, S.T. (2004): Enhancing Microbial Gas FromUnconventional Reservoirs: Geochemical And Microbiological Characterization Of Methane-Rich Fractured Black Shales; Final Report For Research Partnership To Secure Energy For America, Subcontract No. R-520, GRI-05/0023, 7 p.
Mohammed S., Opuwari M., Titinchi S., Bata T., and Abubakar M. B. (2019): Evaluation Of Source Rock Potential And Hydrocarbon Composition Of Oil Sand And Associated Clay Deposits From The Eastern Dahomey Basin, Nigeria, Journal of African Earth Sciences, 160 ,103603. https://doi.org/10.1016/j.jafrearsci.2019.103603.
Mohammed, S., Opuwari, M., Titinchi, S., Bata, T. and Mohammed, B. A. (2019):Evaluation of Source Rock Potential and Hydrocarbon Composition of Oil Sand and Associated Clay Deposits From the Eastern Dahomey Basin, Nigeria. J. Afr. Earth Sci. 160, 1–8
Nton, M.E. and Elueze, A.A. (2005): Compositional Characteristics and Industrial Assessment of Sedimentary Clay Bodies In Part of Eastern Dahomey Basin, Southwestern Nigeria.Journal of Mining and Geology, 412 Pp. 175 -184.
Ogala, J. E. (2019): Geochemical and Organic Petrological Study of Bituminous Sediments from Dahomey Basin, SW Nigeria. Mar.Pet. Geol. 99, 577–595
Ogungbesan G. O. and Adedosu T.A (2019): Geochemical Record For The Depositional Condition And Petroleum Potential Of The Late Cretaceous Mamu Formation In The Western Flank Of Anambra Basin, Nigeria, Green Energy & Environment,5,8396.
https://doi.org/10.1016/j.gee.2019.01.008
Okosun, E. A.(1990).A Review of the Upper Cretaceous Stratigraphy of the Dahomey Embayment, West Africa. Cretaceous Research, 11, pp. 17 - 27.
Omatsola M. E. and Adegoke O. S. (1981): Tectonic Evolution and Cretaceous Stratigraphy of the Dahomey Basin. Jour. Min. Geol. v. 18, pp. 130-137.
Petters, S.W. (1978a). Stratigraphic Evolution of the Benue Trough and Its Implications for the Upper Cretaceous Paleogeography of West Africa. Journal of Geology, 86, pp. 311-322.
Rokosh, C.D., Pawlowicz, J.G., Berhane, H., Anderson, S.D.A. and Beaton, A.P. (2009):What Is Shale Gas? An Introduction to Shale-Gas Geology in Alberta; Energy Resources Conservation Board, ERCB/AGS Open File Report 2008-08, 26 p.
Wang H., Ma F., Tong X., Liu Z., Zhang X., Wu Z., Li D., Wang B., Xie Y., and Yang L.(2016): Assessment of Global Unconventional Oil And Gas Resources. Journal of Petroleum Exploration Development, 43(6), 925–940.
Whiteman A.J. (1982): Nigeria: Its Petroleum Geology, Resources and Potential. Grahman and Trottan Ltd, London, 394p
Wright L. 2016: The Potential of Shale Gas in the Bowland-Hodder,IsItTheNextBarnett?DOI:10.13140/RG.2.2.13223.55203
Yohanna, O. M. (2015): Evaluation of Shale Gas Resource Potential of the Middle Benue Trough, Nigeria. Proceedings of the International Academic Conference for Sub-Sahara African Transformation & Development-University of Ilorin. 3(2)
Zhang H., Jun-Tai S., and Xiang-Fang L. (2018): Optimization of Shale Gas Reservoir Evaluation and Assessment of Shale Gas Resources in the Oriente Basin in Ecuador.PetroleumScience.15,756–771.
https://doi.org/10.1007/s12182-018-0273-7