TECHNICAL AND ECONOMIC EVALUATION OF NATURAL GAS RESOURCES FROM CAMPANO-MAASTRICHTIAN NKPORO SHALE OF ANAMBRA BASIN/LOWER BENUE TROUGH

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DECEMBER, 2016

CERTIFICATION

I certify that this work was carried out by Mr. H. O. Igwilo in the Department of Petroleum Engineering, University of Ibadan, Nigeria.

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ABSTRACT

Nigerian gas reserves is currently characterised by high production/reserves ratio due to increasing demand from liquefied natural gas, power generation plants and other industrial users. There has been increasing efforts at identifying new opportunities for conventional and/or non-conventional gas reserves. The Campano-Maastrichtian Nkporo shale is one of the potential sources of non-conventional gas reserves in Nigeria. Despite geological, geophysical and geochemical evaluations that have been carried out and published, there is sparsity of data on the reserves, engineering, and petrophysical parameters required for possible development and production. This study was designed to obtain engineering and petrophysical data, evaluate the resource volumes and producibility of Nkporo shale gas and to formulate appropriate technical and economic strategies for the development and production.

Published geochemical evaluation results were obtained from literature and interpreted. Log suites and other data such as sidewall cores and bottom hole temperatures were obtained from five wells: Alo-1, Anambra River-2, Ogbabu-1, Oda River-1, Akukwa-2; which were earlier drilled, logged and tested. Engineering and Petrophysical evaluations of the well logs were undertaken to obtain geothermal profiles, porosity, permeability, fluid saturations, compressibility and compressive stresses. The initial in-place volumes, fracturability and producibility of the shale gas were estimated using petroleum industry standard procedures. Data were benchmarked with similar shale systems in USA and Australia. Net Present Value (NPV) and Return On Investment (ROI) were determined at different operating and economic conditions.

Nkporo shale has Total Organic Carbon (TOC) ranging from 0.40 to 3.01 wt % with low average Hydrogen Indices revealing kerogen type III and mixed III/II that is predominantly gas prone. Multiple temperature profiles exist within the formation with gradients ranging from 0.0043-0.0366 ^{o}C/m (0.0142–0.1200^{o}C). Porosity ranges from 5.0–28.1 % while effective permeability ranges from 0.0–95.5 millidarcy. Water saturation ranges from 0.70–0.99. The original gas in place was established at 2.93 million m^3 per km^2 (268.69 BCF/640-acre well spacing) with the potential to increase to 7.33 million m^3 per km^2 (685 BCF/640-acre well spacing). Vertical and horizontal compressive stresses range from 4.6–5.27 and 2.41–2.77 x 10^7 N/m^2 (6673–7646 and 3498–4008 psia) respectively. Maximum production requires high conductivity linear hydraulic fracturing using 20/40 mesh size fluid, and 305 m (1000 feet) fracture length per section of well spacing. The properties of Nkporo shale compared well with some established shale-gas formations in the USA and Australia. Developing the gas reserves profitably requires dual completions to achieve high well off-takes. For wells drilled and completed at $10,000/m and at recovery factors between 10-50 % and gas price of $2.50/MM Scf, NPV varies between 0.0287–0.1420 billion dollars per 640-acre spacing while ROI ranges between 0.43-52 % for interest rates between 10-30 % with development incentive ranging between 1-10% for investors.

There is scope for additional gas reserves from the Campano–Maastrichtian Nkporo shale within the Anambra Basin/Lower Benue Trough. This may apply to other similar shale formations in Nigeria.

Keywords: Shale gas development, Petrophysical evaluation, Hydraulic fracturing, Nigerian gas reserves.
Word count - 485

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Above all; I want to give special thanks and all the glory to our Almighty Creator and beloved God who owns and does this Project in Jesus name; Amen.

DEDICATION

To God be the Glory for accepting and supporting me throughout this project.

ABREVIATIONS

Symbol	Description	Unit
TCF	Trillion Cubic Feet	
Gi	Initial Gas in Place	TCF
Ni	Initial Oil in Place	Barrels
D	Depth under Sub-surface ref	FTss
T	Temperature	^{o}F
BHP	Bottom Hole Pressure	Psi
AGV	Associated Gas Volume	TCF
NAGV	Non Associated Gas Volume	TCF
Fm	Formation	
Grp	Group	
SS	Sand Stone	
MFS	Maximum Flood Surface	
SB	Sequence Boundary	
HST	High Stand System Track	
TST	Transgressive System Track	
LST	Low Stand System Track	
MST	Medium Stand System Track	

K_f	Permeability of proppant, md	md
wKf	Conductivity of fracture	md-in
J/Jo	Productivity index ratio(after/before)	
r_e	Drainage radius of well	ft
rw	Well radius,	ft
Cr	Dimensionless fracture Conductivity	
LR	Dinensionless fracture lenght from wellbore	
σh	Total horizontal Stress	Psi
σv	Total vertical Stress	Psi
Q_D	Dimensionless Rate	
K	Permeability	md
T(t)	time	hrs
Ø	Porosity	%
Ct	Total compressibility	Psi^{-1}
X_f	Lenght of one wing of Fracture	ft
t_D	Dimensionless time	
Q	Cumulative Production	mcf
Xe	Distance to drainage boundary	ft
KG6	1.3597*10^-6	

DENS	Layer density from log	gm/cc
KV4	0.000043560	
Sg	gas saturation	%
Sw	water saturation in un-invaded zone	%
Bg	gas formation volume factor	Scf/stb
TAV	Total Assets value	Naira(₦)

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CHAPTER ONE

INTRODUCTION

1.1 Preamble

There are very few dedicated gas explorations in Nigeria, hence most gas discoveries are associated with the search for oil . Most of the exploration and production activities focus on the conventional hydrocarbon reserves, hence reserves replacement rate is generally low, and Nigerian reserves growth has been static for years while the demand is continuously increasing.

Furthermore, increasing demand for gas for LNG, power generation and other industrial use, has led to increase interest in gas exploration and exploitation.

One of the areas to look into for increasing gas reserve is unconventional gas reserves, just like the United States of America will increase hers by 50% through development of shale gas reserves(Energy Information Administration,2012). Successful hydraulic fracuring requires horizontal drilling and multistage hydraulic fracture stimulation for economic exploitation of Shale gas.

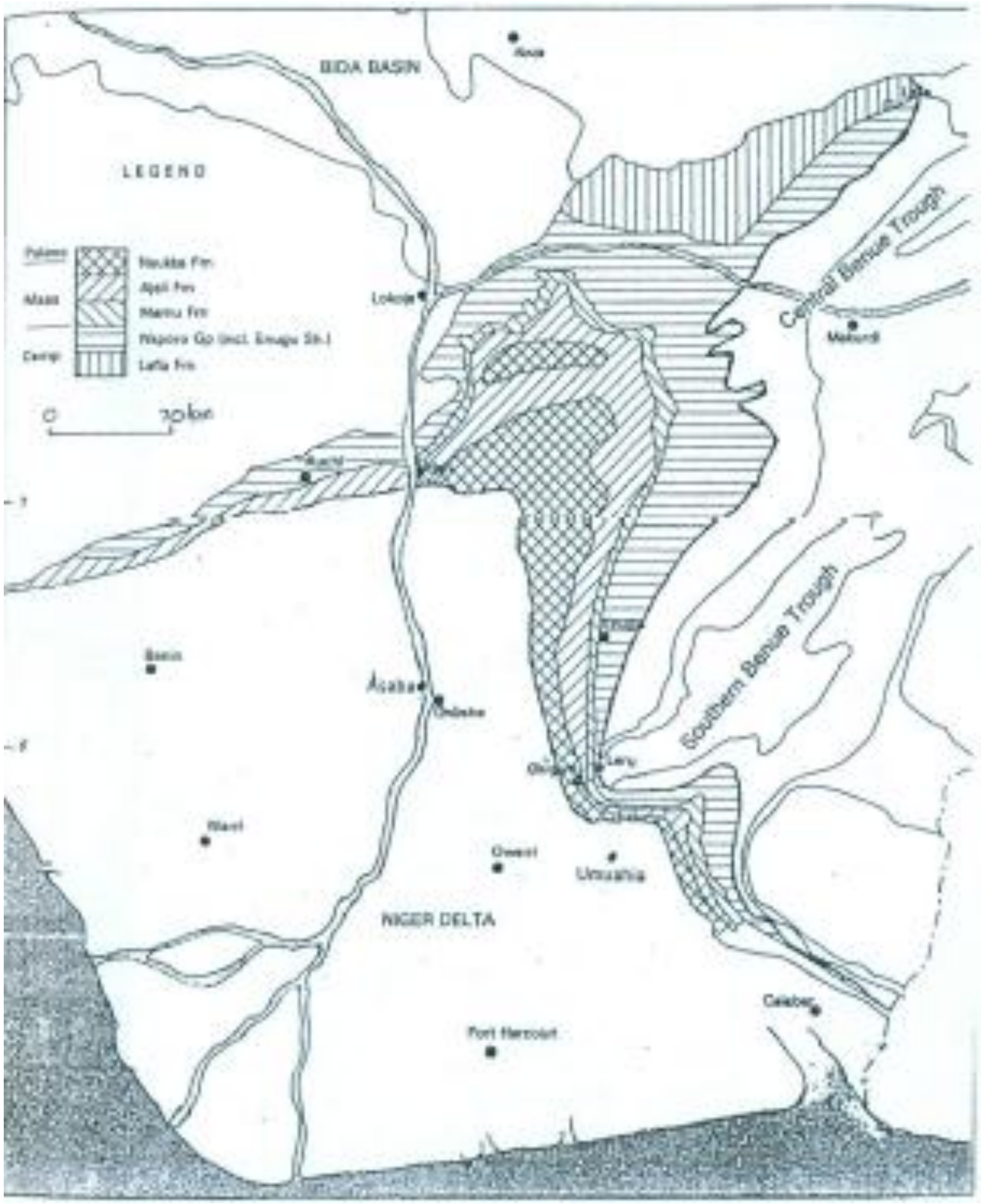

Fig:1.1Regional Geology of the outcropping components of the Anambra Basin(Nwajide C.S. and Reijers;1996)

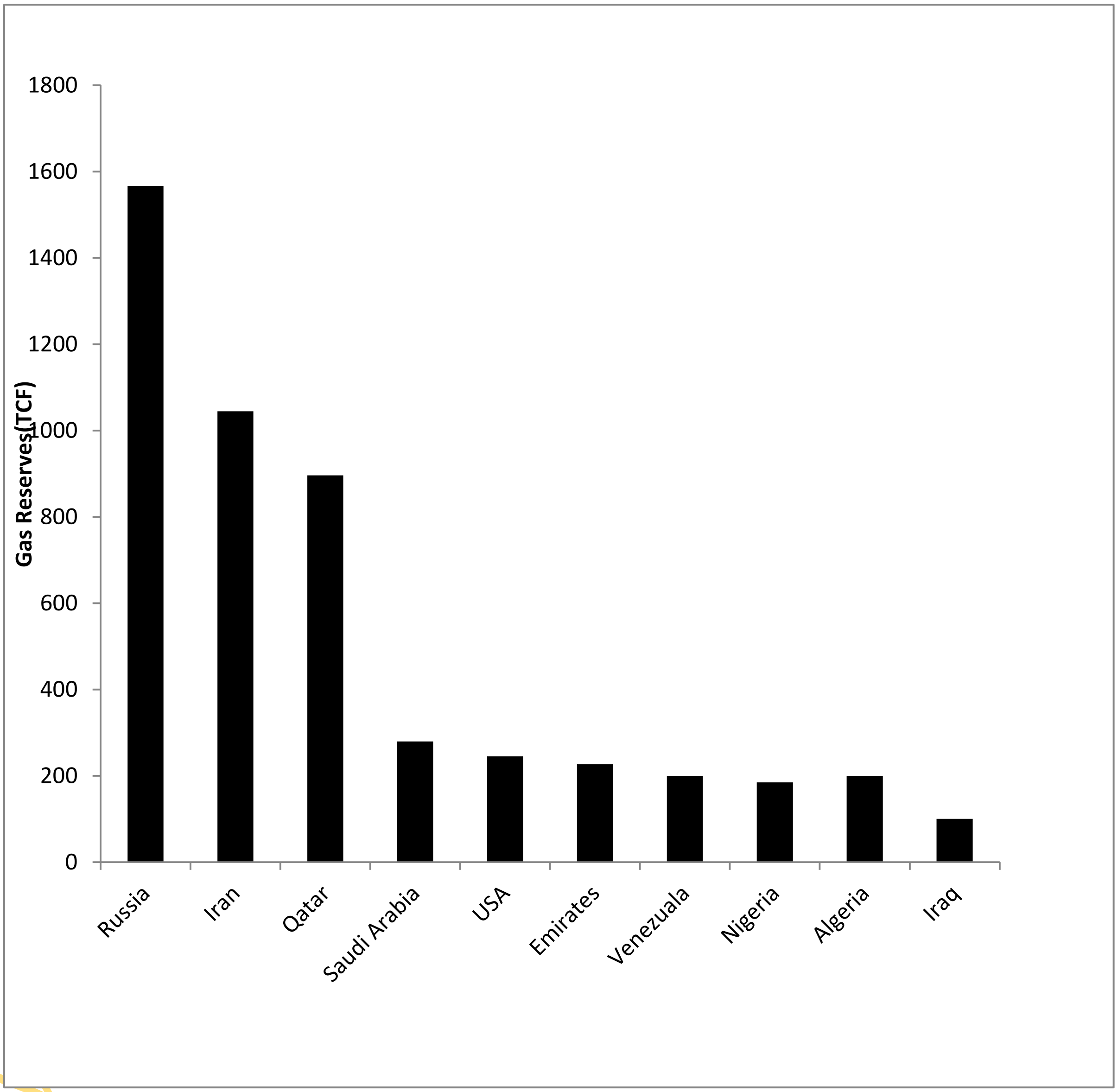

Fig:1.2 GLOBAL HISTORICAL GAS RESERVES GROWTH (Ige D.O.2013)

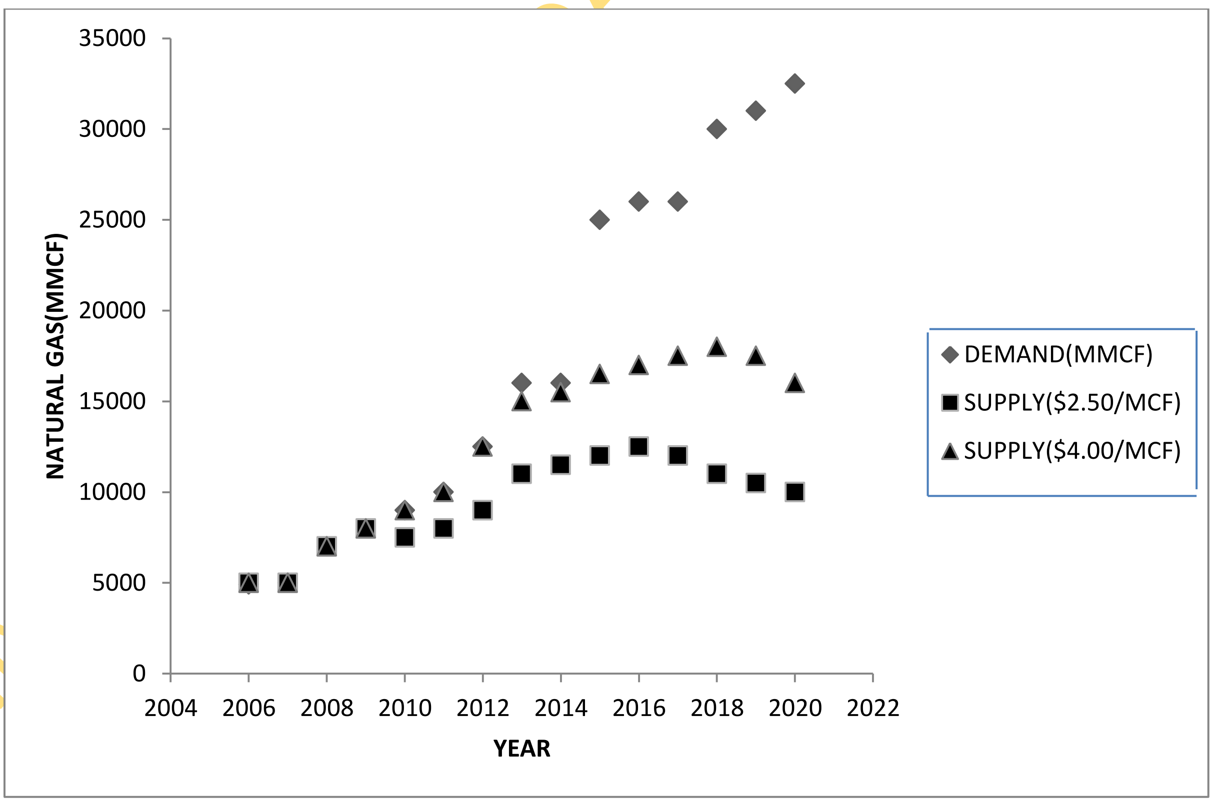

Fig:1.3 NIGERIAN GAS DEMAND/SUPPLY AND PROJECTION(Ige D.O.2013)

Nigerian Shale Formations are made up of the following: Coniacian Afowo Shales (Dahomey Basin), Lokpanta shales of the late Cenomanian – Turonian Eze-Aku formation of the Anambra Basin, Araromi shales (Dahomey Basin), Enugu/Nkporo/Mamu shales (Anambra Basin). Imo and Agwu shales are also in this category; (Onyekuru and Iwuagwu;2010).

The Nkporo Shale is targetted for study among others because of the large areal coverage straddling from Anambra Basin to Lower Benue Trough containing organic rich shales that are marginally mature for hydrocarbon generation and some of the Hydrocarbon content generated are impregnated in the ultralow-permeability rock metrix unable to migrate (Ehinola, et al, 2005). The hydrogen indices of Nkporo shale are relatively low and range within 20-153mg HC/g TOC (Total Organic Carbon) confirming the kerogen of Type III and mixed with III/II organic matter (OM) which is predominantly gas prone (Ehinola et al). Nkporo Shale Formation though immature Shale Formation, if explored and exploited, will significantly increase our gas reserve and will halt the current rate of decrease in our reserve.

1.2 General Background on Shale Gas Formations

Shale gas reservoirs are known as low quality formations due to low permeabilities associated with them. They are gumbo-like in nature constituting fissile shale, sandy shale, siltstone and round-stones.

The low-permeability structure and the response to overburden stress affects very significantly the low permeability structure versus relative permeability relationship.(Crain, 2000)

Challenges of this type of formation are:

1. Poor reservoir quality
2. Adverse initial saturation conditions
3. Damage induced during drilling and completion
4. Damage induced during hydraulic or acid fracturing
5. Damage induced during kill or work-over treatments
6. Damage induced during production operations;

The shale gas sand exploitation cost control factors are the following (Thomas and Robert,1989):

1. Effective permeability to gas
2. Initial saturation conditions
3. Size of effective sand face drainage area accessed by the completion
4. Reservoir pressure
5. Liquid deposit from gas;

Focus on the fundamental elements of hydrocarbon traps must be achieved for the exploration efforts in low permeability shale gas formations systems to be successful. To effectively and efficiently explore and exploit shale gas and the rich gas condensate from the Nkporo formation, the petrophysical properties and the architecture of the distribution of these properties which includes lithofacies associations, facies distribution, insitu porosities, saturations, effective gas/liquid permeability at reservoir conditions must be determined. Enhanced completion and drilling technology will allow the gas traps and the condensate in Nkporo shale to be fully exploited. The technology will also optimize production. The extensive collection of reservoir description data which economics sometimes cannot typically support is required. Proper planning is required to balance data collection costs with the level of detail necessary to describe the reservoir accuracy . Nkporo shale gas formations have natural fractures. Hence, two different wells having the same log signatures may have different production behavior.

The shale gas formations are difficult to characterize because the routine methods developed for conventional reservoirs are not applicable.

Shale gas formation often exhibit unique gas storage and predrilling characteristics that require:

1. Understanding fracture stimulation
2. Hydraulic fracture stimulation
3. More dense well spacing
4. Enhanced production technique
5. Improved knowledge of the nature, geometry and distribution of petrophysical properties

Petrophysics and Geomechanics information are required in shale gas formation analysis in order to understand these low permeability reservoirs and to apply correct advanced drilling technologies, adequate stimulation and production strategies.

HYDRAULIC FRACTURING

The Research to exploit shale gas formation despite the low permeability characteristics associated with it has taken a long period with good success story. The Hydraulic Fracturing is now employed to create a highly conductive path (i.e. high effective permeability)some distance away from the well bore into the formation. It is one of the stimulation technique being applied for shale gas exploitation and had recorded very high success story. This increase in conductivity is achieved through the propping with sand mixed with polymer to hold the fracture faces apart. This is achieved when the pumping rate into the formation is greater than the leak off rate. Hence the fluid pressure (stress) build up overcomes the earth compressive stress holding the rock together and when this is achieved, fracture along a plane perpendicular to the minimum compressive stress in the formation motive occurs. This fracture could be horizontal or vertical.

Mechanics of Fracturing

Fracture developed is a function of stress applied near the borehole,properties of the rock, the characteristics of the frac fluid including the injection horsepower. The parking fraction of the formation is a factor that can result to multidirectional fracturing. Fracture is extended when sufficient differential hydraulic pressure is greater than the rock compressive stresses.

Considering the earth crust as elastic system in a relaxed tectonic condition;the vertical and horizontal compressive stress can be calculated.

$\sigma_v = 0.007\rho D$-------------------------------(3.6)

where σ_v= Total vertical stress, psi

ρ=average rock density,lb/ft^3

D= Depth,Ftss

The compressive stress could be affected by the pore pressure emanating from the presence of pore spaces and fluid content of the pore spaces. This pore pressure reduces the compressive stress as it increases. This is very common in shale compaction behavior.

Hence,

$\sigma_v = 0.007\rho D - P_r$---------------(3.7) where P_r is the pore pressure of the formation

$$\sigma_h = \frac{V}{1-V}(\sigma_v - P_r)\text{-----------------}(3.8)$$

where V = Poisson's ratio

Shale V = 0.35, $E=4x10^6$

Sand V=0.30, $E=3x10^6$

ShaleV=0.33, $E=4x10^6$

Where E is Young's Modulus of Elasticity

PKN ==== Perkins, Kern and Nordgren

The PKN model is used in describing the fracture geometry.The Young's Modulus and Poisson's ratio can apply considering the geometry,dirtiness of the sand and the compaction of the Nkporo Shale Formation. The fracture closure pressure is calculated based on estimated fracture gradient of 0.60psi/ft. It should be noted that the pore pressure studies for Nkporo must be carried out prior to well drilling during the full Field Development Stage. This is necessary inorder to design an effective drilling mud or hydraulic mud system needed to encounter unexpected high subsurface pressure surge that may result to blow out.

PRODUCTION INCREASE FROM FRACTURING

The above is possible due to the following:

(1) Exposure to new zones
(2) Reduction in permeability bypassed.
(3) Flow pattern in reservoir changed from radial to linear flow.

The production increase due to the new zones exposed depends on a combination of geologic and formation stress factors whose uncertainties are very high.

The production increase due to bypassing of reduced permeability zone is dependent on the depth of the damaged zone and the ratio of damaged to undamaged permeability.

The production increase due to change in the flow pattern from radial to linear flow is a function of high conductivity fracture; i.e. extending long distance from wellbore.

Considering the Nkporo Geological and Engineering parameters generated and applying McGurre and Sikoro model in fracturation analysis; the following equations will be utilized in the generation of scaling factors used in the model development

$$\frac{wK_f}{K} = \frac{\sqrt{Reference\ well\ spacing}}{\sqrt{Specific\ well\ spacing}} \text{ ---------------------3.9}$$

$$\frac{J}{Jo} = \frac{3.095}{Log(0.472)(\frac{re}{rw})} \text{ -----------------------------------3.10}$$

Where J = Productivity Index after fracturing

J_o = Productivity Index before fracturing

r_e = Drainage Radius (ft)

K = Formation Permeability (md)

r_w = Well bore radius

w = Propped frac width; in

K_f = Permeability of the propant, md

w K_f = Conductivity of fracture, md in

$\frac{wK_f}{K}$ = Permeability Contrast

$\frac{J}{Jo}$ = Productivity Index Contrast

X_f = Fracture length,ft

L_R = Dimensionless fracture length = $\frac{X_f}{Xe}$ ---------------------(3.11)

C_r = Dimensionless fracture Conductivity(radial patern) = $\frac{wKf}{\prod X_f K}$ ---------3.12)

Poison Ratio = 0.34

Nkporo Shale Formation rock Density(ρ) = 144lb/ft^3

$$Q_D = \frac{0.8936QB}{\emptyset C_t \, h X_f^2 \, (\mathrm{Pi} - \mathrm{Pf})} \text{ -------------------------(3.13)}$$

Where

Q_D	=	Dimensionless Cummutative production
Q	=	Cumulative Production mcf
B	=	Formation Volume Factor, res bbl/mcf
Ø	=	Total Porosity,fraction
C_t	=	Total Compressibility, psi
h	=	net pay, f t
X_f	=	Fracture half length,
P_i	=	Initial Reservoir Pressure
P_f	=	Flowing bottom hole pressure, psi.

$t_D = \frac{0.0002637Kt}{Ø\mu Ct\, X_f^2}$ ---------------------------------- (3.14)

Where

t_D	=	Dimensionless time
t	=	Time, hrs
K	=	Formation Permeability, md
µ	=	Reserve Fluid Viscosity, cp

Conductivity

$C_r = \frac{wK_f}{\prod X_f K}$ -----------------------------3.15

C_r	=	Dimensionless fracture conductivity(radial)
w	=	Propped fracture width, ft
K_f	=	Fracture Permeability, md

Dimensionless Length(radial) L_R = Xe/Xf ----------(3.15)

Where:

X_e = Distance to drainage boundary, ft

X_f = Length of one wing of the fracture ft

1.3 Aims and Objectives of the Study

1. To determine the hydrocarbon reserves in place for the Nkporo Shale Gas (unconventional) formation in Nigeria.
2. To determine the technical criteria for the optimal exploitation of the hydrocarbons.

1.4 Significance of the Study

Much work has been carried out on the Geophysics, Geochemistry, and Geology of Nkporo shale formation ,while Petrophysics and Engineering data are sparse. This study focused on scope for increasing Nigeria gas reserves significantly from unconventional sources. The study will act as a platform for further research work or enhancement on the area of Shale exploration/exploitation in Nigeria and globally.

There are very few dedicated gas exploration wells in Nigeria. Most gas discoveries are associated with the search for oil. The current demand for LNG and power sector is creating a supply interest for gas and encouraging increase in the exploration and exploitation process.

Most operators are currently exploiting than exploring the conventional hydrocarbon reserves, hence reserves replacement rate is very low when compared with the production due to the current oil price. Nkporo shale formation though unconventional reservoir, if explored and exploited, will significantly increase our gas reserve and will halt the current rate of decrease in our reserve. This development will increase the Nation's energy security, fueling job growth and strengthening local economies.

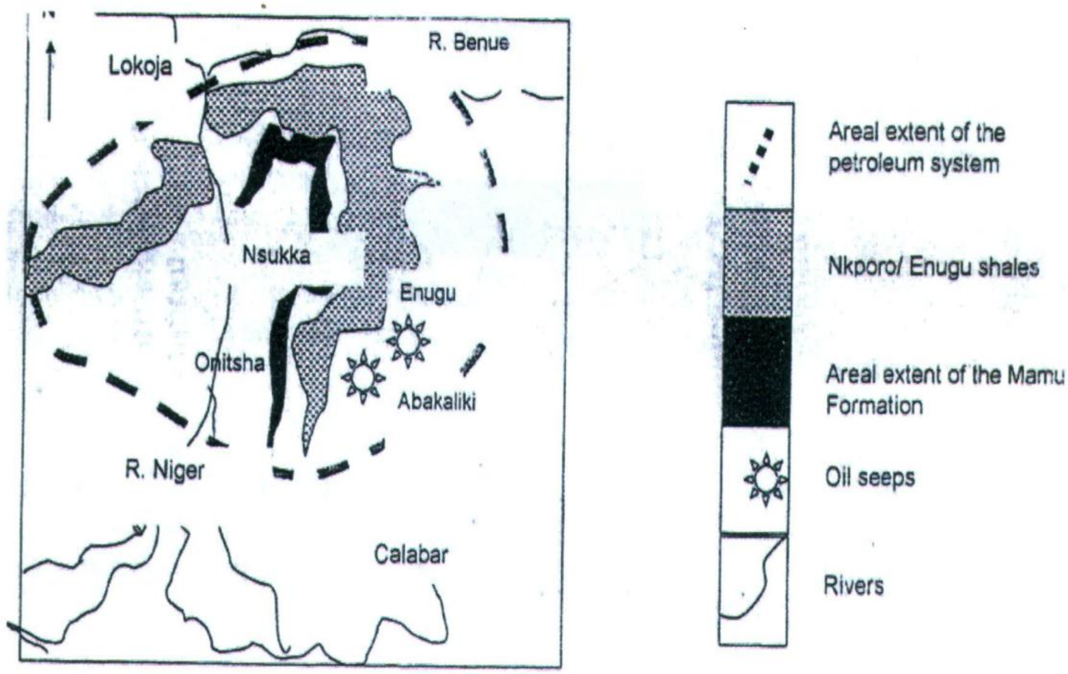

Fig:1.4 Petroleum System Map of the Anambra Basin showing pods of active source rocks(Modified after Akaegbobi et al 2000)

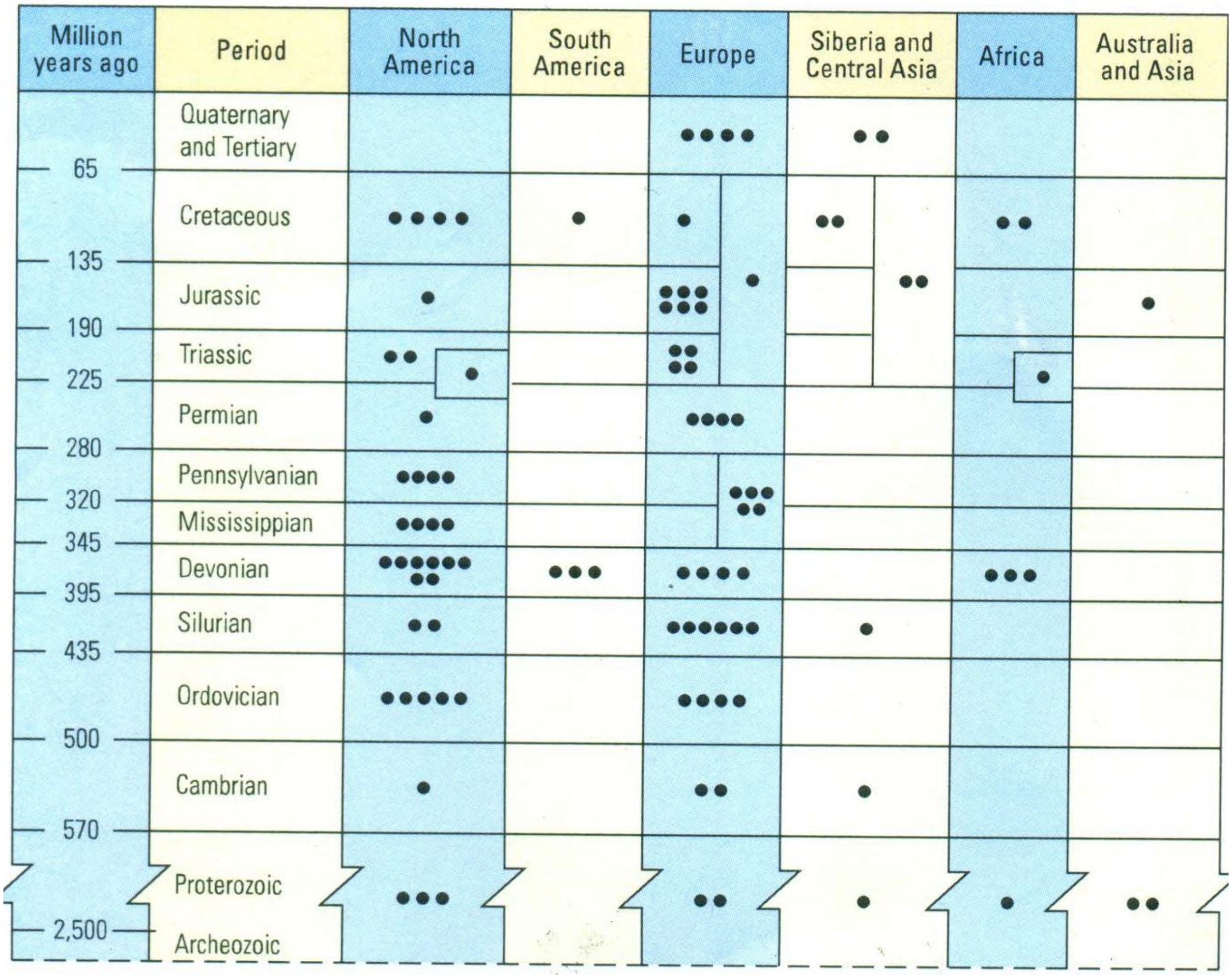

Fig:1.5 Global and Stratigraphic Distribution of Marine Organic rich sediments(Adapted from Tourtelot, Oilfield Review,2011)

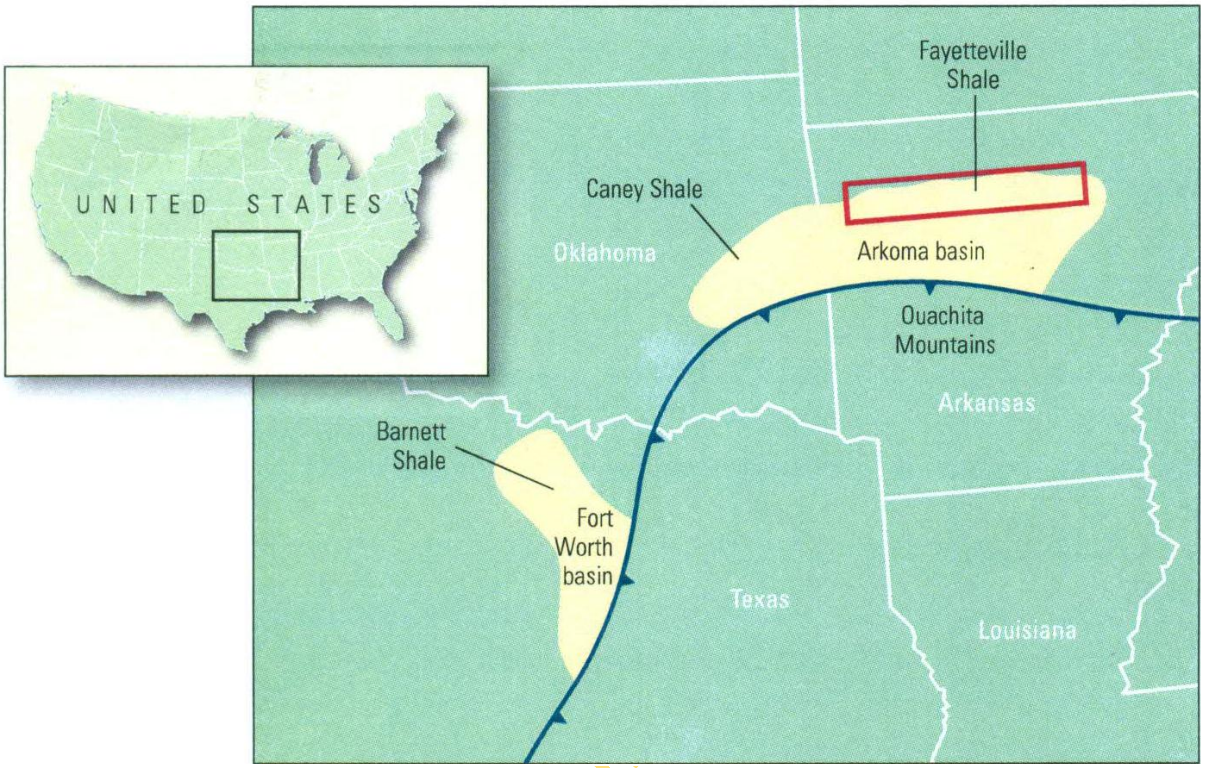

Fig:1.6 Fayetteville Shale, Arkoma Basin, developed by Southern Energy in north central Arkansas,USA(Shale Field Examples in Operation).(Oil Field Review,2011 Extract)

The huge hydrocarbon deposits discovered in the Niger Delta contributed immensely in slowing down the rate of exploration in Anambra basin/Benue trough including Shale Gas/oil formations. . Furthermore, many wells have been drilled successfully in the Niger Delta with attendant reduced risk of exploration and exploitation, unlike Anambra basin/Benue trough where the risk involved discourages investors. Increase in unconventional oil and gas reserves in addition to reserves in Anambra basin could reduce risks and attract more investors. This can further be enhanced with increasing gas demand and price.

1.5 Justification of the study

The study will answer the following questions

1. Is there existence of unconventional Shale Hydrocarbon formations in Nigeria?
2. What are the Petrophysical and Engineering properties of this typical Shale formation in Nigeria that is being studied, considering non- existence of such data from the literature review?
3. What is the current possible reserves of such hydrocarbon in place and which technology are available to exploit it?
4. How can the reserves be economically recovered in Nigeria?

Nigeria will be a benefactor if such formation like Nkporo shale is explored and exploited. This will increase the Nation's energy security, fueling job growth and strengthening local economies. Natural gas extracted from dense shale rock formations such as Nkporo shale formation will soon become the fastest additional growing source of gas in Nigeria and could become a significant new global energy source especially in this era of Shale Gas/Oil boom. This also will further reduce depletion stress on current conventional reserve.

The Nigerian natural gas resources are classified into conventional and unconventional.

Conventional gas involves extraction of the natural gas through conventional means.The process includes drilling and completion, producing using natural pressure from different drive mechanism affecting the wells by pumping or compression. Enhanced recovery technique or artitificial lift may apply to boost production. Any other gas reserve that can currently be produced by hydraulic fracturing or through pyrolysis such as Nkporo gas are dominantly unconventional reserves.

The gas reserves are defined based on either economics and technology needed to extract it or some absolute measure of the permeability of the source rock.

Further reserves classifications are explained using McKelvey box shown in Fig1.7 and Table 1.1

Table:1.1 Brief Description of resource and reserves for Natural gas.(Mcglade,et al;2013)

Name	Short Description	Include Gas in Undiscovered Formations	Include Gas Not Economically Recoverable with Current Technology	Include gas not Recoverable with Current Technology	Include Gas that is not expected to become recoverable
Original gas in place	Total Volume present	X	X	X	X
Ultimately recoverable Resources	Total Volume recoverable over all times	X	X	X	
Technically recoverable resources	Recoverable with current Technology	X	X		
	Economically recoverable with current technology	X			
1P/2P/3P reserves					

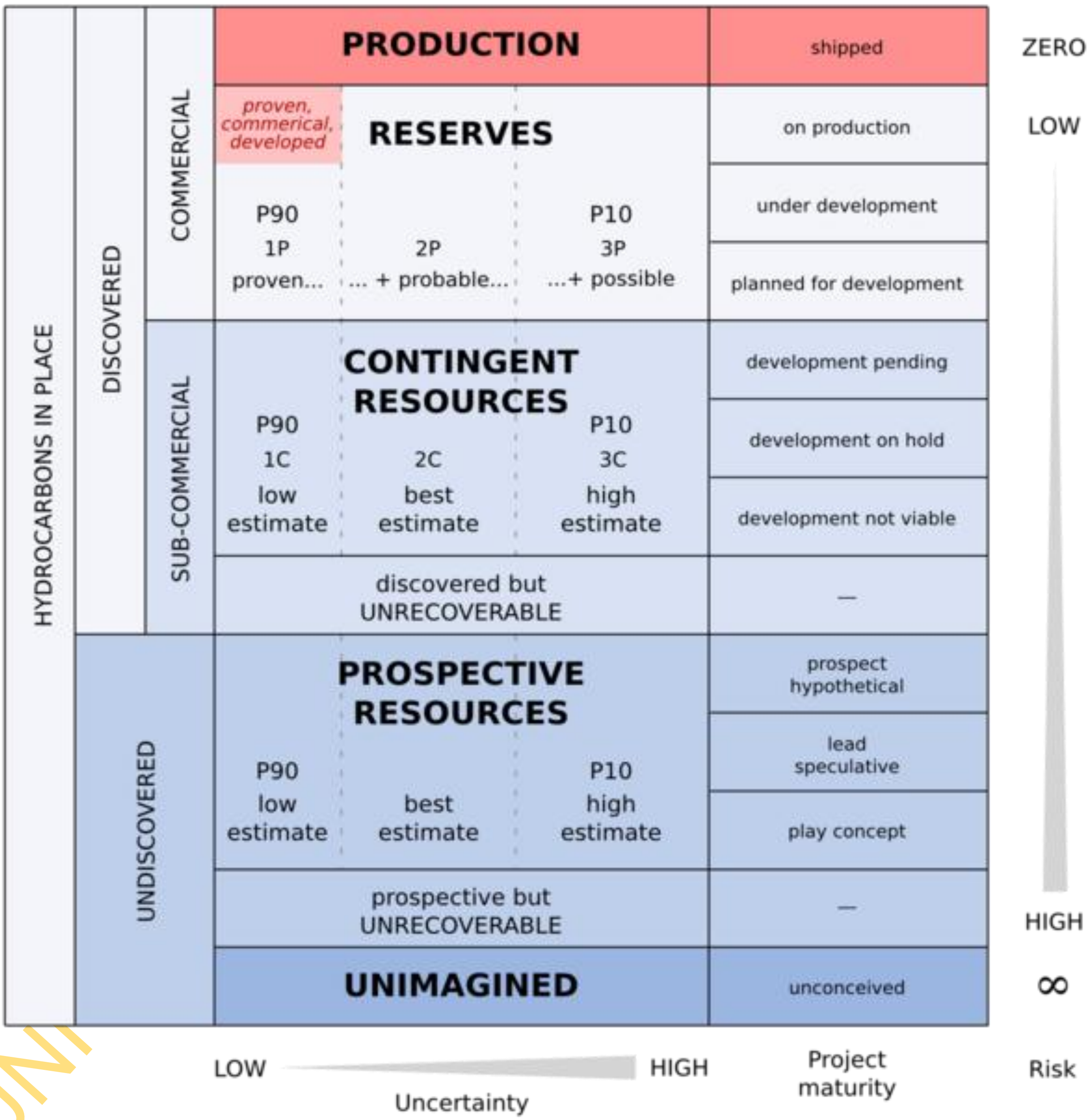

Fig:1.7 McKelvey box of resource classification for unconventional gas(Mcglade,et al;2013)

Most of current Nigerian gas production is predominantly conventional located partly in Niger Delta and Anambra Basin/Benue Trough through different drive mechanisms such as gravity,solution,water,lifts,etc. Tight gas sands which sometimes could be classified as partial unconventional resource depending on the permeability/porosity extremities exist also in Niger delta.The unconventional gas reserves such as Shale gas,Coal Bed Methane(CBN) are yet to be exploited.

The energy industry has long known about huge gas resources trapped in shale rock formations in United States of America(Whiteman,2005). USA processes more than 2500 trillion cubic feet of gas reserve and 33 percent of this gas is held in shale rock formations and is projected to increase to 50% by 2035.The cost of technology transfer in the area of Shale Oil/Gas from the developed Countries like USA, China, etc; are becoming cheaper unlike in the early days when such venture is highly uneconomical. The current production from these global Shale formations is threatening OPEC conventional Oil/Gas sales. Nigeria with her high Shale Gas/Oil reserve potential, has not taken off in the process of benefitting from this boom. This study will act as a stop gap.

CHAPTER TWO

LITERATURE REVIEW

2.1 Oil/Gas Reserve Situation in Nigeria

The rate of decrease in oil and gas reserves in Nigeria cannot be underestimated. The Nigerian economy is monolithic with petroleum (oil and gas) being the dominant foreign exchange earner for Nigeria. The rate of production increase is far higher than that of reserves replenishment. The current oil reserves is less than 40 billion barrels while the current gas reserve is about 187TCF. There is need for our national reserves to increase at the rate higher than that of production. Many basins remain untapped in Nigeria including Anambra Basin, Dahomey and Benue Trough. Nigeria is projecting to move from the 7th to 4th position with the largest gas reserve globally(Ige, 2008). The proposed increase in gas reserve cannot be achieved without intensive exploration and exploitation of the unconventional Gas. The most dominant unconventional gas formation is shale (Onyekuru and Iwuagwu ;2010). These formations are coniacian Afowo Shales (Dahomey Basin), Lokpanta shales of the late Cenomanian – Turonian Eze-Aku formation of the Anambra Basin, Araromi shales (Dahomey Basin), Enugu/Nkporo/Mamu shales (Anambra Basin). Imo and Agwu shales are also in this category; (Onyekuru and Iwuagwu;2010). The Pre-Santonian sequences will generate and expel significantly earlier than Campanian – Danians sequence. The best oil intervals lie within the Cenomanian – Coniacian sequence and these are being traced into the Middle and Upper Benue Basin(Olawoki;2009). Volumetric estimate from the available Cenomanian – Coniacian data set showed that the oil reserve in Lokpanta shale unit is about 260,000,000 barrels, while that of Afowo shales in the Dahomey Basin is up to 398,000,000 barrels. Schmaker (1994) methods were used for the volumetric calculation; (Akaegbobi,.et al;2000). None of these reserves are being listed by Energy Commission of Nigeria as highly authentic due to presence of very high risk data that were used in their evaluation and the low number and limited spread wells drilled. Detailed petrophysical and Engineering analysis are non available. Much geological, geochemical, research work had been carried out on these basins with little petrophysics work due to lack of high spread and sufficient logged wells existing in many of these areas. Many of the drilled wells were not cored due to risk cost. There is very minimal reservoir Engineering work performed on the basins. The study will cover the shale formations of santonian to Maatrichtian sediments. The major shale formation Nkporo will be the center of the study because of the prominency especially containing very high potential organic matters that spans through a large sub-surface area from Anambra Basin to lower Benue Trough.

Nkporo shale characterization shows the presence of abundant gas prone formation (Ehinola and Sonibare;2005). The geology of the shale formations has been studied by notable workers. Reservoir Engineering Analysis technique will be employed to estimate the reserve and also researching the best way of exploitation including the economic implications. Studies showed not much work has been carried out on these shale formations involving Reservoir Engineering Analysis. Lack of reservoir engineering data is one of the challenges in the study. Analogue data may be employed where necessary. Some of the research work published showed that Nkporo shale constituted the main source and seal rocks of shale base and that the percentage of the organic carbon of the santonian shales was quite comparable to those of the nearby Niger Delta. (Unomah and Ekweozor;1993) have assessed the petroleum source rock potential of the Nkporo shale in Calabar flank using organofacies analysis to be rich with oil prone marine derived organic matter which will not be economical considering the cost of exploitation. Meanwhile a similar analysis for Anambra basin/Afikpo syncline is gas prone (Ehinola and Sonibare;2005).

Table 2.1: Nigeria's Energy Reserves/Capacity as at December 2013)

ENERGY SOURCE	RESERVES
Crude Oil(Conventional)	37billion barrels
Natural Gas (Conventional)	187TCF
Tar Sands	30 billion barrels of oil equivalent
Coal and Lignite	>4billion tonnes
Large Hydropower	11,250MW
Small Hydropower	3,500MW
Fuel Wood	13,071,464 Hectares
Animal Waste	61 million tonnes/yr
Crop Residue	83 millions tonnes/yr
Solar Radiation	3.5-7.0 KWh/m³
Wind	2-4m/s at 10m height

Source: Energy Commission of Nigeria,2013

1barrel of oil = 0.136 tonnes of oil

100m³ of natural gas = 0.857 toe

1Tonne of coal =0.223toe.

1Km² =247.105acres

1square mile =640acres

The older lower Benue Abakiliki Basin, shales of the Albian Asu River group, the Cenomanian – Turonian Ezeaku shales including the “oily” Lokpanta shale member and those of the Turonian – Coniacian Agwu formation constitute the source rock of interest (Unomah and Ekweozor 1993). Proto-Niger Delta successions of the Paleocene Imo-formation Ameki and Ogwashi formation belonging to the fourth cycle of sedimentation are exposed on the northern fringes of the Niger Delta. Previous source rocks studies showed the dominance of terrigenous kerogene assemblages with proven source potentials. (Bustin, 1988, Ekweozor and Okoye, 1980). The middle Benue Basin source rock facies are represented by the shales of the regionally continuous Asu River Group. Following the overlay is the second transgressive and regressive cycle which deposited the name marine to marginal marine facies of shales, claystones and coals of the Agwu formation with proven source potentials (Obaje, 2004a and b). Further studies will be carried out on the geology thru petrophysics as part of the Reservoir Management prior to the Engineering determination of the gas reserve in place .The best method of exploitation will be recommended prior to carrying out an economic evaluation.

The Research design and methodology forms the strategy of the work. These will cover a thorough Reservoir description required to describe the resource in place and the research potential. Proper reservoir characterization will be carried out which involves the use of acquired data along with the structural framework from sensitive interpretation to identify and characterize the mechanisms controlling production and development optimization. The simple Reservoir modeling will apply in-order to validate the reservoir description and characterization required for accurate prediction of future performance. The proper drilling and completion technique studies will be carried out including the formation damage impact that are necessary for an effective and efficient reserve evaluation. The Health, Safety and Environmental risk will be mentioned prior to the economic evolution of such exploration/exploitation projects. The impact of reserve decline when compared with our rate of production will soon create a devastating petroleum scarcity which will impact on our health, safety and environment. The risks associated with Petroleum scarcity are known, many specifics remain elusive.

There is need to evaluate the most effective policy solutions to support sound planning, preparedness, and adaptation. Similar research has been carried out in developed countries to determine the rate of decline methods to adjust to less energy use, sensible alternative such as unconventional sources like shale oil and Gas that will not exacerbate environmental challenges; the reasons necessary to implement alternatives; and the timing of their implementation. We should be able to forecast, predict and adapts and to study how various polices can dampen or amplify risk. Similar work on Fiscal policies required to create enabling economic environment for both government and investors intake has been carried out by experts such as Isehunwa;et al(2009). Most peak production will signal long production decline marked by abrupt shortages and reliance will increasingly shift to hard-to-get reserves with a higher risk of environmental damage. The "Age of Tough Oil and Gas is looming. The management of the challenges from less expensive, higher quality sources to more expensive, lower quality sources that carry higher risk of environmental damage such as oil spills and climate change (Campbell et al, 1990). The challenges experienced in the Gulf of Mexico by Deep Water Horizon oil rig beginning in April, 2010, resulted to the worst oil spill in U.S.A. history demonstrating the increasing difficulty, cost and environmental risk associated with the remaining conventional petroleum resources as well as the limits of technology's effectiveness in efforts to maintain production rates, enhance safety and protect the environment. The work done by Isehunwa, S.et al(2013), on Natural Gas pipeline leakage early detection using pressure transient analysis approach will prevent future spill during the exploitation phase;thereby reducing environmental risk.

The importance of exploring and exploiting these unconventional petroleum resources such as the Nkporo, Agwu and other shale formations cannot be over-emphasised. Shale Oil/Gas production will boost global economy by $2.7tr by 2035. Nigeria should strategise now to be involved in this economic boom.

2.2 Reservoir Description/Characterization

2.2.1 Geophysics/Geology/Geochemistry

The Nkporo shale Gas formation straddles from Anambra Basin to lower Benue trough with Campano-Maastrichtian geological origin. The Campano-Maastrichtian Nkporo Shale is highly exposed along Enugu to Portharcourt highway through Leru in Anambra Basin complex which overlies the Lowerer Benue Trough. (Okoro; 2009). Previous studies by Ekweozor et al;1983, Akande and Erdttmann;1998, Akaegbobi and Schmitt;1998 confirmed the presence of Post folding Camponian-Maastrichtian paralic shales of the Enugu and Nkporo Formation with coal measures of the Mamu and Nsukka formations and fluviodeltaic sandstones of the Ajali Formation.

The Anambra Basin Structure is made up of Post-Santonian Synclinal Sedimentary, containing over 5 to 6Km thickness of Upper Cretaceous to recent sediments; representing the third phase of marine sedimentation in the Benue Trough (Ladipo,1988; Akande and Erdttmann,1998). The Anambra Basin covers 40,000Km square.(Bassey and Emime,2012). The Stratigraphic succession of the Anambra Basin comprises of the Campanian to Maastrichtian Enugu/Nkporo/Owelli Formations(lateral equivalents)(Ojo et al 2009). This is sequentially followed by Maastrichtian Mamu and Ajali formations which is capped by the tertiary Nsukka Formation and Imo Shale(Petters,1978; Agagu et al,1985; Reijers,1996). The lithology indicates deltaic progadation during active delta growth(Ojo et al,2009).

The Nkporo Shale is made up of dark grey and highly fissile shale with interbeds of sandy shale, siltstone and mud stone(Ehinola et al,2005). Akaegbobi and Schmitt,(1998) also observed along Enugu-Port-Harcourt Expressway where the facies are dominated with mudstones resulting in blocky fissility.

The Total Organic Carbon(TOC) ranges from 0.54 to 4.42wt% which is more than the minimum value of 0.5wt% required for potential petroleum source rocks. The Soluble Organic Matter Content(SOM) ranges from 578 to 1931ppm(Ojo et al,2009). Nkporo Shale formation has a low Hydrogen Index range of 20 to 153mgHC/g TOC; revealing Kerogen of Type III mixed with III/II Organic matter; which is predominantly gas prone.

The finding that Nkporo Shale is dominated by type III/II Kerogens with terrestrially derived Organic matter dominance in Anambra Basin was further supported by Akaegbobi and Schmitt,1998. The Tmax and Production Index(PI) range of 426 to 439^{o}C and 0.02 to 0.08 respectively showing that the Nkporo Shales are presently thermally immature. The Geochemistry Of Nkporo shale showed the prospects of gas generation rather than oil(Ehinola et al,2012). Nkporo Shale from previous studies showed exhibition of average hydrocarbon Pyrolytic yield (S_1 +S_2) > 2000ppm hydrocarbon showing the fair to moderate hydrocarbon source potential. S_1 the first peak is the hydrocarbon already present in the sample(Rock-Eval pyrolysis) which are mainly stripped at temperature of above 300^{o}C while the S_2 the second peak represents the hydrocarbon generated from thermal cracking the kerogene between 300-550^{o}C. The S_3 represents the CO_2 generated during the same cracking. The Genetic Potential is S_1/S_1 + S_2 whose value is used for the classification of oil,gas/condensate prone rocks(Fig 2.1).Nkporo Shales constitute the main source and seal rocks in Anambra basin/Lower Benue Trough(Ekweozor and Gormly,1983).

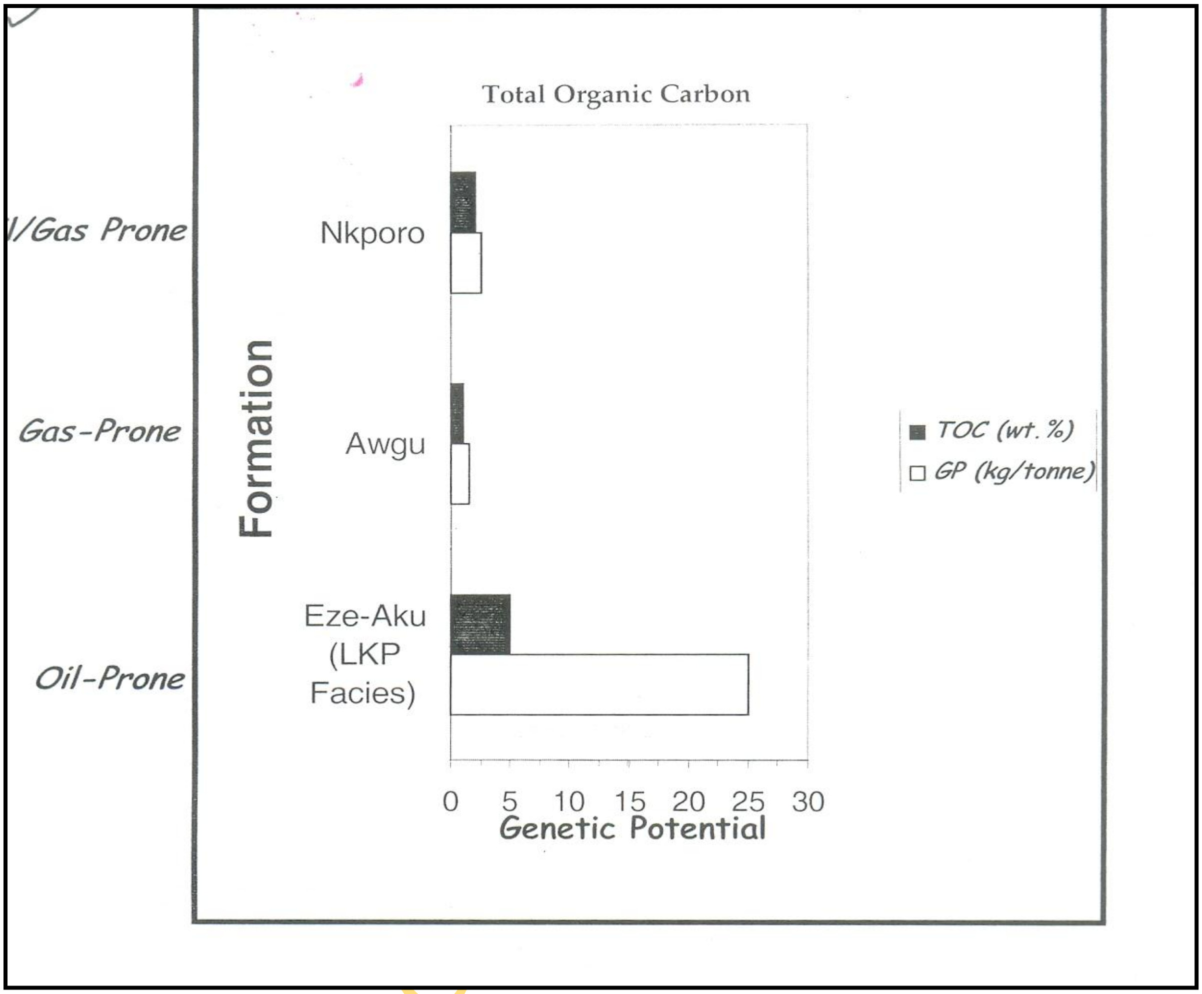

Fig:2.1 Genetic Potential for the source rock units of the Ezeaku, Awgu and Nkporo Formations (Ekweozor,2006)

Table: 2.2 Global Benchmark of Total Organic Carbon versus Source Potential for the Shale Gas formations.(Oilfield Review 2011)

TOTAL ORGANIC CARBON, WEIGHT %	RESOURCE POTENTIAL
<0.5	Very poor
0.5 to 1	Poor
1 to 2	Fair
2 to 4	Good
4 to 10	Very good
>10	Excellent

TOC(Total Organic Carbon) is one of the criteria in geochemistry used for preliminary assessment of Nkporo Shale source potential(Table:2.2). The Total Organic Carbon(TOC) ranges from 0.54 to 4.42wt% which is more than the minimum value of 0.5wt% required for potential petroleum source rocks. The Soluble Organic Matter Content(SOM) ranges from 578 to 1931ppm(Ojo et al,2009). Nkporo Shale formation has a low Hydrogen Index range of 20 to 153mgHC/g TOC; revealing Kerogen of Type III mixed with III/II Organic matter; which is predominantly gas prone.

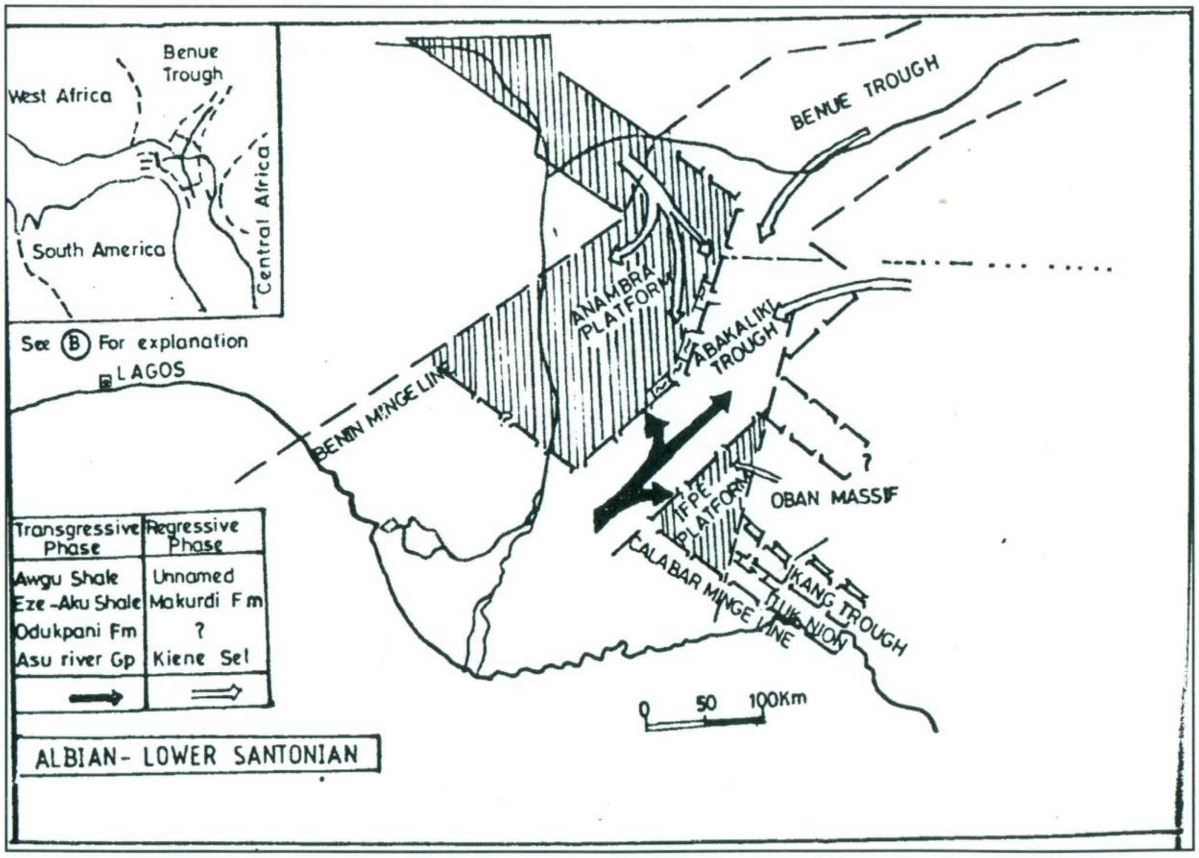

Fig:2.2 Tectonic Setting of the Anambra and Afikpo Sub-basin from the Albian-Santonian(Murat,1972)

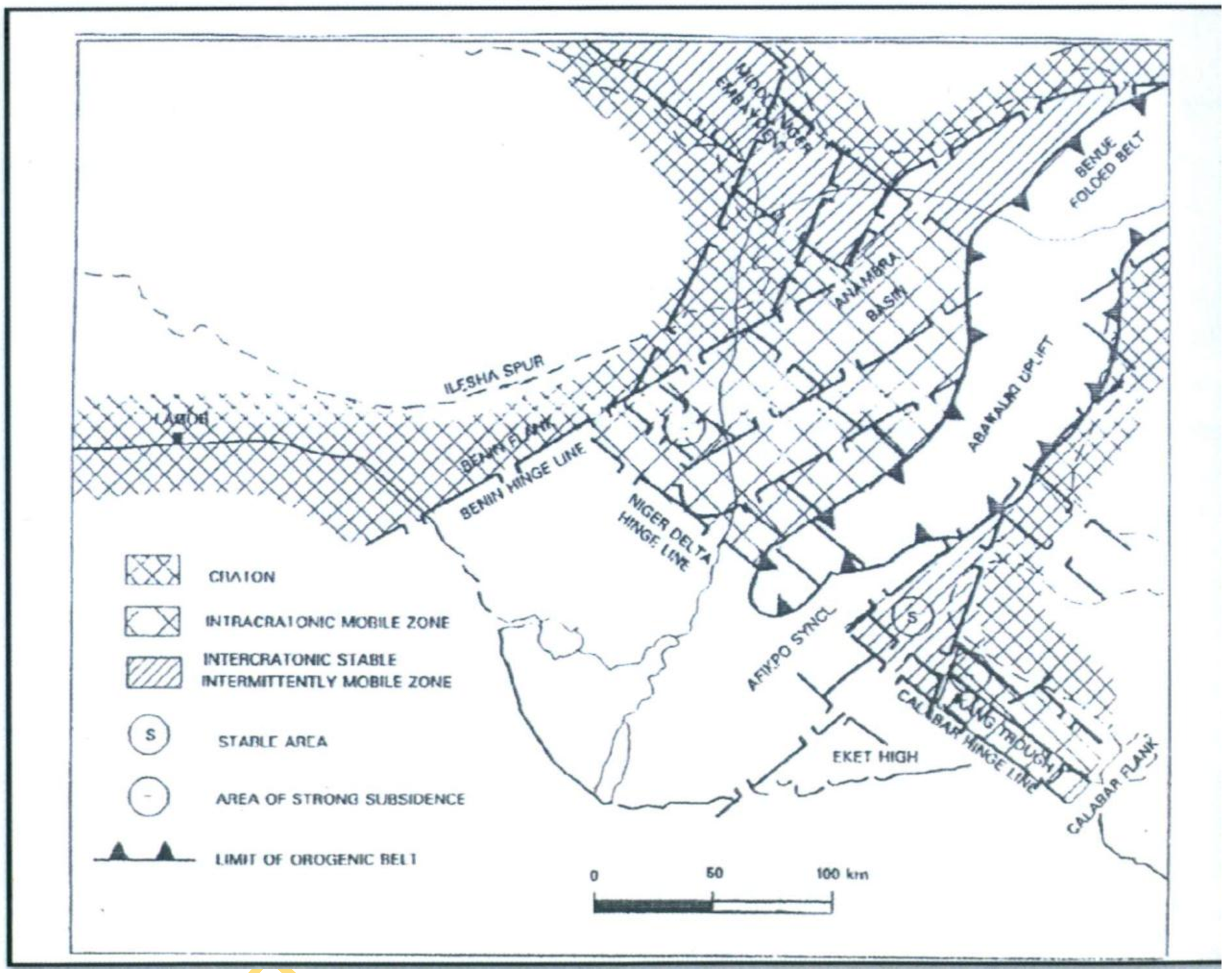

Fig:2.3 The Ancestral Benue Trough and Subsidence of the Anambra and Afikpo Sub-basin from the Campanian-Maastrichtian(Murat,1972)

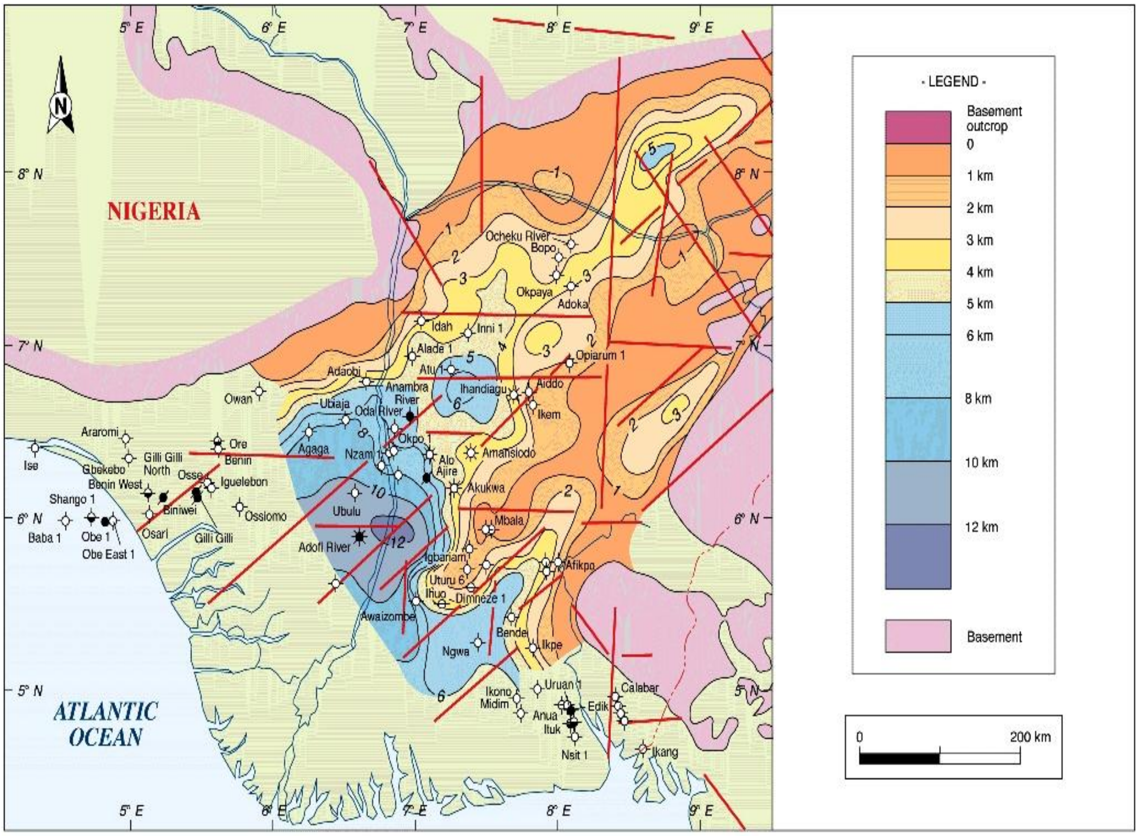

Fig:2.4 Map of Sedimentary Thickness of the Anambra and Neighboring Basins(International Hydrocarbon Services(IHS)(2010))

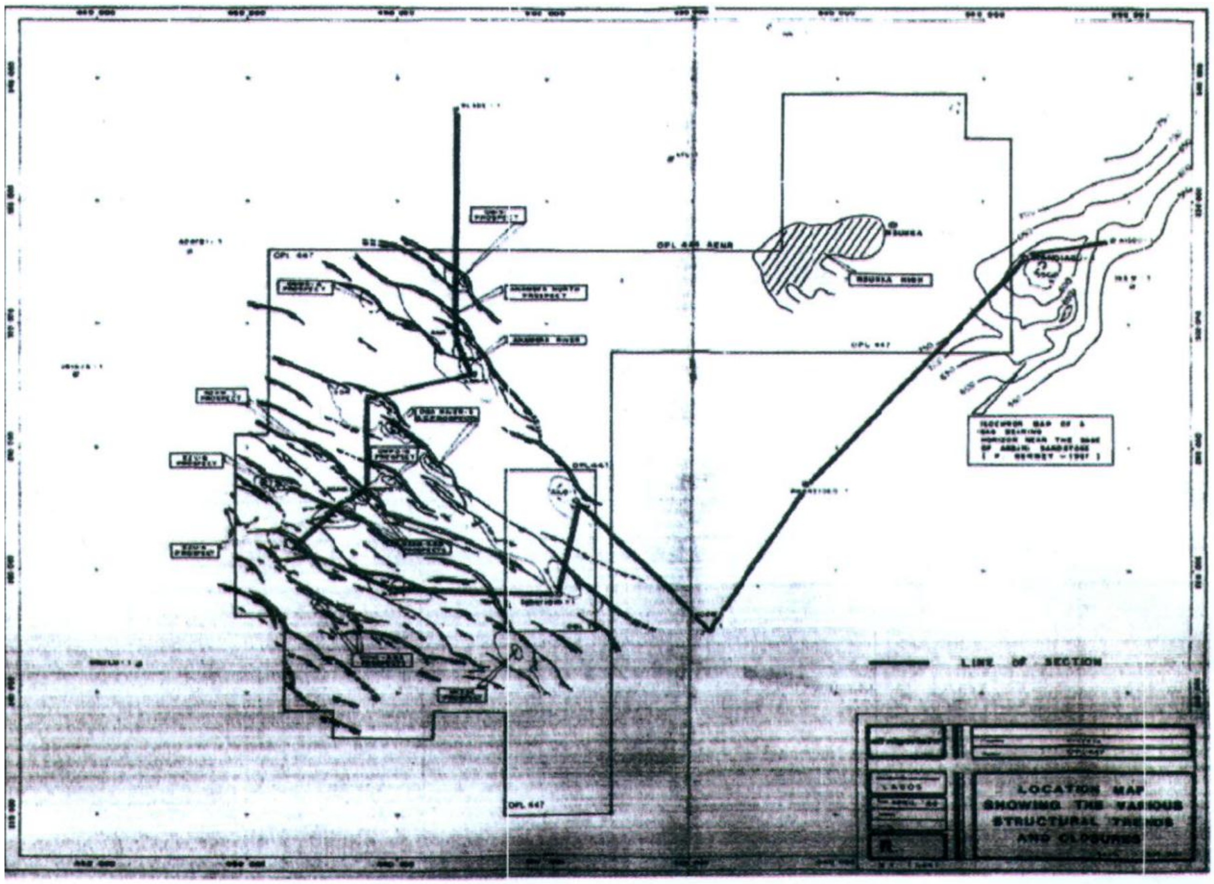

Fig:2.5 Regional Fault and Top Structure Map of drilled prospects in the Anambra Basin(Nigeria Frontier Service(NFS);2010)

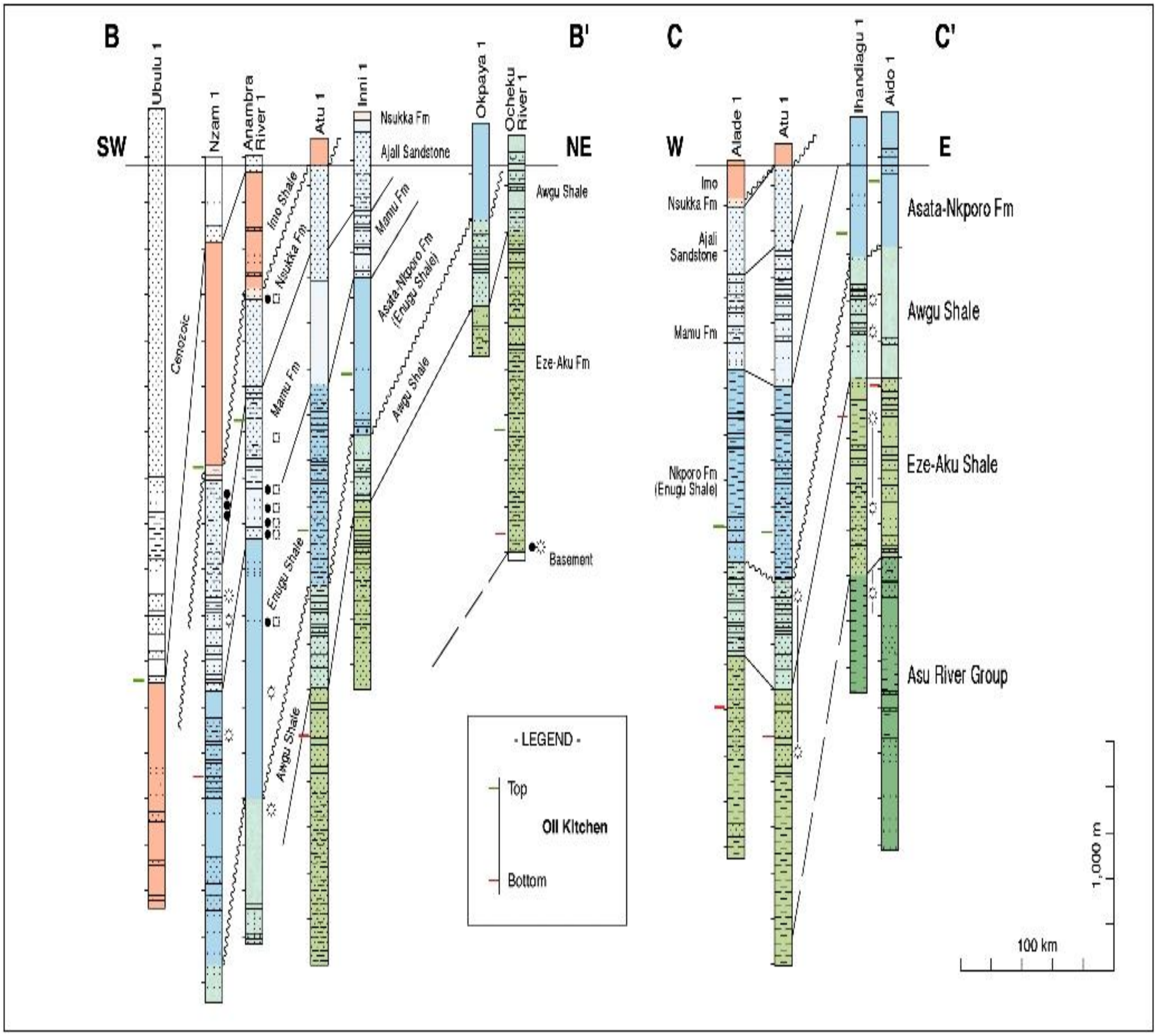

Fig: 2.6 Location map of Key Correlating wells in the Anambra Basin(IHS);2010

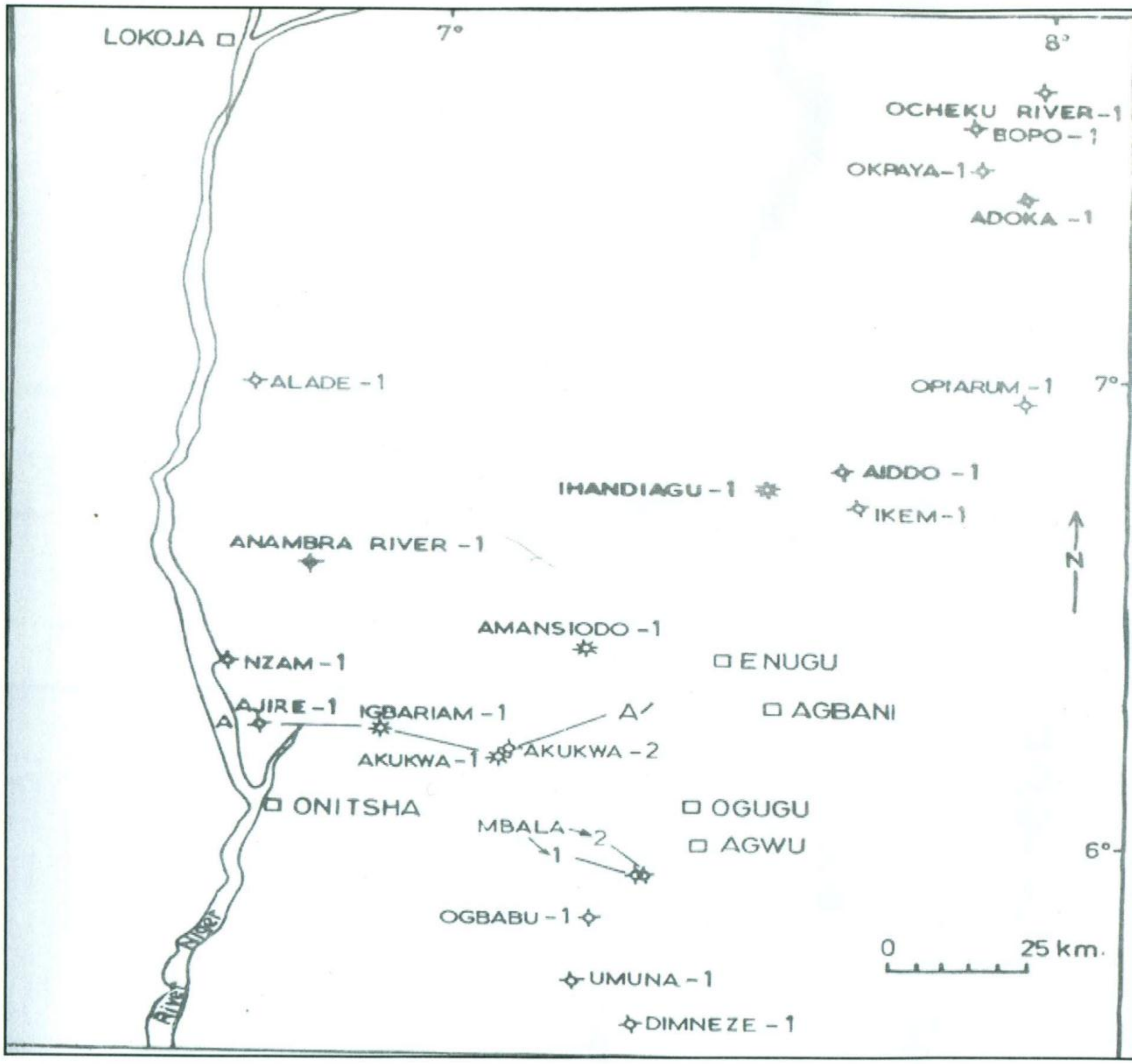

Fig:2.7 Location Map of some Oil Wells in Anambra Basin(Okoro;2009)

2.2.2 STRATIGRAPHY AND DEPOSITIONAL HISTORY

The Nkporo shale is the basal sedimentary unit that was deposited after the Santonian Folding and inversion phase of the Anambra Basin in SE Nigeria. The poor exposure of the unconfirmity relationship with the Abakiliki Antichnorum can be observed along Enugu-Okigwe Express way at Leru(Okoro; 2013). This is also confirmed by Ekweozor;1988, Akande;2007, and Akaegbobi;1998 in their earlier publications on the geological structure/chemistry of Nkporo Formation.

Nkporo shale formation is located with Anambra Basin that are closely tied to compressive event. It is a post-rift associated system which originated as a continental marginal sag Basin (Kingston et al, 1983) that opened up into the South Atlantic in the late Campanian following the Santonian "squeeze" which folded and inverted the Aptian – Coniacian sediment – fill of the Benue Trough. The Nkporo Shale is interpreted as a lowstand pro-delta to delta-front sequence, deposited at the shelf edge that was probably located at the "Onitsha High". The Nkporo formation has a double edge history behaving like a hydrocarbon Kitchen (source rock) at the early upper portions in Enugu area. The hydrocarbon generated migrated and were trapped inthe part of lower Nkporo-Shale formation that has significant pores acting as a reservoir with low permeability(Akaegbobi et al,2000).

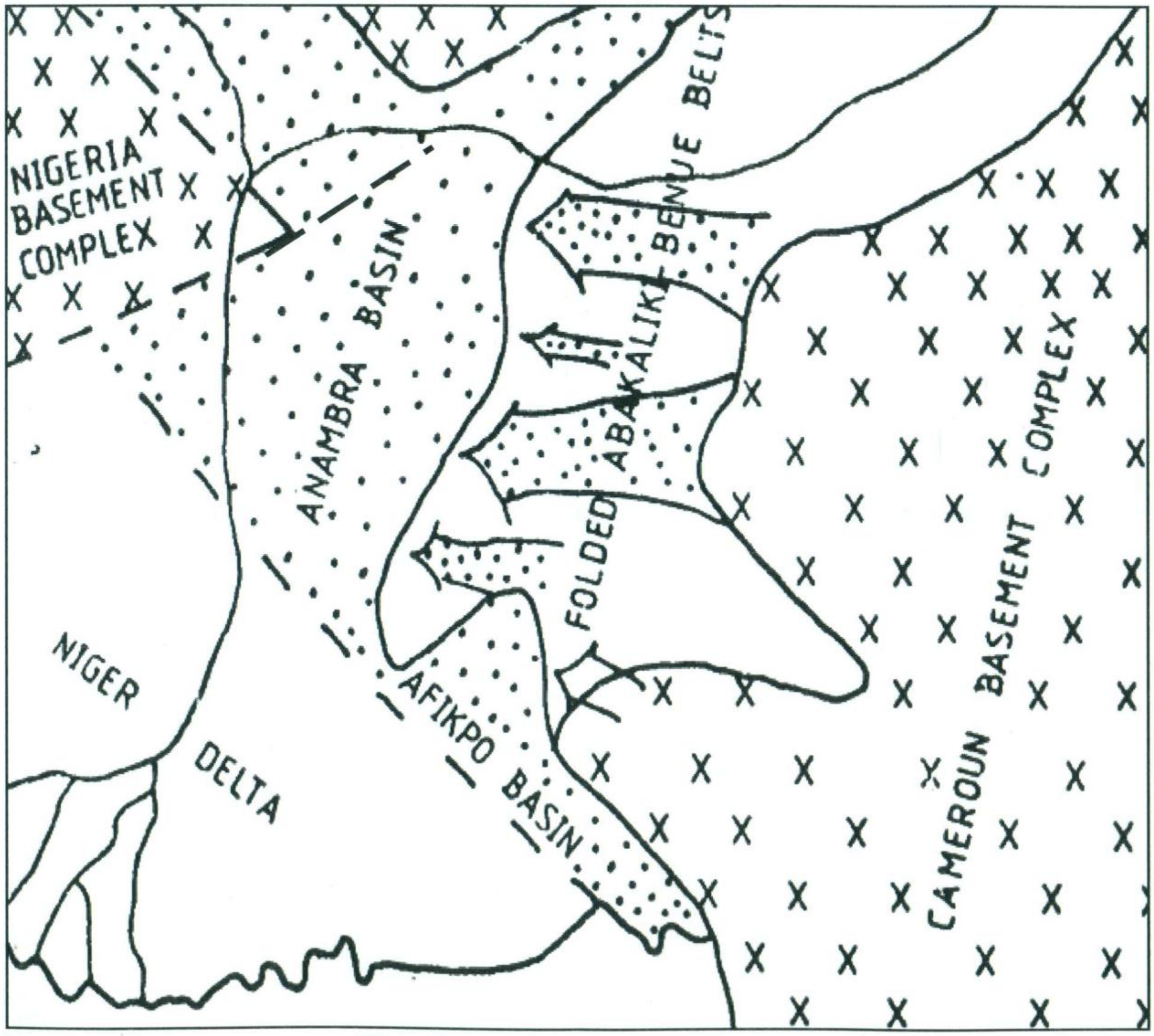

Fig: 2.8 Provenance Map of the Anambra Basin after the Santonian Squeeze(Kingston et al,1983)

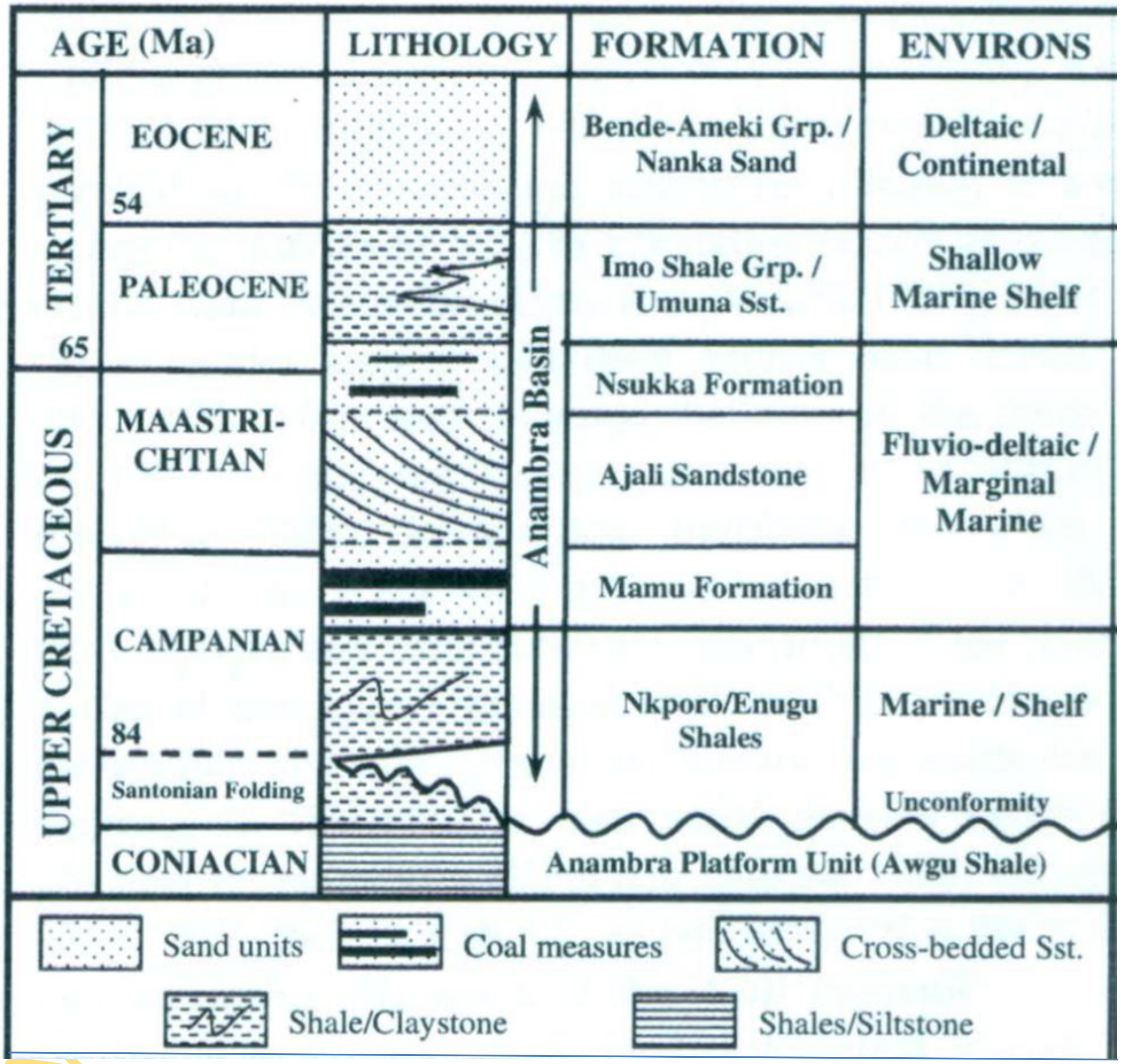

Fig:2.9 Depositional Environment of Stratigraphic Units of Anambra Basin(Tijani,et al; J 2008)

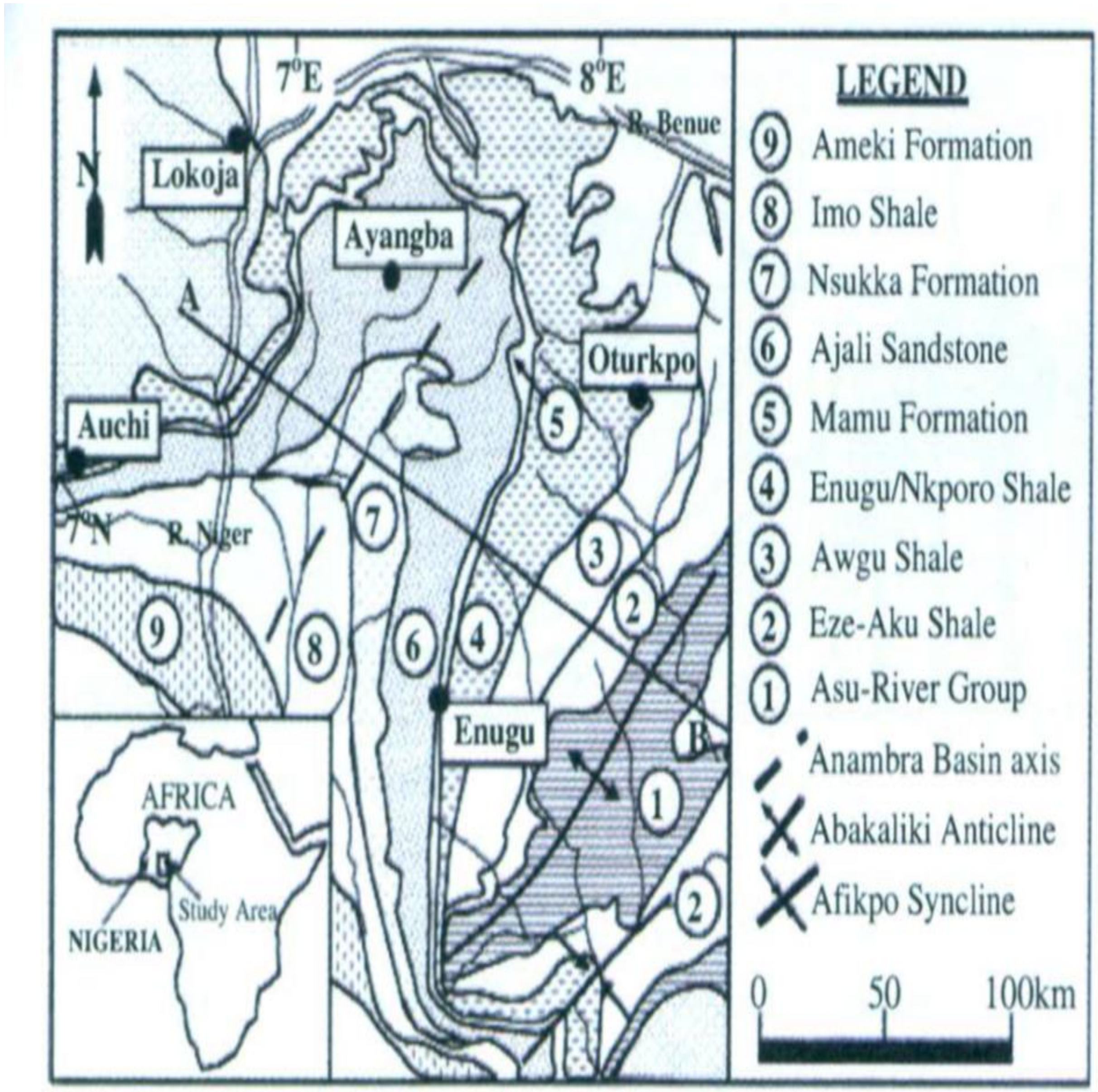

Fig:2.10 Geological map of Anambra Basin showing the different sedimentary Units.(Tijani,et al; 2008)

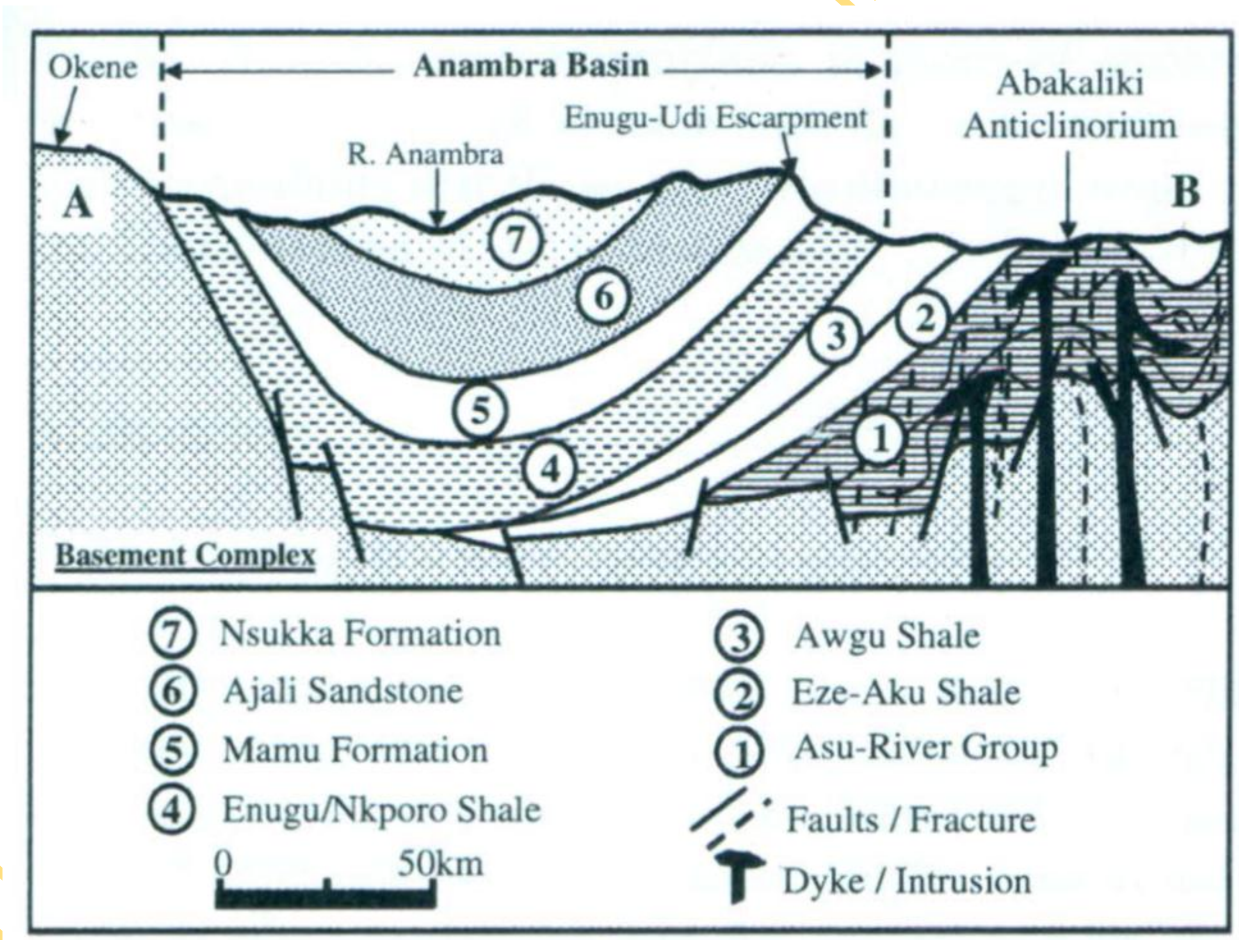

Fig:2.11 (Line A-B) Cross-sectional view of the Sedimentary units within the Anambra Basin.(Tijani,et al; 2008)

Table:2.3 Litho-facies and environment of Deposition (Zaborski 1983)

Litho Unit	Lithofacies	Sedimentary Structure	Biostratigraphy	Environment of Deposition
Upper Nkporo shale	Black to dark grey shales and mudstones carb, pyritic shelly lst, volitic ironstone and milriticlst	Horizontal laminations with occ. Siltstones interlaminations. Indication: Marine Environment	Bivalves, gastropods Foramsdynoflagelate cysts and pollens and spores	Shallow marine
Lower Nkporo shale	Shales and mudstones, dark grey – black, pyritic,gryps,ferous, sideritic and calcareous nodules	Horizontal Laminations,calcareous and sideriticnodules	Dwarfed Juvenile bivalves gastropods ammonites benthic forams, dinoflagellates cysts, pollens and spores	Anoxic shallow marine environment.

Hence Obaje (2004) showed that one of the main source rock facies in the Anambra Basin is Nkporo-Shale and they are terrestrial in origin from the analysis of biomarkers of n-Alkanes of lipid extracts. However, increased burial and consequent temperature increase could have pushed this source rock into maturity zone. The paleographic model by Akande, et al (1998), Akande (2000) suggests the limit of coal formation essentially to the northern part of Nkporo could be sufficiently high enough for expulsion. Coals have good potential to generate hydrocarbons with increasing depth of maturity and burial. Nkporo shale formation due to partial maturity is gas prone due to the low TOC(**Ekweozor,2006)**.

Fig 2.9 shows that Nkporo Shale formation is sanwitched between Mamu formation and Anambra Platform Unit (Agwu shale) whose Upper Cretaceous age fell between campanian and santonian folding. The lithology is interrupted with an uncomformity structure dominated by a marine/shelf environment. Figure 2.10 map showed the sandwitch characteristics of Nkporo Shale and the extension of this formation including the tappering end at the lower benue trough where Agwu and Ezeaku Shale formations fizzled out

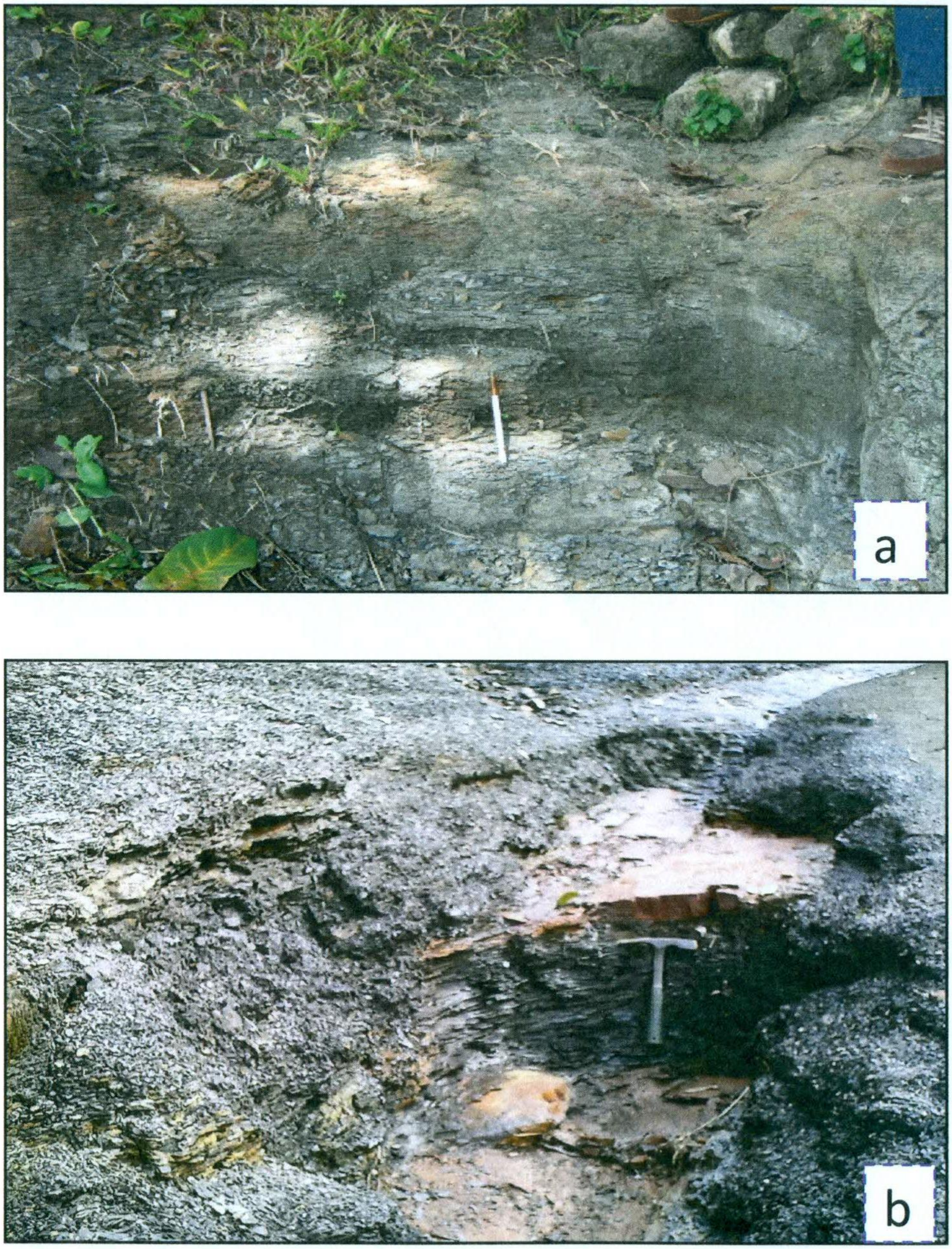

Fig:2.12 Source Rock Facies of the Nkporo and Enugu Formations(Okoro;2009)

Fig:2.12 contd Source Rock Facies of the Nkporo and Enugu Formations

Fig:2.13 **Organic laminated Shale of a Typical USA Shale Gas Field similar to Nkporo (Anambra Basin/Benue Trough) with TOC>2%(Oilfield Review 2006)**

Age		Benue Trough Lithostratigraphy	Anambra basin Lithostratigraphy	Afikpo Sub-basin Lithostratigraphy	Sedimentary Cycles
Cenozoic	Eocene		Nanka SS	Ameki Fm	3^{rd} Sedimentary Cycle
	Paleocene		Imo Fm	Imo Fm	
	Danian unconformity				
Late Cretaceous	Late Maastrichtian – Early Danian		Nsukka Fm	Nsukka Fm	2^{nd} Sedimentary Cycle
	Middle Maastrichtian		Ajali SS	Ajali SS	
	Early Maastrichtian		Mamu Fm	Mamu Fm	
	Late Campanian		Enugu Fm	Nkporo Fm	
	Santonian	Santonian Unconformity			
	Coniacian	Awgu Fm	Awgu Fm		1^{st} Sedimentary Cycle
	Cenomanian - Turonian	Eze-Aku Grp.	Eze-Aku Grp.	Eze-Aku Grp.	
	Cenomanian	Odukpani Fm		Odukpani Grp	
Lower Cretaceous	Albian - Aptian	Asu River Grp.	Asu River Grp.	Asu River Grp.	
Precambrian					

Fig:2.14 Lithostratigraphic Units of the Anambra-Basin(Okoro, 2009)

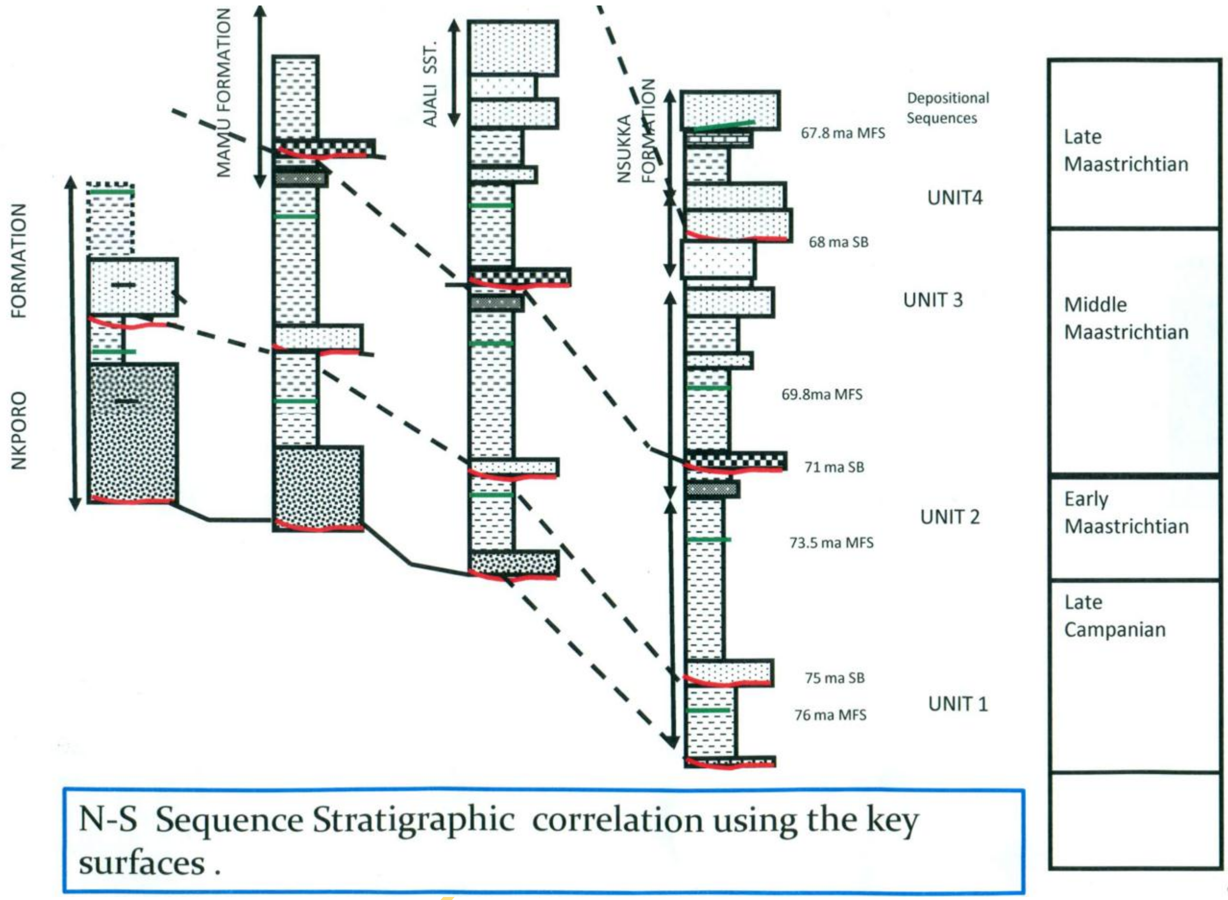

Fig:2.15(Okoro,A 2009)

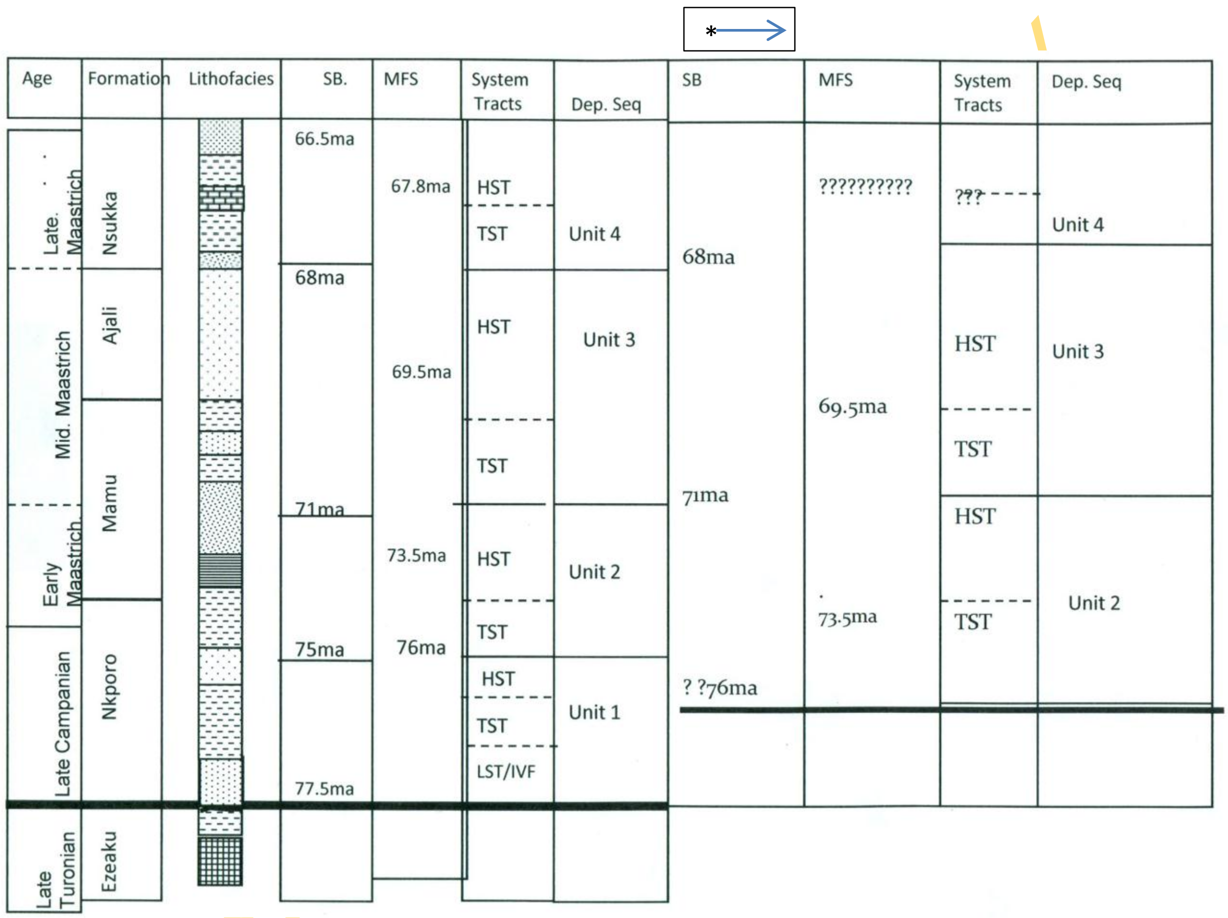

Fig:2.16 Sequence Stratigraphic Framework, Afikpo Sub-basin (after Okoro 2009)/Sequence Stratigraphic Framework, Anambra Basin(*after Nwajide,2005)

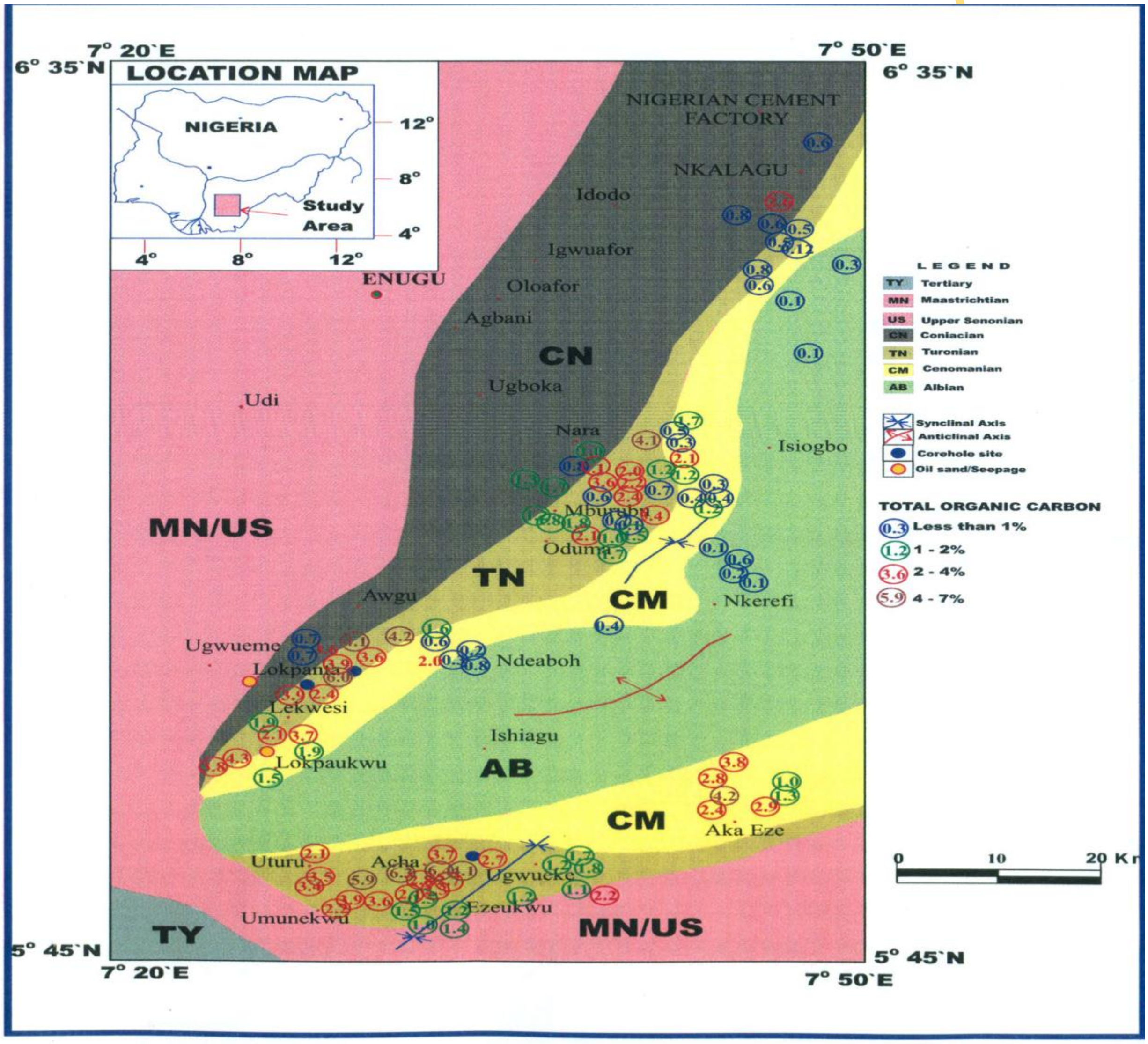

Fig:2.17 Lower Benue Trough Oil Shales Organic Carbon Map(Okoro, 2009)

- The main reservoir for the Anambra Basin discoveries are:
- Mamu(oil in Anambra River 1, Gas in Alo 1)
- Nkporo (Oil in Anambra R. 2; Gas in Alo 1, Igbariam 1 & Akukwa 1)
- Awgu Fm (Gas in Ihendiagu 1 and Amansiodo 1)
- Ezeaku Gp (Gas in Ihendiagu 1)

(after Avbovbo and Ayoola, 1981)

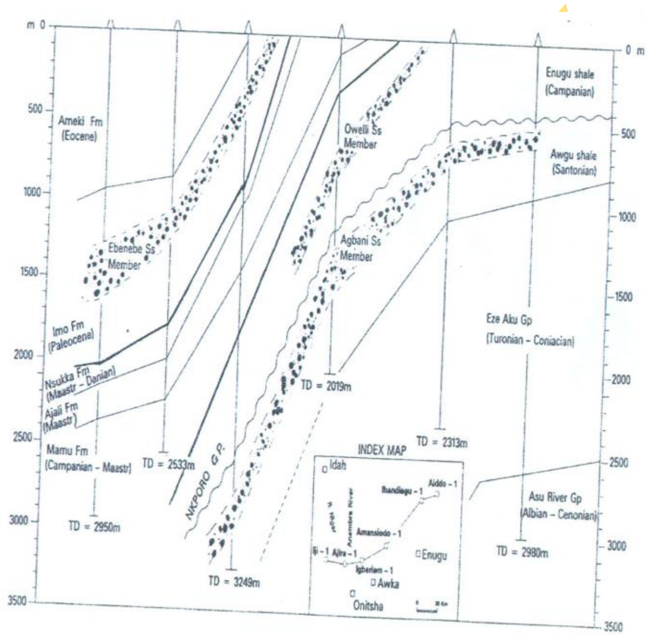

Fig 2.18 Reservoir Facies of the Anambra-Basin(after Nwajide and Reijers,1996)

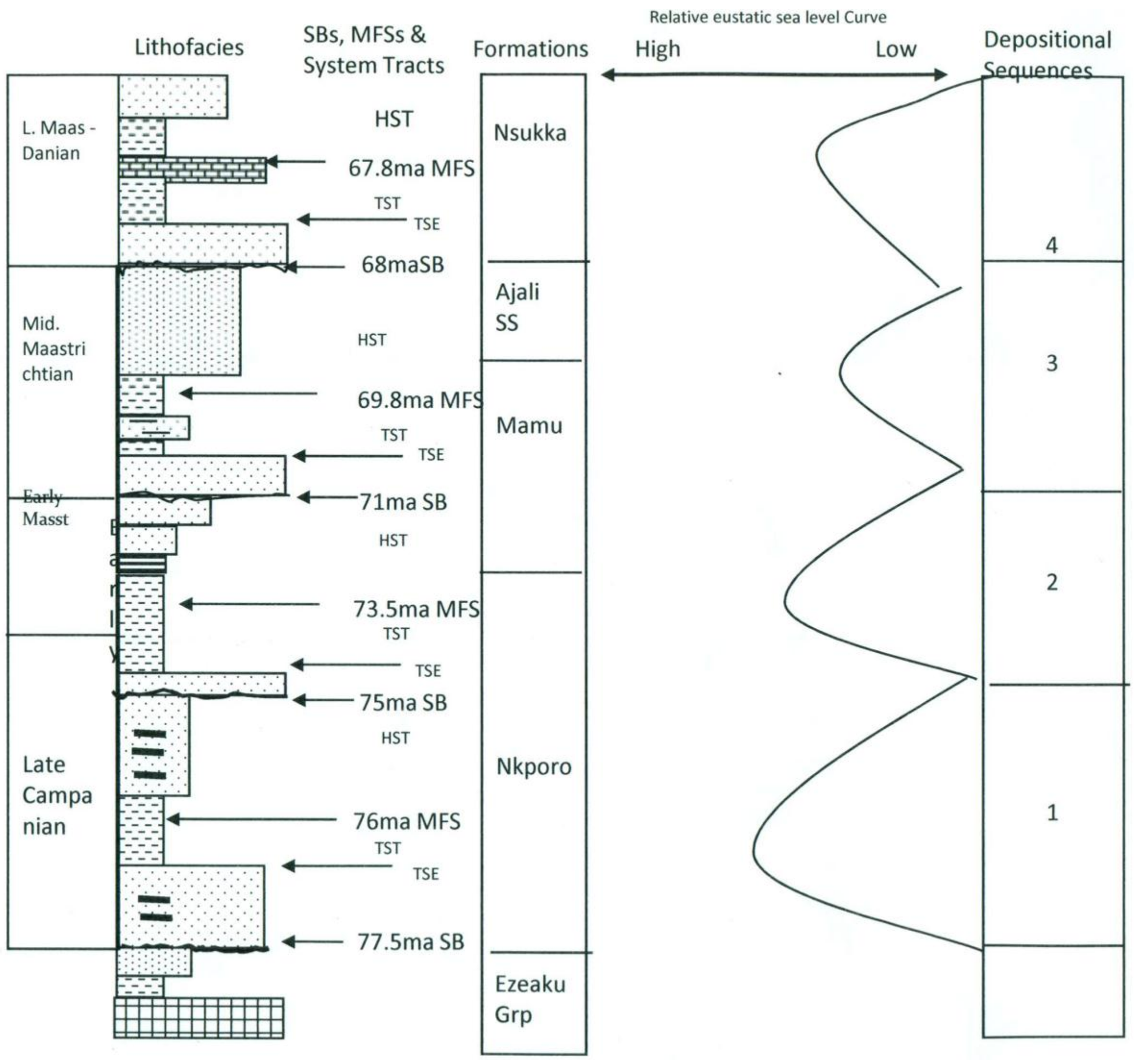

Fig:2.19 Sequence Stratigraphic Model for the Afikpo Sub-Basin(Okoro, A 2009)

2.2.3 PETROPHYSICS

The exploratory well density in Anambra Basin/Benue Trough is very low compared with Niger Delta. Nkporo shale formation experienced very low well penetration with less completion activities. Little or no work has been done in Petrophysics,Engineering and Exploitative Economics . This study captured five major wells that penetrated Nkporo shale formation. The primary data used for shale gas formation are similar to that of conventional reservoir analysis-gamma ray, resistivity, porosity and acoustic including neutron capture spectroscopy data. The formation study of unconventional reservoirs requires heavily on the understanding the minerology of rocks. Clay type, fluid sensitivity, mechanical properties, geometry covering the structure such as lamination, argillaceousity, dispersity, combo, etc are essential factors in the analysis. This study is essential in the determination of the volume of gas in place, sensitivity of the shale to the fracturing fluids and to understand the fracturing characterization of the formation. Permeability to gas in shale gas formation characterization is very difficult. Permeability is a function of effective porosity, hydrocarbon saturation, and minerology. Down-hole logging analysis results are very essential which can be caliberated with cores if available.

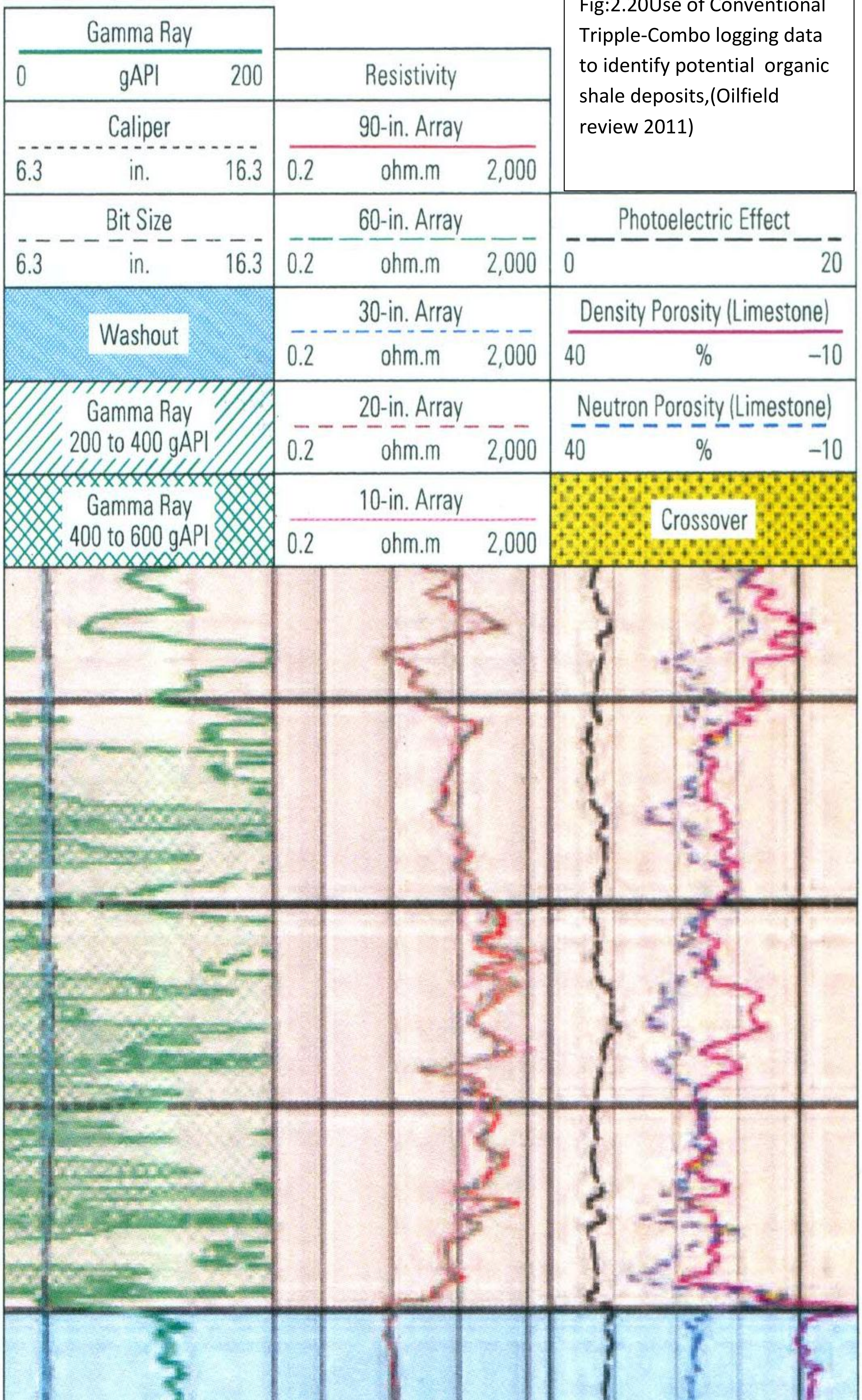

Fig:2.20Use of Conventional Tripple-Combo logging data to identify potential organic shale deposits,(Oilfield review 2011)

2.2.4 Historical Engineering Well Test

Akukwa -1 and Alo – 1 wells drilled in the Anambra Basin were tested (Avbovbo and Ayoola, 1981 and Whiteman, 1982) with the following result.

Akukwa-Well: Experienced high pressure gas and condensate at the depth 2402m(ss), traversed Nkporo. The Bottom hole pressure up to 6600 psi blow-out. Drilled in 1955 by Shell BP

Alo – 1 : The well bottomed in the Nkporo shale, 31m in net gas sand. Drilled in 1976 by SHELL BP.

Table 2.4: Hydrocarbon-indicative wells drilled in the Anambra Basin (compiled from Avbovbo and Ayoola, 1981 and Whiteman, 1982)

Well name	Date drilled	Oil Co.	TD (m)	Remarks
Akukwa – 1	1955	Shell – BP	2403	High-Pressure gas and condensate at 2402m,traversed Nkporo Gp Bottom hole Pressure up to 6600psi, blow-out
Anambra River -1	1967	Safrap	4333	Tested 2280 b/d from 3 Cret. Sst bodies; 25m net oil sand in the Mamu Fm.
Alo-1	1976	Shell – BP	Not avail.	Well bottomed in the Nkporo Shale, 31m net gas sand in 4 intervals bw 618 & 2210m

CHAPTER THREE

RESEARCH DESIGN AND METHODOLOGY

3.1 Research Design

3.1.1 Reservoir Description

The objective is to obtain sufficient data to accurately describe the resource in place, reserve potential, the producibility and economic impact. Data required are:

1. Geophysics
2. Geochemistry
3. Geology
4. Petrophysics
5. Engineering
6. General Oil and Gas economic informations.

The Campano-Maastrichtian Nkporo Shale is one of the potential sources of un-conventional gas reserves in Nigeria. Extensive geological, geophysical and geochemical evaluations have been carried out on it and published. These published information exposed part of characteristics of Campano-Maastrichtian Nkporo Shale through sedimentological analysis and Rock-Eval pyrolysis by notable workers;which confirmed that Nkporo shale has a total organic carbon (TOC) range of 0.4 to 3.01 wt % with low hydrogen indices revealing kerogene of typeIII and mixed III/II organic matter which is predominantly gas prone. TOC is one of the criteria used for preliminary assessment of hydrocarbon source potential. The Nkporo shales thermally immature is located within Anambra Basin of South East of Nigeria and lower Benue Trough. However, there is sparsity of data in literature on petrophysical and engineering parameters.

A typical log montage similar Nkporo shale gas formation in USA will be considered.

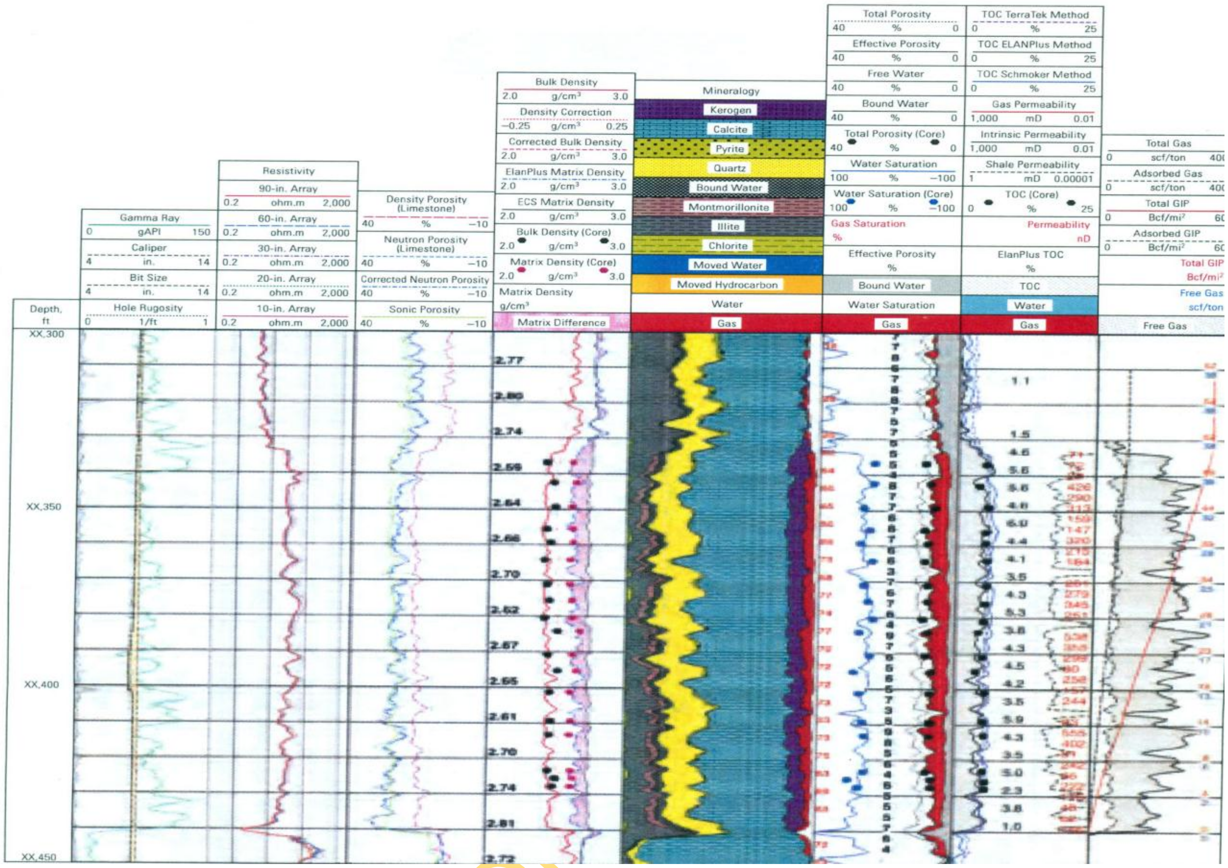

Fig:3.1 **Composite Shale montageLog of a Typical USA Shale Gas Field/Reservoir/well similar to Nkporo(Oilfield Review 2011)**

3.2 Methodology

3.2.1 Reservoir Characterization

This study was designed to evaluate the gas reserves and the producibility of potential Nkporo Shale gas formation of Anambra Basin/Lower Benue Trough and to formulate an appropriate technical and economic strategy for the development. The wells such as Alo-1,Anambra River-2, Ogbabu-1, Oda River-1, Akukwa-2 which were earlier drilled and logged, had sidewall core and well production test result and these were utilized during the data gathering phase. Hence, the log suits during the Petrophysical analysis carried out on the wells applied two-feet slice interval and the 5% porosity cut off based on the shale structure and geometry. The driving parameter for shale gas formation analysis is porosity and not permeability which are very low and not too significant.Power-Log Software was used for the analysis.

The results of the above analysis were used for the Petrophysical and Engineering evaluations that were undertaken for this study, to obtain geothermal profiles,porosity,permeability, saturations. Considering the scarcity of data on Nkporo shale reservoir, and the uncertainties in the acquired data. For example, in resistivity measurements from logs, Archive parameters and log derived porosities are made of uncertainties. There was essential integration of side-wall core data and log analysis to obtain a saturation height functions that will better define SW and FWH. The extent, size and fracturability,producibility of Nkporo Shale gas reserves were carried out using established procedures. The Rate Transient Analysis(RTA) of simulated vertical and horizontal wells was carried out to obtain hydraulic fracture and some other reservoir properties. Profile parameter measurement data assisted in assessing fine scale heterogeneities in permeability. The measurements were corrected to in-situ stress conditions due to high stress sensitivity that exists in such formation.This was achieved by different plots at selected probe measurement points and measuring permeability at two or three confining stresses. The averages of these points of measurement were used to calibrate logs. In ideal situation where proper core sample is obtained, high pressure mercury injection capillary pressure data can be used to obtain pore throat size distributions; and infer pore shape and dominant pore sizes. The plot of probe permeability measurements versus estimated pore sizes were used to identify petrofacies/flow units which are used for layering identification.

The estimates of hydraulic fracture properties (producing half strength and conductivity) which were obtained from Rate Transient Analysis (RTA) and compared to other estimates from microsensure and post-fracture hydraulic fracture models.

This process of integration applied in the methodology reduced the uncertainty in the estimation of the hydrocarbon in place in shale gas reservoirs.

Comparative analysis of similar Shale systems by international benchmarking was done.

Finally Economic analysis were carried out under different scenarios inorder to Arrive at vital conclusions and recommendations.

3.2.2 Reservoir Modeling

The main target of this process is to validate the reservoir description and characterization programs and to develop realistic 2D/3D well bore and reservoir models that can be used to predict future performance. This process involves the use of acquired data along with structural framework from sensitive interpretation to identify and characterize the mechanisms controlling production and optimize development. Poor description of reservoir result in unreliable production forecast. The accurate prediction of the post-fracture well performance will result in the optimization of the fracturing process which is very essential in shale gas formation analysis. Hence, decisions regarding compressor installation, infill drilling or reconstruction treatment will not be feasible when adequate characterization process is lacking. Furthermore, for layered reservoirs, over simplified reservoir descriptions often result in an overestimated well productivity.

This is unlike conventional reservoirs; shale gas formations typically have gas storage and producing characteristics requiring denser well spacing. The key to effectively exploiting low permeability gas reservoirs such as shale gas formation like Nkporo is to utilize the development model that recognizes optimum well spacing.

3.2.3 Drilling and Completions

Most wells drilled that penetrated Nkporo formation are exploratory only. No well has been completed yet for historical purpose. The wells such as Alo-1,Anambra River-2, Ogbabu-1, Oda River-1, Akukwa-2 which were earlier drilled were all exploratory.

The current technologies that have been successful in shale formations are horizontal, multilateral wells, including unbalanced drilling. Gas shale formations are prone to intense fracturing and fractures and have a strong impact on drilling, exploration and exploitation activities. A good understanding of the relationships between the in-situ stress and fracture system which is primarily important through different plots were carried out for future exploitation drilling inorder to:

1. Minimize drilling risks
2. Maximize hydrocarbon production
3. Minimize operational costs

These required an effective geo-mechanical/Stress study that were carried out.

3.2.4 Formation Damage

The gas shale reservoirs are very sensitive to formation damage because the low permeability rock can only tolerate only a minimal amount of damage due to a higher degree of sensitivity to capillary retentive effects, rock-fluid and fluid-fluid compatibility concerns. As a result of low permeability nature of the matrix, unless huge losses are experienced during drilling, the zone of extreme permeability impairment is generally contained in a fairly localized region near the wellbore. The application of hydraulic fracturing as normally counter-plated in final completion technique, for many low permeability vertical gas wells, shallow damage by drilling, cementing and perforating may be bypassed by the fracture. Drilling induced formation damage becomes more of an issue when open hole non fractured completions are expected. Open hole completions are usually considered only in horizontal wells, large vertical pay zone on a shorter pay zone with micro/macro fractures.

The fluid retention effect is the biggest formation damage problem with shale gas formation during drilling, completion, fracturing or work over operations. These can consist of the permanent retention of both water or hydrocarbon based fluids or the trapping of hydrocarbon fluids retrograded in the formation during the production of the gas itself. Capillary pressure forces which exist in the porous media are the dominating factor behind fluid retention countercurrent inhibition. Unbalanced drilling is one of the means of minimizing formation damage in shale gas drilling but it may actually increase the severity of near wellbore aqueous phase trap problems when it is done with water based fluids in for instance horizontal wells which will be completed open hole in tight gas formations.

The glazing, mashing or wellbore polishing can be problems in some open hole shale gas completions particularly if pure gas is used as the drilling media. The permeability can be reduced significantly in low quality formations or elevate water relative permeability if a free water saturation is present in the formation. The reduction in permeability is caused by physical adsorption of high molecular weight polymers or oil wetting surfactants. The pH of these fluids must be studied and monitored during the Field Developmental phase to prevent effects that could be observed on interfacial tension and gas droplets-water emulsion mentioned by Isehunwa, et al;2012,2013)in similar studies in Niger delta crude oil exploitation.

Rock-fluid interactions can also occur due to clays because the low permeability associated with many shale formations is generally caused by small grown size in sandstone or limited intercrystalline porosity. The significant concentration of clays also can reduce permeability significantly. A variety of different types of clay can be present. Highly fresh water sensitive expandable clays can occur in mud type of formation. These clays expand in size and causes sloughing when contacted by fresh or low saline water into clay lattice. The clay swelling can cause total permeability impairment. There are other types of clays such as kaolinite that can moderately reduce permeability in conventional reservoirs can totally occlude available permeability in shale gas formation low quality zone in the near wellbore area.

The Nkporo shale group consists of dark grey, very fissile shales and mudstones with occasional thin sandy shale interbeds, fine grained sandstone and mavl with coatings of sulphur and numerous white specks of *Bolivina explicat* (Onyekuru,et al,2010)

When only gas is flowing, migration of particulates in the porous media should be minimized. Problems can occur when fluid invasion occurs due to relatively high spurt losses potentially encountered during the drilling or fracturing process, due to motion of invaded fluids during high drawdown cleaning operations, or if the formation produces liquid at rates above the critical migration rate during unbalanced drilling operations.

It has been observed that the Enugu-Nkporo shales group belong to the early campanian units which underlie the eastern plain of the Udi-Enugu escarpment and consists of dark grey fissile, soft shale and mudstone with maximum thickness of 1,000m and characterized by interbedded sandy units and sulphur coated mavl. A shelter marine environment was predicted due to the presence of foraminifera and ammonitis (Reyment 1965; Agagu et al,1985)

This formation straddles from Anambra Basin to Benue troughs. It lies between Mamu formation and Agwu shale which are of Maastrictian and Santonian folding/ Coniacian age.

The majority of shale gas sands require hydraulic or acid fracturing in order to obtain economically viable production rates. Studies have shown from lab and field evidences that damage occurring during fracturing treatments is a big issue. The following factors may impair the productivity of a fracture treatment:

1. Physical mechanical problems with the fracture treatment
2. Formation damage to the high conductivity fracture
3. Formation damage to the fracture face.

The retrograde condensation phenomenon is another damage mechanism. Dry gas formations (typically a gas having a liquid yield of less than about 10 to 15bbl condensate per MMscf of gas) follows a depletion path that never intersect the two phase envelope and hence this type of system is not prone to problems associated with downhole condensate dropout effects. These types of reservoirs may still produce liquid condensate at surface.

3.2.5 DATA AVAILABILITY

The available Logs are Dual Laterolog, Microspherically focused Log, Neutron, sonic and Density Logs; Resistivity Logs.

Table:3.1 Log Inventory of the Nkporo Shale Formation Wells

Well No.	Log Interval (ss)	Log Date	Well Trajectory	GR/SP	Vsh	Res Deep	Resh LN	RHOB	WPHI	PHIE
Alo-1	6500 – 7480	1976	Vertical	√	√	√	√	√	√	√
Anambra River-2	6200 – 7146	1984	Vertical	√	√	-	-	√	√	√
Oda River – 1	6540 – 7696	1986	Vertical	√	√	√	√	√	√	√
Okpo-1	6733.5 – 7479.5	1986	Vertical	√	√	√	√	√	√	√
Ogbabu -1	4200 - 7500	1954	Vertical	√	√	√	√	-	-	-

3.2.6 Quality of Logs

Plots were made of all electronic log data of the five wells and quality controlled; with the original hard field copies. They were found to be in agreement. TVD calculations have been carried out on Nkporo formation wells (Alo-1, Oda-River – 2,Anambra River - 2, Ogbabu-1, Okpo River and Akukwa-1) which are virtually straight holes with little or no deviations with regards to the measured depth. Borehole environmental corrections were applied to all GR, FDC, CNL, LLD, MSFL curves using algorithms in powerlog, belonging to Schlumberger and Atlas wire line services.Composite plots of the wells were generated. The Semi-Log Plot of Permeability versus Porosity relationship within Nkporo shale Formation was established. Multiple LAS –files were generated prior to the plots. The semi-log plot of permeability versus porosity shows the three significant facies present in Nkporo-shale formation having marine origin.

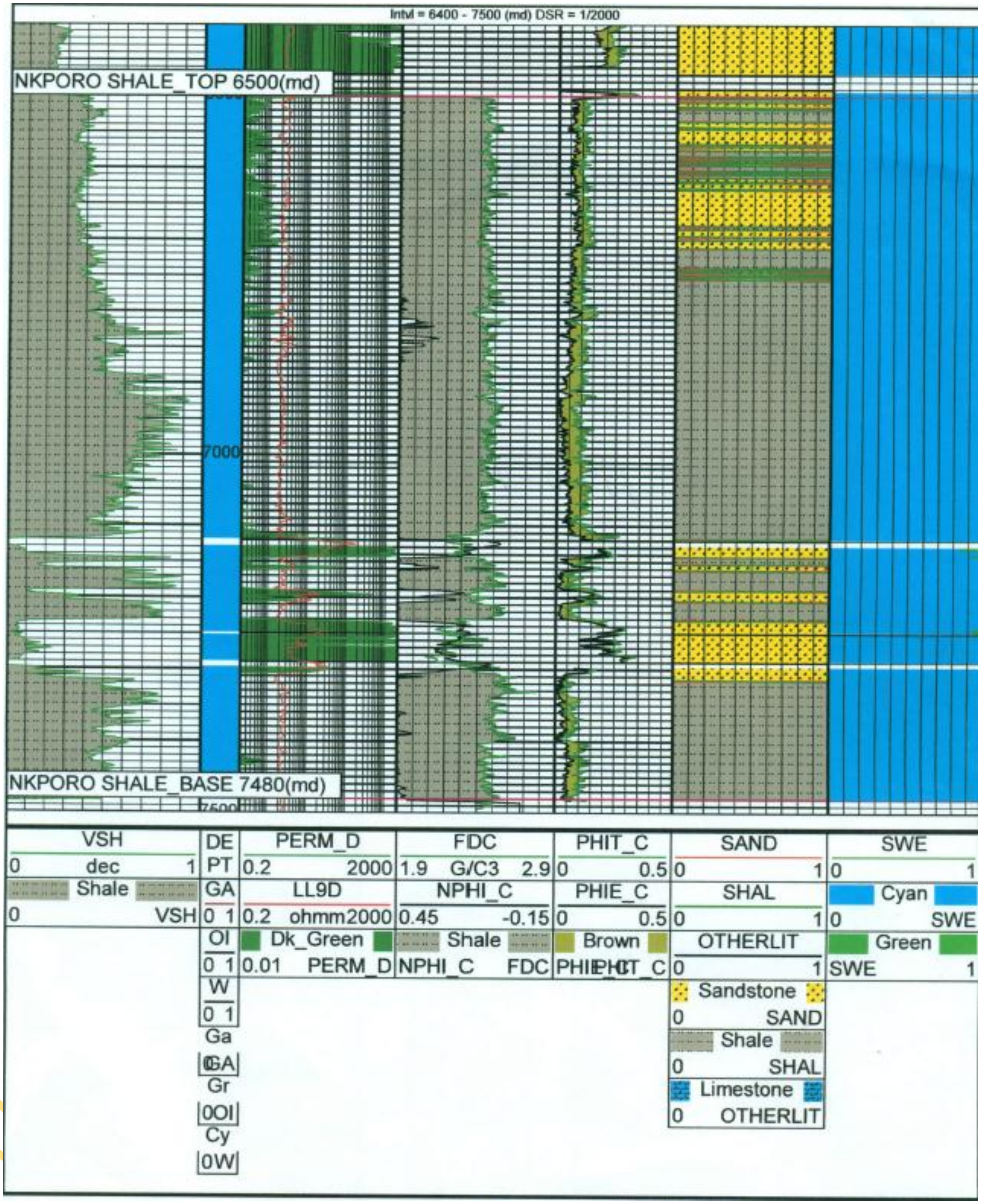

Fig.3.2 : **Composite well Log-plot analysis of Alo-1**

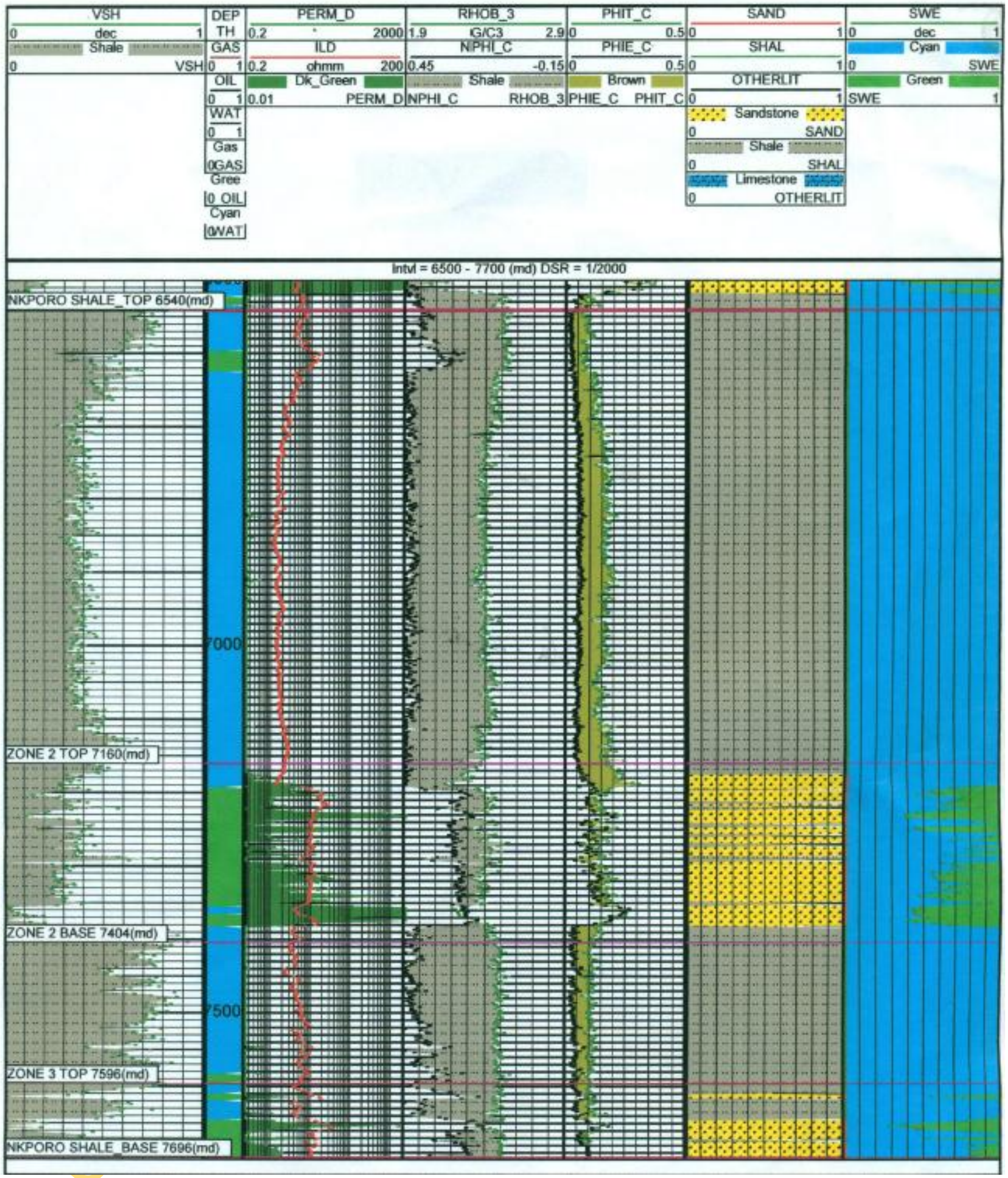

Fig.3.3: **Composite well Log-plot analysis of Oda-River-1**

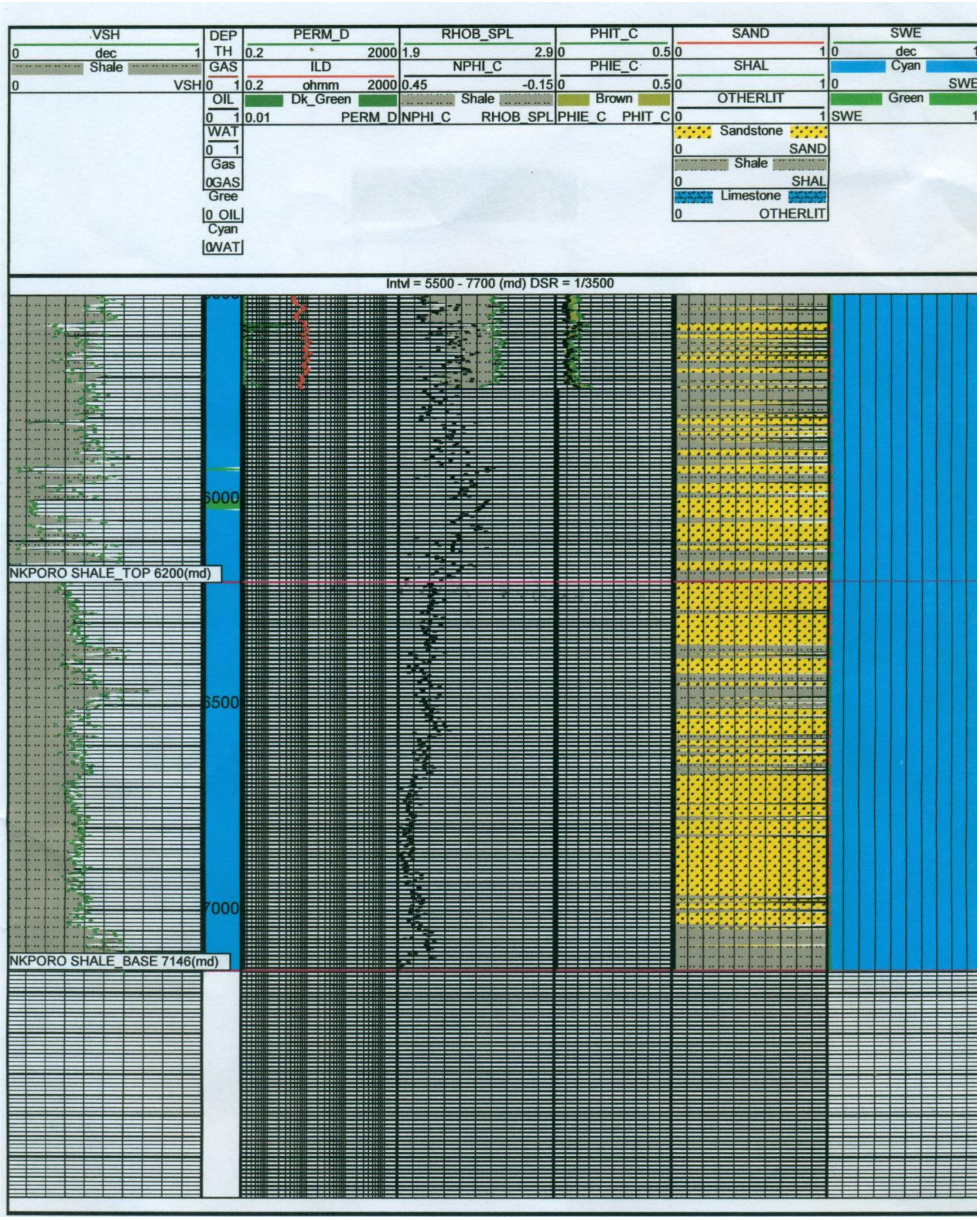

Fig.3.4: **Composite well Log-plot analysis of Anambra-River-2**

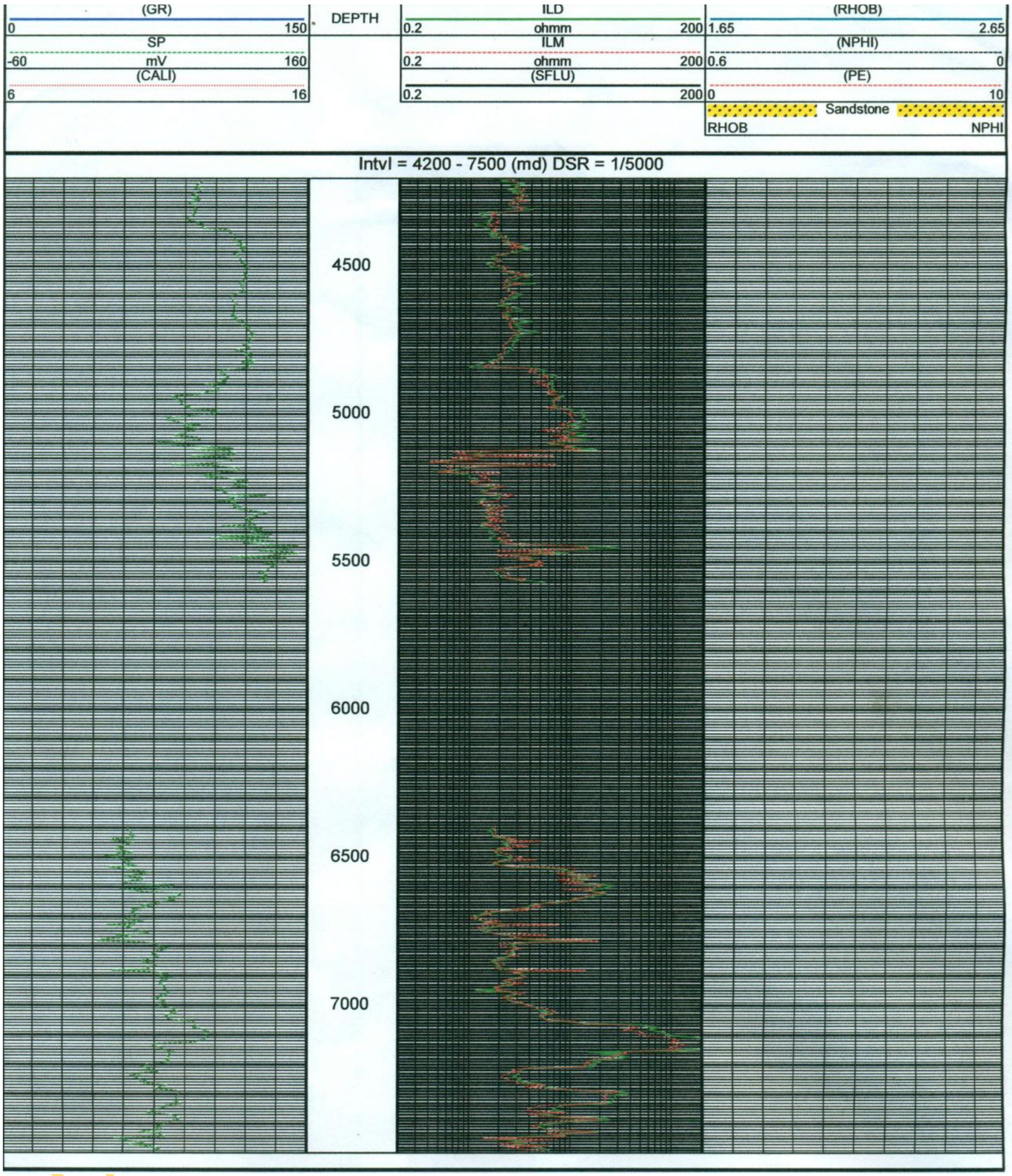

Fig.3.5**: Composite well Log-plot analysis of Ogbabu-1**

On the average in the production forcasting the cumulative production will increase 9 folds applying vertical hydraulic fracturing linearly using 2inch 20/40 mesh prop sand in a polymer fluid with a 1,000 ft fracture lenght and 640 acre well spacing dually completed.

3.2.7 Core Data

Conventional core analysis data were not available for this study. Side wall core data result was used provided in Alo-1. The physical characteristics were compared with the lithofacies within Nkporo formation with that from well log data.

3.2.8 Side-wall Core Samples

Side-wall core samples were taken in Alo-1, Oda-River 1, Akukwa -1 namely for fluid type identification that confirmed gas.

3.2.9 Produced Formation Water

Nkporo shale formation has only been tested and not produced since 1955/1976 as published by (Avbovbo and Ayoola, 1981). Hence there are no measured salinities and deduced resistivities which would have been corrected to formation temperatures.The pH value must be certified to avoid fracture fluid contermination.

3.2.10 Formation Temperature

Temperature versus Depth profiles regionally and locally on Nkporo Shale Formation were generated(Figs 4.1-4) from Bottom Hole temperature surveys(Table 3.2) includingcomposite plot of all the surveyed wells from different combination logs(Fig4.5).

Table: 3.2: **Regional Temperature Profile of Nkporo Shale Formation(*Different formation)**

Well/OML or OPL	Depth (FT – ss)	Temp(°F)	LogType
Anambra-2/OML 447	4001 5069 5225 5228 6532	129 146 140 146 182	CDL-GR,LDL-CNL,ISF-MSFL
ODA River-1 /OML 447	5940 5964 6654 7035 7065 7158	178 164 199 195 195 199	CNL,DIP,DL,GR,LDL-CNL,P-TEST
ALO-1/OML 7	2000 5816 5818 6470 7500 8082 8712	136 150 168 164 191 205 206	LDL-GR LDL-CNL Nuclear Resistivity
Ogbabu-1/ OPL 910	2177 2429	182 215	CNL-GR DLL
Akukwa-2/ODL 907	4664 4670 6948 7908 8760 *10375 *11014	134 134 149 170 185 180 248	IGR Electrical Log Micro Log GR/Neutron Temp Log Formation Density Induction Electrical Log

3.2.11 Detailed Analysis of Formation Fluid Distribution

Table of Hydrocarbon distribution data was generated using well Logs, sidewall samples and fluid distribution curves(Tables 4.6 to 4.8). The tops and bottoms were taken from the PDL (Petrophysical Data Logs). The hydrocarbon occupying the pore spaces is predominantly gas from the test conducted through temperature survey and fluid test recorded by Ayoola and Avbovbo, (1981) and the present study. Alo – 1 and Oda River – 1 have a similar Log signature.

3.2.12 Grain Density

The model and average grain densities are 2.64 and 2.663 gm/cc respectively. Matrix densities of 2.62 and 2.74 gm/cc were used for shale and silts respectively. Density of 1.0 gm/cc was used for water.

3.2.13 Fluid Saturation

The connate water saturation was calculated using Simandoux model for the Nkporo shale structures.

3.2.14 Evaluation of Hydrocarbon in-Place

Nkporo has not been produced, hence there is no production history to perform decline curve analysis, Material Balance, or Reservoir Simulation inorder to determine the hydrocarbon-in-place. Data from Nkporo wells were used for preliminary estimates of Shale Gas in place. Crain's Unconventional Shale Gas Volume in Place Model is applied for this study considering the presence of the free and adsorbed gas reserves in Nkporo organic rich shale that must be evaluated.

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TOTAL SHALE GAS IN PLACE(GIPtotal) = GAS in place(interstitial(free gas)) + Gas in place(adsorbed under reservoir conditions)—--------(3.1)

SHALE GAS IN PLACE-adsorb Gas content from correlation or core analysis data(Crain,2000):

Gc = KG11 X TOC%----------(3.2)

Where:

Gc= gas content(scf/ton)

TOC%= total organic carbon(weight percent)

KG11= gas parameter, varies between 5 and 15

GIPadsorb = KG6 X Gc X DENS X THICK X AREA------------(3.3)

Where:

GIPadsorb = gas in place(Bcf)Gc = adsorbed gas content in isothermal condition(scf/ton)

DENS = layer density from log or lab measurement(g/cc) 2.20 to2.60

THICK=layer thickness(feet)

AREA = spacing unit area(acres)

KG6 = 1.3597X10^{-6}

SHALE GAS IN PLACE(GIP) – free gas

$$\text{GIPfree} = \frac{KV4\ X\ (1-Qnc)\ X\ PHIeX(1-Sw)\ X\ THICK\ X\ AREA}{Bg} \quad \text{------------------------(3.4)}$$

$$\text{Bg=} \quad \frac{(Ps\ X\ \ (Tf + K\ T2))}{((Pf\ X\ (Ts + KT2))\ X\ ZF)} \quad \text{--(3.5)}$$

Where:

AREA=reservoir area(acres)

Bg = gas formation volume factor(ft^3/scf)

GIPfree = original free gas in place(Bcf)

PHIe = effective porosity(fractional)

Sw = Water Saturation in un-invaded zone(fractional)

THICK=layer thickness(feet)

Pf=formation pressure

Ps= surface pressure(feet)

Tf = formation Temperature(^{o}F)

Ts = surface Temperature(^{o}F)

ZF =gas compressibility factor(fractional)

KT2 = 460^{o}F

KV4=0.000043560

Qnc =fraction of gas that is non combustible(CO2,N2,etc)If area is assumed to be 640acres, then GIP = Bcf/Section=Bcf/sq.mile)

3.2.15 Production forecasting

Production from gas Shale requires finite capacity vertical fracturing under closed boundary and constant pressure(Thomas and Roberts,1989). The performance is a function of propped fracture length, fracture conductivity, reservoir rock and fluid properties. Cinco et al,1998 and Agarwal et al,1989 are known to have developed the technique for the computation of production forecasts using type curves(Thomas and Roberts,1989). This method is quick and unexpensive solutions to complex problem like shale formations production system. Holditch et al,1984 generated the type curves that can readily be applied to most fracture situation. The Nkporo shale formation has some fluid filled porosity but very low permeability which the inter-connectivity could only be improved through hydraulic fracturing. This approach is necessary to improve the hydrocarbon productivity in this formation and thereby improving the economic of production.

The following Holditch equations were used in Nkporo Shale production forecast. Some of the data were obtained from Nkporo well log data analysis and some other analogue well data. Twenty Years prediction were considered and the radial flow pattern was converted to Linear to effectively and efficiently improve the productivity Index contrast following the application of Hydraulic Fracturing considering different fracture length Scenarios. The most optimized fracture length was choosen.

From the Holditch et al,(1998) curves:

$$Q(t) \quad = \quad F(t_D \, Q_D)\text{----------------}(3.16)$$

Equation 3.16 is used for the production forecast using the Holditch et al(1998) curves and the Nkporo shale formation properties enumerated in Table 3.3. The cumulative gas production at a given time is a function of dimentionless time and rate.

Table: 3.3: Properties used for the Production Forecast using Holditch et al curves.

PROPERTIES	REFERENCE VALUES
Average Depth	7,520ft
Formation Permeability (k)	1.05md
Formation Porosity (Ø)	16%
Water Saturation Swi	73%
Gas Saturation Swg	17%
Net Gas Pay (h)	1261ft
Initial Reservoir Pressure (Pi)	5000 psig
Flowing Bottom Hole Pressure (Pf)	1,500 psi
Bottom Hole Temperature (BHT)	167.5^{o} F
Gas gravity	0.6
Gas Viscosity	0.0187 cp
Bg	1.0669 res bbl/mcf
Gas Compressibility, Cg	0.0002747psi
Water Compressibility, Cw	1 x 10 $^{-6}$ psi $^{-1}$
Period of prediction	20 years
Fracture lengths	500ft, 1000ft, 1,500ft, 2000ft
Well Drainage Area	640 acres

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 Characterization of the Petrophysical and Engineering Properties of Nkporo Shale

4.1.1 Temperature/Depth Profile

Fig 4.1 showed that that the temperature depth profile of Anambra-2 well is approximately linear such that the plot obeys the basic equation of a straight line:

$$T = mD + C$$

Where,

D =depth(ftss)

m = slope =.0221 ^{o} F/ftss

C = intercept = 38.84 ^{o} F

There is similarity with that of some Niger Delta wells. The medium depth temperature cluster unlike the shallower depth temperature has a higher deviation from the line of best fit.

The result of Fig 4.2 showed that that the temperature depth profile of Oda River-1 well is approximately linear and has a lower gradient and higher intercept when compared with Fig 4.1.The plot obeys the basic equation of a straight line.

$$T = mD + C$$

Where,

D =depth(ftss)

m = slope =.0205 ^{o} F/ftss

C = intercept = 51.60 ^{o} F

There is similarity with that of some Niger Delta wells. Lower depth temperature difference is highly noticeable unlike the deeper region where the difference of temperature with depths are very small and could be seen as temperature cluster at the terminal part of the curve.

Fig 4.3 showed that that the temperature depth profile of Alo-1 well is linear but there exist a temperature data from the shallowest point having a spurious characteristics which showed a test result belonging to a different formation from Nkporo. It has a much lower gradient and higher interce compared with Figs 4.1-2 and obeys the basic equation of a straight line:

$$T = mD + C$$

Where,

D =depth(ftss)

m = slope =.012 ^{o} F/ftss

C = intercept = 94.02 ^{o} F

There is similarity with that of some Niger Delta wells. The gradient of the curve will be much lower if the spurious data is removed and the line of the best fit is allowed to shift down.

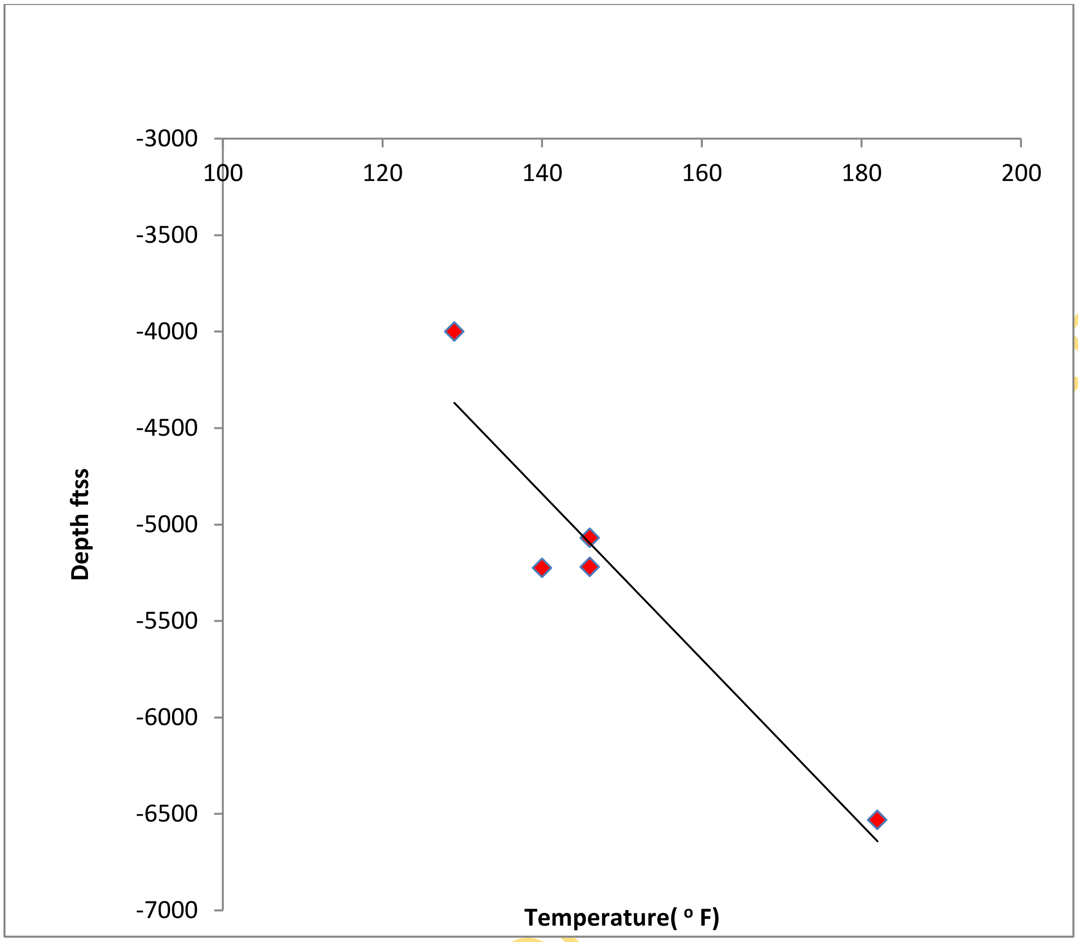

Fig: 4.1 **Plot of Temperature versus Depth of Anambra-2 /Nkporo Well**

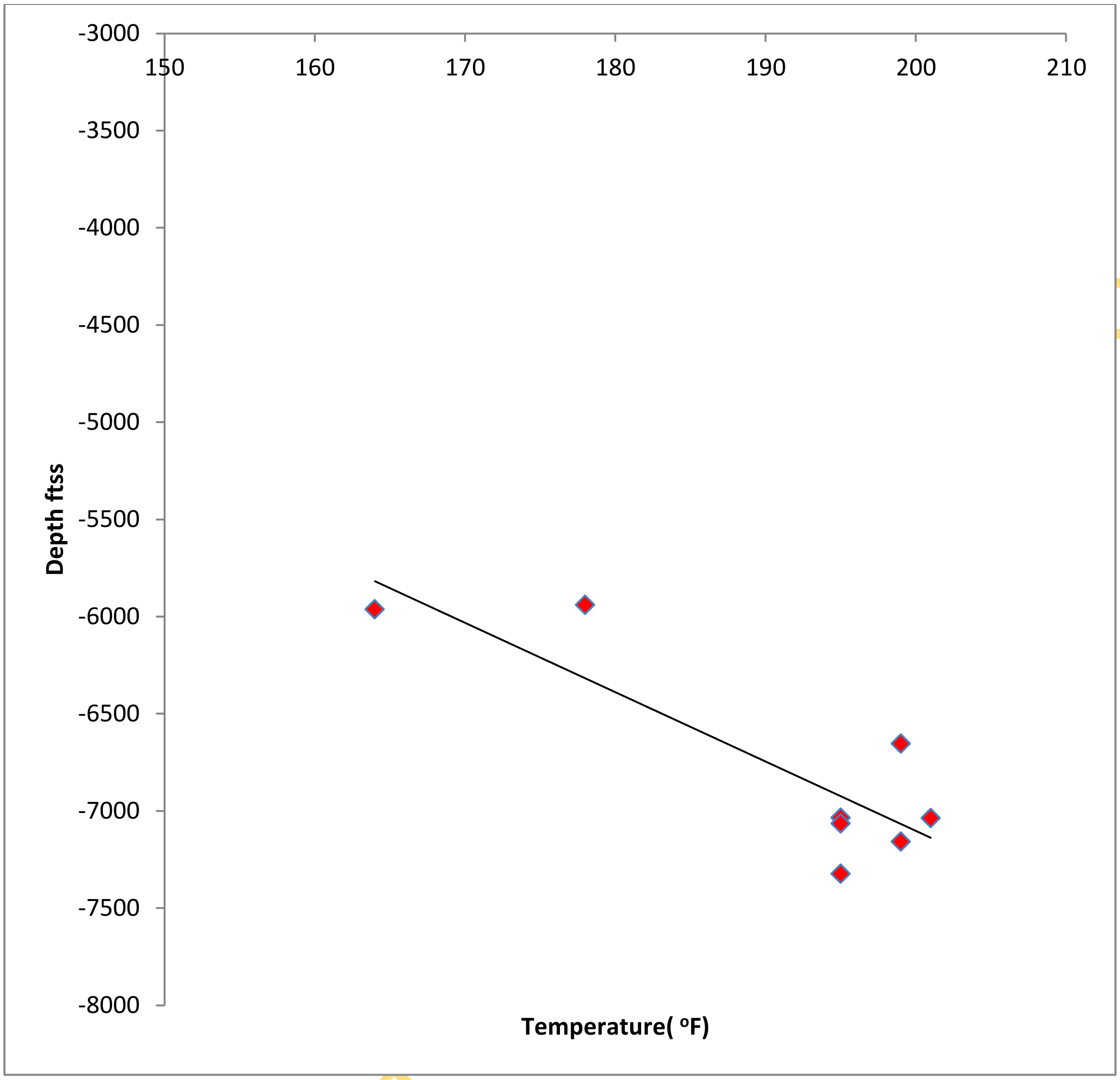

Fig:4.2 **Plot of Temperature versus Depth of Oda River-1 /Nkporo Well**

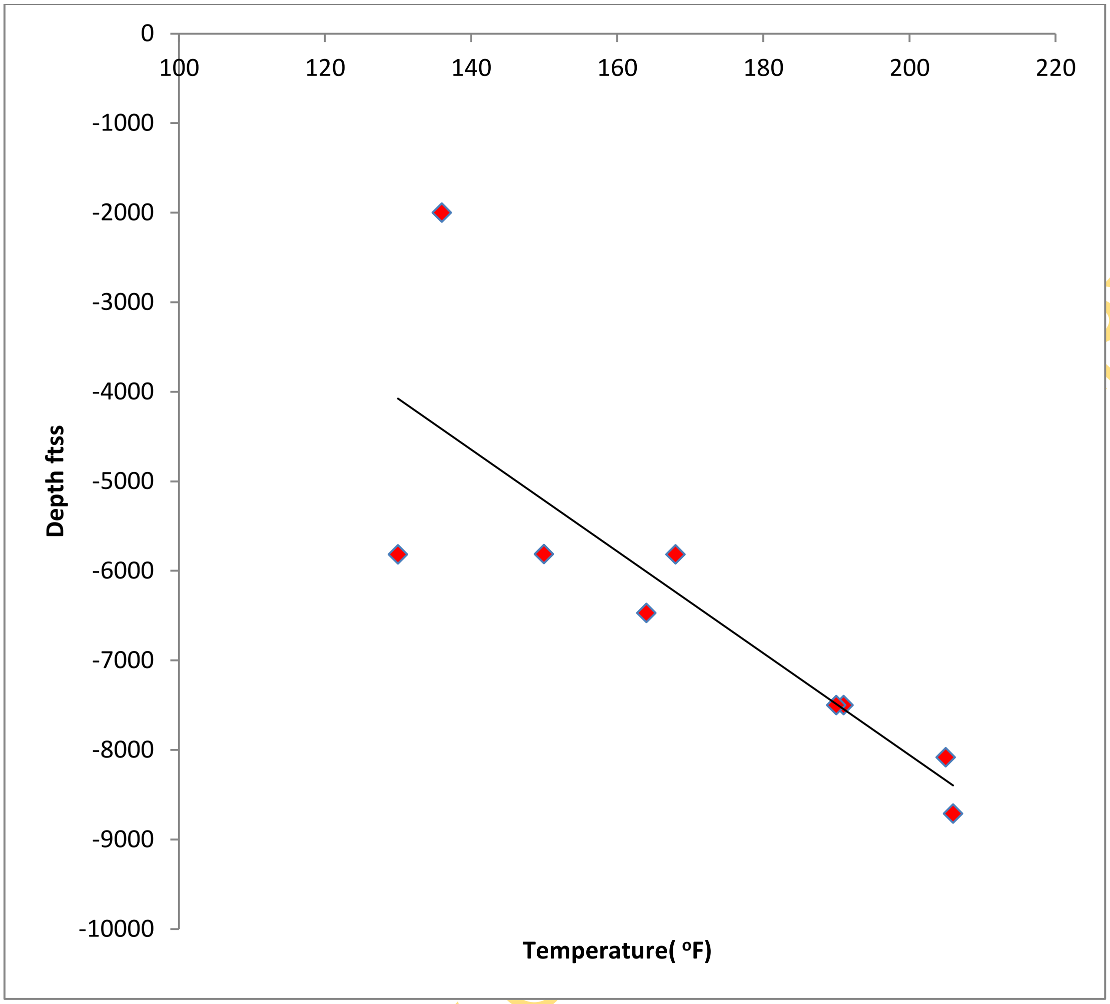

Fig: 4.3 **Plot of Temperature versus Depth of Alo-1 /Nkporo Well**

Fig 4.4 showed that that the temperature depth profile is linear with a lower gradient than Anambra-2 and Oda River-1 wells but higher than Alo-1 well. The intercept is the lowest when compared with those ofl other wells but close to that of Anambra-2 well.The shallowest point is spurious considering the temperature linearity which tend to show that the value belong to another formation. Also above 10000ftss, there exist another formation like Agwu shale having different temperature profile.

Fig 4.4 obeys the basic straight line equation of

$$T = mD + C$$

Where,

D =depth(ftss)

m = slope =.0177 ^{o} F/ftss

C = intercept = 36.91 ^{o} F

Fig 4.5 is a composite plot of Nkporo Temperature-Depth profile.

Multiple Temperature Depth profiles were observed in different wells which can be deducted from the plotted curves equations having different gradients and intercepts. Also some of the temperature test points belong to different formation that is not Nkporo. The general equation representing the line of best fit:

$$T=mD + C$$

Where,

D =depth(ftss)

m = slope =.0142 ^{o} F/ftss

C = intercept = 79.05 ^{o} F

Figs 4.1-5 and Table 4.1 showed that reprensenting the entire formation region like in Niger Delta with an equation is not practicable and if carried out will be full of uncertainties.

The multiple high temperatures behavior observed regionally from well to well in Nkporo shale formation could be attributed to the presence of high pressure Shale gas in the deep region and very characteristic of Nkporo shale unique petrophysical structure. Hence the kinetic effect of temperature on the gas in the pore spaces could attract this multiple sharp temperature gradient/intercept values. The Bottom Hole Temperature data is quite good and the resulting profile representative including detecting the data belonging to the neighbouring formations different from Nkporo.

The intercept for the composite(Eqn5) Temperature/Depth plot(FIGURE:4.5) for Nkporo showed the common effect of the Anambra basin/Benue Trough surface temperature despite different geostatic effects encountered in Nkporo formation. The composite plot also showed that another reservoir below Nkporo were encountered below the depth of approximately 10,200 Feet-ss due to the sudden sharp gradient change.

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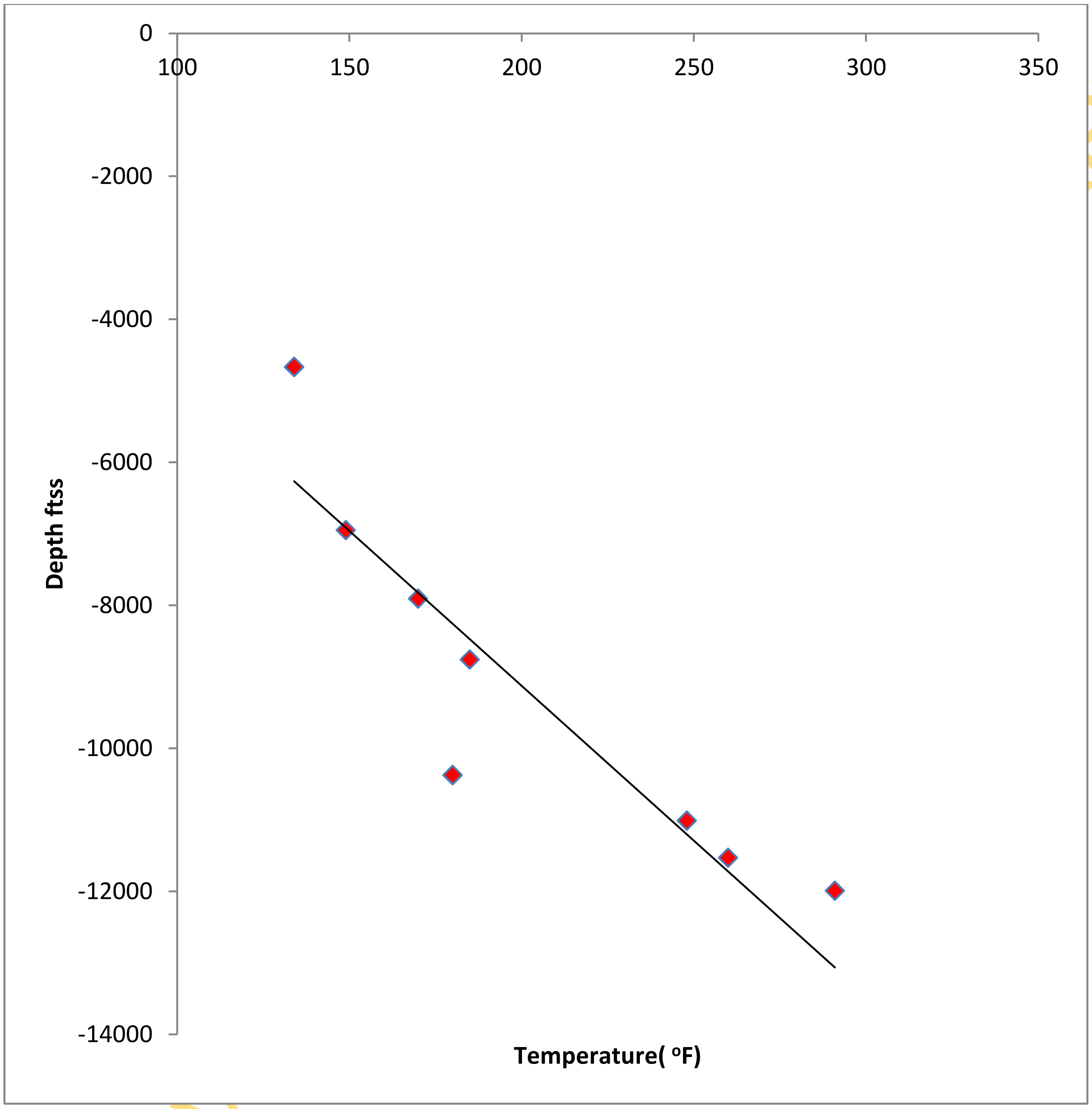

Fig: 4.4 **Plot of Temperature versus Depth of Akukwa-2 /Nkporo Well**

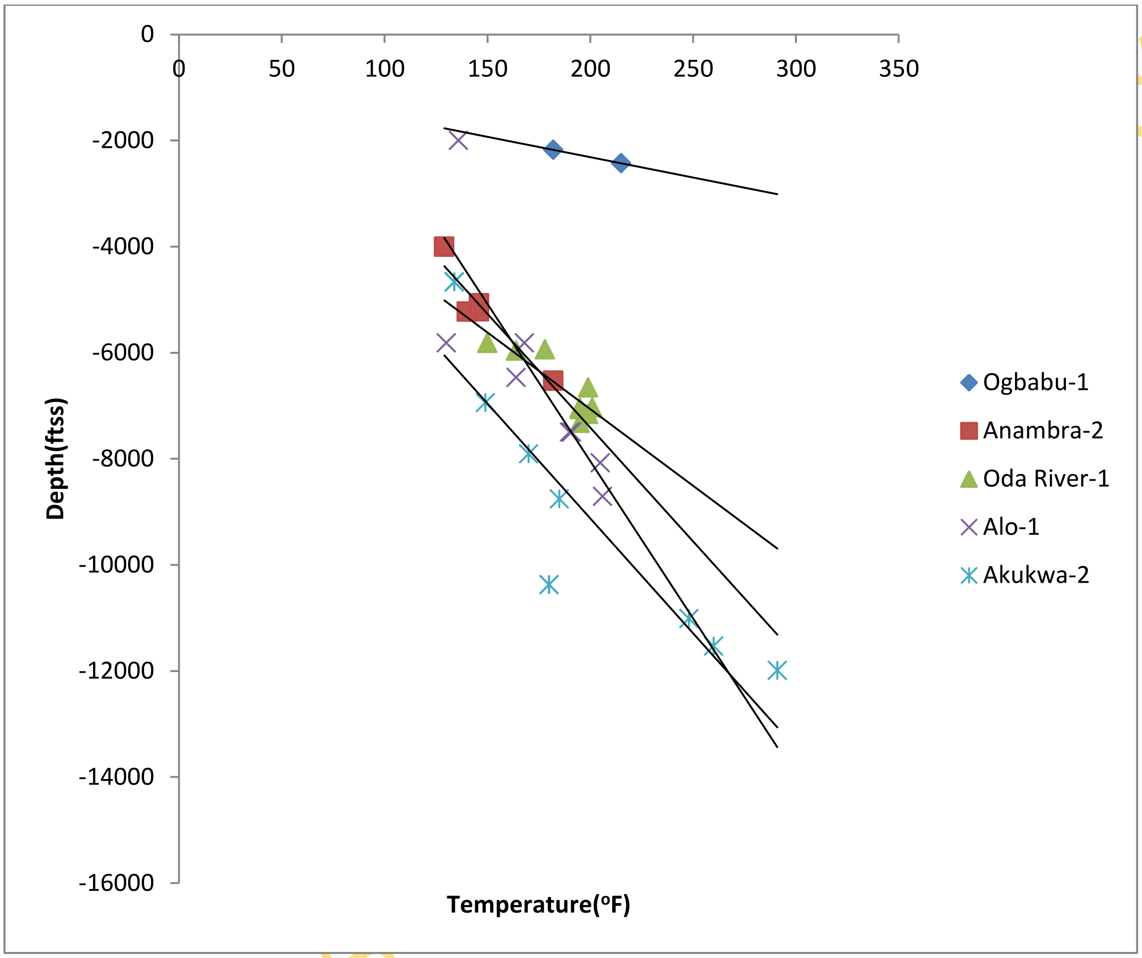

Fig: 4.5 **Composite Plot of Temperature versus Depth of Nkporo Shale Formation.**

TABLE:4.1 Temperature Analysis Result of Nkporo Shale Gas well/Reservoir/Field

Well Name	m-degF/FTss	C deg F
Anambra-2	0.0211	38.84
Oda River-1	0.0205	51.60
Alo-1	0.012	94.02
Akukwa-2	0.0177	36.91
Composite	0.0142	79.05

4.1.2 FORMATION POROSITY/PERMEABILITY EVALUATION

Statistical and standard deterministic approach were used in porosity estimation from density and Neutron Logs using matrix dρρpensity of 2.62gm/cc and mud (salt) density of 1.1 gm/cc. This is best done with the shale corrected density neutron complex lithology model.Nkporo Formation has some element of tight sand properties.

$$\varnothing_T = \frac{\rho ma - \rho b}{\rho ma - \rho f} \text{ ....(4.1))}$$

$\varnothing_T$ = Total Porosity

ρ_{ma} = Matrix Density

ρ_f = Mud (Salt) Fluid Density

ρ_b = Bulk Density (RHOB)

V_{sh} = Volume of Shale

$$V_{sh} = \frac{GRsh - GR}{GRsh - GRsand} \text{ ------------------(4.2)}$$

ϕ_e = Effective Porosity

$$V_e = V_T (1 - V_{sh}) \text{-------------------(4.3)}$$

The power log software was used to process all the well Logs.

The Regional equation using powerlog software is stated below:

$$\text{Perm D} = 10^{(1100\phi_e \, A) + B)} \text{ -- (4.4)}$$

The following boundary conditions were deducted for Anambra Basin / Lower Benue Trough as stated in Table 4.2

Table:4.2 Boundary Conditions for Anambra Basin/Benue Trough Permeability generation

Porosity Range	A –Factorial Constant	B-Factorial Constant
<0.05	0.20	-2
0.05-.12	0.23	-2
0.12-.16	0.25	-2
0.16-.20	0.35	-3
>0.20	0.20	-1

The current study went further to study specifically the Porosity/Depth, Permeability/depth, Permability/Porosity profiles of Nkporo Shale Formation including the composite plot behaviour of the wells of interest. Each of the wells were analysed considering different porosity and permeability functions encountered prior to obtaining these average values for Nkporo shale formation. The porosity and permeability were generated from the Log suites analysis from respective wells as enumerated in Table 4.3, Figs. 4.6-15.The plots showed the multiplicity effects of facies and formation compaction from well to well and depth to depth profile. These characteristics resulted to the application of different boundary conditions in the permeability versus porosity of Nkporo relationship.

4.1.3 Effective Porosity/depth Profile(Alo-1)

There are multiple porosity changes observed with depth. This is a non uniform profile (Fig:4.6). The presence of multiple facies having marine shale environmental deposition characteristics. The porosity range is higher when compared with a similar USA geological structure showing higher fluid content capacity in the shale formation.

4.1.4 Permeability/Depth Profile(Alo-1)

The well is characterized with lower permeability values less than 12md in the shallow region unlike the deeper region near the bottom where the permeability got above 50md(Fig:4.7).The productivity index for the shallow region will be higher hydraulically fractured.

Table:4.3: **Petrophysical parameters of Nkporo Shale Formation wells**

Well	Top-Depth (md-Ft)	Bottom-Depth (md-Ft)	PorosityRange(ϕ) (%)	Permeability(K)Range (Millidarcy)
Alo-1	6500	7480	5-26.5	0-95.5
Oda-River-1 (Zone-1)	6540	7160	5-23.8	0-0.4
(Zone-2)	7160	7404	5-28.1	0-90.7
(Zone-3)	7404	7596	5-17.5	0 - 69.4
Anambra-River-2	6200	7146	Data scanty	Data scanty
Ogbabu-1	4200	7500	No Nkporo Shale Fm observed	No Nkporo Shale observed
Okpo-River	6733	7479.5	5-24.2	0 - 84.3

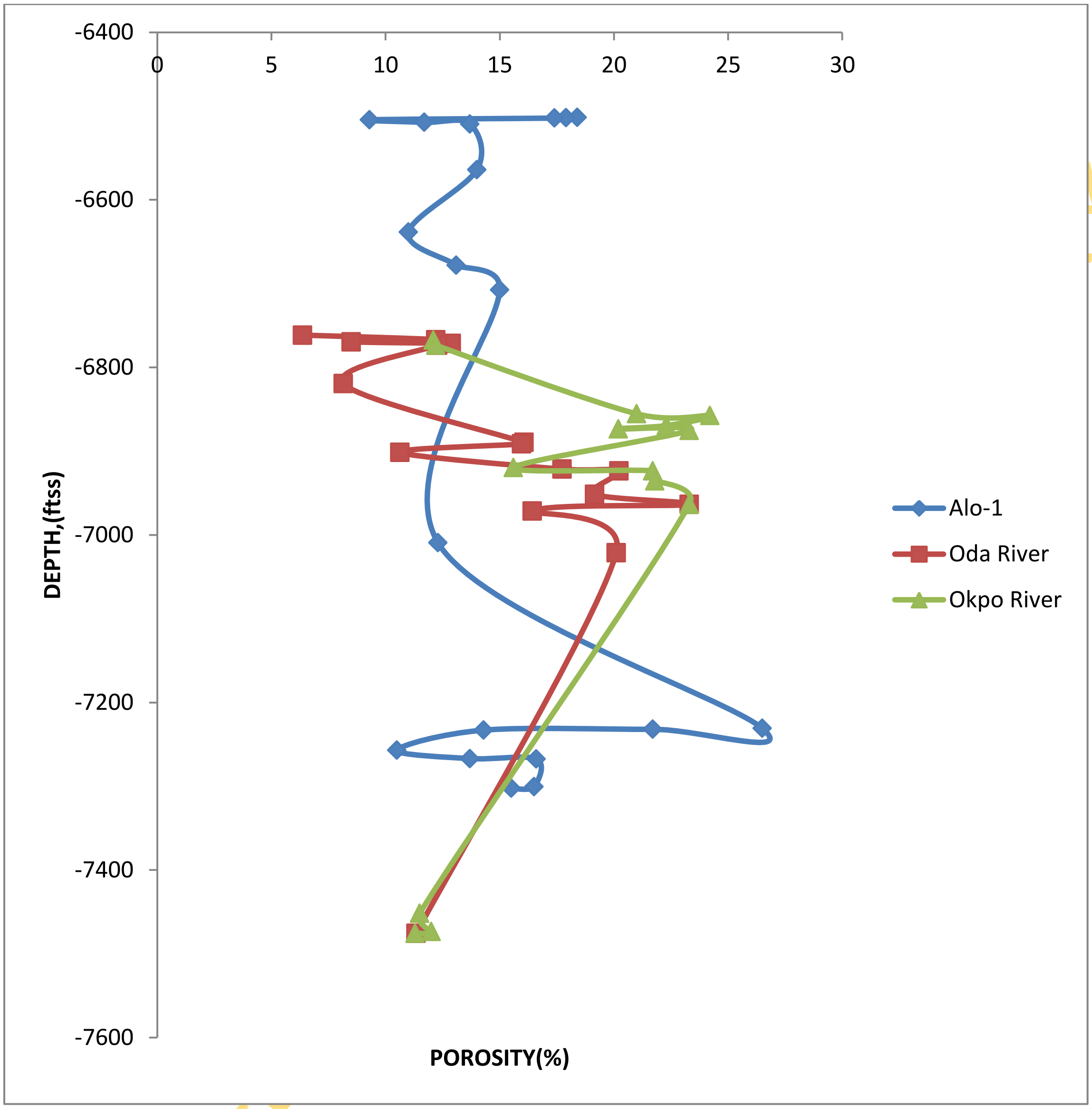

Fig:4.6 **Composite Plot of Effective Porosity versus Depth of Nkporo wells**

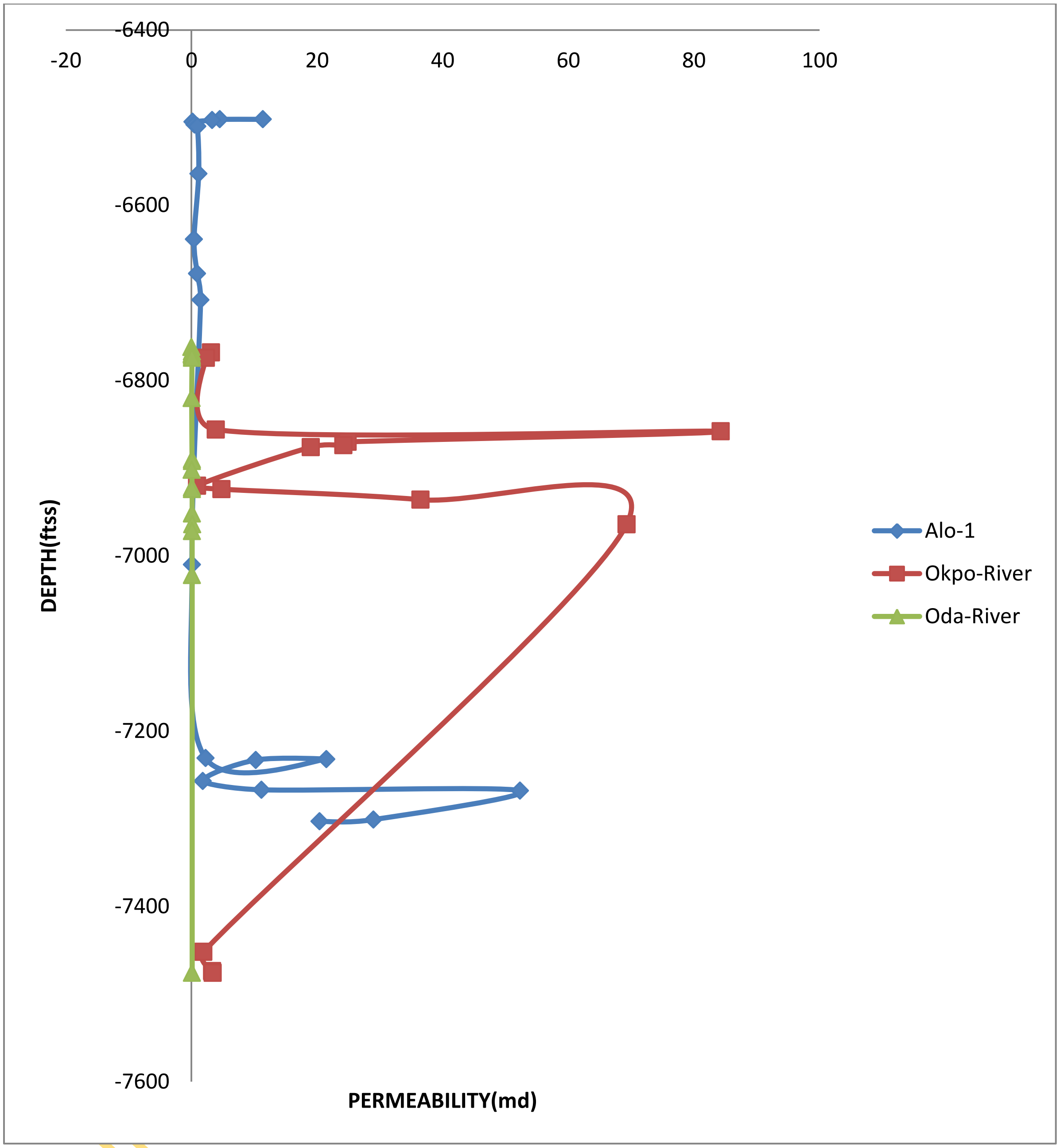

Fig:4.7 **Composite Plot of Effective Permeability versus Depth of Nkporo wells**

4.1.5 EffectivePorosity/Depth Profile (Okpo – River)

The non- uniformity of the porosity range profile was observed especially in shallow region where the average porosity is 20% having a high fluid capacity content. Facies effects on the formation were prominently noticed especially between 6800 and 7000FTss.

4.1.6 Permeability/Depth Profile(Okpo-River)

There is existence of high permeabilities at the shallow area of the well which will act as a good evacuation conduit for the high porosity fluid observed in the same region. The permeability value got higher than 80md in the same area. It is a good candidate for hydraulic fracturing.

4.1.7 Effective Porosity/Depth Profile(Oda-River)

The Porosities range between 6%- 24% and is higher in the shallow region. The average porosity is approximately 15%. There is presence of non uniformity of the porosity structure with-respect to depth showing the effects of the gumbo like structure of the facies type.

4.1.8 Permeability/Depth Profile(Oda-River)

The non-uniformity of the permeability values were observed. The permeability values in the shallow region of the well are very low showing the existence of high shale formation compaction effects. The facies changes observed cannot be ignored. The shale formation is very tight. Hydraulic fracturing is necessary for this formation to enhance future production.

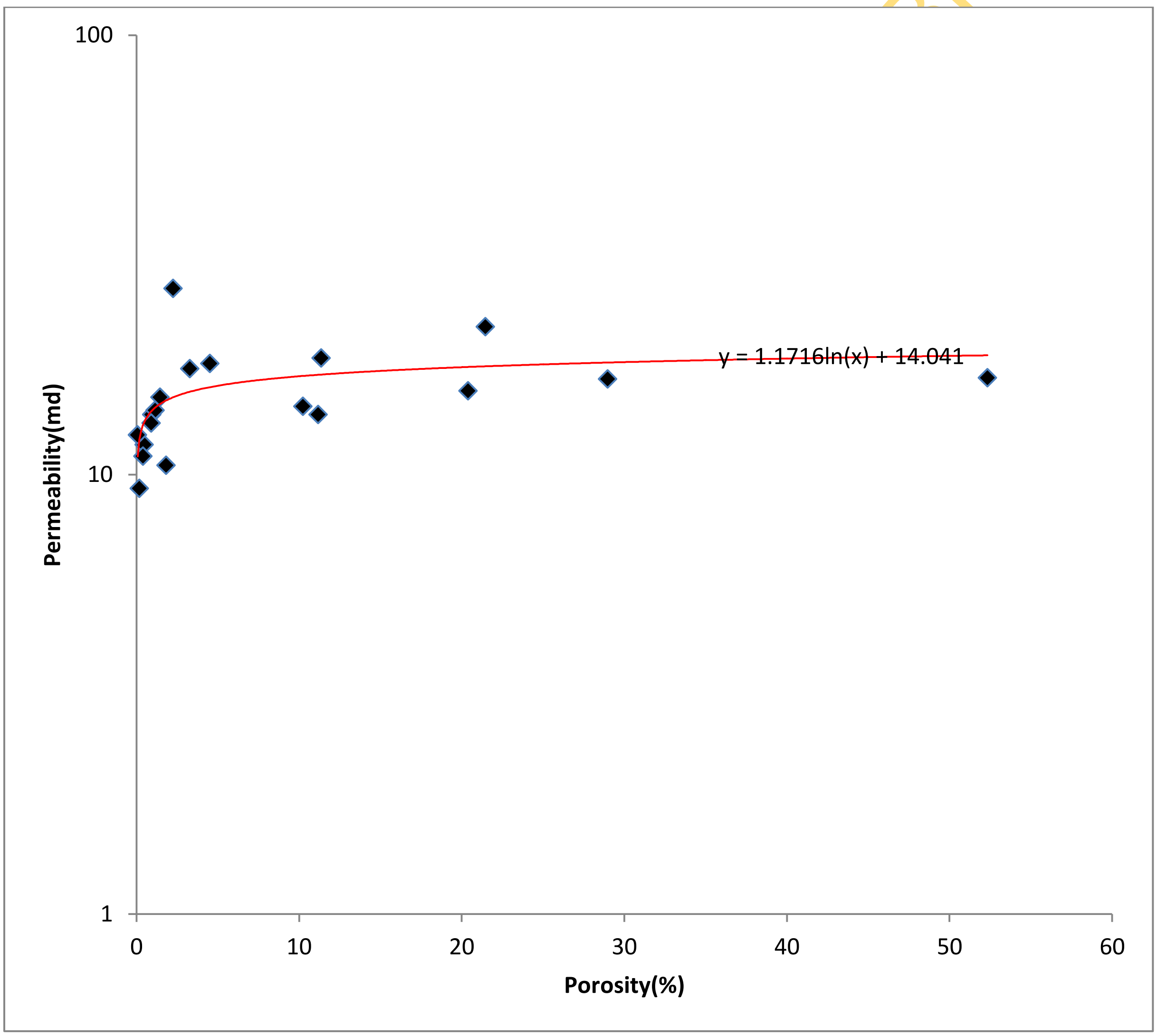

Fig :4.8 **Semi-Log Plot of Permeability versus Porosity of Alo-1 /Nkporo well**

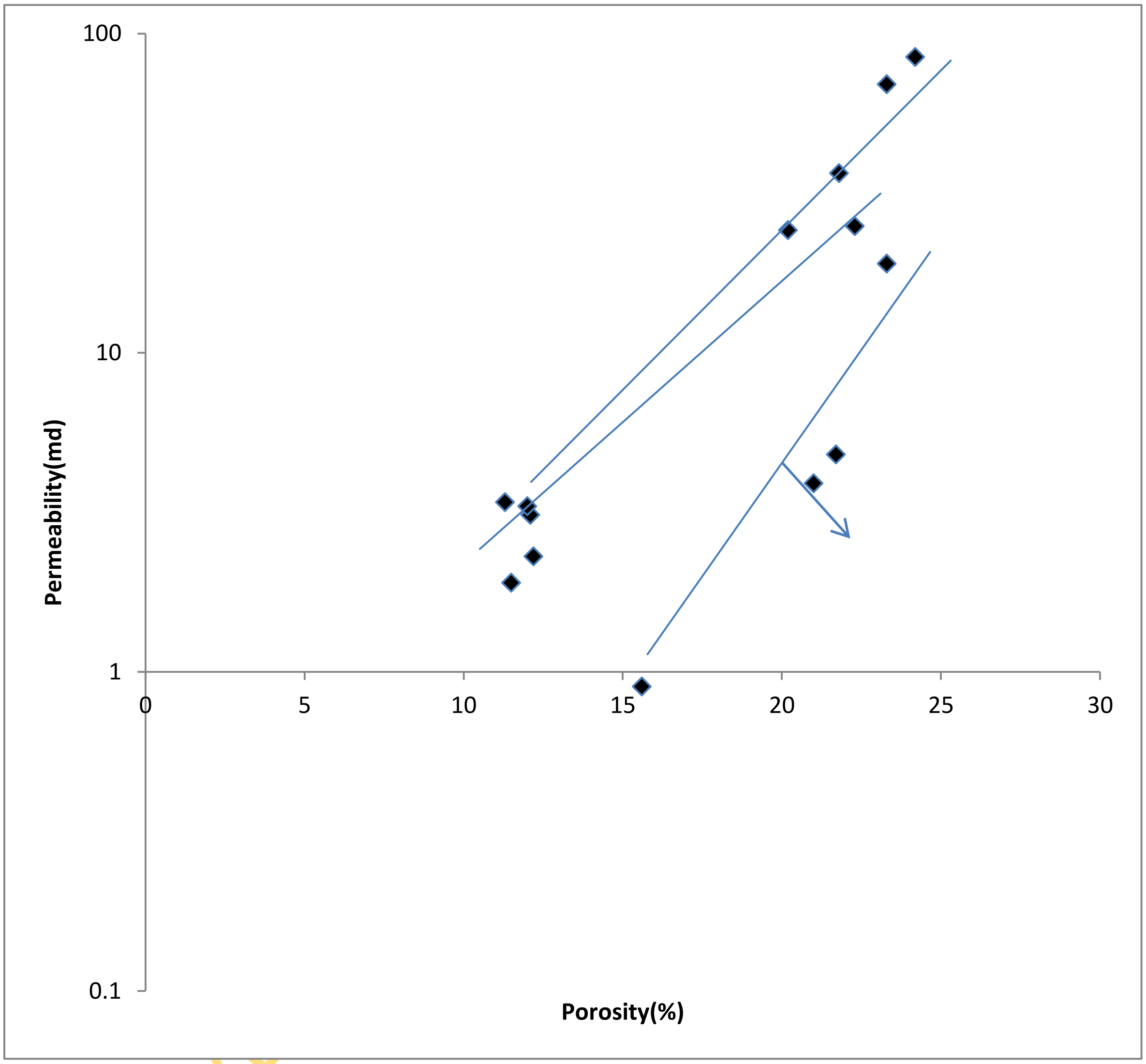

Fig: 4.9 **Semi-Log Plot of Permeability versus Porosity of Okpo River /Nkporo well**

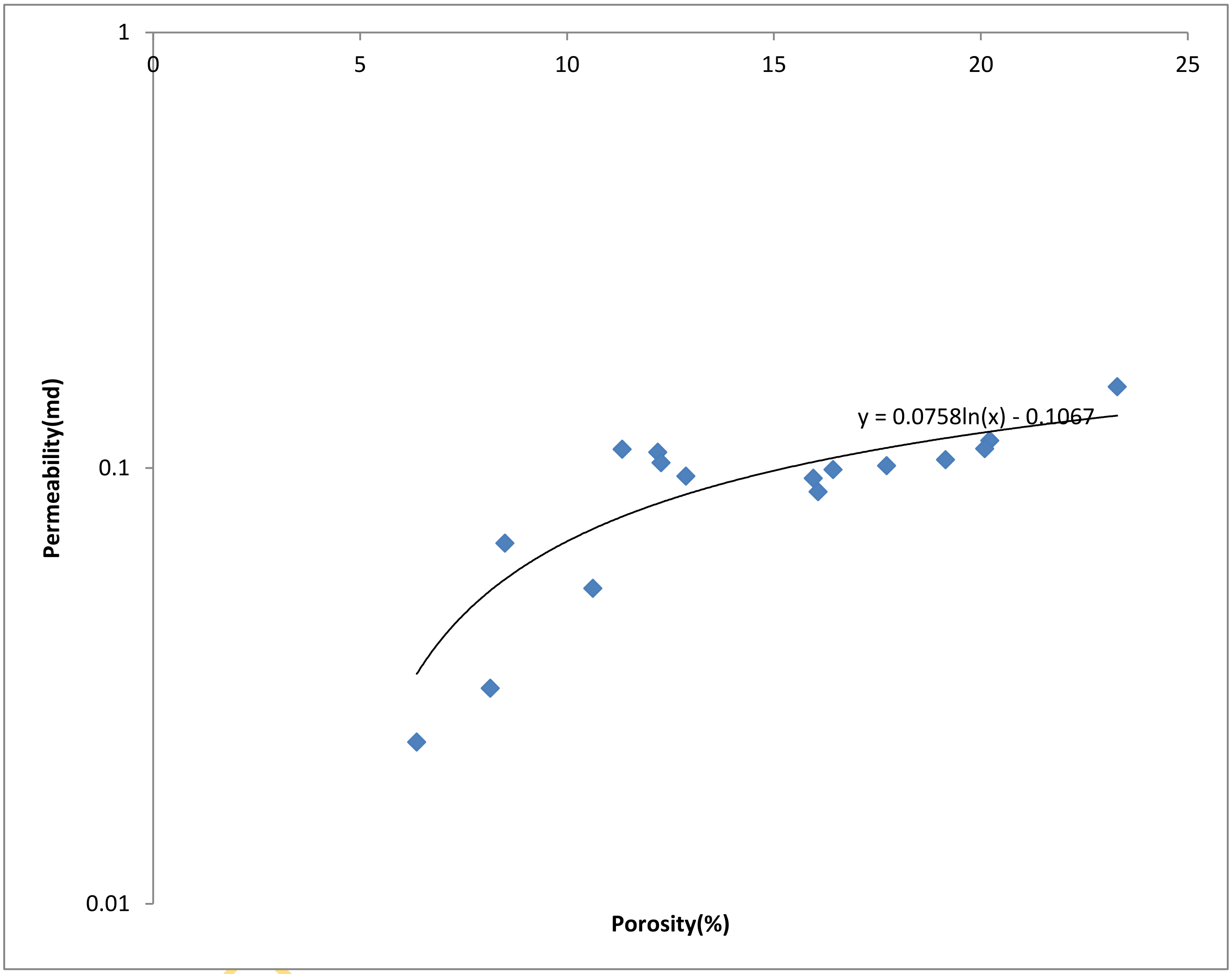

Fig 4.10 **Semi-Log Plot of Permeability versus Porosity of Oda River /Nkporo well**

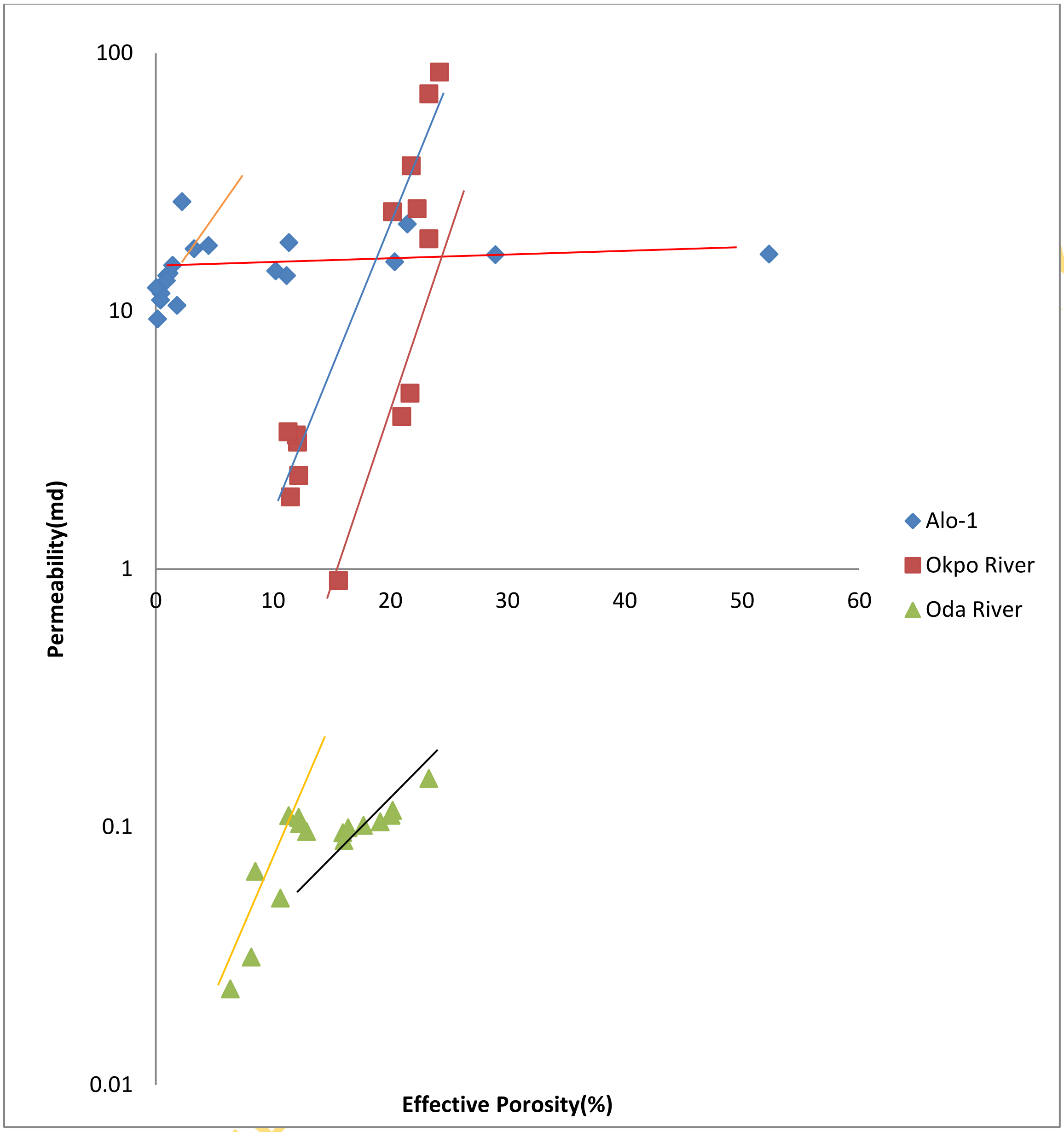

Fig: 4.11 **Composite Semi-Log Plot of Permeability versus Effective Porosity of Nkporo**

Fig 4.8 plot showed the existence of different facies in Alo-1 but not as prominent in Fig4.9-11 plots of Okpo and Oda River wells.The multifacies characteristics of Nkporo shale formation is highly prominent in the composite plot of Fig 4.11.The presence of these facies reduced significantly the permeability and effective porosity.The existence of shale geometrical structure coupled with facies type determined the petrophysical cut-off points used for the analysis,Table 4.3.

In general the porosity measurement is unique in gas bearing shales showing more variabilities, higher density porosity and lower neutron porosity due to presence of gas in the rock. This is unlike conventional shale which is known to have a uniform separation between the density porosity and neutron porosity measurements. The effective permeability range of the shale – gas formation is very low compare with that of conventional. It is also noted that Nkporo formation permeability is much higher than that of USA Shale-gas formations despite their similarity in physical appearance and structure(Figs 4.16-17),Table 4.32.

Fig:4.13 **Organic laminated Shale of Nkporo/Enugu (Anambra Basin/Benue Trough) with TOC>2.5**%wt***(Okoro,A 2009*)**

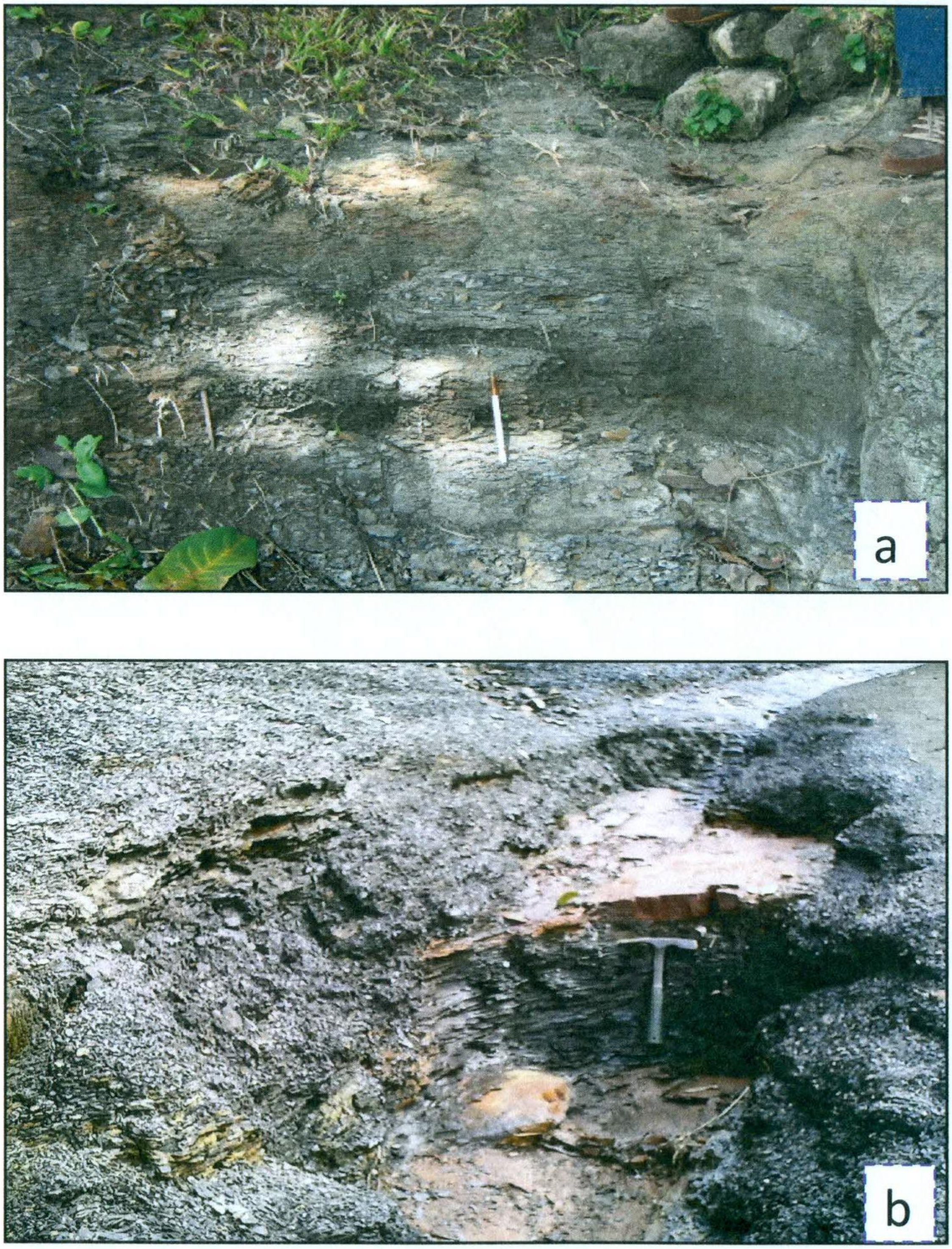

Fig :4.14**Contd Organic laminated Shale of Nkporo/Enugu (Anambra Basin/Benue Trough) with TOC>2.5%wt *(Okoro,A 2009)***

The porosity and permeability increase were observed in the deeper region compared with the shallow region except in some wells where decrease in porosity at depth above 7400 Feet-ss were observed like Okpo and Oda(figures 4.5-10). Three types of correlational equations covering the respective facies were generated covering low compact shale, high compact shale and silty shale having a gumbo-like stone mix. The wells analysed include: Alo – 1 Anambra River - 2, Ogbabu – 1, Oda-River – 1, Okpo- 1. The porosity range is (5% - 28.1%) while the permeability is (0 – 95.5) millidarcy. The semi-log plots of permeability versus porosity were carried out and partial single to multiple sand facies structures were observed for different wells. The composite plot confirmed significantly the existence of these multi-facies with the gumbo-like formation structure of marine origin, bearing high to low compact shale with silt and stony mix(figures 4.7-10). The 5% porosity cut off used is based on the shale structure and geometry.   The driving parameter for shale analysis is porosity and not permeability which are very low and not too significant(Thomas and Robert,1989).

The correlational equation from high compaction, to low compaction and very silty with gumbo-like stone mix are as follows

$(K(_{\phi}) = m\ln(\emptyset) \pm R)$

Where K(Ø)------permeability

m----------slope dependent on environmental factors(facies type)

R--------- intercept in semilog plot.

Table:4.4 Permeability as a function of Porosity/Facies Type Analysis Result of Nkporo Shale Gas well/Reservoir/Field

Formation Description	m	R
High compaction with less significant multiple facies	1.1716	14.041
Lower compaction with some multiple facies slightly significant	0.0758	-0.1067
Multi-facies with silty and gumbo-like stony mix	55.318	-137.49

Where K(ϕ)is the permeability as a function of porosity in milli-darcy (md), m is the gradient dependent on environment of deposition, Ø is porosity in percentage(%), and R is the intercept in millidarcy.

4.1.9 Core Data Analysis Results

Conventional core analysis data were not available for this study. Side wall core data result was used provided in Alo-1. The physical characteristics were compared with the lithofacies within Nkporo formation with that from well log data. The Nkporo shale formation exhibited high porosity with low permeability. Some areas of Nkpro shale formation exhibited a static porosity value irrespective of the increase in permeability. Alo – 1 and Oda River-1 wells exhibited similarities in Log signature. The Anambra-2 properties were correlated from Oda-river -1 and Alo-a wells that had more complete set of Log suite compared with Anambra River – 2.

4.1.10 Fluid Saturation Analysis Results

The connate water saturation was calculated using Simandoux model for the Nkporo shale structures.

Table:4.5 **Petrophysical Determinants(Discriminator cut off points) for Nkporo Shale Formation Wells(TOC>2.5%)**

Cutoff Type	Curve Name	Discriminator Cutoff
Pay	SWES	1.00
Res	PHIT_CS	0.050
Res	VSHS	1.00

Table:4.6 **Petrophysical Determinants(Net Reservoir) for Nkporo Shale Formation Wells(TOC>2.5%)**

Well Name	Zone Name	Top Dept(Ftss)	Bottom Depth(Ftss)	Gross Interval(Ft)	Net Res Int	Avg Phi(Res)	Avg VClay	Avg Net Sw
Anambra River-2	NKPOROS1	6200	7146	949.349	0	0	0	0
ALO-1	NKPOROS1	6500	7119	619.5	615	0.113	0.521	1
OKPO-1	NKPOROS1	6733.5	7429.5	698	441	0.108	0.374	0.933
ODA-RIVER-1	NKPOROS1	6540	7160	622.002	622.002	0.14	0.429	1
ALO-1	NKPOROS2	7129	7249.5	121	110.5	0.152	0.432	1
OKPO-1	NKPOROS2	7431.5	7479.5	50	40	0.114	0.162	0.831
ODA-RIVER-1	NKPOROS2	7160	7404	246.002	246.002	0.165	0.344	0.743
ALO-1	NKPOROS3	7251	7289.5	39	39	0.247	0.106	1
ODA-RIVER-1	NKPOROS3	7404	7596	194.002	194.002	0.10	0.667	1
ALO-1	NKPOROS4	7297.5	7480	183	150	0.097	0.535	1
ODA-RIVER-1	NKPOROS4	7596	7696	102.002	102.002	0.103	0.322	0.85

Table:4.7 **Petrophysical Determinants(Net Pay) for Nkporo Shale Formation Wells(TOC>2.5%)**

Well Name	Zone Name	Top Dept(Ftss)	Bottom Depth(Ftss)	Gross Interval(Ft)	Net Pay Int	Avg Phi(Pay)	Avg VClay	Avg Net Sw
Anambra River-2	NKPOROS1	6200	7146	949.349	0	0	0	0
ALO-1	NKPOROS1	6500	7119	619.5	615	0.113	0.521	1
OKPO-1	NKPOROS1	6733.5	7429.5	698	441	0.108	0.374	0.933
ODA-RIVER-1	NKPOROS1	6540	7160	622.002	622.002	0.14	0.429	1
ALO-1	NKPOROS2	7129	7249.5	121	110.5	0.152	0.432	0.991
OKPO-1	NKPOROS2	7431.5	7479.5	50	40	0.114	0.162	0.831
ODA-RIVER-1	NKPOROS2	7160	7404	246.002	246.002	0.165	0.344	0.743
ALO-1	NKPOROS3	7251	7289.5	39	39	0.247	0.106	1
ODA-RIVER-1	NKPOROS3	7404	7596	194.002	194.002	0.10	0.667	1
ALO-1	NKPOROS4	7297.5	7480	183	150	0.097	0.535	1
ODA-RIVER-1	NKPOROS4	7596	7696	102.002	102.002	0.103	0.322	0.85

Table:4.8 **Petrophysical Determinants(Reservoir-Pay/Gross,HPVH(Pay)) for Nkporo Shale Formation Wells(TOC>2.5%)**

Well Name	Zone Name	Top Dept(Ftss)	Bottom Depth(Ftss)	Gross Interval(Ft)	Res/Gross (Res)	Pay/Gross Ratio	HPVH (Pay)	Fluid Type
Anambra River-2	NKPOROS1	6200	7146	949.349	0	0	0	
ALO-1	NKPOROS1	6500	7119	619.5	0.993	0.993	0	Water
OKPO-1	NKPOROS1	6733.5	7429.5	698	0.632	0.632	3.192	Gas
ODA-RIVER-1	NKPOROS1	6540	7160	622.002	1	1	0	Water
ALO-1	NKPOROS2	7129	7249.5	121	0.913	0.913	0.156	Gas
OKPO-1	NKPOROS2	7431.5	7479.5	50	0.8	0.8	0.771	Gas
ODA-RIVER-1	NKPOROS2	7160	7404	246.002	1	1	10.4	Gas
ALO-1	NKPOROS3	7251	7289.5	39	1	1	0	Water
ODA-RIVER-1	NKPOROS3	7404	7596	194.002	1	1	0	Water
ALO-1	NKPOROS4	7297.5	7480	183	0.82	0.82	0	Water
ODA-RIVER-1	NKPOROS4	7596	7696	102.002	1	1	1.578	Gas

4.1.11 Summary Application of the Crain's Unconventional Shale Gas Volume in Place Model as applied for this study.

TOTAL SHALE GAS IN PLACE(GIPtotal) = GAS in place(interstitial(free gas)) + Gas in place(adsorbed under reservoir conditions)—--------(4.1)

SHALE GAS IN PLACE-adsorb

Gas content from correlation or core analysis data:

Gc = KG11 X TOC%----------(4.2)

Where:

Gc= gas content(scf/ton)

TOC%= total organic carbon(weight percent)

KG11= gas parameter, varies between 5 and 15

GIPadsorb = KG6 X Gc X DENS X THICK X AREA------------(4.3)

Where:

GIPadsorb = gas in place(Bcf)

Gc = adsorbed gas content in isothermal condition(scf/ton)

DENS = layer density from log or lab measurement(g/cc) 2.20 to2.60

THICK=layer thickness(feet)

AREA = spacing unit area(acres)

KG6 = $1.3597X10^{-6}$

SHALE GAS IN PLACE(GIP) – free gas

GIPfree = $\frac{KV4\ X\ (1-Qnc)\ X\ PHIeX(1-Sw)\ X\ THICK\ X\ AREA}{Bg}$ -------------------------(4.4)

Bg= $\frac{(Ps\ X\ (Tf+KT2))}{((Pf\ X\ (Ts+KT2))\ X\ ZF)}$ --(4.5)

Where:

AREA=reservoir area(acres)

Bg = gas formation volume factor(ft/scf)

GIPfree = original free gas in place(Bcf)

PHIe = effective porosity(fractional)

Sw = Water Saturation in un-invaded zone(fractional)

THICK=layer thickness(feet)

Pf=formation pressure

Ps= surface pressure(feet)

Tf = formation Temperature(^{o}F)

Ts = surface Temperature(^{o}F)

ZF =gas compressibility factor(fractional)

KT2 = 460^{o}F

KV4=0.000043560

Qnc =fraction of gas that is non combustible(CO2,N2,etc)

If area is assumed to be 640acres, then GIP = Bcf/Section=Bcf/sq.mile)

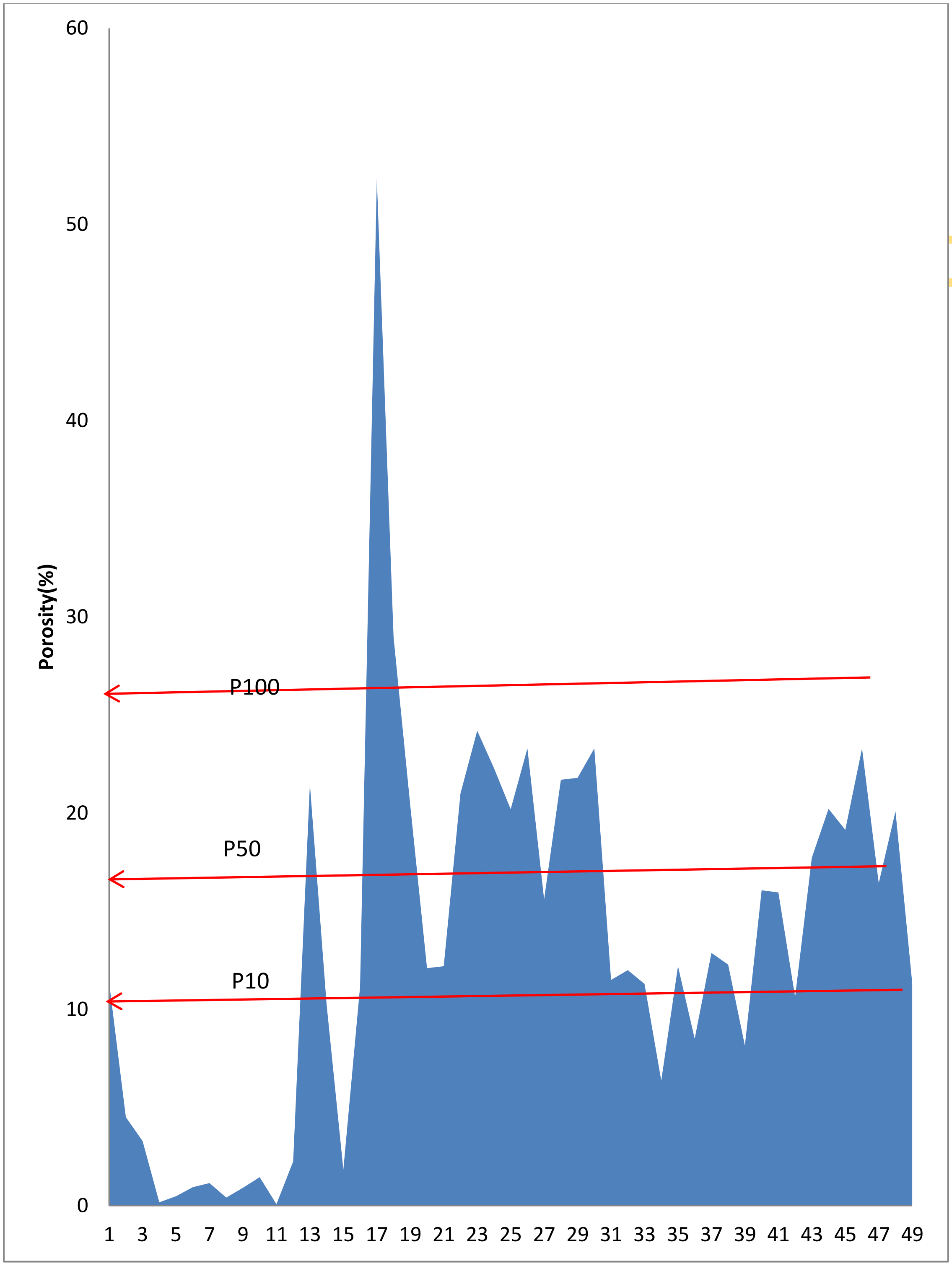

Fig: 4.14 Nkporo shale Porosity probability chart

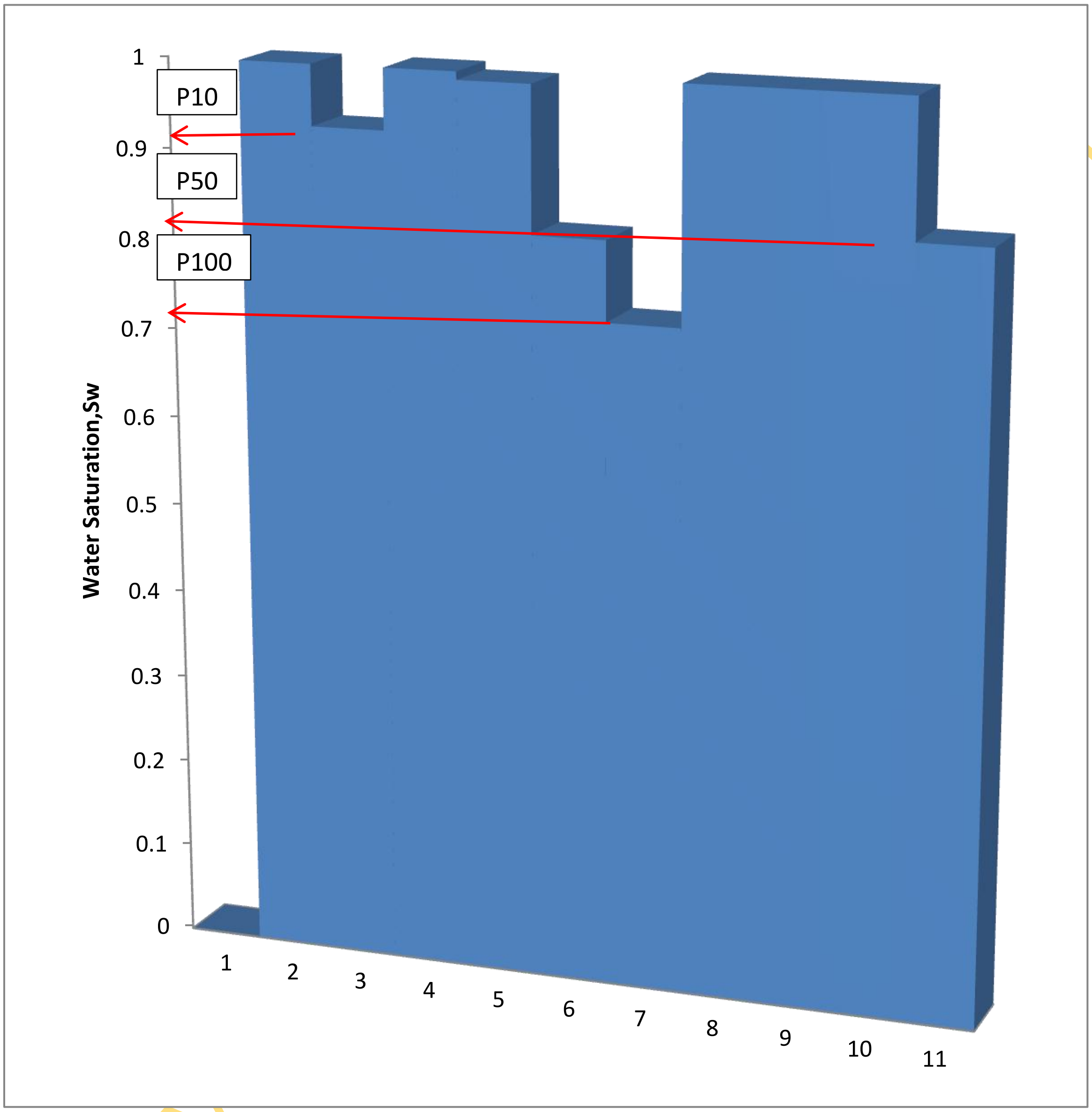

Fig:4.15 Nkporo shale water saturation probability chart

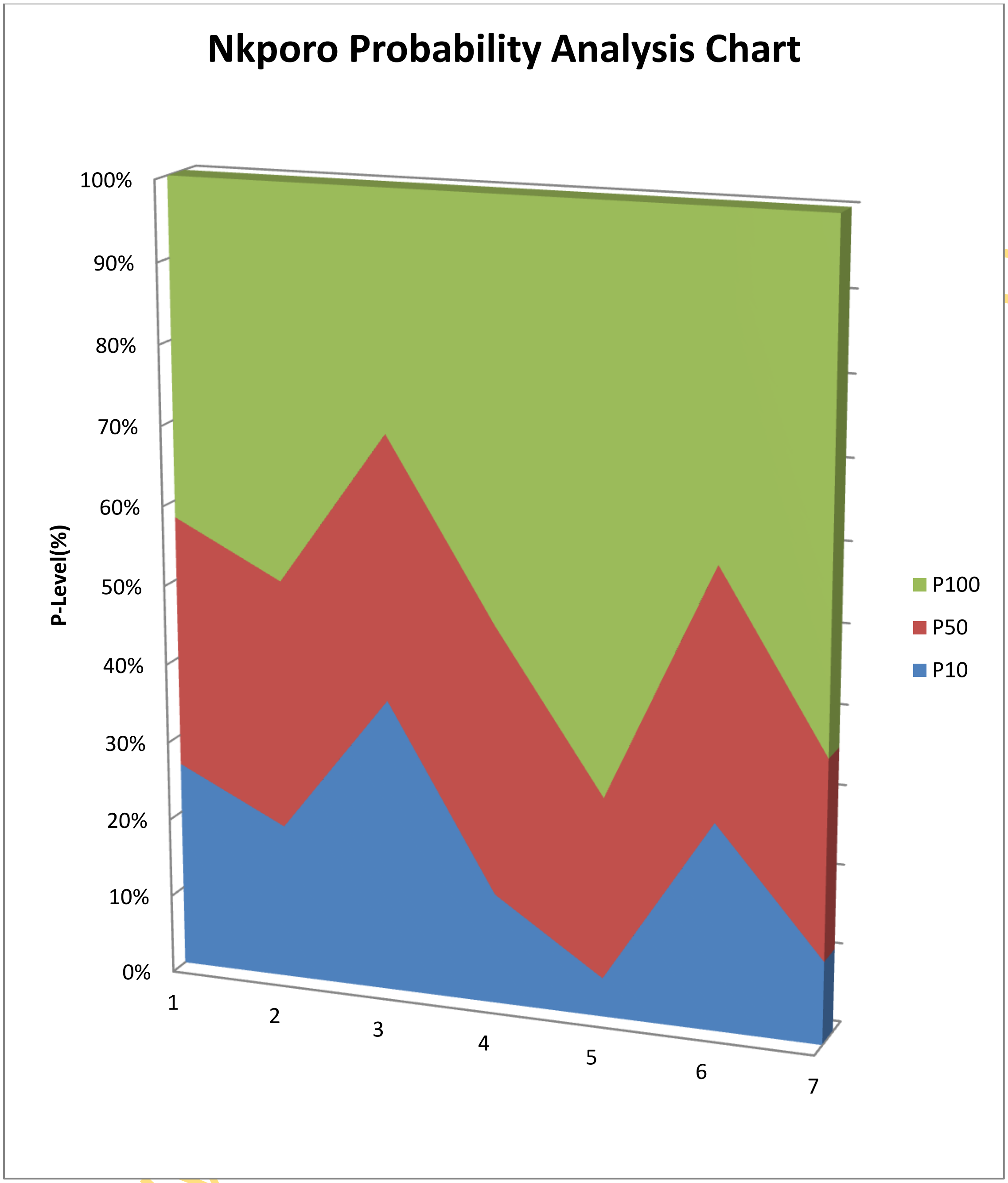

Fig 4.16: Nkporo Probability Analysis Chart

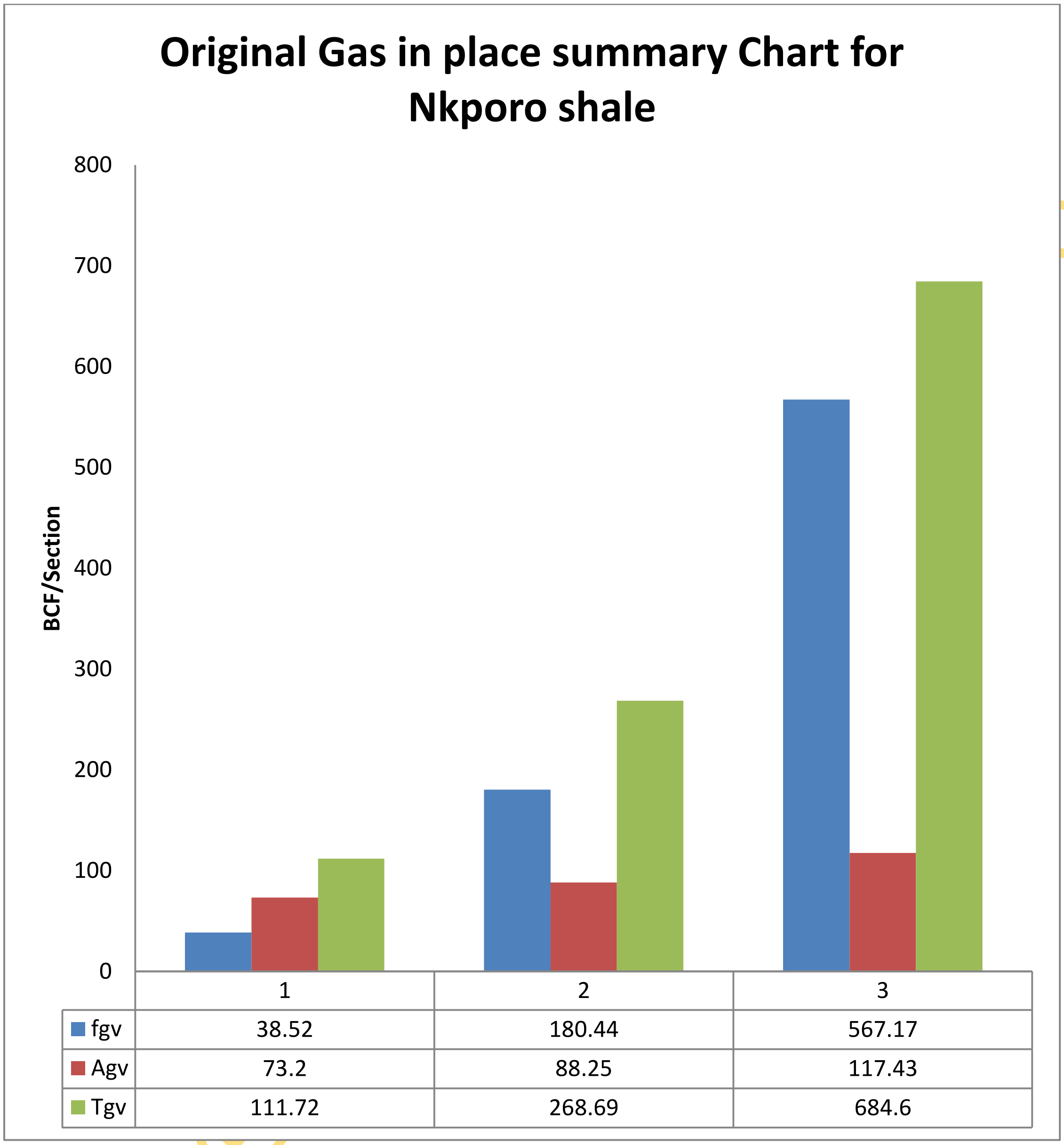

Fig 4.17: Original Gas in place summary Chart of Nkporo Shale

Table: 4.9 Original Gas in Place of Nkporo Shale Formation(Free and Adsorbed) applying Crains Model

Parameter	P10	P50	P100
Delta h(ft)	1046	1261	1678
Phie	0.1	0.16	0.25
Sw	0.93	0.83	0.74
Sg	0.07	0.17	0.26
GIPfree(BCF/Section(sq mile)) ie per 640 acre well spacing	38.52	180.44	567.17
GIPadsorbed(BCF/Section(sq mile)) ie per 640acre well spacing	73.20	88.25	117.43
GIPtotal(BCF/Section(sq mile))ie per 640acre well spacing	111.72	268.69	684.60

4.1.12 Summary Analysis of the Original Gas in Place for Nkporo Shale Formation

The most contributary gas volume reserves areas can be observed from the petrophysical analysis of different determinants for different well layers (Tables 4.5-8).). Porosity ranges from 5.0–28.1 % while effective permeability ranges from 0.0–95.5 millidarcy. Water saturation ranges from 0.70–0.99. The original gas in place was established at 2.93 million m^3 per km^2 (268.69 BCF/640-acre well spacing) with the potential to increase to 7.33 million m^3per km^2 (685 BCF/640-acre well spacing).The total(Tgv) is made up of Original free gas in place(fgv) of 180.44BCF/640acre well spacing with potential to increase to 567.17BCF/640acre well spacing and the Original adsorbed gas in place(Agv) of 88.25BCF/640acre well spacing with potential to increase to 117.43 BCF/640 acre well spacing. The total gas volume in place(P50) is skewed toward P10 but will move toward P100 as Nkporo is derisked through drilling of more wells(figure 4.15). The gas fluid in place is subjected to vertical and horizontal stresses.

Vertical and horizontal compressive stresses range from 4.6–5.27 and 2.41–2.77 x 10^7 N/m^2 (6673–7646 and 3498–4008 psia) respectively.The vertical compressive stress range obtained from the study tallied with the production test result carried out on Nkporo well (Akukwa-1) which experienced bottom hole pressure up to 6600 psi blow-out (Avbovbo and Ayoola;1981).

This study will act as a guide during future drilling for the Full development plan and

also in carrying out a full pore pressure study needed to prevent future well blow out.

4.3.1 Simulation of the Production Forecasting of Nkporo Gas Shale Formation

The Nkporo shale Formation has some good properties with high porosities but low permeabilities. Hence hydraulic fracturing must be employed. The simulation of the fracture lenght was carried out using Holditch Model approach. This method offer a practical solution. The effective drainage radius is required.

4.3.2 Analysis of Nkporo shale formation mechanics and hydraulic fracture design

Designing the well that requires frac job will require the understanding of the following:

1. Lithology and Minerology of the Formation
2. Fracture Geometry Parameters
3. Reservoir Fluids and Reservoir Energy
4. Physical Well Configuration

The hyraulic fracturing can be enhanced to improve the gas productivity by considering the following factors:

- Treatment cost- Type and volume of frac fluid,Propping agents,hydraulic horse power required.
- Productivity Increase- minimize formation damage,fracture conductivity,multizone sectional coverage,injection rate.

Table: 4.10 Result analysis of Total Vertical and Horizontal Stress , Permeability versus Depth of Nkporo Shale Formation

Well Name	**Zone**	**Mid Depth** **ftss**	**Total Vertical Stress; σ_v** **Psi**	**Formation Permeability; K (md)**	**Total Horizontal Stress; σ_h** **Psi**
Anambra River – 2	S1	6673	6,726.38	1.01	3497.72
Alo – 1	S1	6809.5	6,864.00	1.01	3569.28
Okpo – 1	S1	7081.5	7,138.15	56	3711.84
Oda River – 1	S1	6850	6,904.80	0.035	3,590.50
Alo – 1	S2	7189.25	7,246.76	0.50	3768.34
Okpo – 1	S2	7455.5	7,515.14	2.00	3907.87
Oda-River – 1	S2	7282	7,340.26	0.11	3816.94
Alo – 1	S3	7,270.25	7,328.41	20.0	3810.78
Oda River – 1	S3	7,500	7,560	0.10	3931.2
Alo – 1	S4	7,388.75	7,447.86	29.0	3872.89
Oda River - 1	S4	7,646.00	7,707.17	0.11	4007.73

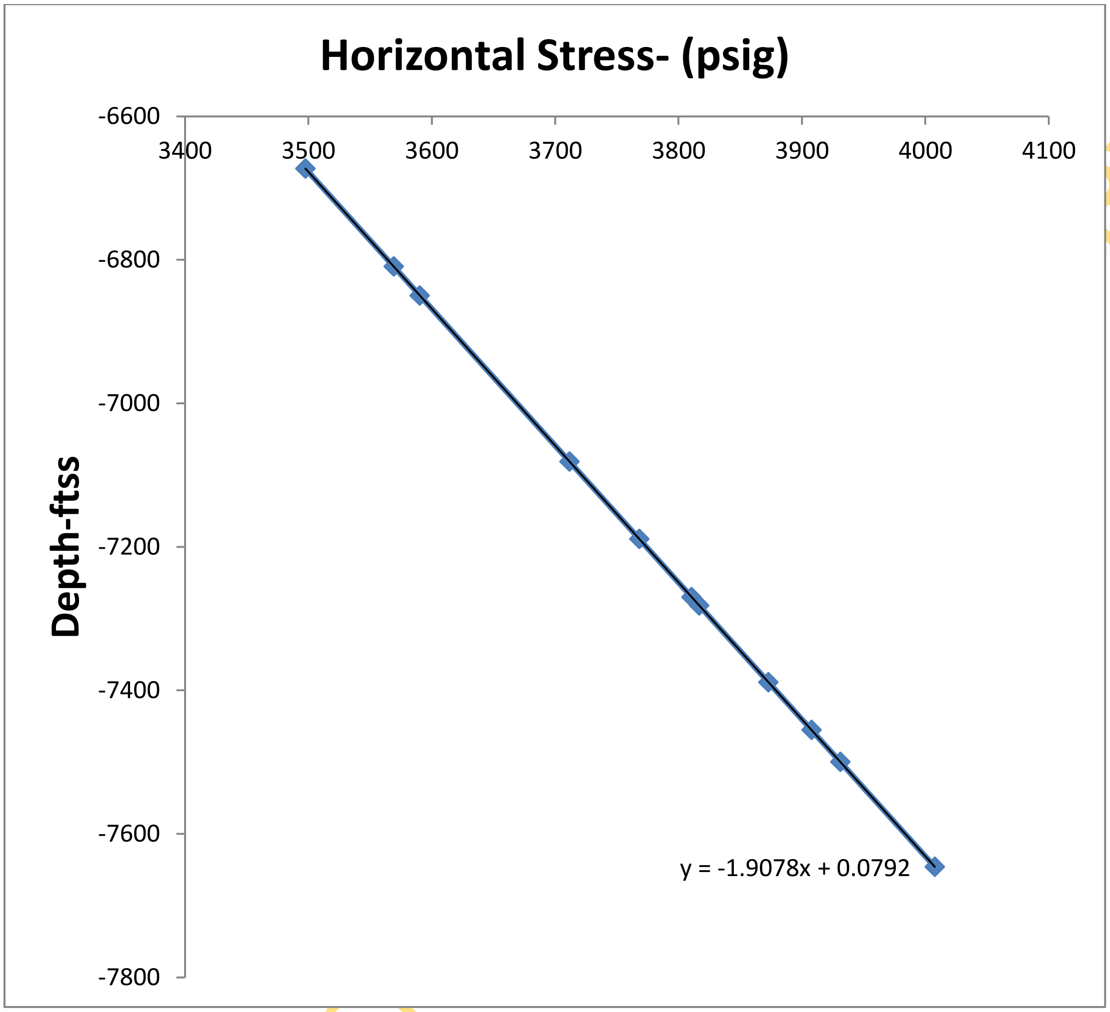

Fig: 4.18 **Horizontal Stress of Nkporo Shale Formation versus Depth**

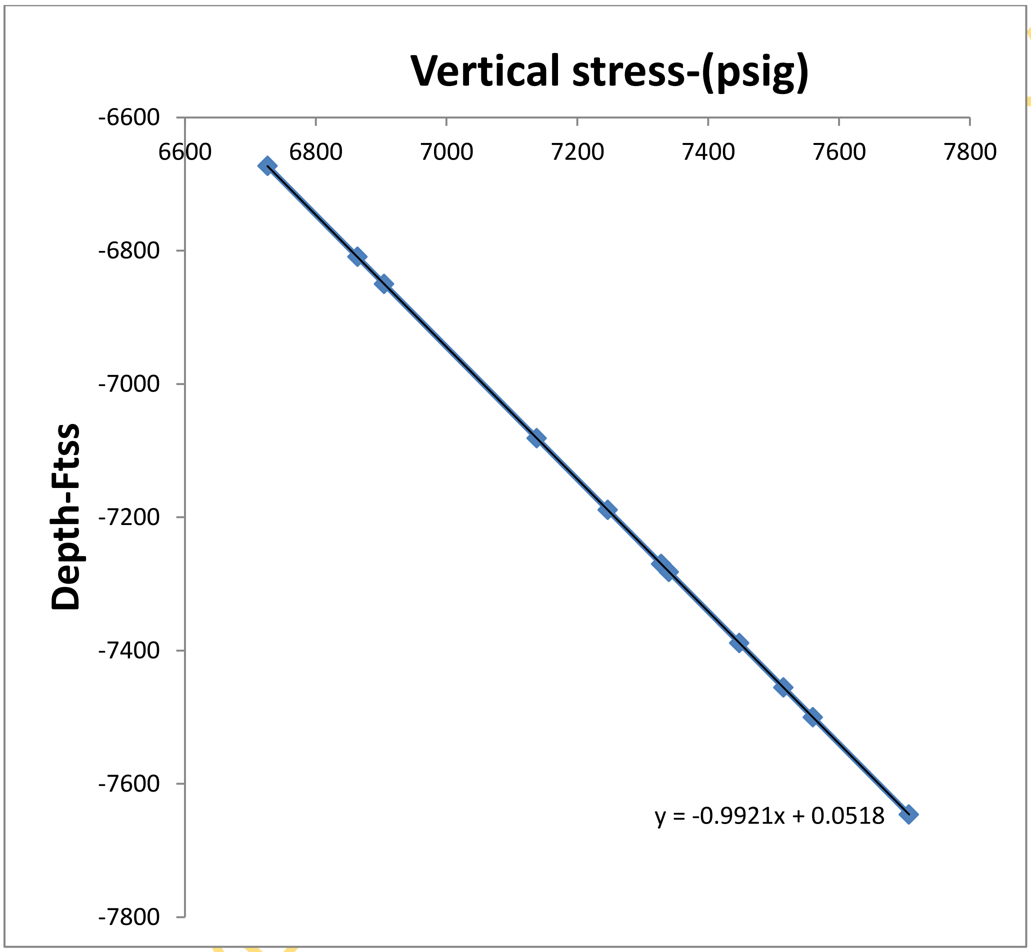

Fig: 4.19 Vertical Stress of Nkporo Shale Formation versus Depth

There is higher vertical and horizontal compressive stress of the formation observed in deeper regions /sands of the wells in Nkporo shale formation. Hence, the drilling design must take cognizance of possible blow out if the mud system is not properly managed. This might result to loss of wells. There should be a full study of the pore pressure distribution in Nkporo shale formation during a full field development study. Nevertheless, the pore pressure obtained from the intercept of the vertical stress/depth plot is 6650psig.The vertical compressive stress ranges from 6673 to 7646.0 psi while that of horizontal compressive stress ranges from 3497.7 to 4007.7 psi. Currently, the minimal Pore pressure assumptions has uncertainties and will be derisked following the full pore pressure study during the full field development study in future. The high conductivity fracture relative to the formation permeability could only be achieved when the flow pattern is changed from radial to linear pattern(McGraw and Sikora). Fracture length generated becomes significant only where there are high permeability and productivity index contrast.

The understanding of the formation geomechanics will enhance the design of the hydraulic fracturing system. Equations 3.6-8 were applied to carryout the horizontal/vertical stress analysis that yielded the result in Table 4.9,Figs 4.18-19. Higher compaction is observed in the deeper wells.The vertical stress are more prominent than horizontal but they both affect the frature geometry depending on the location.

Table:4.11 Summary Analysis Result of Fracture Design Scaling of Nkporo Shale Formation using 40acre well space referencing,and 1000ft fracture length

Well spacing (Acres)	**Drainage (Radii – ft)**	**wK_f/K**	**J/Jo**	**re/rw**	**Cr**	**LR**
20	467	1.42	1.05	1,868	0.00045	2.14
40	660	1.00	1.00	2,640	0.00032	1.52
60	808	0.82	0.97	3,232	0.00026	1.24
80	933	0.71	0.95	3,732	0.00023	1.07
100	1044	0.63	0.94	4,176	0.00020	0.96
160	1320	0.50	0.91	5,280	0.00016	0.76
200	1467	0.45	0.90	5,904	0.00014	0.68
320	1867	0.35	0.87	7,468	0.00011	0.54
640	2640	0.25	0.84	10,560	0.0001	0.38

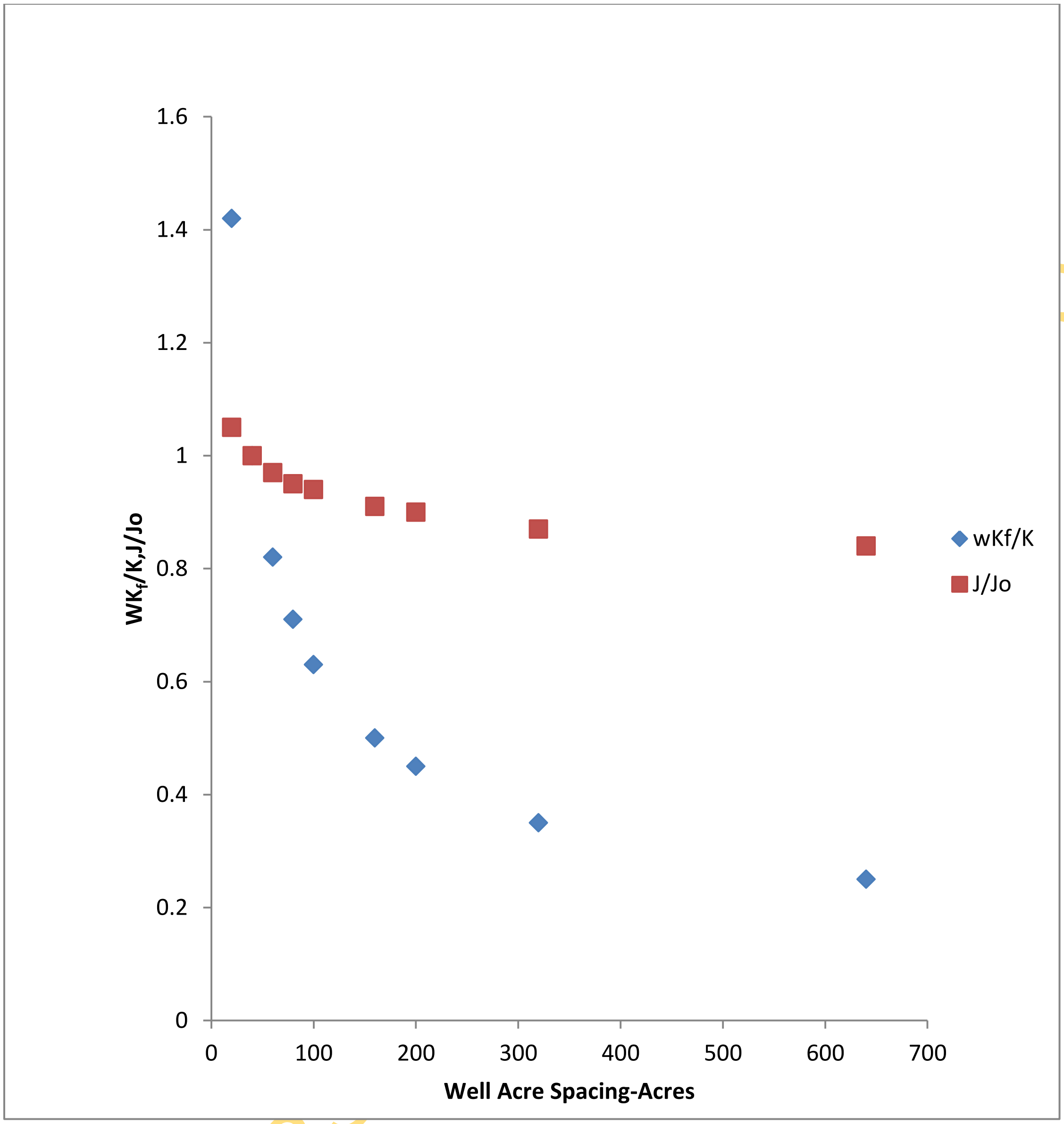

Fig:4.20 Fracture Design Scaling of WK_f/K,J/Jo versus Well Acre Spacing using 40acre referencing

Table:4.12 Summary Analysis Result of Fracture Design Scaling of Nkporo Shale Formation using 100acre well space referencing.and 1000ft fracture length

Well spacing (Acres)	**Drainage (Radii – ft)**	**wK_f/K**	**J/Jo**	**re/rw**	**Cr**	**LR**
20	467	2.24	1.05	1,868	0.00072	2.14
40	660	1.58	1.00	2,640	0.00051	1.52
60	808	1.29	0.97	3,232	0.00041	1.24
80	933	1.12	0.95	3,732	0.00036	1.07
100	1044	1.00	0.94	4,176	0.00032	0.96
160	1320	0.79	0.91	5,280	0.00025	0.76
200	1467	0.71	0.90	5,904	0.00023	0.68
320	1867	0.56	0.87	7,468	0.00008	0.54
640	2640	0.40	0.84	10,560	0.00013	0.38

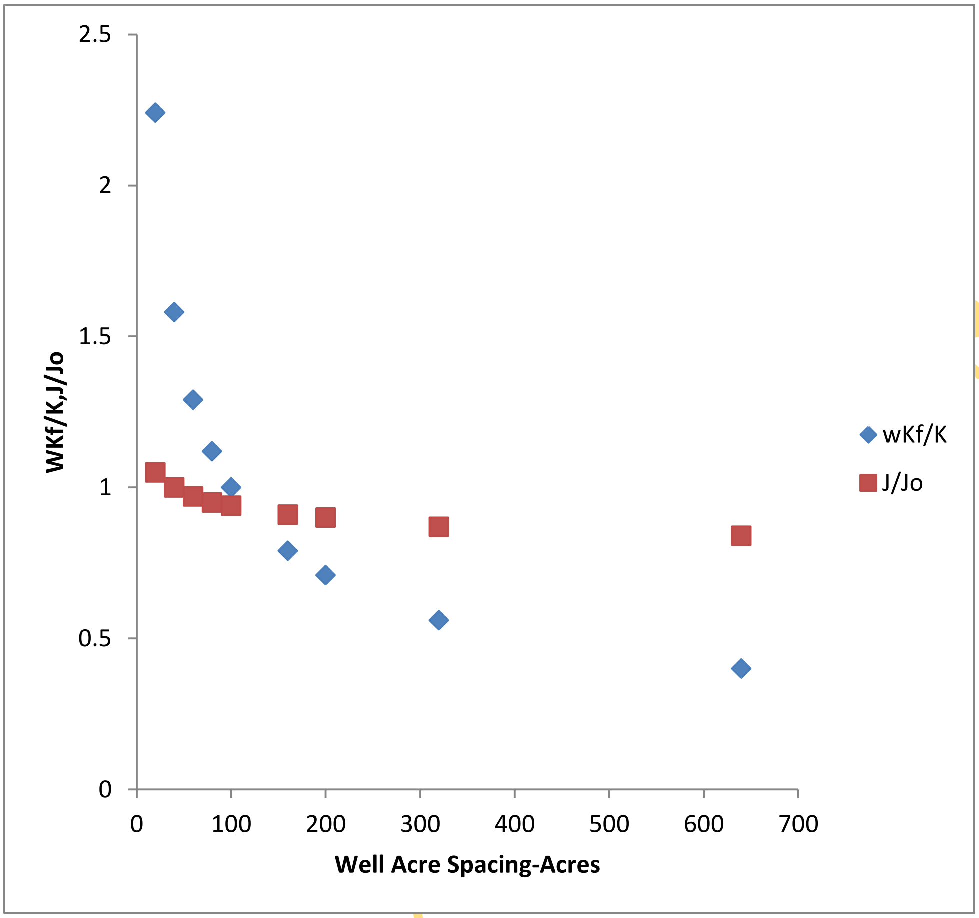

Fig:4.21 Fracture Design Scaling of WKf/K,J/Jo versus Well Acre Spacing using 100 acre spacing referencing and 10000ft fracture lenght

Table:4.13: Summary Analysis Result of Fracture Design Scaling of Nkporo Shale Formation using 200acre well space referencing,and 1000ft fracture length

Well spacing (Acres)	Drainage (Radii – ft)	wK_f/K	J/Jo	re/rw	Cr	LR
20	467	3.16	1.05	1,868	0.0010	2.14
40	660	2.24	1.00	2,640	0.00074	1.52
60	808	1.83	0.97	3,232	0.00059	1.24
80	933	1.58	0.95	3,732	0.00051	1.07
100	1044	1.41	0.94	4,176	0.00045	0.96
160	1320	0.12	0.91	5,280	0.00036	0.76
200	1467	1.00	0.90	5,904	0.00032	0.68
320	1867	0.79	0.87	7,468	0.00025	0.54
640	2640	0.56	0.84	10,560	0.00018	0.38

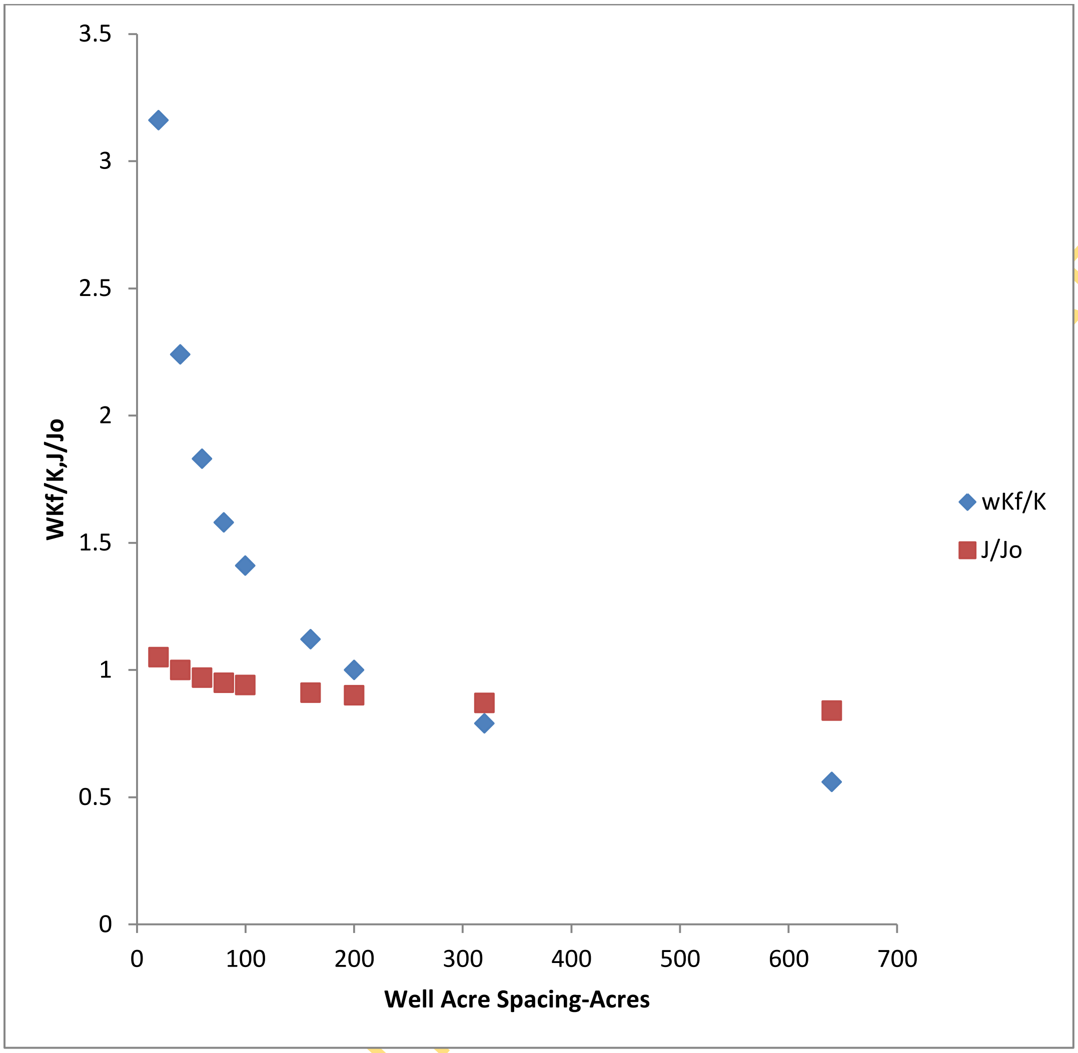

Fig:4.22 Fracture Design Scaling of WK_f/K ,J/Jo versus Well Acre Spacing using 200 acre referencing and 1000ft fracture lenght.

Table:4.14 Summary Analysis Result of Fracture Design Shale Formation using 640acre well space referencing,and 1000ft fracture length

Well spacing (Acres)	**Drainage (Radii – ft)**	**wK_f/K**	**J/Jo**	**re/rw**	**Cr**	**LR**
20	467	5.66	1.05	1,868	0.00018	2.14
40	660	4.00	1.00	2,640	0.00013	1.52
60	808	3.27	0.97	3,232	0.0010	1.24
80	933	2.83	0.95	3,732	0.00091	1.07
100	1044	2.53	0.94	4,176	0.00081	0.96
160	1320	2.00	0.91	5,280	0.00064	0.76
200	1467	0.79	0.90	5,904	0.00057	0.68
320	1867	1.41	0.87	7,468	0.00045	0.54
640	2640	1.00	0.84	10,560	0.00032	0.38

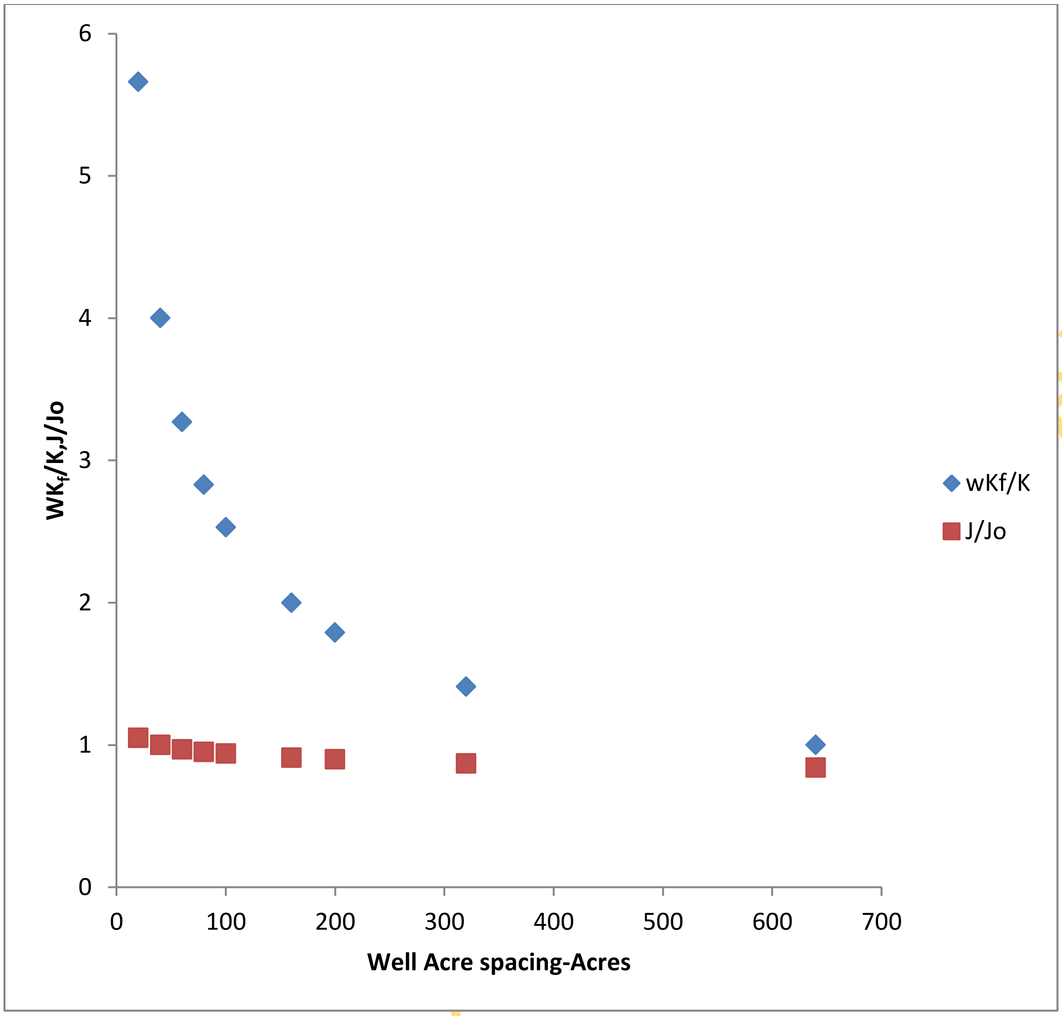

Fig:4.23 Fracture Design Scaling of WK_f/K,J/Jo versus Well Acre Spacing using 640 acre referencing and 1000ft fracture lenght.

It is difficult to achieve permeability contrast of about 10,000md in /md, except in such formations like Nkporo shale or other tight sands where there are existence of very low permeabilities. It is observed that high fracture conductivity and permeability contrasts were achieved in Nkporo shale formation.The optimum well spacing choosen for Nkporo Production is 640 acres while the fracturing length is 1000ft.

Fig 4.24 shows low permeability contrast at shallow depth range of 6600-6850ftss and also in deeper region 7388-7500ftss,while other areas experienced high permeability contrast using sand producing conductivity fracture of 10000md-in with .2in 20/40 mesh.

Fracture productivity contrast index are high at low permeability with cluster characteristics but dropped as the permeability increases prior to maintaining a consistent value before dropping again within 30-60md range(Fig 4.29). Increase in fracture lenght index improved the fracture conductivity contrast with respect to formation depth where the most optimized J/Jo values ranges from 1-7.0 at different fracture index lenght following several sesitivity computations such as(Table 19) and others.

Table:4.15 Summary of the Results of Nkporo Shale Formation Permeability Contrast(wK_f/K),Productivity Index Contrast (J/Jo) as a function of Dimensioless Fracture Length(LR)=0.2,Aerial well radius(Xe)=2640ft,Fracture Length(X_f)=500ft packed with .2inch- 20/40 mesh propping Sand in polymer having production conductivity(wK_f) of 10,000in-md applying McGraw and Sikora(Radial low pattern) model.

Well name	**Sand**	**Mid Depth (ftss)**	**σ_v (psi)**	**σ_h (Psi)**	**K (md)**	**LR (Dimensionless Fracture lenght)**	**wK_f/K in-md/md**	**J/Jo**
Anambra-River -2	S1	6673	6,726.38	3497.72	1.01	0.2	9,901.00	3.8
Alo -1	S1	6809.5	6,864.00	3569.28	1.01	0.2	9,901.00	3.8
Okpo – 1	S1	7081.5	7,138.15	3711.84	56	0.2	178.57	1.0
Oda Rivers -1	S1	6,850	6,904.80	3,590.50	0.035	0.2	285,714	4.2
Alo – 1	S2	7,189.25	7,2616.76	3,768.32	0.50	0.2	20,000	4.0
Okpo -1	S2	7,455.5	7,515.14	3907.87	2.00	0.2	50,000	4.05
Oda River-1	S2	7,282	7,340.26	3816.94	0.11	0.2	90,909	4.1
Alo-1	S3	7,270.25	7,328.41	3810.78	20.00	0.2	500	1.9
Oda River -1	S3	7,500	7,560	3931.20	10.11	0.2	989	2.0
Alo-1	S4	7,388.75	7,447.86	3872.89	29.00	0.2	345	1.8
Oda River – 1	S4	7,646.00	7,707.17	4007.73	0.11	0.2	90,909	4.1

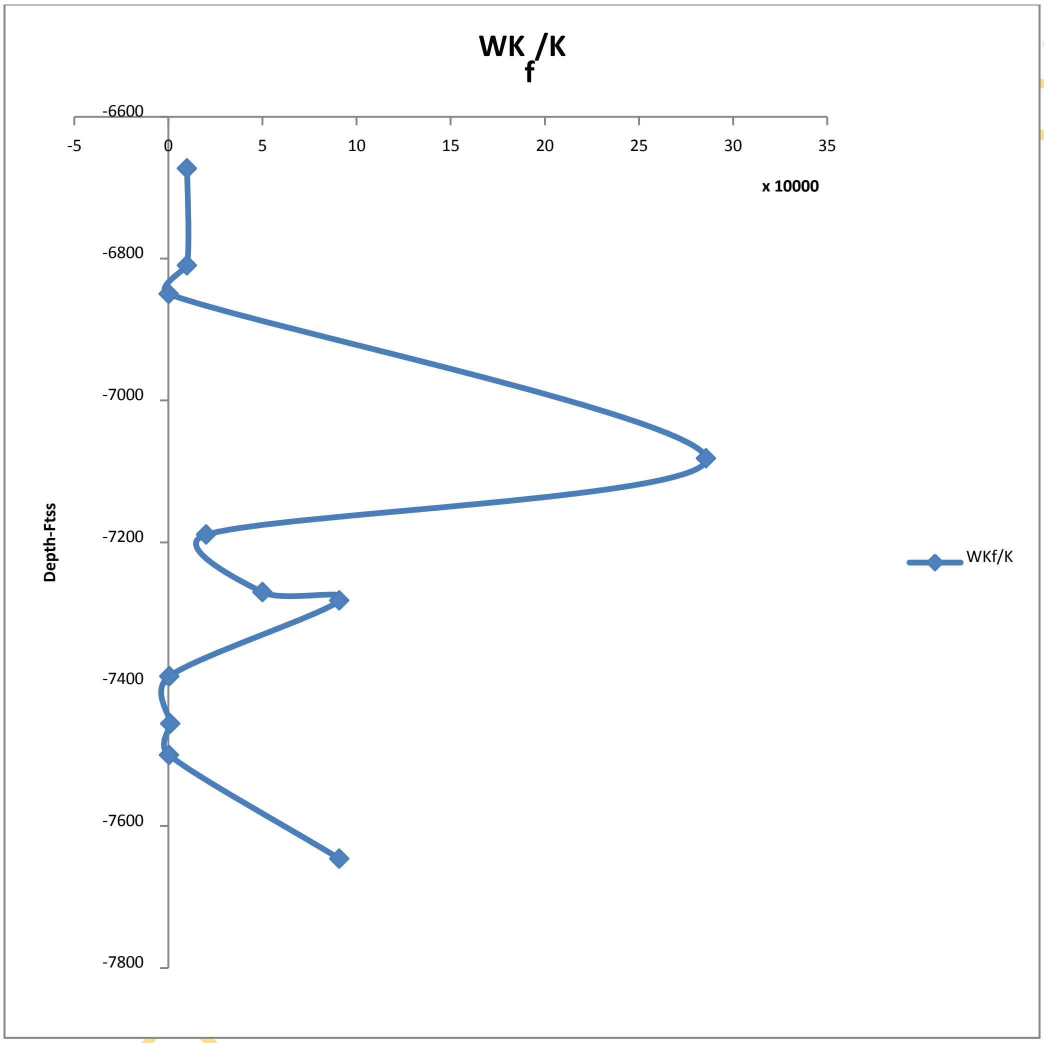

Fig:4.24 Plot of Fracture Permeability Contrast(wK_f/K) versus Depth of Nkporo Shale Formation using Sand producing conductivity (wK_f=10,000md-in with .2in 20/40mesh)

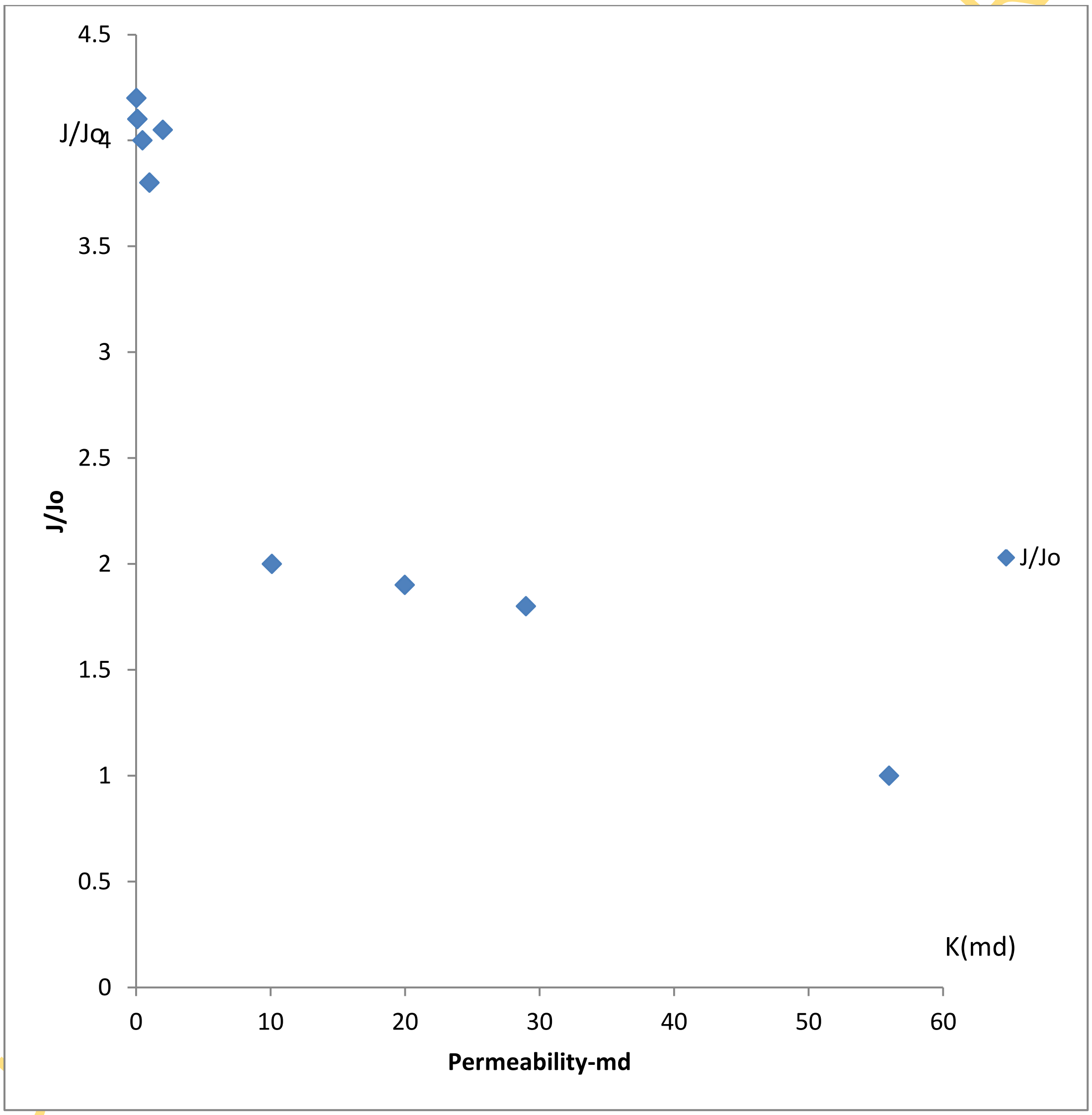

Fig:4.25 Plot of Fracture Productivity Index Contrast(J/Jo) versus Formation Permeability of Nkporo Shale at LR=0.2 using Sand producing conductivity(WK_f=10,000md-in with .2in 20/40mesh)

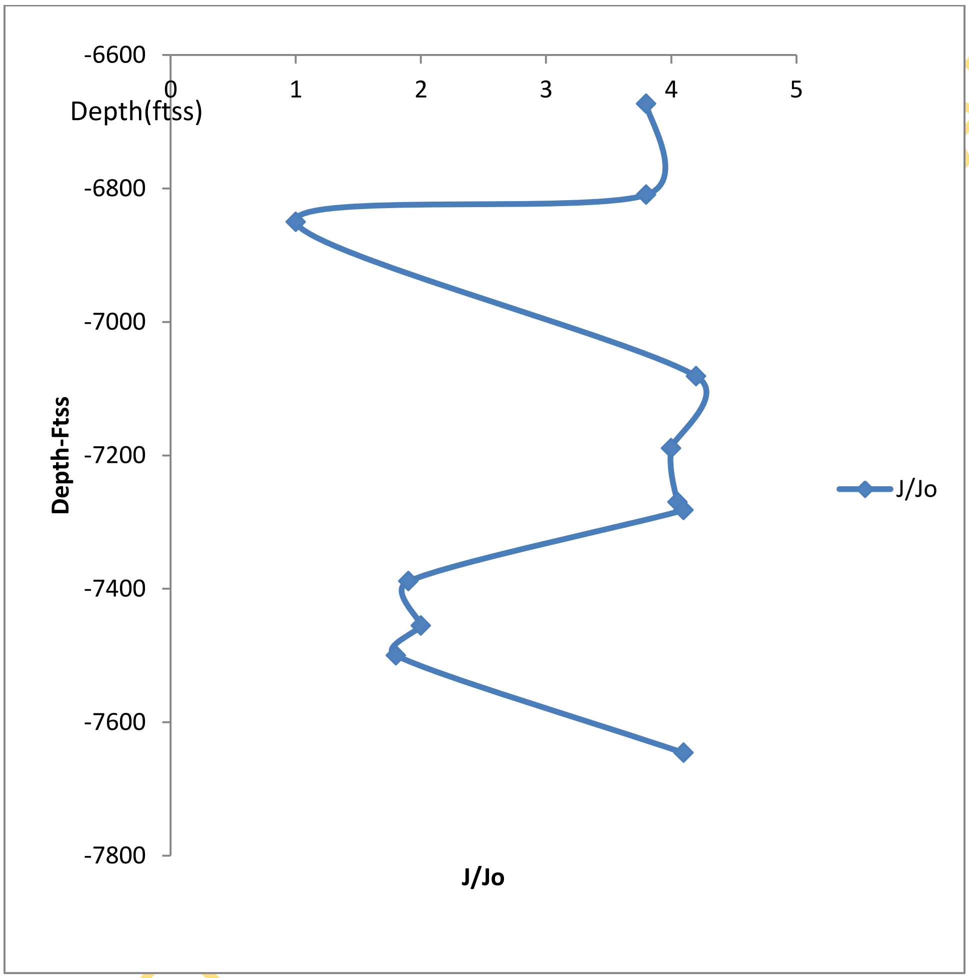

Fig:4.26 Fig:Plot of Fracture Productivity index contrast(J/Jo) versus Depth of Nkporo Shale Formation at LR=0.2 using Sand producing conductivity (WK_f=10,000md-in with .2in 20/40mesh)

The 20/40 mesh prop sand was used during the Fracture packing following the propping phase. The S1 Sand when fractured and propped with 20/40 mesh and increased the productivity fold range within (1-7.0) at 6673 to 7081.5ftss covering wells such as Anambra – River – 2, Alo-1, Okpo-1 and Oda River-1. S2 sand observed in Alo-1, Okpo-1 and Oda River- 1 witnessed increase productivity index fold range of (5.5-6.8). S3 sand observed in Alo-1 and Oda-River-1 wells witnessed increase of productivity index fold range of (1.9-2.0) while that of S4 sand ranges (1.8-6.8). The sand with very low permeabilities had a better productivity and permeability contrast when fractured and propped.

On the average in the production forcasting the cumulative production will increase 9 folds using vertical fracturing using 2inch 20/40 mesh prop sand into a 1,000 ft fracture lenght and 640 acre well spacing dual completions.

Table:4.16 Summary of the Results of Nkporo Shale Formation Permeability Contrast(wK_f/K),Productivity Index Contrast (J/Jo) as a function of Dimensioless Fracture Length(LR)=0.3,Aerial well radius(Xe)=2640ft,Fracture Length(X_f)=800ft packed with .2inch- 20/40 mesh propping Sand in polymer having production conductivity(wKf) of 10,000in-md applying McGraw and Sikora(Radial low pattern) model.

Well name	**Sand**	**Mid Depth (ftss)**	σ_v **(psi)**	σ_h **(Psi)**	**K (md)**	**LR (Dimensionless Fracture lenght)**	wK_f/K **in-md/md**	**J/Jo**
Anambra-River -2	S1	6673	6,726.4	3497.7	1.01	0.3	9,901	4.0
Alo -1	S1	6809.5	6,864.00	3569.3	1.01	0.3	9,901	4.0
Okpo – 1	S1	7081.5	7,138.2	3711.8	56	0.3	178.6	1.0
Oda Rivers -1	S1	6,850	6,904.8	3,590.5	0.035	0.3	285,714	5.8
Alo – 1	S2	7,189.25	7246.8	3,768.3	0.50	0.3	20,000	4.2
Okpo -1	S2	7,455.5	7,515	3907.9	2.00	0.3	50,000	5.0
Oda River-1	S2	7,282	7,340.3	3816.9	0.11	0.3	90,909	5.8
Alo-1	S3	7,270.25	7,328.4	3810.8	20.00	0.3	500	1.9
Oda River -1	S3	7,500	7,560	3931.2	10.11	0.3	989	2.0
Alo-1	S4	7,388.75	7,447.9	3872.9	29.00	0.3	345	1.8
Oda River – 1	S4	7,646.00	7,707.2	4007.7	0.11	0.3	90,909	5.8

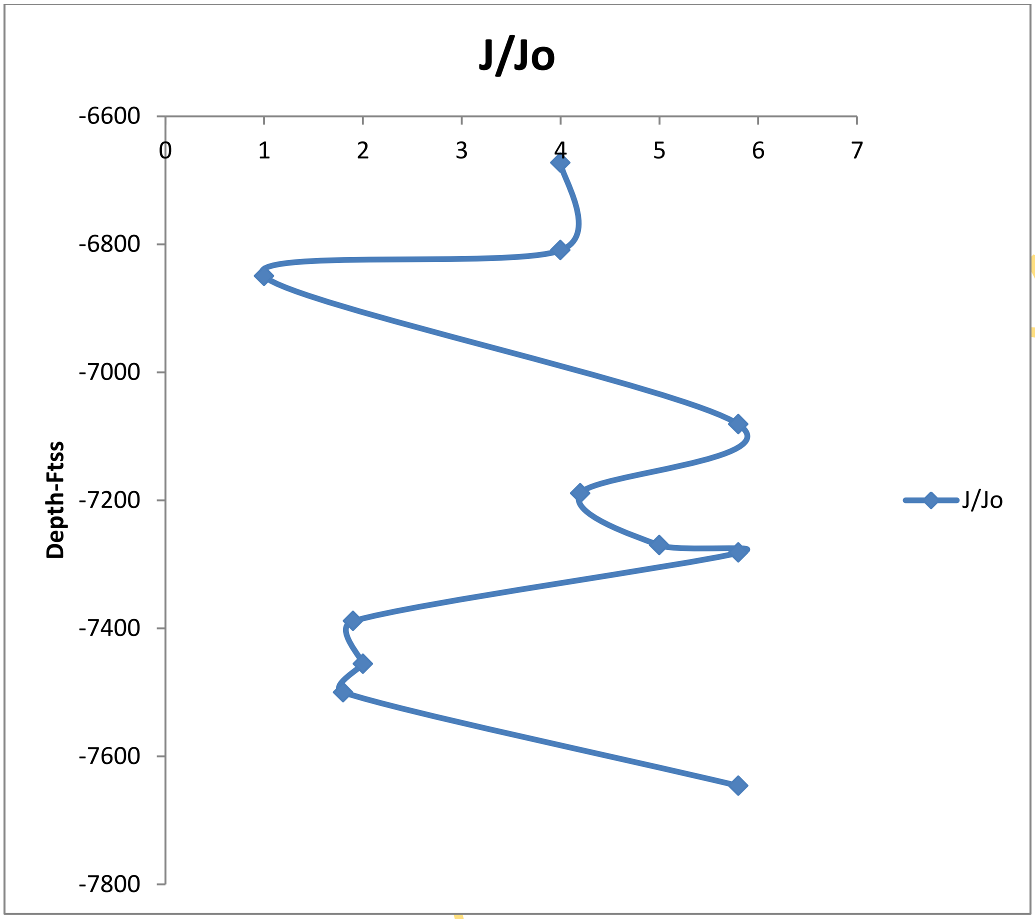

Fig:4.27 Plot of Fracture Productivity Index Contrast(J/Jo) versus Depth of Nkporo Shale Formation at LR=0.3 using Sand producing conductivity (WK_f=10,000md-in with .2in 20/40mesh)

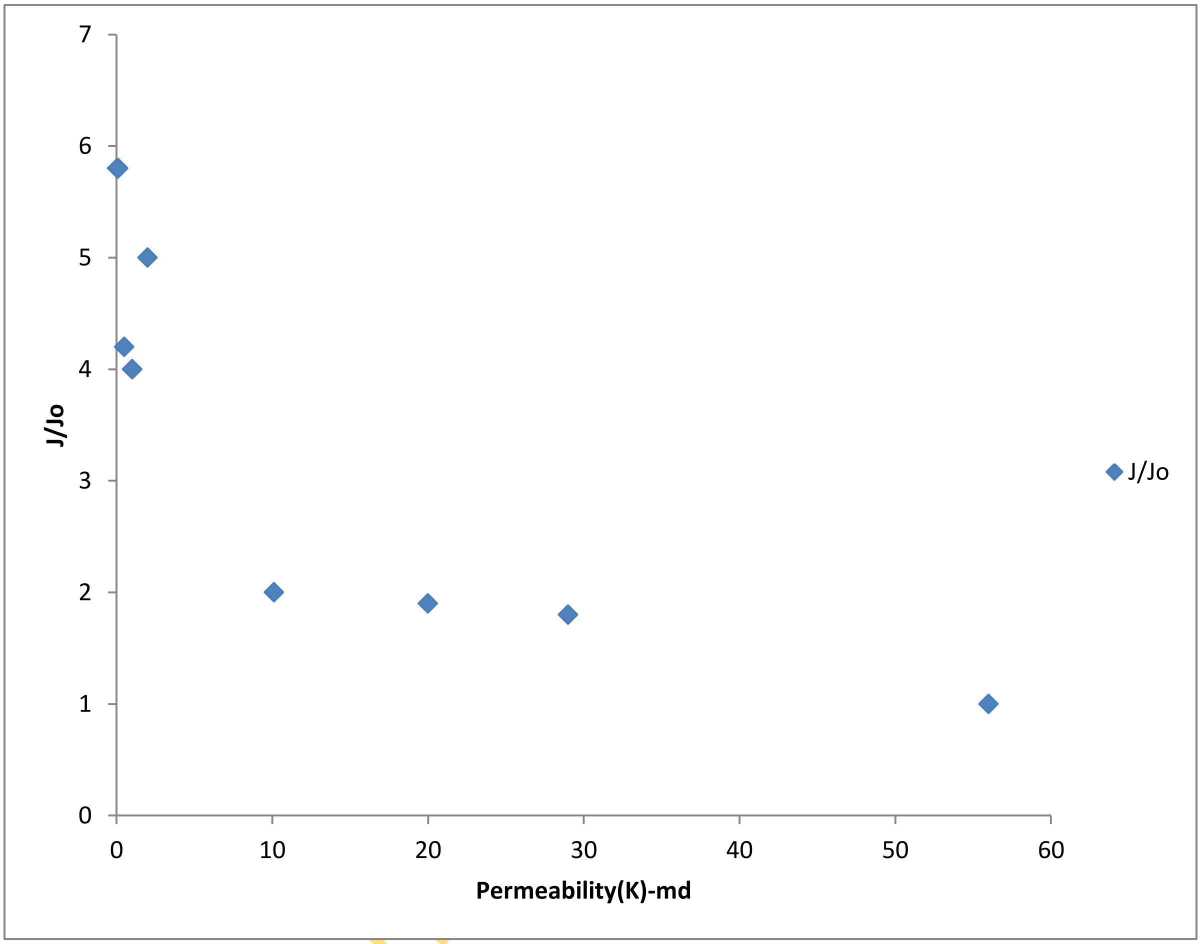

Fig:4.28 Plot of Fracture Productivity Index Contrast(J/Jo) versus Formation Permeability of Nkporo Shale at LR=0.3 using Sand producing conductivity(WK_f=10,000md-in with .2in 20/40mesh)

Table:4.17 Contrast (J/Jo) as a function of Dimensioless Fracture Length(LR)=0.4,Aerial well radius(Xe)=2640ft,Fracture Length(X_f)=1000ft packed with .2inch- 20/40 mesh propping Sand in polymer having production conductivity(wK_f) of 10,000in-md applying McGraw and Sikora(Radial low pattern) model.

Well name	**Sand**	**Mid Depth (ftss)**	σ_v **(psi)**	σ_h **(Psi)**	**K (md)**	**LR (Dimensionless Fracture lenght)**	wK_f/K **in-md/md**	**J/Jo**
Anambra-River -2	S1	6673	6,726.38	3497.72	1.01	0.4	9,901	5.0
Alo -1	S1	6809.5	6,864.00	3569.28	1.01	0.4	9,901	5.0
Okpo – 1	S1	7081.5	7,138.15	3711.84	56	0.4	178.6	1.0
Oda Rivers -1	S1	6,850	6,904.80	3,590.50	0.035	0.4	285,714	7.0
Alo – 1	S2	7,189.25	7,2616.76	3,768.32	0.50	0.4	20,000	5.5
Okpo -1	S2	7,455.5	7,515.14	3907.87	2.00	0.4	50,000	6.0
Oda River-1	S2	7,282	7,340.26	3816.94	0.11	0.4	90,909	6.8
Alo-1	S3	7,270.25	7,328.41	3810.78	20.00	0.4	500	1.9
Oda River -1	S3	7,500	7,560	3931.20	10.11	0.4	989	2.0
Alo-1	S4	7,388.75	7,447.86	3872.89	29.00	0.4	345	1.8
Oda River – 1	S4	7,646.00	7,707.17	4007.73	0.11	0.4	90,909	6.8

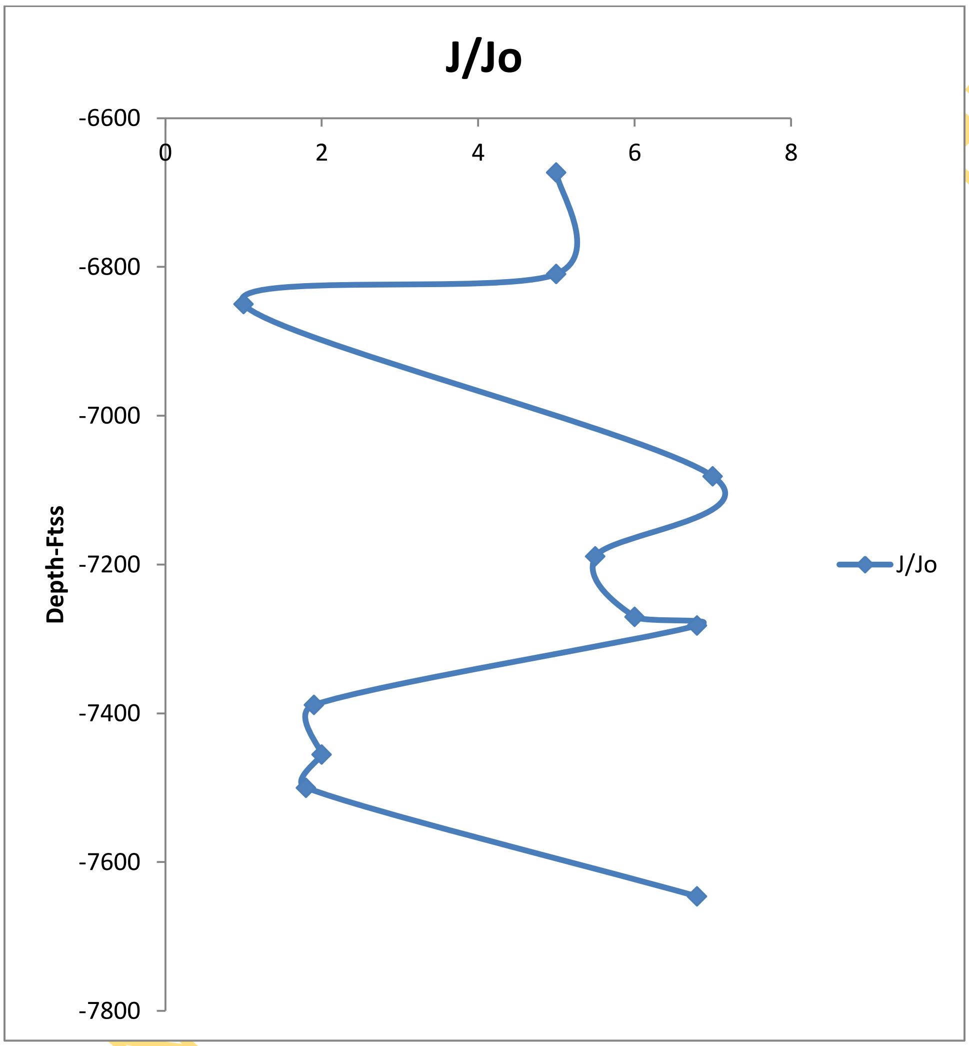

Fig:4.29 Plot of Fracture Productivity Index Contrast(J/Jo) versus Depth of Nkporo Shale Formation at LR=0.4 using Sand producing conductivity (WK_f=10,000md-in with .2in 20/40mesh)

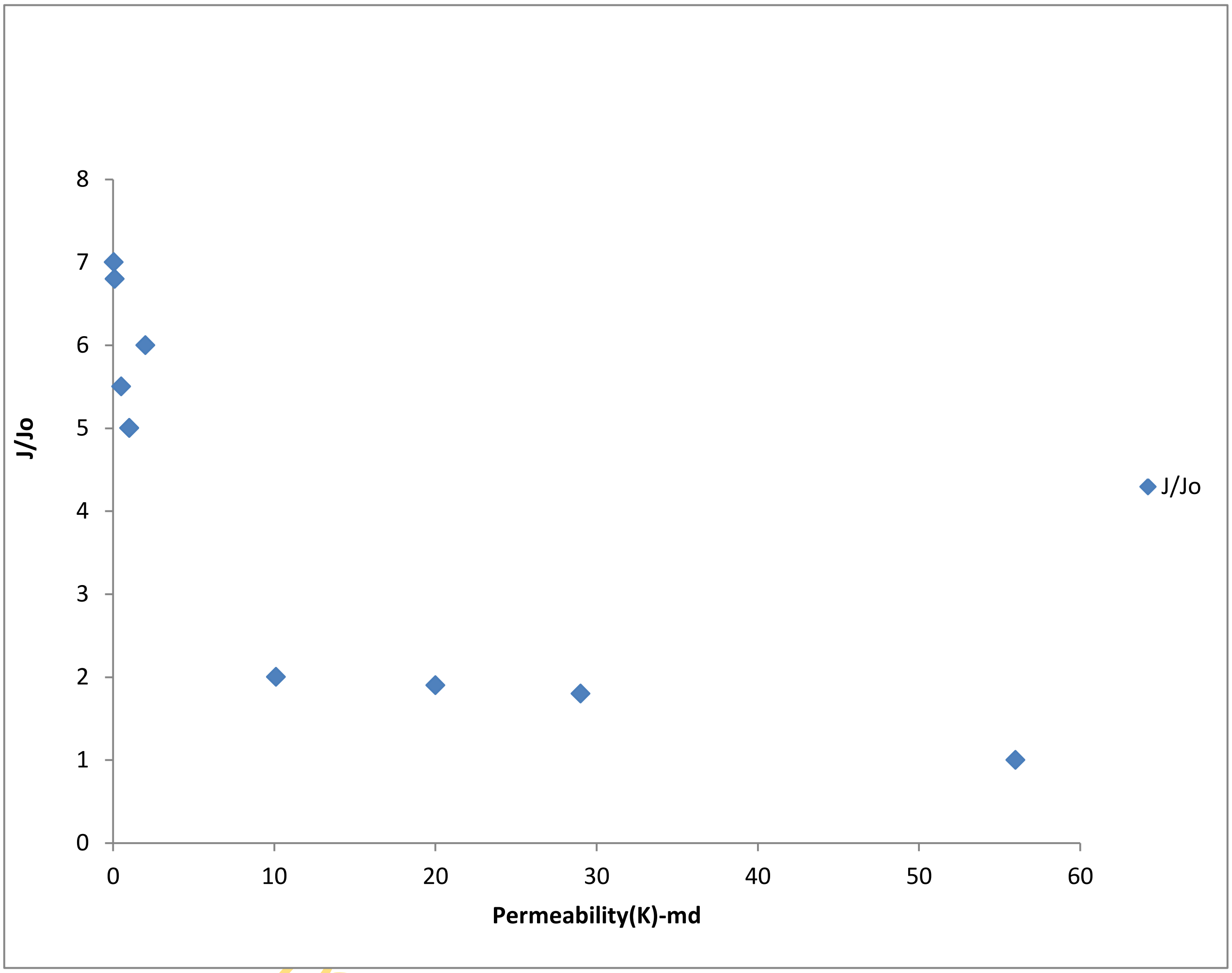

Fig:4.30 Plot of Fracture Productivity Index Contrast(J/Jo) versus Formation Permeability of Nkporo Shale at LR=0.4 using Sand producing conductivity(WK_f=10,000md-in with .2in 20/40mesh)

Table:4.18 Summary of the Results of Nkporo Shale Formation Permeability Contrast(wK_f/K),Productivity Index Contrast (J/Jo) as a function of Dimensioless Fracture Length(LR)=0.3,Aerial well radius(Xe)=2640ft,Fracture Length(X_f)=800ft packed with .2inch- 20/40 mesh propping Sand in polymer having production conductivity(wKf) of 10,000in-md applying McGraw and Sikora(Radial low pattern) model.

Name	**Sand**	**Mid Depth (ftss)**	σ_v **(psi)**	σ_h **(Psi)**	**K (md)**	**LR (Dimensionless Fracture lenght)**	wK_f/K **in-md/md**	**J/Jo**
Anambra-River -2	S1	6673	6,726.4	3497.7	1.01	0.3	9,901	4.0
Alo -1	S1	6809.5	6,864.00	3569.3	1.01	0.3	9,901	4.0
Okpo – 1	S1	7081.5	7,138.2	3711.8	56	0.3	178.6	1.0
Oda Rivers -1	S1	6,850	6,904.8	3,590.5	0.035	0.3	285,714	5.8
Alo – 1	S2	7,189.25	7246.8	3,768.3	0.50	0.3	20,000	4.2
Okpo -1	S2	7,455.5	7,515	3907.9	2.00	0.3	50,000	5.0
Oda River-1	S2	7,282	7,340.3	3816.9	0.11	0.3	90,909	5.8
Alo-1	S3	7,270.25	7,328.4	3810.8	20.00	0.3	500	1.9
Oda River -1	S3	7,500	7,560	3931.2	10.11	0.3	989	2.0
Alo-1	S4	7,388.75	7,447.9	3872.9	29.00	0.3	345	1.8
Oda River – 1	S4	7,646.00	7,707.2	4007.7	0.11	0.3	90,909	5.8

Table:4.19 Summary of the Results of Nkporo Shale Formation Permeability Contrast(wK_f/K),Productivity Index Contrast (J/Jo) as a function of Dimensioless Fracture Length(LR)=0.4,Aerial well radius(Xe)=2640ft,Fracture Length(Xf)=1000ft packed with .2inch- 20/40 mesh propping Sand in polymer having production conductivity(wK_f) of 10,000in-md applying McGraw and Sikora(Radial low pattern) model.

Well name	**Sand**	**Mid Depth (ftss)**	**σ_v (psi)**	**σ_h (Psi)**	**K (md)**	**LR (Dimensionless Fracture lenght)**	**wK_f/K in-md/md**	**J/Jo**
Anambra-River-2	S1	6673	6,726.38	3497.72	1.01	0.4	9,901	5.0
Alo -1	S1	6809.5	6,864.00	3569.28	1.01	0.4	9,901	5.0
Okpo – 1	S1	7081.5	7,138.15	3711.84	56	0.4	178.6	1.0
Oda Rivers -1	S1	6,850	6,904.80	3,590.50	0.035	0.4	285,714	7.0
Alo – 1	S2	7,189.25	7,2616.76	3,768.32	0.50	0.4	20,000	5.5
Okpo -1	S2	7,455.5	7,515.14	3907.87	2.00	0.4	50,000	6.0
Oda River-1	S2	7,282	7,340.26	3816.94	0.11	0.4	90,909	6.8
Alo-1	S3	7,270.25	7,328.41	3810.78	20.00	0.4	500	1.9
Oda River -1	S3	7,500	7,560	3931.20	10.11	0.4	989	2.0
Alo-1	S4	7,388.75	7,447.86	3872.89	29.00	0.4	345	1.8
Oda River – 1	S4	7,646.00	7,707.17	4007.73	0.11	0.4	90,909	6.8

4.3.3 Production Forecast Results and Discussion

Different Scenarios were tried in the choice of optimum fracture lenght. The radial model was used prior to applying the linear forecasting which is more effective.(Table:4.20)

Table: 4.20 Generation of Scenario equations required for the Nkporo gas production prediction

SCENARIO	X_f (ft)	X_e (ft)	X_e/X_f	C_t (psi^{-1})	t_D	Q_D
1	350	2640	7.5	0.00004753	0.0159t	$2.3x10^{-7}Q$
2	500	2640	5	0.00004753	0.00078t	$1.14x10^{-7}Q$
3	1000	2640	3	0.00004753	1.00195t	$2.84x10^{-8}Q$
4	1,500	2640	2	0.00004753	0.000865t	$1.26x10^{-8}Q$
5	2601	2640	1	0.00004753	0.029t	$4.2x10^{-7}Q$
6	0≤Xf≤250	2640	0	0.00004753	0.125t	$1.82x10^{-6}Q$

Table:4.21 Production Prediction (Radial) with fracture lenght of 350feet

Time(t)	Time(t)	t_D	Q_D	$Q \times 10^7$
(yrs)	(hrs)	Dimensionless time	Dimensionless Production	Cumulative Production (Scf)
0.25	2,190	34.821	0.78	1.8
0.50	4,380	69.64	7.83	18.
0.75	6,570	104.46	10.43	24.0
1.00	8,760	139.28	10.87	25.
2.00	17,520	278.57	13.48	31.
3.00	26,280	417.85	15.22	35.0
4.00	35,040	557.14	15.26	35.1
5.00	43,800	696.42	15.26	35.1
10.00	87.600	1,392.84	15.26	35.1
15.00	131,400	2,089.26	15.26	35.1
20.00	175,200	2,785.68	15.26	35.1

Table:4.22 Production Prediction (Radial) with fracture lenght of 500feet				
Time(t) (yrs)	**Time(t) (hrs)**	**t_D Dimensionless time**	**Q_D Dimensionless Production**	**$Q \times 10^7$ Cumulative Production (Scf)**
0.25	2,190	17.08	7	6.14
0.50	4,380	34.16	9	7.89
0.75	6,570	51.25	13	11.40
1.00	8,760	68.33	14	12.18
2.00	17,520	136.66	15	13.16
3.00	26,280	204.98	16	14.04
4.00	35,040	273.31	16	14.04
5.00	43,800	341.64	16	14.04
10.00	87.600	683.28	16	14.04
15.00	131,400	1,024.921	16	14.04
20.00	175,200	1,366.56	16	14.04

Table:4.23 Production Prediction (Radial) with fracture lenght of 1000feet				
Time(t)	**Time(t)**	**t_D**	**Q_D**	**Q x 10^7**
(yrs)	**(hrs)**	**Dimensionless time**	**Dimensionless Production**	**Cumulative Production (Scf)**
0.25	2,190	4.27	2.25	7.92
0.50	4,380	8.54	3.50	12.32
0.75	6,570	12.81	4.20	14.79
1.00	8,760	17.08	5.00	17.61
2.00	17,520	34.16	5.50	19.37
3.00	26,280	51.25	5.80	20.42
4.00	35,040	68.33	5.80	20.42
5.00	43,800	85.41	5.80	20.42
10.00	87.600	170.82	5.80	20.42
15.00	131,400	256.23	5.80	20.42
20.00	175,200	341.64	5.80	20.42

Table:4.24 Production Prediction (Radial) with fracture lenght of 1500feet

Time(t) (yrs)	Time(t) (hrs)	t_D Dimensionless time	Q_D Dimensionless Production	$Q \times 10^7$ Cumulative Production (Scf)
0.25	2,190	1.90	1.60	12.7
0.50	4,380	3.79	1.80	14.3
0.75	6,570	5.69	2.05	16.3
1.00	8,760	7.58	2.05	16.3
2.00	17,520	15.17	2.05	16.3
3.00	26,280	22.75	2.05	16.3
4.00	35,040	30.33	2.05	16.3
5.00	43,800	37.92	2.05	16.3
10.00	87.600	75.84	2.05	16.3
15.00	131,400	113.75	2.05	16.3
20.00	175,200	151.67	2.05	16.3

Table:4.25 Production Prediction (Radial) with fracture lenght of 2601feet

Time(t) (yrs)	Time(t) (hrs)	t_D Dimensionless time	Q_D Dimensionless Production	$Q \times 10^7$ Cumulative Production (Scf)
0.25	2,190	63.51	2.0	4.76
0.50	4,380	127.02	31	7.38
0.75	6,570	190.53	40	9.52
1.00	8,760	254.04	46	10.95
2.00	17,520	508.08	60	14.29
3.00	26,280	762.12	62	14.76
4.00	35,040	1,016.16	62	14.76
5.00	43,800	1,270.2	62	14.76
10.00	87.600	2,540.4	62	14.76
15.00	131,400	3,810.06	62	14.76
20.00	175,200	5,080.8	62	14.76

Table:4.26 Production Prediction (Radial) with fracture lenght of approx zero feet(No Fracture)

Time(t) (yrs)	Time(t) (hrs)	t_D Dimensionless time	Q_D Dimensionless Production	$Q \times 10^7$ Cumulative Production (Scf)
0.25	2,190	273.75	70.00	3.85
0.50	4,380	547.50	104.00	5.71
0.75	6,570	821.25	200.00	10.99
1.00	8,760	1,095	300.00	16.48
2.00	17,520	2,190	Not Defined	Not Defined
3.00	26,280	3,285	ND	ND
4.00	35,040	4,380	ND	ND
5.00	43,800	5,475	ND	ND
10.00	87.600	10,950	ND	ND
15.00	131,400	16,425	ND	ND
20.00	175,200	21,900	ND	ND

Table 4.27 Summary Result of Nkporo Shale Composite Simulated Cumulative Production(BCF/640acre well-spacing) versus Time(Years) as a function of Fracture Length using radial pattern with single completion

Time (Years)	Q (BCF) LR=8	Q (BCF) LR=5	Q (BCF) LR=3	Q (BCF) LR=0 No Frac	Q (BCF) LR=2	Q (BCF) LR=1
0.25	0.0078	0.0614	0.0792	0.0385	0.127	0.0476
0.5	0.0783	0.0789	0.1232	0.0571	0.143	0.0738
0.75	0.1043	0.114	0.1479	0.11	0.163	0.0952
1	0.1087	0.1228	0.1761	0.165	0.198	0.11
2	0.109	0.1316	0.1937		0.198	0.143
3	0.135	0.1404	0.2042		0.198	0.148
4	0.152	0.1404	0.2042		0.198	0.148
5	0.153	0.1404	0.2042		0.198	0.148
10	0.153	0.1404	0.2042		0.198	0.148
15	0.153	0.1404	0.2042		0.198	0.148
20	0.153	0.1404	0.2042		0.198	0.148

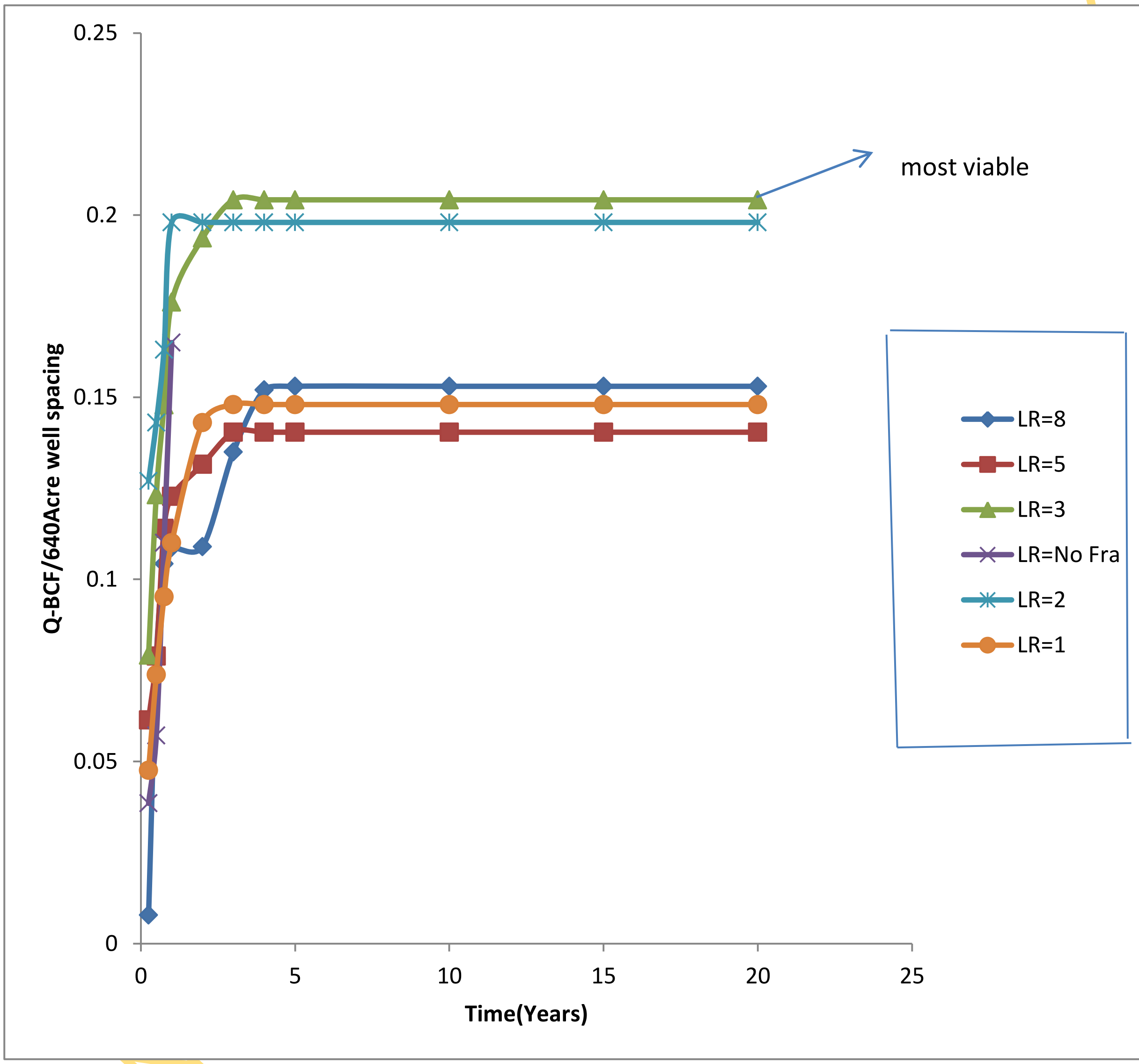

Fig 4.31 Plot of Cumulative Production(Q) versus Time(t) as function of dimensionless fracture lenght(LR) using radial pattern with single completion

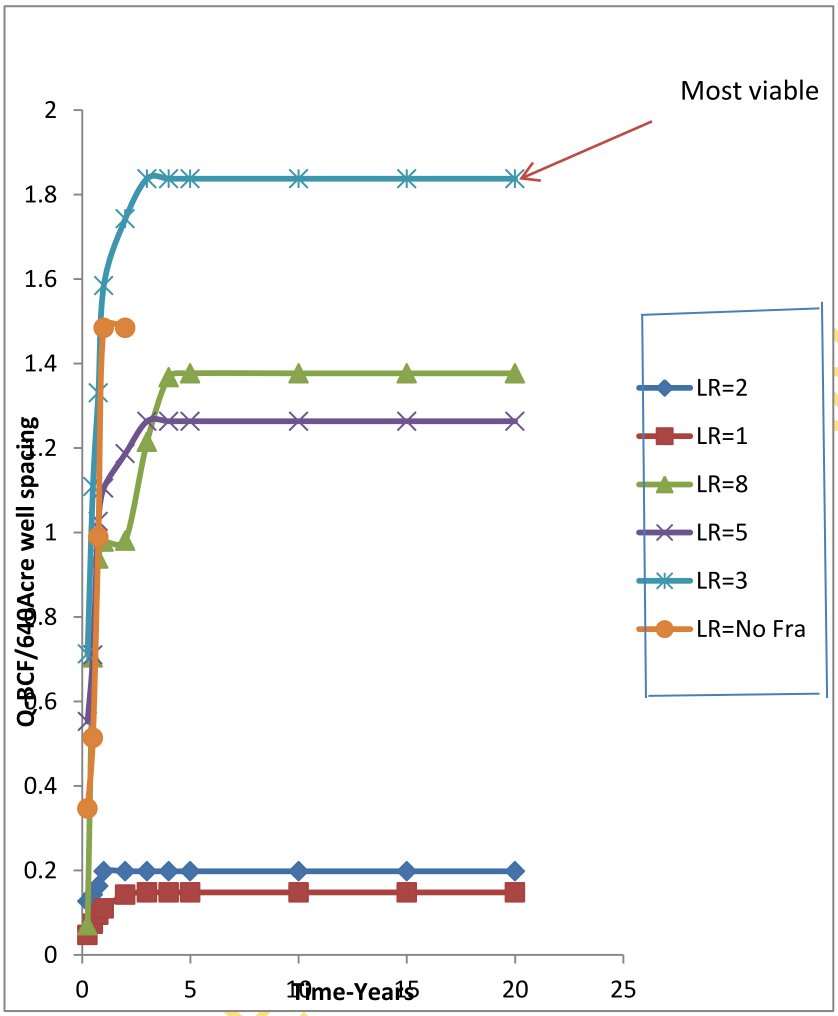

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Fig:4.32 Plot of Nkporo Shale Composite Simulated Cumulative Production (BCF/640acre well spacing) versus Time(Years) as a function of dimensionless fracture lengths using Linear Pattern vertical fractured /dual completion with 9Productivityfold

Table: 4.28 Summary Result of Nkporo Shale Composite Simulated Cumulative Production (BCF/640acre well spacing) versus Time(Years) as a function of dimensionless fracture lengths using Linear Pattern vertical fractured /dual completion with 9 Productivityfold.

Time (Years)	Q (BCF) LR=8	Q (BCF) LR=5	Q (BCF) LR=3	Q (BCF) LR=0 No Frac	Q (BCF) LR=2	Q (BCF) LR=1
0.25	0.0702	0.5526	0.7128	0.3465	1.1430	0.4284
0.5	0.7047	0.7101	1.1088	0.5139	1.2870	0.6642
0.75	0.9387	1.0260	1.3311	0.9900	1.467	0.8568
1	0.9783	1.1052	1.5849	1.4850	1.7820	0.9900
2	0.9810	1.1871	1.7433		1.7820	1.2870
3	1.215	1.2636	1.878		1.7820	1.3320
4	1.368	1.2636	1.878		1.7820	1.3320
5	1.377	1.2636	1.878		1.7820	1.3320
10	1.377	1.2636	1.878		1.7820	1.3320
15	1.377	1.2636	1.878		1.7820	1.3320
20	1.377	1.2636	1.878		1.7820	1.3320

4.3.4 Production Forecasting

The hydraulic fracturing must be linearly employed with 2inch 20/40 propping sand in polymer fluid using 640acre well spacing and fracture lenght ratio of 3. Several fracture conductivity were applied in several production Scenarios. Some of the fracture lenghts shut out within a short period. The analysis showed that multiple wells dually completed at different levels will apply. The fluid capacity range is about 20-32,500 md-ft. The production becomes more efficient as the fracture lenght starts to increase. Above a given fracture lenght further increase will not increase fluid recovery. Multiple wells dually completed will apply for the gas extraction/exploitation. On the average in the production forcasting the cumulative production will increase 9 folds using vertical hydraulic fracturing using 2inch 20/40 mesh prop sand in polymer fluid with fracture lenght ratio of 3 and 640 acre well spacing dually completed.

4.4.1 Validation of Resullts:

Comperative analysis of Nkporo Shale versus other International Gas Shale Formations table were prepared and similarites in the geophysical,geochemical,geological,petrophysical and engineering properties were observed.

The net thickness range of the Nkporo Shale formation is much higher compared with others listed in the Table:5.1. Likewise, the fluid capacity and effective porosity range of Nkporo is also higher justifying the high fluid content in place. The multiple temperature range observed in Nkporo Shale occured in New Albanny and Lewis Shale Formations in Indiana and New Mexico,USA. There are similarities in the TOC value range between Nkporo Shale Formation and Barnett,Ohio,Lewis Shale formations which are dorminantly gas unlike Antrim and New Albanny that have lower gas liquid ratio range. Nkporo Shale Formation yet to be exploited is expected to have higher original gas in place due its high free gas content despite the lower percentage of adsorbed gas in place compared with other Shale formations being benchmarked. Barnett Shale formation has the lowest percentage range of the adsorbed gas in place compared with others. All the benchmarked formations apart from Nkporo are all producing successfully through hydraulic fracturing; hence Nkporo Shale high gas reserves potential cannot be ignored.

Table:4.29 Summary of the Original Gas in place of Nkporo Shale Gas Formation using Crain's unconventional model:

Parameter	**P10**	**P50**	**P100**
GIP free (BCF/Section)	38.52	180.44	567.17
GIP absorbed (BCF/Section)	73.20	88.25	117.43
GIP total (BCF/Section)	111.72	268.69	684.60

Table:4.30 Comparative Analysis of special Gas Shale Formation Cases Internationally

Property	Nkporo Shale	Barnett	Ohio	Antrim	New Albanny	Lewis
Depth,ft	6200-7596	6,500-8500	2000-5000	600-2,200	500-2000	3000-6000
Net thickness, ft	39-622	50-100	30-100	70-120	50-100	200-300
Bottomhole Temperature, degF	129-206	200	100	75	80-105	130-170
TOC,%	0.54-4.42	4.5	0.0-4.7	1-20	1-25	0.45-2.5
Effective Porosity,%	5-25	4.4	4.7	8	10-14	3-5.5
Kh, md-ft	39-62,200	0.01-2	0.15-50	1-5000	NA	6-400
Gas Content,Scf/ton	15-30	300-350	60-100	40-100	40-80	15-45
Adsorbed Gas,%	33	20	50	70	40-60	60-85
Gas-In-Place,Bcf/Section	268.69	30-40	5-10	6-15	7-10	8-50
Historic Production Area Basis for data	Yet to be acquired for Exploitation from Nigeria Government	Wise Co, Texas, USA	Pike Co, Kentucky, USA	Otsego Co, Missouri, USA	Harrison Co; Indiana	San Juan& Rio Arriba Co; New Mexico

1.5.1 Economic Strategy:

Cash flow rate of return,interest rate of borrowed capital, Royalties and taxes, hydraulic fracturing pay out time,profitability,incentives and recoverable reserves were crystal balled in the economic software model used for this project.

The economics of the frac job involves fixed and set-up costs including the hydraulic horsepower requirement effects. The operator's experience is a major factor considering anticipated gas revenue and the discount rate (Thomas and Roberts,1989,International Hydrocarbon Services,2000, Isehunwa et al,2009).

Hydraulic horsepower unit cost	$1.05/hp
CAPEX	30% for 1st 5years, 10% for the rest of the 15yrs
OPEX	15%/year
Present Value Discount rate	15%
Gas unit revenue ,	$2.50/mscf
Recovery Factors	10%,15%,20%,30%
Well cost/ft	$2000.00
Completion cost/ft	$1500.00
Royalties:	
Land(Oil/Gas)	20%
Swamp/Offshore	18%
NDDC(tax)	3%
Education(tax)	2%
Others(tax)	4%

Incentives(Variable based on Conntract: 0.5%,1%,3%,4%,5%,10%

LNG pays higher price than DOMGAS Consumer

TABLE:4.31 Gross Assets Value(GAV) versus Deductions and the Incentives(1%) with application of recovery factors(RF) on the P50 reserve

P50(BCF/Section or 640acre well spacing)= 269

	RF1	RF2	RF3	RF4	RF5	RF6
	10%	15%	20%	30%	40%	50%
	26.9	40.35	53.8	80.7	107.6	134.5
TAV(B$)	0.067	0.101	0.135	0.202	0.269	0.336
CAPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
OPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
ROYALTIES(-20%)	(-0.013)	(-0.020)	(-0.027)	(-0.040)	(-0.054)	(-0.067)
TAXES(Edu,NDDC,etc(-9%)	(-0.006)	(-0.009)	(-0.012)	(-0.018)	(-0.024)	(-0.030)
INCENTIVES(1%,3%,5%,7%,10%)	0.0007	0.0010	0.0014	0.0020	0.0027	0.0034
NET PROFIT($Billion)	0.0287	0.043	0.0574	0.086	0.114	0.142
RETURN ON INVESTMENT(ROI)%	43%	43%	43%	0.43%	42%	42%

TABLE:4.32 Gross Assets Value(GAV) versus Deductions and the Incentives(3%) with application of recovery factors(RF) on the P50 reserve

P50(BCF/Section or 640acre well spacing)= 269

	RF1	RF2	RF3	RF4	RF5	RF6
	10%	15%	20%	30%	40%	50%
	26.9	40.35	53.8	80.7	107.6	134.5
TAV(B$)	0.067	0.101	0.135	0.202	0.269	0.336
CAPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
OPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
ROYALTIES(-20%)	(-0.013)	(-0.020)	(-0.027)	(-0.040)	(-0.054)	(-0.067)
TAXES(Edu,NDDC,etc(-9%)	(-0.006)	(-0.009)	(-0.012)	(-0.018)	(-0.024)	(-0.030)
INCENTIVES(1%,3%,5%,7%,10%)	0.002	0.003	0.004	0.006	0.008	0.010
NET PROFIT($Billion)	0.03	0.045	0.06	0.09	0.119	0.149
RETURN ON INVESTMENT(ROI)%	45%	45%	44%	0.45%	44%	44%

TABLE:4.33 Gross Assets Value(GAV) versus Deductions and the Incentives(5%) with application of recovery factors(RF) on the P50 reserve

P50(BCF/Section or 640acre well spacing)= 269

	RF1	RF2	RF3	RF4	RF5	RF6
	10%	15%	20%	30%	40%	50%
	26.9	40.35	53.8	80.7	107.6	134.5
TAV(B$)	0.067	0.101	0.135	0.202	0.269	0.336
CAPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
OPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
ROYALTIES(-20%)	(-0.013)	(-0.020)	(-0.027)	(-0.040)	(-0.054)	(-0.067)
TAXES(Edu,NDDC,etc(-9%)	(-0.006)	(-0.009)	(-0.012)	(-0.018)	(-0.024)	(-0.030)
INCENTIVES(1%,3%,5%,7%,10%)	0.003	0.005	0.007	0.010	0.013	0.017
NET PROFIT($Billion)	0.031	0.047	0.063	0.094	0.124	0.156
RETURN ON INVESTMENT(ROI)%	46%	47%	47%	0.47%	46%	46%

TABLE:4.34 Gross Assets Value(GAV) versus Deductions and the Incentives(7%) with application of recovery factors(RF) on the P50 reserve

P50(BCF/Section or 640acre well spacing)= 269

	RF1	RF2	RF3	RF4	RF5	RF6
	10%	15%	20%	30%	40%	50%
	26.9	40.35	53.8	80.7	107.6	134.5
TAV(B$)	0.067	0.101	0.135	0.202	0.269	0.336
CAPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
OPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
ROYALTIES(-20%)	(-0.013)	(-0.020)	(-0.027)	(-0.040)	(-0.054)	(-0.067)
TAXES(Edu,NDDC,etc(-9%)	(-0.006)	(-0.009)	(-0.012)	(-0.018)	(-0.024)	(-0.030)
INCENTIVES(1%,3%,5%,7%,10%)	0.005	0.007	0.009	0.014	0.019	0.024
NET PROFIT($Billion)	0.033	0.049	0.065	0.098	0.13	0.163
RETURN ON INVESTMENT(ROI)%	49%	49%	48%	49%	48%	49%

TABLE:4.35 Gross Assets Value(GAV) versus Deductions and the Incentives(10%) with application of recovery factors(RF) on the P50 reserve

P50(BCF/Section or 640acre well spacing)= 269

	RF1	RF2	RF3	RF4	RF5	RF6
	10%	15%	20%	30%	40%	50%
	26.9	40.35	53.8	80.7	107.6	134.5
TAV(B$)	0.067	0.101	0.135	0.202	0.269	0.336
CAPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
OPEX(-15%)	(- 0.01)	(- 0.015)	(-0.020)	(-0.030)	(-0.040)	(-0.050)
ROYALTIES(-20%)	(-0.013)	(-0.020)	(-0.027)	(-0.040)	(-0.054)	(-0.067)
TAXES(Edu,NDDC,etc(-9%)	(-0.006)	(-0.009)	(-0.012)	(-0.018)	(-0.024)	(-0.030)
INCENTIVES(1%,3%,5%,7%,10%)	0.007	0.010	0.014	0.020	0.027	0.034
NET PROFIT($Billion)	0.035	0.052	0.07	0.104	0.138	0.173
RETURN ON INVESTMENT(ROI)%	52%	51%	52%	51%	51%	51%

TABLE:4.36 Net Present Value(NPV) versus Gas Reserve Recovery

Gas Reserve Recovery(%)	NPV(i, 20Yrs) (i=Intrest Rate(%)) 10% (.1486)	15% (.0611)	20% (.0261)	30% (.0053)
	(B$)			
10% (26.87)	9.98	4.10	1.75	.36
11%(29.56)	10.98	4.52	1.93	.39
14%(37.62)	13.98	4.60	2.45	.50
40%(107.48)	39.93	16.42	7.01	1.42
50%(134.35)	49.91	20.52	8.77	1.78

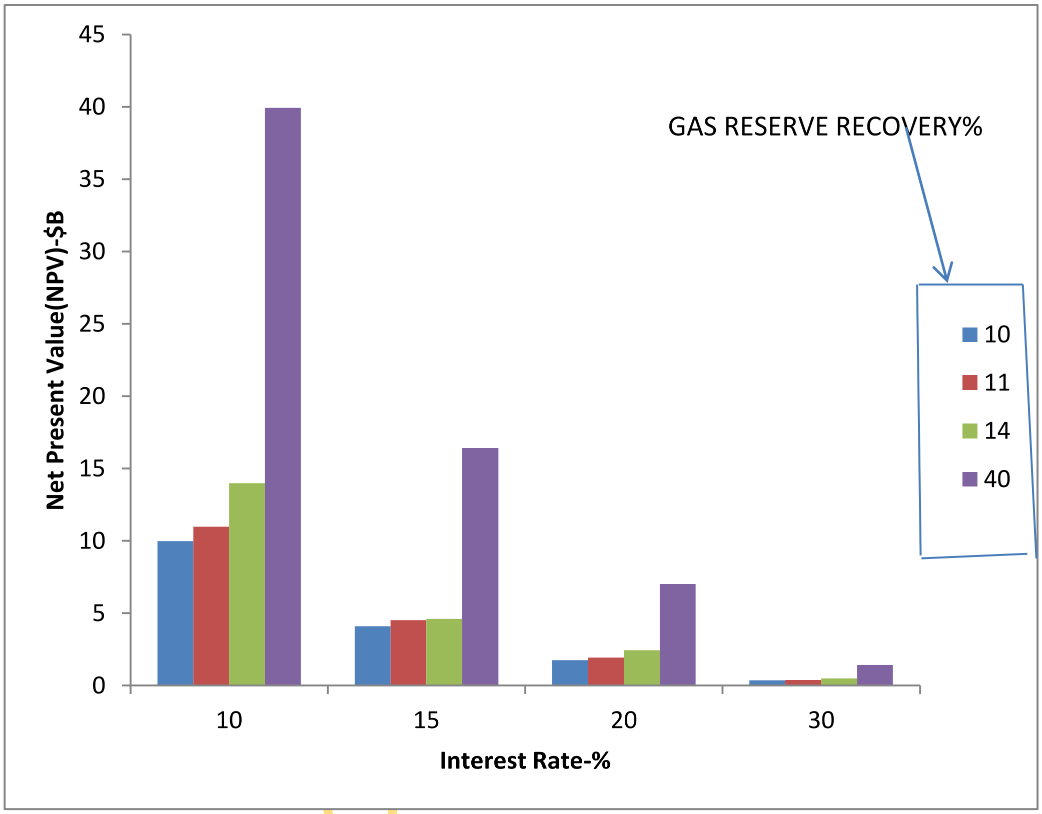

FIG:4.33 Net Present Value(NPV) versus Interest Rate as per Reserve Recovery (%)

4.5.2 Economic Analysis

The effects of fiscal terms and contractual agreements on government take in Nigeria oil industry studied by Isehunwa et al;2011 using the Napims cash flow model and the fiscal terms for oil industry were considered(Appendix-3). Nevertheless,summary of the regimes were captured as OPEX,CAPEX,TAXES/ROYALTIES and INCENTIVES. Isehunwa et al;2011 recognized higher return on capital investment of oil ranging 45-85% for Government take under Joint Venture Agreement unlike PSC.These are conventional oil.Full economic study will be carried out during the full field development study of Nkporo shale exploitation phase considering the shale gas fiscal regime that will be put in place by the government.

The major activities that will influence the NPV of the exploitation of the Nkporo Formation are the multiple well drilling/completion/hydraulic fracturing cost, including the Health Safety and environmental cost. The cumulative production of the gas in each 640 acre well spacing in Nkporo is low compared with a similar conventional gas well within the region and will last for a short period of about 5 to 6years provided effective hydraulic fracturing is employed(Fig:4.35). The implication is that many wells dually completed will be required for high recovery. The Recovery factor affects NPV tremendously at interest below 20%. It should be observed that within 10 to 20% interest rate the investment is viable irrespective of the Reserve Recovery factor(Tables: 4.32-36). NPVs above 20% interest rates collapses irrespective of any recovery factor(Fig:4.36). 40% recovery factor has the highest NPV making it easier for the amortization of the initial CAPEX. The value of the gas price benchmark of the conventional well affects the viability of Shale gas exploitation.The well density is very high. Currently, there is a significant drop in the price of World Oil/Gas and as such, making the exploitation less viable. Nevertheless, the cost of hiring rigs presently for drilling wells has dropped and as such is the best time drilling most of the wells and capping them for future hydraulic fracturing and completions. Increase in incentives percentage during the contract negotiation with the Joint Venture(JV) or Profit Sharing partners will encourage the Shale Gas investors as this will improve their return on investment and minimize risk.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

1.1 Conclusion

From this study, the following can be stated:

The Nkporo Shale when compared with other known international shale producing fields during the literature review showed significant similarity in petrophysical structure consisting of dark grey,very fissile shales and mudstones with occassional thin sandy shale interbeds, fine grained sandstone and mavl with coatings of sulphur and numerous white specks and with laminated shape.

There is an existence of multiple Subsurface Temperature Profiling within Nkporo Geological Formation(Anambra Basin/Lower Benue Trough).This could be deducted from the multiple Temperature gradients and intercepts obtained from different wells within Nkporo region. The future field development plan will take cognisance of this observation during the drilling and fluid characterization to enable the reservoir management process to be effective and efficient.

The research results showed that the porosity range of Nkporo Formation is (5% - 25%) while the permeability is (0 – 95.5)millidarcy.There is existence of multiple facies which were confirmed from the Permeability/Porosity composite plots.

The water saturation ranges from 70-100% while the gas saturation is in the range of 0.0 to 26%.The Geochemistry,Production test and sidewall core test result from Literature Review showed the existence free gas and gas Kerogene with TOC range of 0.54 to 4.42wt%. Hence, Nkporo Geological Formation has higher gas volume capacity range of 20-32500md-ft with high exploitation potential using hydraulic fracturing when compared with a similar USA shale producing gas structure. There is no production history in Nkporo Formation,hence, the gas in place is assumed to be original.

The original Gas in Place is established at 268.69BCF/640acre well spacing with the potential to increase to 685BCF/section.

Production would require high conductivity linear hydraulic fracturin using 20/40 mesh size fluid,1000feet fracture lenght and 640acre well spacing.

Geostress analysis showed vertical and horizontal compressive stress range of 6673-7646 and 3498-4008psia respectively. Although there is high water saturation in the inter spaces ranging from 74-100% but not interconnected, hence, there is little or non-existence of acquifer front.

The formation from the geostress analysis is highly compacted and pressured; hence, the drive mechanism of the formation is predominantly geological compaction/Gas expansion.

The comparative analysis through benchmarking of similar World Shale gas systems showed properties similarities of Nkporo Shale formation with some international Shale producing fields which further comfirmed the existence of high producible hydrocarbon gas reserve in Nkporo Shale region.

Economic analysis showed that developing Nkporo Shale gas reserves gave a net profit range of 0.045-0.09$Billion/section or 640acre well spacing with interest rate below 20% and minimum of 3% development incentive for investors.

This study confirmed that there is scope for additional gas reserves from unconventional sources like Campanon-Maastrichtian Nkporo Shale in Anambra basin/Lower Benue Trough which could be profitably developedunder appropriate technical and economic conditions.

Nkporo Shale Gas development will act as a platform and a spring board for a similar research work to be carried out on other potential shale formations such as Afowo,Araromi(Dahomey-Basin),Lokpanta(late-Cenomanian-Turonian), Eze-Aku,Imo, Agwu, Ameki, Odukpani, Nsukka,Mamu, Asaga, Amangwu,Amaiyi Edda,(Anambra Basin).

5.2 CONTRIBUTIONS TO KNOWLEDGE

The study has made contributions to knowledge in the following areas.

(1) The characterization model of the Petrophysical and Engineering properties required for the Reserve Evaluation of Nkporo Shale Geological formation has been developed.

(2) The existence of multiple temperature profile within Nkporo Geological Shale Formation(Anambra Basin/Lower Benue Trough) has been established and model equations generated for different sectors. This will act as a guide for future temperature impact studies on fluid characterization, Pressure Simulation Analysis, etc. Furthermore this development will derisk the Uniform temperature assumption analysis during Reservoir Management Studies.

(3) The Engineering model for Nkporo Formation Compaction with all the guiding equations has been developed and this will assist in guiding future drillings in order to avoid loss of wells/blowout etc.

(4) Nkporo Shale Formation being gas kitchen, has also good gas reserve storage capacity as revealed by the research work.

(5)Effective and Efficient Production approach are required in Nkporo Shale Gas Reserve exploitation through hydraulic Fracturing with multiple wells and completions.

(6) The research methodology used for Nkporo Gas Shale to carry out petrophysical and engineering characterization can be applied on other similar potential unconventional energy source in Nigeria such as Imo, Agwu, Ameki, Odukpani, Nsukka,Mamu, Ezeaku, Asaga Amangwu, Amaiyi Edda.

(7) The economics is viable considering a quick gas fiscal summary and the current cost of exploiting shale formations globally compared with a typical conventional gas system provided that the incentives are given and interest rate must not exceed 20%.

5.3 RECOMMENDATIONS FOR FURTHER WORK

It is recommended that a similar research study of hydrocarbon Shale formations such as Afowo, Araromi(Dahomey-Basin), Lokpanta (late-Cenomanian-Turonian), Eze-Aku,Imo, AgwuImo, Agwu, Ameki, Odukpani, Nsukka, Mamu,Asaga, Amangwu, Amaiyi Edda (Anambra Basin);be undertaken in other to further explore the unconventional shale formations in Nigeria.

Also full economic studies considering shale gas regime will be carried out on Nkporo shale formation exploitation during the Full development Plan stage applying (Isehunwa et al;2011) economic evaluation approach detailing all the fiscal regime for shale gas.

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APPENDIX I

1.0 Some of the assumed Perimeters to be applied for the calculation of Gas In Place for Shale Gas Formation using Crain' Model:

KV4=.000043560
Qnc=0
(1-Qnc)=1
1-Sw=Sg
Area=640Acres/Section or sq mile
Bg=0.0053cuft/Scf
KG6=1.3597*10**-6
DENS=2.68gmm/cc-----Shale Matrix Density
1sq Km=247.11acres

APPENDIX 2

2.0 Example: of the Scenario generation of equation for the production prediction

Scenario 2: (Table:4.23)

$Xe = [(143560)(640)/4]^{½}$

$= 2640$

$X_f = 500ft$

$Xe/X_f = 2640/500$

$\equiv 5$

$Ct = SgCg + Sw\ Cw$

$Ct = 17\ (0.0002747) + 0.83\ (1 \times 10^{-6})$

$= 0.00004\ 753\ Psi^{-1}$

$$Q_D = \frac{0.89346Q\ Bg}{\emptyset\ Ct\ h\ X\ f\ 2\ (P1-P2)}$$

$= 0.8936\ (1.0668)\ Q/0.16\ (.00004753)(1261)(500)^2(3,500)$

$Q_D = 1.14 \times 10^{-7}\ Q$

$$t_D = \frac{0.0002637Kt}{\emptyset NCtX2f}$$

$= 0.0002637(1.05)t/0.16(.0187)(.00004753)(500)^2$

$= 0.00078t$

(Isehunwa et al;2011)

3. Abbreviations

CPX = Capital expenditure as defined by legislation ($)
C = Expenses/Cost Recovery as a percentage of net revenue
CSBT = Company share before tax ($)
CT = Company take
CTX = Company tax
EXP = Expenses
GE = Government Expenses
GR = Gross revenue
GS = Government share
GTT = Government Take
NR = Net revenue
OPX = Operating expenses as defined by legislation
OOX = other costs, such as environmental fees, abandonment costs, etc.
PR = Profits ($)
RY = Royalty ($)
S = Government Profit Oil Share
X = Royalty
Y = Government Equity Share
Z = Tax

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Appendix: Cash Flow Model Development

$$RY = X * GR \quad \text{(A1)}$$

$$NR = GR - RY \quad \text{(A2)}$$

$$EXP = C * NR \quad \text{(A3)}$$

$$GE = Y * EXP \quad \text{(A4)}$$

$$PR = NR - EXP \quad \text{(A5)}$$

$$CSBT = (1 - S) * PR \quad \text{(A6)}$$

$$GS = S * PR \quad \text{(A7)}$$

$$CTX = Z * CSBT \quad \text{(A8)}$$

Combining Eqs. (1), (4), (7) and (8) gives the government take (*GTT*)

$$GTT = GS + RY + CTX + GE \quad \text{(A9)}$$

Eqn. (8) can be expressed in terms of *GE*. Thus, the generalized model is given thus:

$$GTT = GR * [X + (1 - X) * (C * Y + (1 - C) * (S + Z * (1 - S)))] \ldots\ldots\ldots\ldots\ldots\ldots (A10)$$

For JV, Y = S

Thus,

11

$C\ X\ Z\ Y\ Z\ Z\ X\ Y\ Z\ GR$

$GTT\ X\ Y\ Z\ X\ Y\ X\ Z\ Y\ Z\ X\ Y\ Z\ GR$

$*[\ *\ *\ *\ *\ ]*$

$[\ *\ *\ *\ *\ *\ ]*$

$+ + - -$

$= + + - - - +$

....……………(A11)

And for PSC, Y = 0

Thus,

$C\ S\ Z\ X\ S\ X\ Z\ S\ Z\ X\ S\ Z\ GR$

$GTT\ X\ S\ Z\ X\ S\ X\ Z\ S\ Z\ X\ S\ Z\ GR$

$*[\ *\ *\ *\ *\ *\ ]*$

$[\ *\ *\ *\ *\ *\ ]*$

$- + - - - +$

$= + + - - - +$

...………………(A12)

Current Fiscal Terms for JVs in Nigerian oil Industry (Isehunwa, 2009).
Petroleum Profit Tax 85%
Depreciation Five-year straight line
Deduction Operating Expenditure
Capital Expenditure
Investment allowance (5-30%)
Consolidation All E&P Expenditures in joint venture areas
Royalty 20 % onshore
0-18.5% offshore
MOU Guaranteed after tax margin of $2.3 or $2.5/bbl
Current Fiscal Terms for PSCs in Nigerian Oil Industry (Isehunwa, 2009).
Signature Bonus $0.5-1.00 MM/block
Bid Bonuses $10-30 MM/block
Royalty Oil 0-16.67 % (subject to water depth)
Cost Recovery 100% after Royalty
Depreciation 5 year Straight Line
Profit Oil (Government Share) Niger Delta-60% (<30 MBD) to 65% (>50 MBD)

Frontier: 20% (<350MMB) to 60% (>2BBL)
Petroleum Profit Tax (PPT) 50%
Consolation Ring fence for PSC, All E&P for PPT
Proposed Fiscal Policies in the PIB (Iledare, 2010).
NIGERIA HYDROCARBON TAX (NHT)
Onshore/Shallow water 50%
Deep water 30%
COMPANY INCOME TAX (CITA)
Onshore/Shallow water 30%

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Continue.
Deep water 30%
ROYALTIES
Based on Price of Oil
Oil Price Rates
$0-$70 0%
$70-$110 16%
$110-$140 22%
$140-$170 25%
Above$170 25%
Based on Volume of Production (Onshore)
Productions Rates
0-2000b/d 5%
2000-5000b/d 12.5%
Above 5000b/d 25%
Government Equity Share 60%
Cost Revovery Limit 80%
Rentals Year Rate/ Km2
PPL 2 $100.00
4 $300.00
5 $500.00
PML All $1000.00