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Evaluation of Potential Stranded Gas Assets in Akam Oilfield of the Niger-Delta Area using 3D Seismic, Well Log and Gas Data

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Abstract
The analysis of gas in Akamoilfield of Niger Delta in Nigeria was carried out with a view to evaluate the stranded gas resources using seismic, well log and gas production data. Seis-works and Stratworks Software were used to interpret 3D seismic and well log data respectively while Microsoft Excel was used to analyze gas production data. The integration of well and seismic data identified 3 main lobes and channel systems which are the major reservoir polygons. The well logs reveal that some of the sands are well developed while most of the reservoirs are clean with little or no shale intercalations. The amplitude analysis of the two reservoirs studied indicates that the A1X main reservoir is gas with typical gas value 4 to 6 while A1XX reservoir comprises oil, gas and brine with typical values 3.5, 4 to 6 and 1.5 respectively. The log signatures of well NX_Lag1which penetrated the A1X reservoir has a Net to gross of 0.95 and 1 while the A1XX ODT at 3200m for NX_Lag1ST has Gross of 50m, net to gross of 64%, Porosity of 22% and hydrocarbon saturation of 60%. The study established the presence of hydrocarbon (gas) in the study area while the amplitude response and AVO products of the main geobody are of excellent quality. The analysis of gas production data also revealed the under-utilization of gas resources which calls for optimal solution in converting our vast gas resources to wealth.
Keywords: Stranded Gas, Geobody, Pochmarks, AVO, Akam Oilfield, Niger Delta.

1. Introduction

Natural Gas Exploration is becoming of great necessity to the country because of our huge increasing demand for gas for domestic Independent Power Projects (IPP) projects. Most of our gas discoveries have been incidental to oil exploration. Lack of interest in gas exploration in previous years has resulted in a large proportion of our commercial reserves to be locked up. These stranded gas resources were in the past flared at the well head. This practice however is no longer acceptable due to environmental concerns and, more recently, due to the growing economic value of these reserves in a high energy price environment. Oil producers are now looking to use technology to capture this associated gas and take it to consuming markets (Marcao et al., 2007). However, any reservoir with low frequency values is always suspected to be a sandy environment showing some stratigraphy features and it can also be a channel fill reservoir which may defines some major geological areas that are associated with stranded reservoir in any field (Olaseni et al. 2018)

Stranded gas represents the gas inventory from fields, which are seen to be remote from available markets uneconomically unattractive by major International Oil Company's (IOC's) for the traditional gathering approach and conventional transmission infrastructure (Kidnay et al., 2006).

Nigeria's natural gas reserves are found in relatively simple geologic structures along the country's coastal Niger Delta and offshore blocks. Other possible prospective gas zones which have not been fully explored include the Benin Basin, Anambra Basin, Beune Through, Bida Basin and Chad Basin. Recent discoveries in the Deep Offshore have shown that there are huge gas potentials yet untapped in this area (Corredor et al., 2005). Some exploration campaigns have been undertaken in sedimentary basins of Northern Nigeria with the aim to expanding the national exploration and production base and to thereby add to the proven reserves asset.However, these inland basins have continued to frustrate the efforts of many explorers, principally because of the poor knowledge of their geology and the far distance from existing infrastructure. As a result of this, focus is drifting away from frontier onshore to frontier deep-water and ultra deep-water offshore. Studies have shown the existence of potential source rocks in the Beune trough and Chad Basin, with coal beds constituting a major potential source rock in the whole of the Benue Trough (Obaje et al., 2004).

The abundance of natural gas reserves in our sedimentary basins has over the past few years stimulated a lot of vital projects that placed the country on the global map of major gas players. (Ukpohor, 2009). These projects include the Gas Master Plan put in place by the government of Nigeria to address the network of gas infrastructure, West African Gas Pipeline project and Trans Saharan Pipeline project to encourage regional gas trade. The Natural Gas Pricing Policy is to address the problem of a suitable pricing model while the Domestic gas Supply obligation is to ensure local supply of natural gas for residential consumption and gas based industries (Ukpohor, 2009). However, the technical and economic challenges, which are associated with producing such remotely located reserves restricts the near availability of our non associated gas reserves. It is important for us to identify an appropriate and efficient development concept and solution. Therefore, to ensure viability of the opportunities for gas development, and thereby achieve the goals of the national Gas Master Plan, pertinent strategic approach towards addressing the challenges of remote stranded gas reserves is required (Kanu, 2009).

The A1 structure, is situated in the Cenozoic Deep offshore Niger Delta, which is one of the world's major hydrocarbon provinces. This geologic province lies at the point of a triple junction evolved during the separation of South America from Africa. The sediments prograded slowly to the southwest by switching between three main sedimentary axes as a result of tectonic activities on Benin and Calabar flanks (McGeary, 1996). The A1 structure lies in an average water depth of 800m in eastern Nigerian deep offshore Niger Delta. Three wells have been drilled on this structure resulting in a commercial hydrocarbon discovery. The A1X main (gas) and A1XX (oil and gas) levels that have been mapped constitute the major hydrocarbon bearing levels in the A1 structure.

In this research work, 3-D seismic data, well log suites and gas production data were used to evaluate and optimize potential stranded gas assets.

Through a historical analysis of available gas reserves data in the country and the proposition that most of the Nigerian oil reservoirs are technically unsuitable for large scale injection (Oil and Gas Producers Technical Report No 2.79/288, January 2000), the purpose of this research is to establish the availability of stranded gas in a typical Niger Delta Field using seismic and well log data and also to analyze the existing gas production data in-order to create an awareness for the need for an alternative utilization plan rather than injection especially in our deep offshore discoveries.

1.1 Field Description and Geology of the Study Area

Geographically, the Niger Delta is located between longitude 5^o and 8^{o}E and latitude 3^o and 6^{o}N respectively. This basin occupies a total area of 7,500km^2 in the Gulf of Guinea with a sediment thickness up to 12,000m (Bustin, 1988). It is situated on the Gulf of Guinea (fig. 1) on the west coast of central Africa and extends throughout the Niger Delta Province as defined by (Klett et al., 1997). The study area is situated in the Cenozoic Deep offshore Niger Delta, which is one of the world's major hydrocarbon provinces. This geologic province lies at the point of a triple junction evolved during the separation of South America from Africa. Transform faults involved in the separation of the South American and the African continents were responsible for the evolution of the Nigerian Niger Delta and the deep offshore geologic provinces. Fig 2 shows the base map Akam oilfield

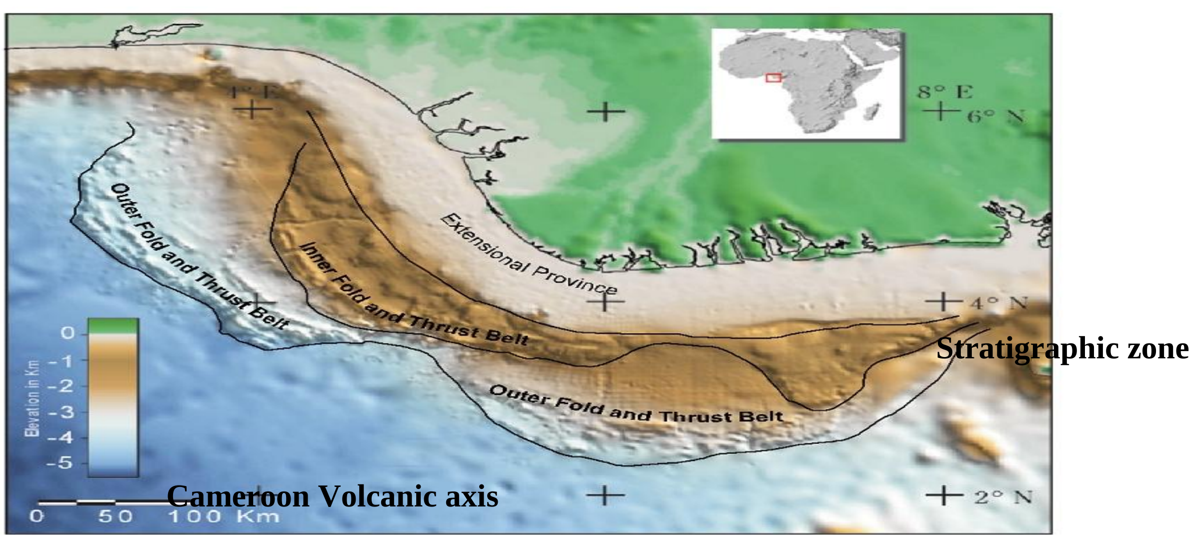

Fig 1: Map of the Nigeria Deep Offshore showing Gulf of Guinea (Corredor et al., 2005).

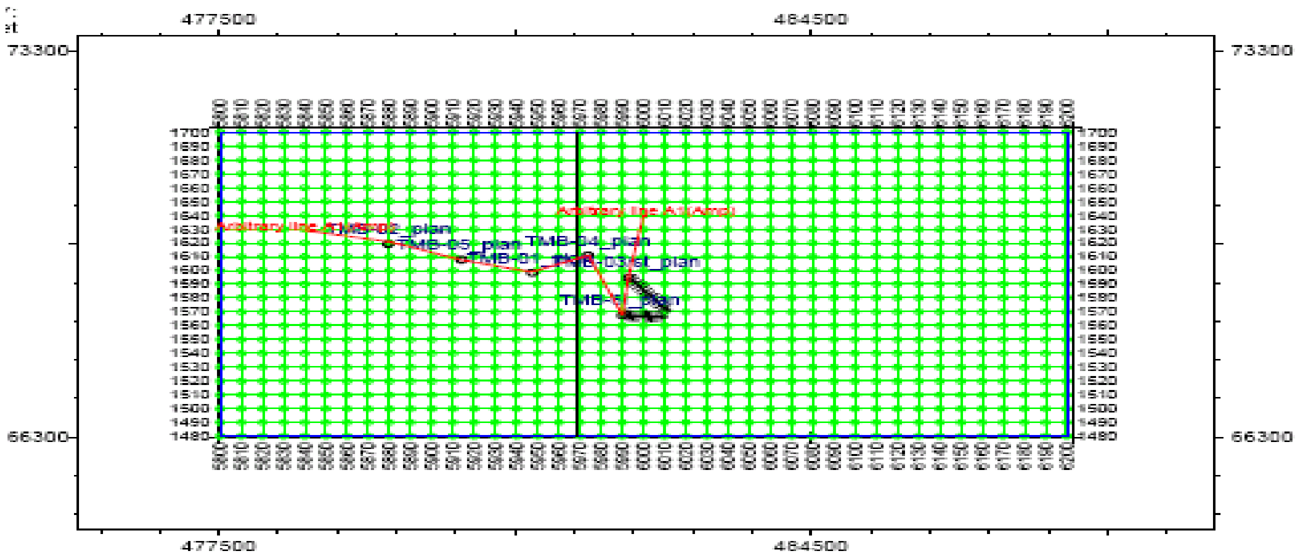

Fig 2: Base map of AkamOilfield

2. Methodology

2.1 Data Acquisition

The following data were obtained from a petroleum company through the Department of Petroleum Resources (DPR): 3D Seismic data, Well Logs (Lithology, Resistivity, Neuton and Density Logs), previous field data and Analysis, Gas Reserves, Production, Utilization and Flare Data in Nigeria for 5 years. Six wells were drilled on Akamoilfield and are labelled X1, X2, X3, X4, X5 and X6. Figure 2 shows the base map of the Akamoilfield.

2.2 Data Processing

The data acquired was processed using Openworks for the 3D mapping while Microsoft excel was used in the chart creation. The following methodology were used in mapping key events in A1X main and A1XX reservoirs.

2.2.1 Seismic: The synthetic seismogram was generated and tied to seismic data as shown in Figures 3 to 5. The Well markers were interpreted as sequence boundaries from the reservoirs of interest. The events were identified and picked in two reservoirs in time along in-lines and cross-lines using variable densities. The loops and sands were tied manually with sand tops corresponding to zero crossing on the dataset. The Zone Attribute Picking (ZAP) was done to automatically pick horizons on subsequent lines which led to the generation of Isochron maps. The Isochron map was converted to Depth Structural map using existing velocity model. The Depth conversion carried out was based on the sidetracked exploration well A1Xst checkshots to create final depth maps over which amplitude extractions were draped. The Stratamp (Halliburton's Software) was used to extract attributes (full and far offset amplitudes were extracted based on map). Polygons were drawn in areas of known fluid fill – Gas, oil and brine and histogram showing distribution of amplitudes vs. occurrence were generated using the software.

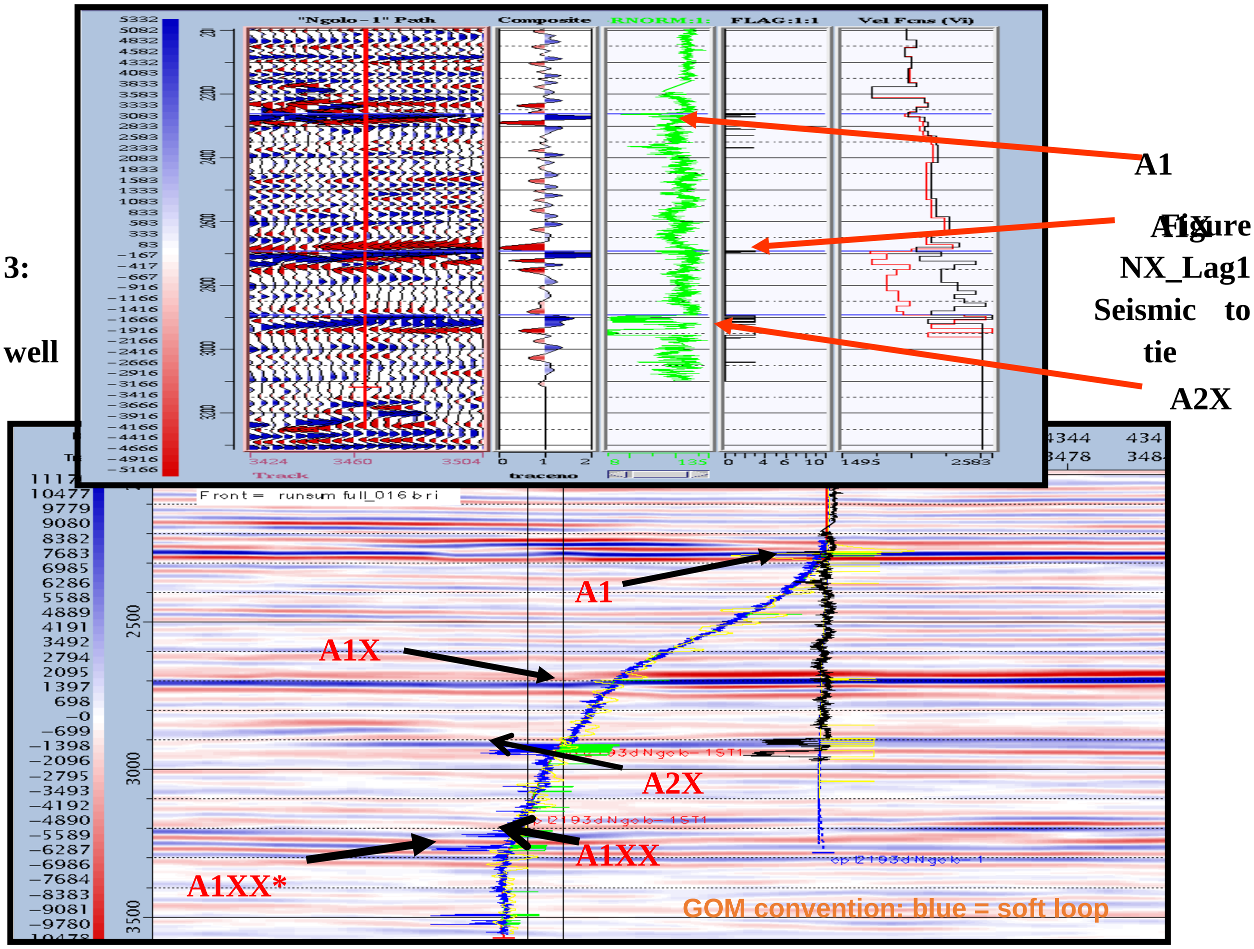

Figure 3: NX_Lag1 Seismic to well tie

Figure 4: NX_Lag1 and NXLag1ST Final Seismic to well tie

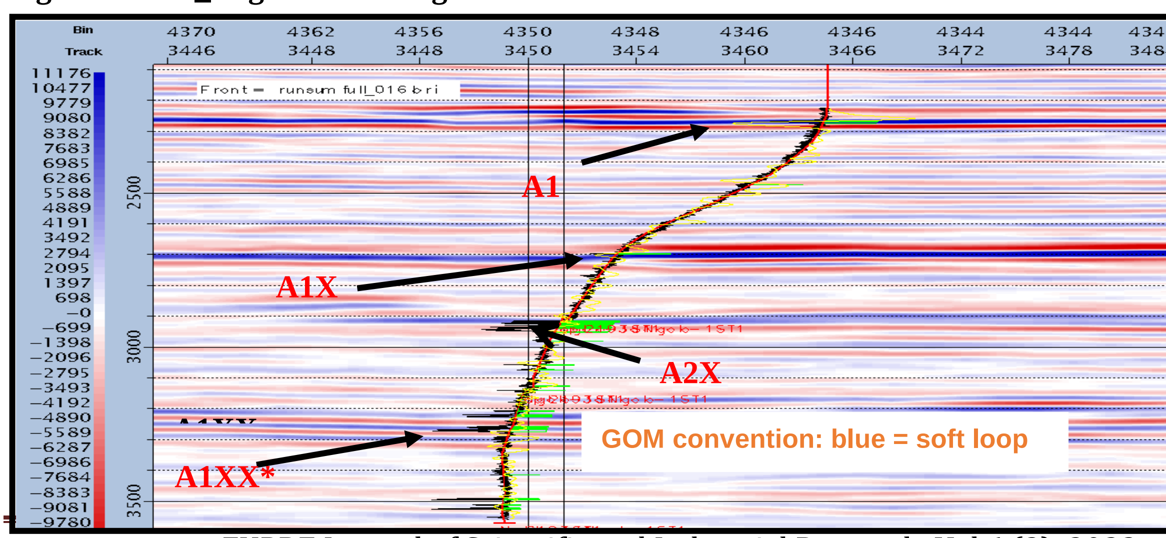

Figure 5: NX_Lag2 Finial Seismic to well tie Transverse

2.3. Theoretical Framework

Theoretically, the following log was done using a deterministic approach, the output curves for permeability, net to gross, effective water saturation, effective porosity, and shale volume were generated. The porosity was calculated using Density and Neutron logs

2.3.1 Fluid Saturation (Water and Hydrocarbon Saturations)

Archie saturation equation, which relates resistivity to porosity, water saturation and various rock parameters, is the industry standard for clean formations and the foundation for quantitative petrophysics (Archie, 1942). The water saturation (S_w) was calculated as shown in equation 1, equations 2 and 3 show the formation factor and Hydrocarbon saturation

$$S_w = \sqrt{\frac{FR_w}{R_t}} \qquad (1)$$

Where R_t= true formation resistivity (Ωm), R_w =formation water resistivity (Ωm),

F = formation factor = $1/\varphi^2$ (2)

Where φ = total porosity

Also, Hydrocarbon saturation (S_h) is computed as

$S_h = 1 - S_w$ (Archie 1942) (3)

Stock Tank Original Oil in Place can be estimated using the formula below

$$STOOIP = 7758\ A\ h\ \frac{\varphi(1-S_w)}{B_o}\ for\ oil$$

(Bateman, 1990) (4)

Where A = Area in acres, h= Net hydrocarbon pay in feet, φ = Porosity in fraction, S_w = Water saturation, B_o= Formation Volume Factor for Oil = 1.3, 7758 = Acre-feet conversion factor for oil

2. 3.2 Volumetric Analysis

Reserve in terms of Original Gas in Place (OGIP) of the sand under study was estimated using equation 5 (Bateman, 1990). Original Gas in Place can be calculated using equation 5.

$$OGIP = 43560\ A\ h\ \frac{\varphi(1-S_w)}{B_g}\ (for\ Gas) \qquad (5)$$

where B_g= formation Volume Factor for Gas (0.016), A = Area in acres, h= Net hydrocarbon (feet), Φ (PHI) = Porosity in fraction, S_w= Water Saturation, GIIP = Gas Initially in Place and 43560 = Acre-feet conversion factor for gas.

2.3.3 Generation of Charts: Different histogram charts were generated using Microsoft Excel Software from associated and non-associated gas reserves obtained from deep offshore and swampy environments for a period of 5 years (1/1/2006 – 1/1/2011).

3. Discussion of Results

3.1. ALag Prospect and Seafloor Mapping

In figure 6, The A1 structure is subdivided into seven (7) prospects with two related prospects to the east. The AX prospect has been penetrated by three wells while the others are yet unpenetrated. The seafloor mapped shows a south dipping slope transgresses by N-S oriented channel while the sea bottom map shows that the study area is relative smooth surfaced seabed topography and bathymetry increases from north to south. The absence of major pockmarks and mud volcanoes further indicate the flatness of the general geomorphology and absence of major seabed geohazards. It can be confirmed that the study area is truly a deep offshore environment and active sedimentation is still taking place (as shown in fig 6).

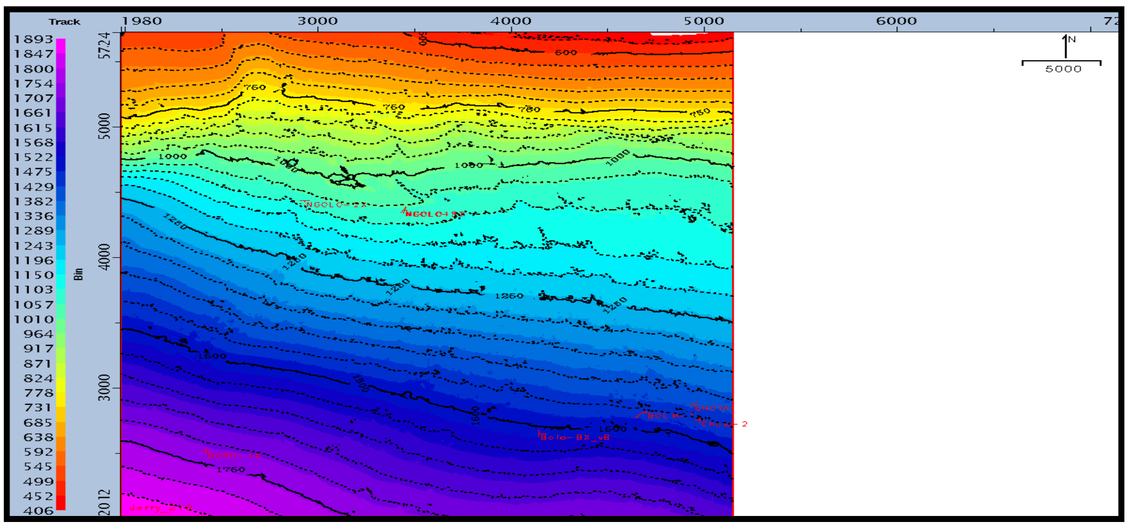

Figure 6: A1X Sea Bottom Isochron Map

3.1.1 A1X_Lag Main Sand

The A1X_Lag sand in figure 7 is located on the southern flank of the A_Lag structure with an up-dip trap against a normal fault and lateral stratigraphic terminations. Amplitude-over background (A/B) maps (in figures 8 and 9) for full and far offset seismic data show the A1X_Lag sand unit to enjoy lateral connectivity (as evidenced by a common fluid contact) and linear channel components trending north-south. The geobody shows good AVO response. Amplitude increases with far offset. The blue is the strongest response (far offset) while the red colour is the dim or no amplitude response near offset. The characteristic variation or contrast in response or Amplitude cutoff or shutoff is predictive of the fluid contact (OWC or GOC) at certain depth and deep-water channel geometry as seen in figures 8 and 9. The lobes can be classified into three which shows AVO characteristic increasing amplitude with the far offset.

The depositional system is considered to be an amalgamated channel-levee complex with all sand connected laterally and vertically. In figure 10, the penetrated

A1X_Lag interval is illustrated on a log plot, which shows that the reservoir is clean with little or no shale intercalation with N/G of 0.94 at the upper unit (A1XMain at depth interval 2537–2570m) while the lower unit (A1XMain* at depth interval 2592–2615m) is very clean sand without any shale streak with N/G of 1.

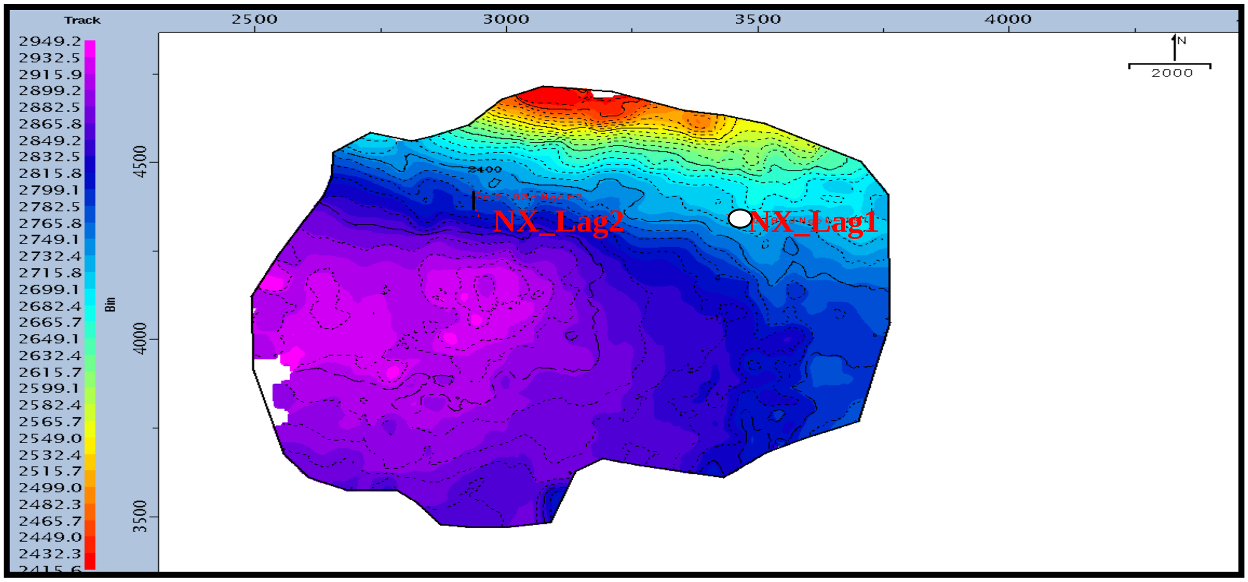

Figure 7: A1X Main Isochron Structure Map

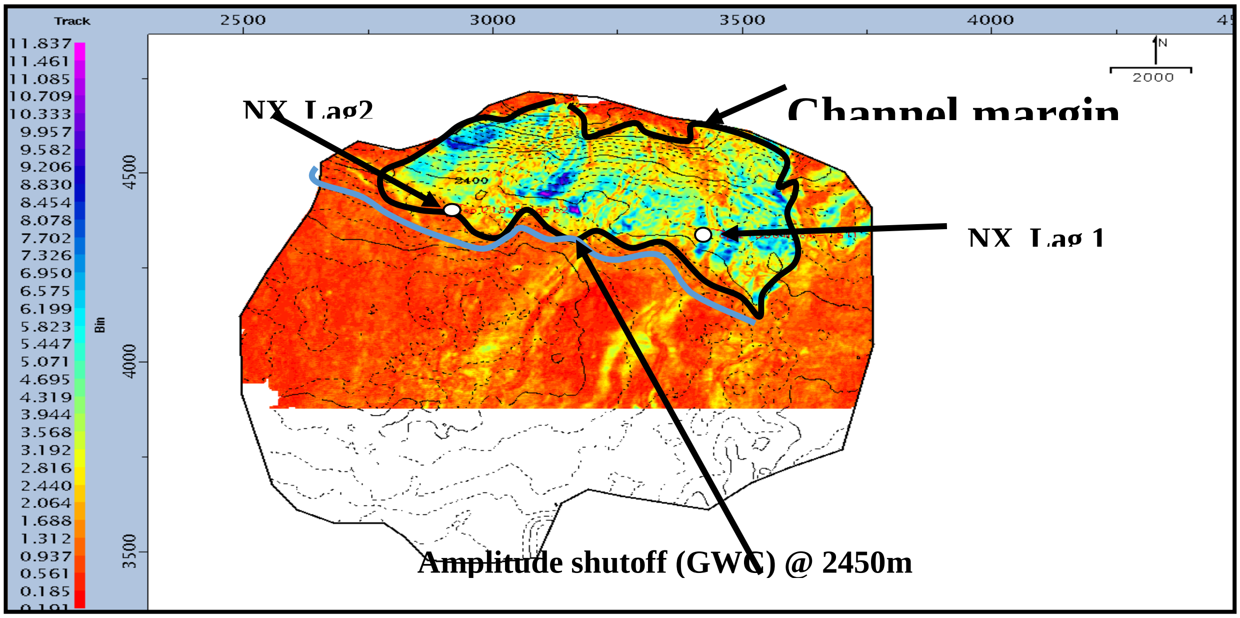

Figure 8: A1X Main Full Stack A/B Map

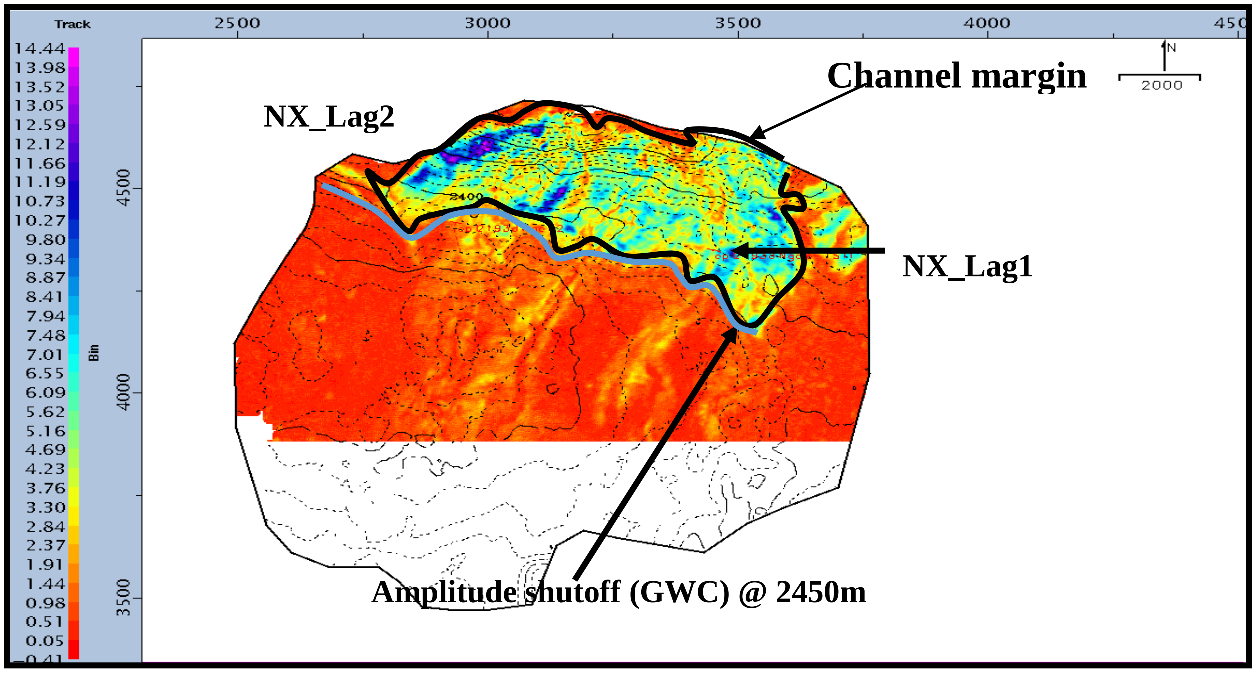

Figure 9: A1X Main Far Stack A/B Map

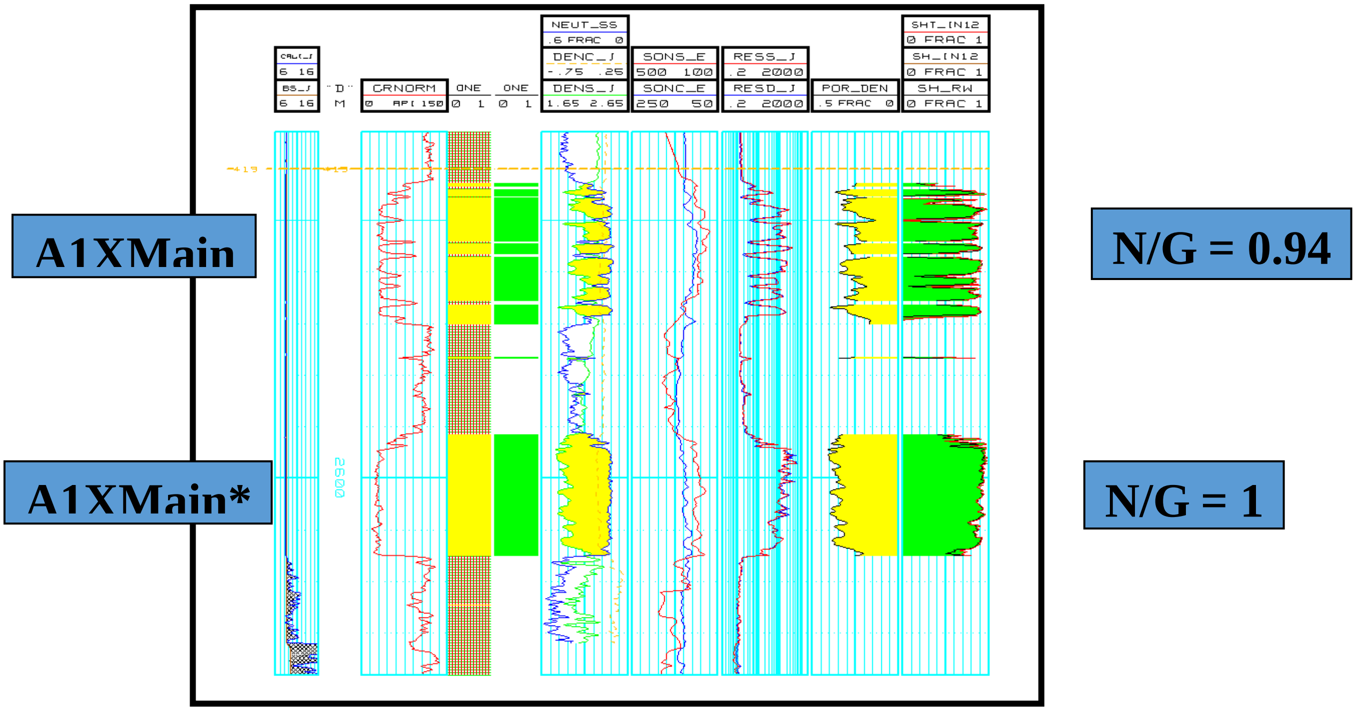

Figure 10: A1X Main Penetration NX_Lag1

4.1.2 A1XX_Sand

From figures 11 and 12, the A1XX_Lag reservoir sand lies below the A1X_lag sand and comprises three (3) main high amplitude units. While in figure 13 and 14, the A/B extractions for full and far offset seismic data show no fluid contact suggesting that the individual reservoir units are not connected and form isolated sands.

These linear high amplitude features are interpreted as turbidite channels deposited within a muddy background that provides lateral seal. The log sections from the eastern A1XX Penetration NX_Lag1ST in figure 15. The lower sands are seen to be more developed than the upper sands. In A1XX Penetration NX_Lag1ST, the A1XX_Lag lower unit (A1XX* at depth interval 3012–3040m) has a N/G of 0.70 and therefore constitutes the main channel while the A1XX_Lag upper unit (A1XX at depth interval 2557–2568m) has a N/G of 0.58 which could probably be channel over-bank deposit.Similarly, in A1XX* the N/G in A1XX Penetration NX_Lag2 lower unit (A1XX* at depth interval 3068–3122m) is 0.62.

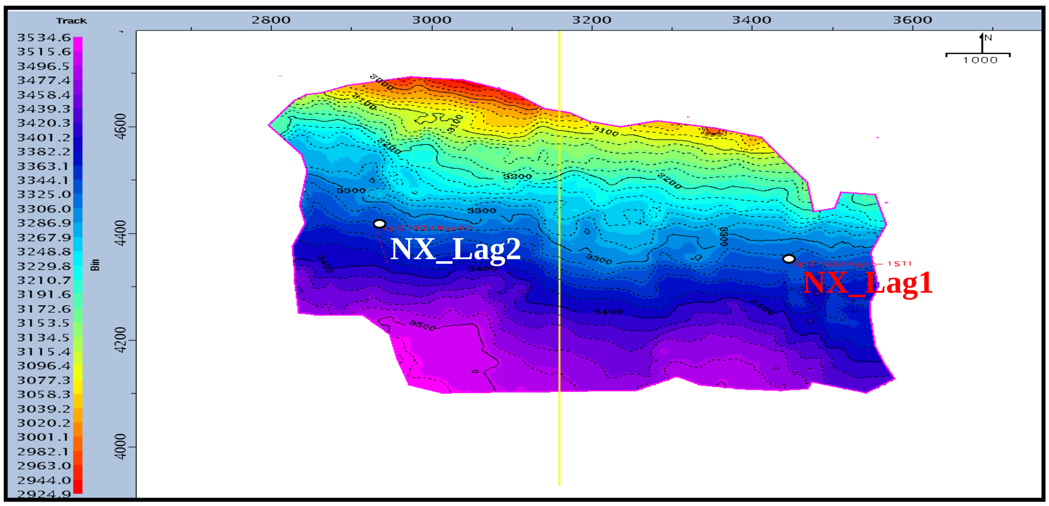

Figure 11: A1XX Time Map

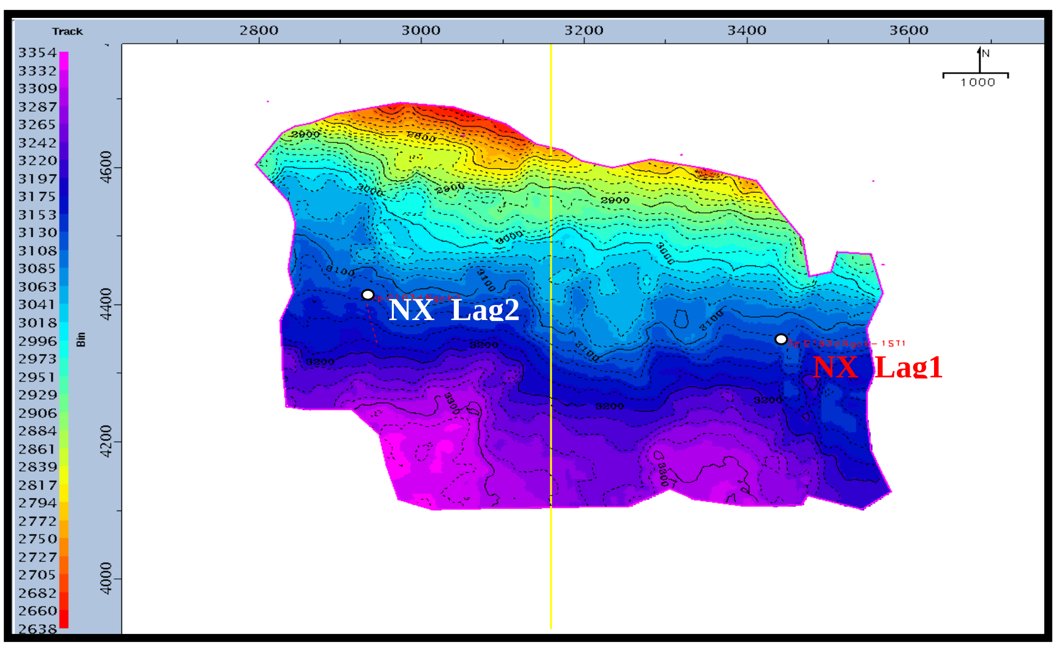

Figure 12: A1XX Depth Map

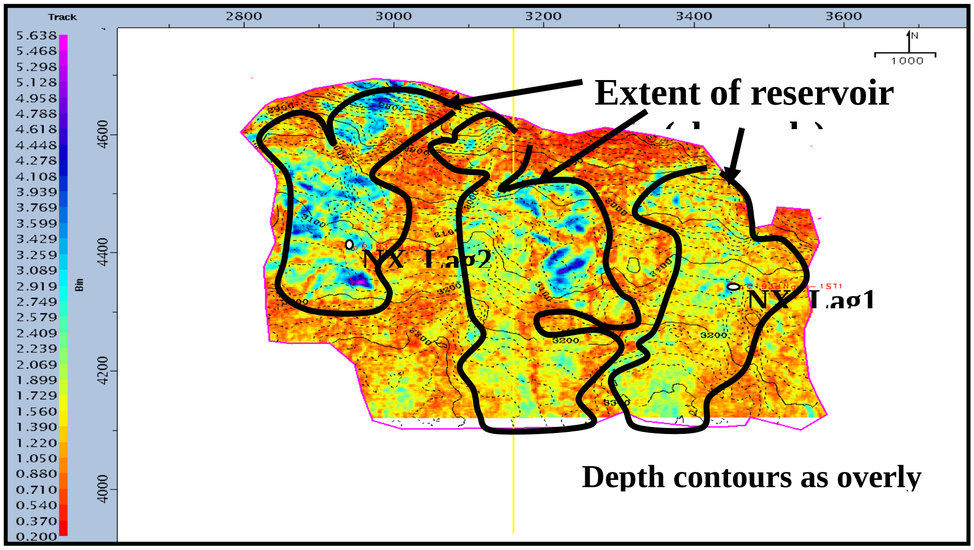

Figure 13: A1XX Full Stack A/B Map

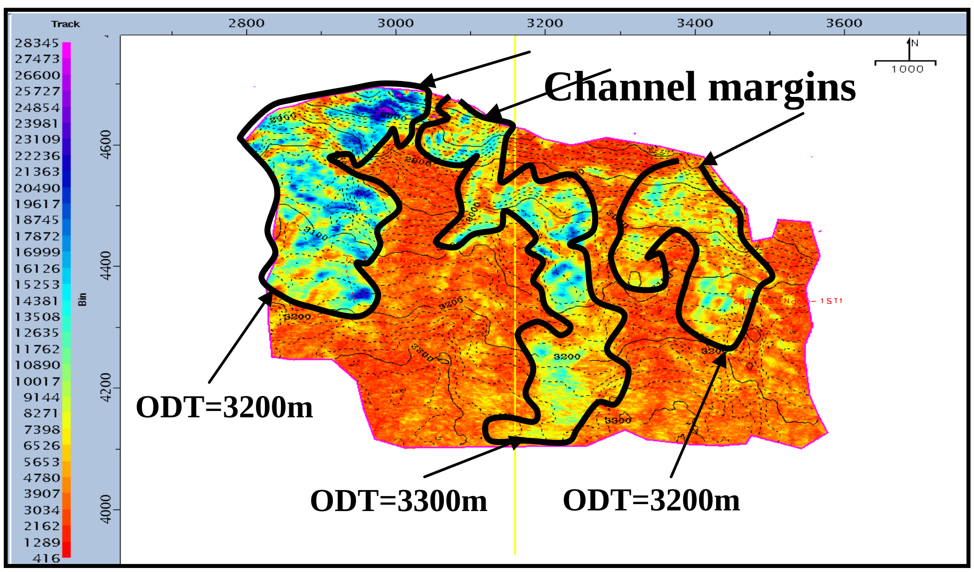

Figure 14: A1XX Far Stack A/B Map

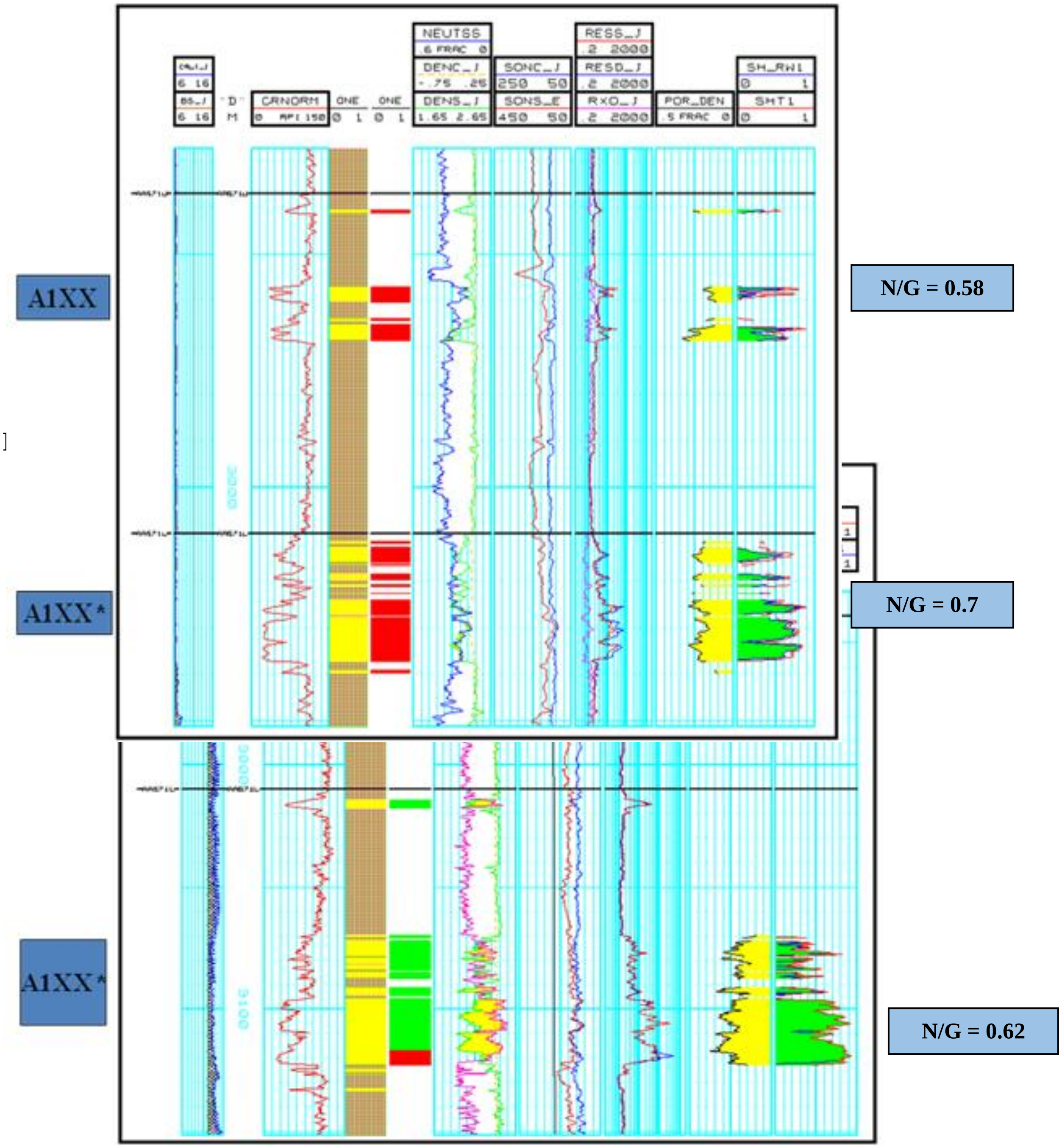

Figure 15: A1XX Penetration NX_Lag2

3.1.3 A/B Calibrated Amplitudes

A/B amplitude extractions were calibrated to give information on the various fluid types. From Figures 16 and 17, the results of calibrated A/B extractions for A1X Main and A1XX sands show that Amplitude versus background ratio values of 1.5, 3.5, and 4 to 6 respectively which are indicative of brine/water, oil and gas based on their respective modal values as shown on the statistical distribution plot of amplitudes versus occurrence. Also, figures 16 and 17 reveal that amplitude anomalies due to gas are brighter and have a higher value than that due to oil or brine.

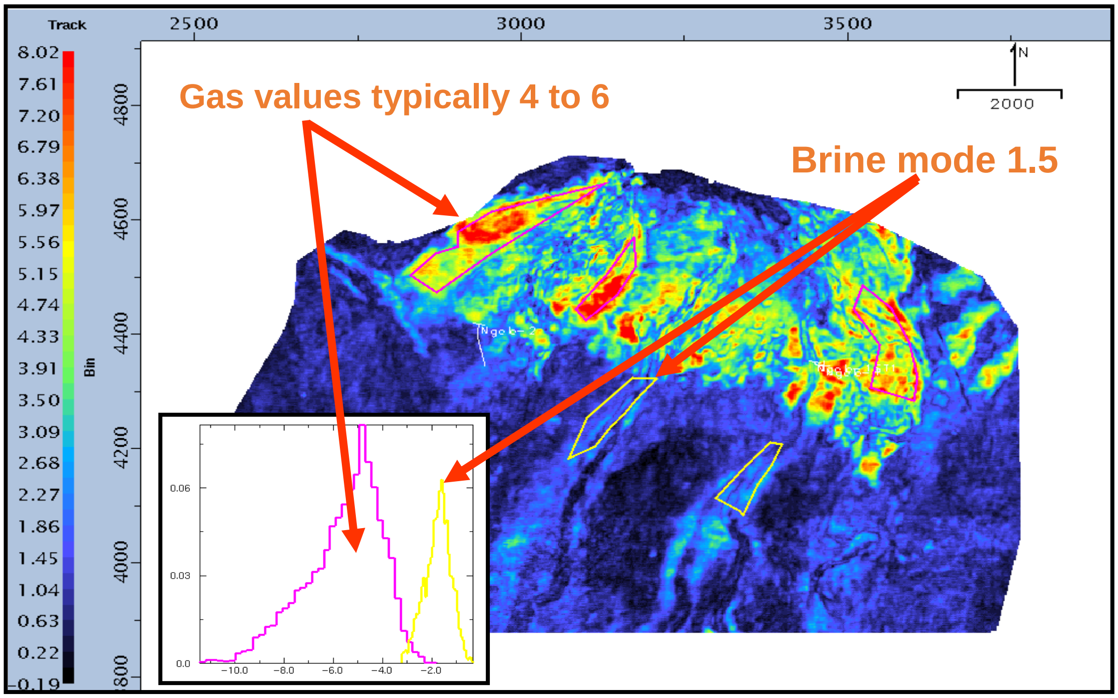

Figure 16: A1X Main Reservoir A/B Amplitude Map

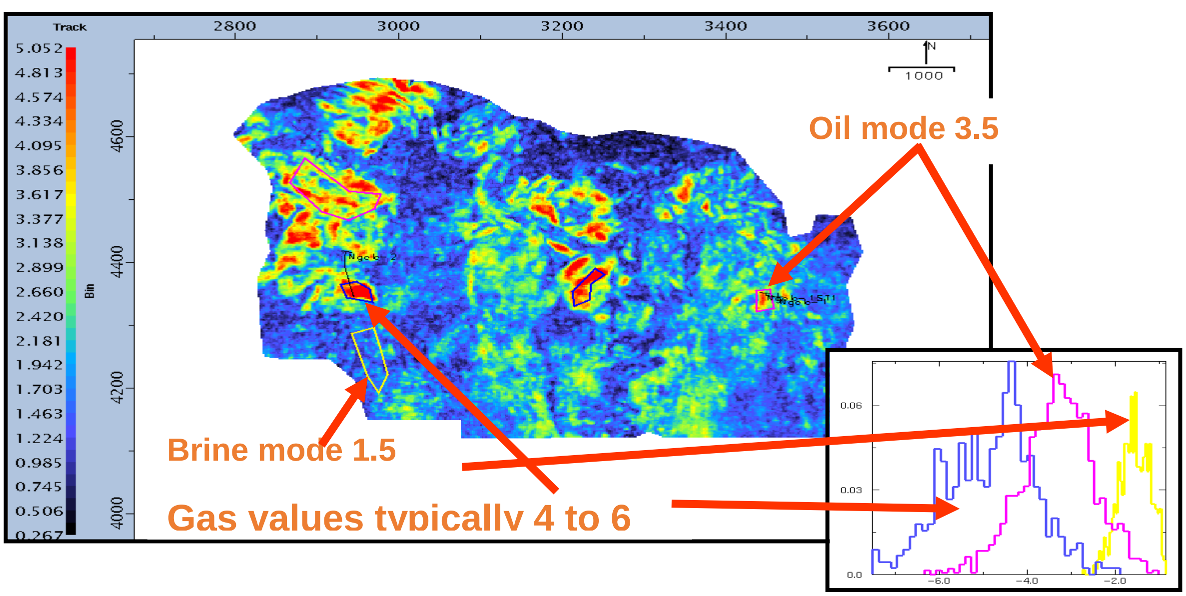

Figure 17: A1XX Reservoir A/B Amplitude Map

3.1.4 Reserve Analysis

Table 1 shows the results of reservoir parameter in which the sand A1XMain reservoir has net to gross of 0.94, porosity of 0.22 and high-water saturation. Since the water saturation is 0.60, therefore the hydrocarbon saturation is 40%. Also, the GIIP is 2269bscf which indicates low reserve. The A1XX reservoir has net to gross of 0.62, porosity of 0.26 and water saturation of 0.47, thus 53% of hydrocarbon saturation. Its GIIP is 5.02bscf which reveal very low reserve. The GIIP for A1XX reservoir is quite small due to the small area extent of the reservoir and also poor net to gross ratio (N/G). However, from table 1, the reservoir is characterized by a very good porosity.

Table 1: Reservoir Parameters

Reservoir	AH (mmacre-ft)	N/G	PHI	Sw	Bg	GIIP(bscf)
A1X Main	15.06	0.94	22	0.60	0.00426	2269
A1XX	0.03	0.62	26	0.47	0.00396	5.02

3.1.5 Gas Reserves and Injection Analysis

There has been no tremendous increase in gas reserves in the past five (5) years (2006 – 2010) (as shown in figures 18 and 19 generated from table 2). Table 3 reveals that 4.9bscf/d of associated gas has still been flared representing 30% of the total associated gas produced. This analysis further shows that over 75% of their produced gas is still flared. Although, there has been a slight increase in the quantity of gas injection as shown in figure 20. Most of our offshore gas potential is still yet untapped because of lack of infrastructure.

Gas Flaring has been a prominent feature in the Nigerian Oil and Gas Sector with current losses estimated at 5.9 million U.S. dollars daily. Most of the flared gases especially in offshore locations are because of their stranded status. Presently, except for the Bonga facility there are no other offshore locations that can boast of an alternative utilization plan so whenever injection fails there is no other option.

Table 2: Gas Reserves as at 1/1/2006 – 1/1/2011 (all units are in tscf). (*Source Department of Petroleum Resources, 2012*).

Year	Terrain	Associated Gas	NonAssociated Gas	Total	Total D & O	%
2006	**Deep Offshore**	8.72	10.44	19.16		
	Land	30.94	26.27	57.20		
	Offshore	34.65	29.33	63.98		
	Swamp	27.81	19.05	46.87		
		102.12	**85.10**	**187.21**	**83.14**	**44.41**
2007	**Deep Offshore**	9.76	10.89	20.65		
	Land	31.80	26.69	58.49		
	Offshore	32.91	28.68	61.59		
	Swamp	27.57	18.83	46.40		
		102.04	**85.09**	**187.13**	**82.24**	**43.95**
2008	**Deep Offshore**	9.79	11.96	21.75		
	Land	30.71	28.57	59.28		
	Offshore	30.52	29.54	60.06		
	Swamp	26.15	19.61	45.76		
		97.16	**89.69**	**186.85**	**81.81**	**43.79**
2009	**Deep Offshore**	10.32	13.10	23.43		
	Land	31.25	29.86	61.11		
	Offshore	29.81	28.55	58.36		
	Swamp	26.14	19.40	45.54		
		97.53	**90.91**	**188.44**	**81.79**	**43.40**
2010	**Deep Offshore**	10.28	14.44	24.72		
	Land	30.62	30.37	60.99		
	Offshore	27.98	24.71	52.69		
	Swamp	27.15	17.70	44.85		
		96.04	**87.22**	**183.26**	**77.42**	**42.24**
2011	**Deep Offshore**	9.34	13.56	22.9		
	Land	29.76	27.47	57.23		
	Offshore	26.40	27.83	54.23		
	Swamp	27.14	20.80	47.94		
		96.04	**87.22**	**182.30**	**77.13**	**42.31**

Table 3: Gas Production, Utilization and Flare 2005 – 2011 (all units are in mscf). (*Source Department of Petroleum Resources, 2012*).

YEARS	TOTAL GAS PRODUCED	TOTAL GAS UTILIZED	TOTAL GAS FLARED	GAS INJECTED
2005	1,915,953,141	1,271,085,361	644,867,780	
2006	2,347,309,738	1,555,708,373	791,601,365	
2007	2,606,865,323	1,788,696,209	818,169,114	492,697,546
2008	2,552,156,730	1,886,390,276	665,766,454	507,760,000
2009	2,197,569,278	1,666,435,397	531,133,881	594,481,378
2010	2,819,681,845	2,274,953,012	544,728,832	751,705,008
2011	2,966,417,481	2,448,227,866	518,189,616	703,579,860

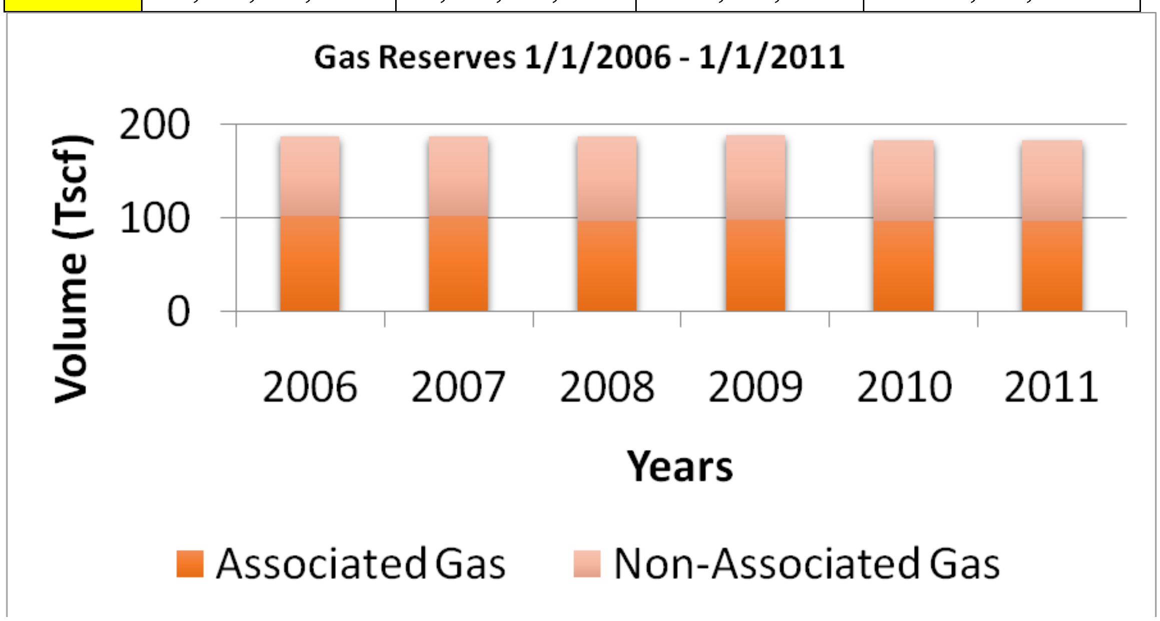

Figure 18: Gas Reserves Chart from 1/1/2006 – 1/1/2011 by Type.

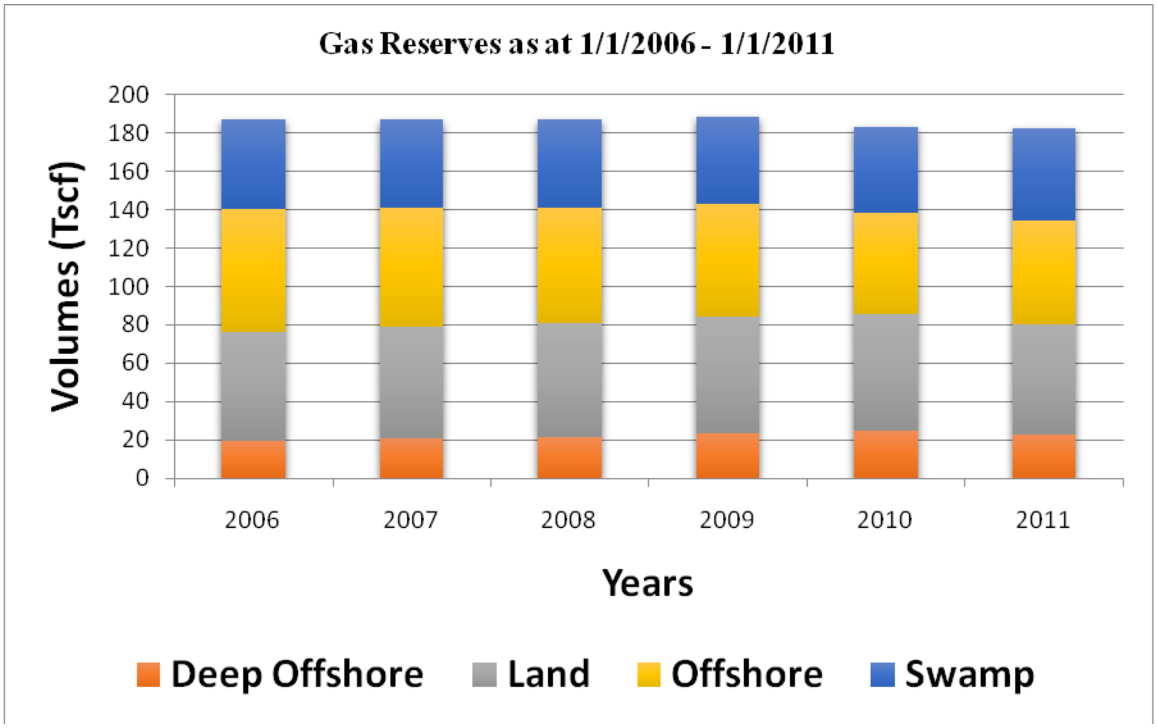

Figure 19: Gas Reserves Chart from 1/1/2006 – 1/1/2011 by Terrain

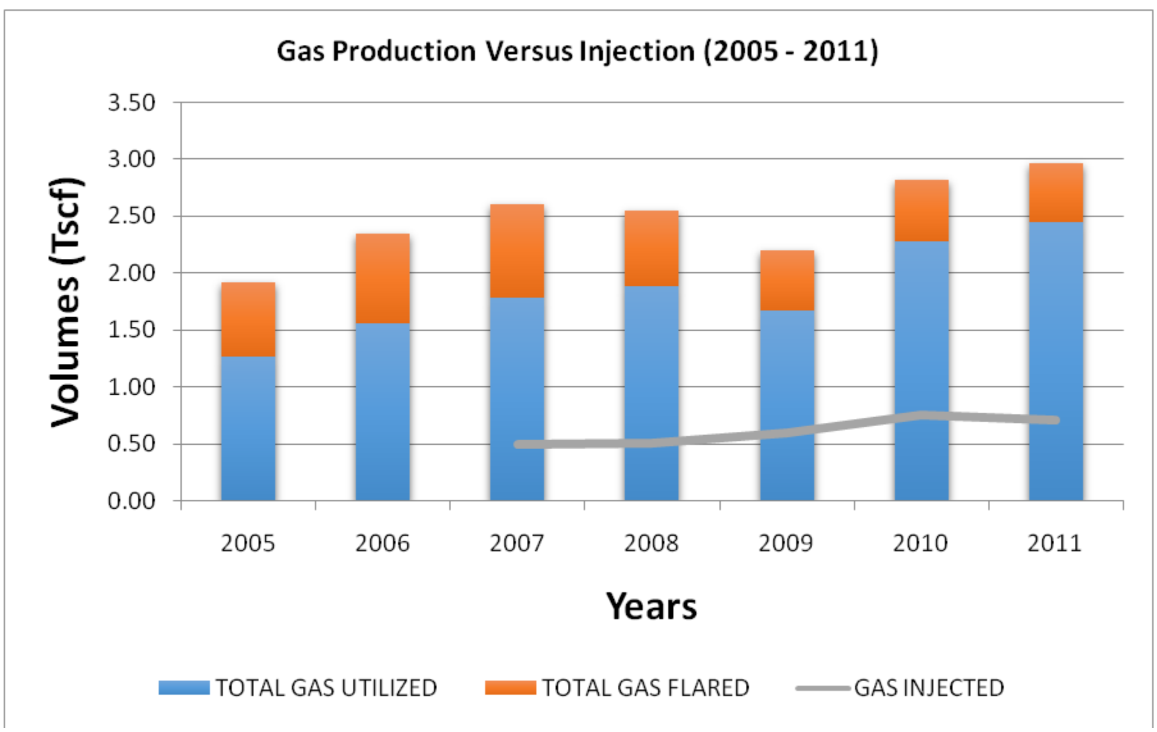

Figure 20: Chart showing Gas Produced and Gas Injected 2005 - 2011

Conclusion

In conclusion, the analysis of 3D seismic and well log data shows that the predominant trapping mechanism is a combination of structural and stratigraphic traps with depositional system comprising amalgamated channel complexes with some vertically and laterally connected sands. Pochmarks though not common are evident on the seabed feature which is indicative of gas and /or water expulsion from sediments insitu. The general seabed topography is smooth and there are no distinct undulations which further suggest that there are no threatening geo-hazards. The amplitude response and AVO products generated from the seismic data of the main geobody are of excellent quality. Also, the integration of well log and seismic data has been able to show that amplitude extraction identified three main lobes and meandering channel systems which are the major reservoir polygons. The A1X Main (Full and far Stack) vividly shows a cut off at 2450m indicative of a fluid contact (GWC). The log signatures of Well NX_Lag1 which penetrated the A1X reservoir has a N/G of 0.95 and 1 while on the A1XX ODT at 3200m for NX_Lag1ST (Gross =50m, N/G = 64%, PHI =22% and Shc =60%). From the well logs some of the sands are well developed, while most of the reservoirs are clean with little or no shale intercalations and the sand lobes as seen from the logs are cleaner than the channel sands. The A/B (amplitude versus background) amplitude analysis of the two reservoirs studied indicates that the A1X main reservoir is gas with typical gas value 4 to 6 while A1XX reservoir comprises oil, gas and brine with typical values 3.5, 4 to 6 and 1.5 respectively. The combination charts (production versus reserves) are indicative of declining gas reserves with increasing gas production and no appreciable decrease in waste gas (flare).

However, the study has established the presence of hydrocarbon in the study area (Akamoilfield), the importance of integrating gas reserves and production data and the need for an optimal solution in converting our vast gas resource to wealth, since most of the Nigerian oil reservoirs have been shown to be technically unsuitable for large-scale re-injection. The need to put in place a framework that will afford us the opportunity to structure a robust and vigorously pursue an early gas utilization plan is necessary.

It is recommended that a domestic energy policy that will drive the domestic market and also a commercial gas pricing framework that would enable investment and sustain the growing gas supply, and in solutions where gas injection is not required for pressure, maintenance companies should be made to put in place a more robust utilization plan. However, an aggressive grassroot campaign for the utilization of natural gas should be done and decentralize the transmission capacity of the NGC and encourage a fair and efficient market. Also, replacement of currently installed Diesel Power generating sets with more efficient gas fired engines should be carried out and encourage third party participation to take gas at flare and installation of CNG Plant, power generation, GTL etc. and conversion of existing vehicles into bi fuel vehicles.

Suggestion

Thus, the need to put in place a framework that will afford us the opportunity to structure a robust gas utilization plan could not be overemphasized. From table 1, the formation volume factor also suggests that A1XX reservoir is probably under higher pressure. Thus, it will be interesting based on the analysis of reservoir parameters to carry out a further appraisal of the A1XX to investigate possible extension of the reservoir boundaries beyond the current known limits.

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