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A Fast-Tracked Development Plan of Alpha Reservoir (A Partially Appraised Field, Niger Delta Basin) Through Integrated Studies

Ogbamikhumi Alexander*, Ahiwe Lawrence , Umeogu Ifekelunma
Center of Excellence in Integrated Petroleum Exploration and Evaluation Studies, University of Benin
Corresponding Author: Ogbamikhumi Alexander

ABSTRACT
The study field is a green field with limited well penetrations. The objective reservoir is a relatively shallow one, with five well penetrations. Two of the wells are wet while the rest penetrated hydrocarbon bearing intervals. Well logs acquired in one of the wells show the presence of gas. Assessment of sidewall samples and ditch cuttings further validated the presence of gas in the reservoir. However, no contact has been logged from any of the wells. 3D static modelling captured static uncertainties of the reservoir following identification of limitations to reservoir development (key amongst which are the fluid contact uncertainty of 103ft between Gas-Down-To and Water-Up-To, and structure). The impact of dynamic reservoir properties on fluid recovery determined the outcome of the production forecast of the selected development concept. Impacting uncertainties in reservoir development have been managed and reduced sufficiently for development. Fluid contact uncertainty has been reduced to 20ft (from 103ft), thus eliminating presence of a producible oil rim, and managing structural uncertainty. The selected development concept targets a single well (with a pilot appraisal hole), and tubing size of 4.5" at a rate of 50MMScf.
Keywords: *Fluid Contact, hydrostatic pressure, Partially Appraised Field, Water Up To, Gas Down To.*

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I. Introduction

The oil and gas industry is well established as a high-cost, high-risk venture, where successes when achieved, are fulfilling. Usually, companies employ cost-cutting strategies (that do not undermine operational safety) to maintain a reasonable bottom-line and margin, especially since the current uncertainty and bust in crude prices and revenue from petroleum products. The main thrust of this work is on technical cost reduction techniques, focused on the pre-production phase of reservoir development.

The reservoir under study is the Alpha reservoir, in a partially appraised field (MAR A field) located in the Niger Delta basin. The MAR A field was discovered in 1971, and up to the time of this work was a green field. 3D seismic data has revealed the field as a fault-bounded simple roll-over structure, with a relatively low relief. It also has minor intra-field listric faults, particularly a large fault which segments the field at some levels. At present, six wells have been drilled into the field and five of the wells penetrated the Alpha reservoir level, but only three of them encountered hydrocarbon. No fluid contact has been logged from any of the wells.

The focus is to fast-track the field development using current technology to delineate possible fluid contact(s) as against dedicated appraisal well(s) to establish the presence or absence of an oil-rim. This in effect, will reduce costs associated with drilling more appraisal wells and building additional facilities (except flow-lines, pipelines and manifolds). As a partially appraised field, a set of uncertainties were identified for management. These include:

1. Structural uncertainty due to sparse well control.
2. Uncertainty in fluid types and depth of fluid contact, since only a Gas Down To (GDT) and Water Up To (WUT) were encountered from the existing wells (Figure1).

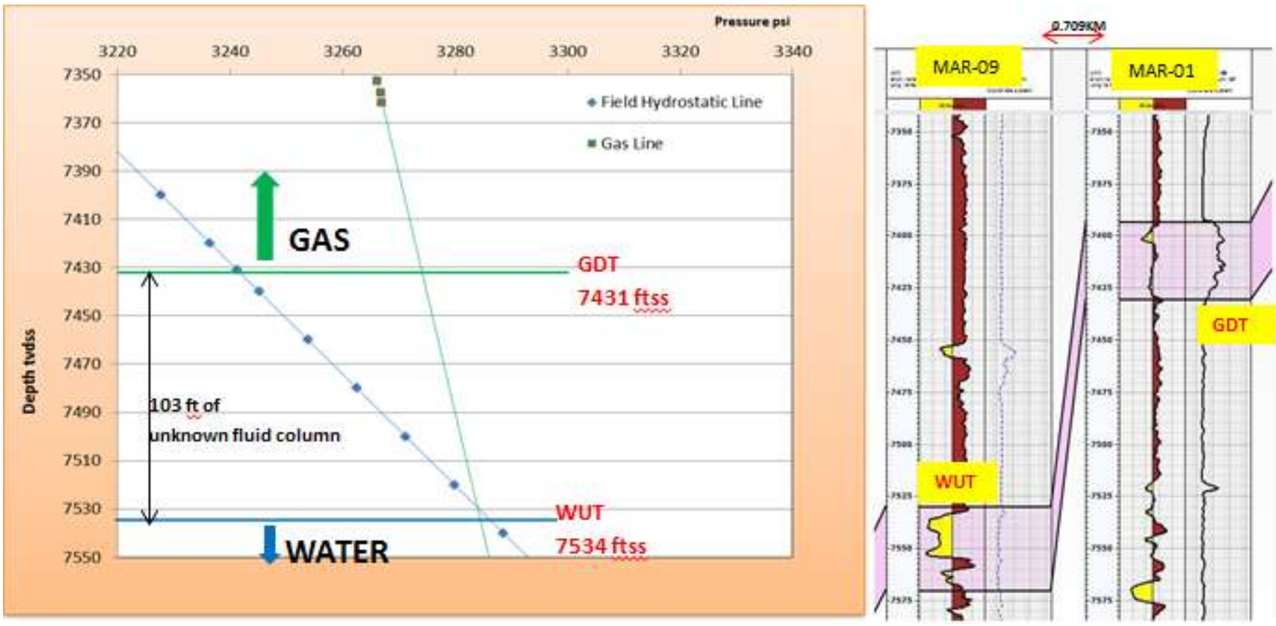

Figure 1: A log panel showing the GDT and WUT of Alpha Reservoir

The interval of uncertainty between the GDT and the WUT as shown in Figure 1, is 103 feet, which presented a challenge in the classification of the reservoir as a gas, oil or dual-phase reservoir.
The objective of this work is to address these uncertainties, manage them such that further appraisal drilling and studies are eliminated, and a development plan is proposed.

II. Research Methods

The methodology employed to fast-track reservoir development from field appraisal was that of an integrated, multi-disciplinary approach. The approach involved carrying out structural interpretation to produce a top structure map for Alpha reservoir using Petrel interpretation software. Velocity models were built deploying both the Polynomial and Vo-k method for depth conversion. Residual values of both methods were compared with the aim of choosing the model with least residuals for depth conversion. To better understand the aquifer behavior relative to the neighboring structure, aquifer support analysis was done on selected time slice.
The petrophysical analysis of the reservoir rock and fluid properties were done using the Techlog software. Resistivity logs and neutron-density logs were used in fluid identification and typing. Side wall samples were analyzed to also type the fluid in MAR-001A[1].
Property curves for Vshale, porosity, permeability and net sand were generated from the original logs[2]. To understand the stratigraphy of the penetrated section, a sequence stratigraphic model of the field was developed, based on the biostratigraphic information available in two wells, with which Maximum Flooding Surfaces (MFSs) were picked. Using these MFSes and creating a stacking pattern of stratigraphy in each well, correlation of the MFSes were carried across the entire field, and Sequence Boundaries (SBs) were also identified. High resolution sequence stratigraphy was developed to infer the reservoir character.
Structural models were generated to simulate faults, horizons, layers and zones, and stochastic algorithms were used to mimic the Alpha reservoir. The generated 3D petrophysical models were constrained to a conceptual depositional model based on the relationship between rock type and rock properties.
Pressure gradient analysis is the method adopted in this study for the investigation of a possible oil rim within the objective reservoir[4]. The theory is based on the variation in fluid gradient especially around the GOC. In testing the possibility of an oil rim in a given reservoir column where a gas column has been established, different possible oil gradients are plotted below the gas gradient line, against an established hydrostatic line. Different depth realisations are tested below the established Gas-Down-To (GDT) in order to evaluate the possibility of a GOC/OWC. The idea is that, should an oil rim exist within the interval of investigation, the different pressure gradients of oil and gas respectively, will establish a pressure gradient profile such that the oil gradient line will intersect the hydrostatic line above the Water-Up-To (WUT) line. The model can also be calibrated with data from reservoirs with established GOCs.

III. Results And Discussion

The interpreted Alpha reservoir top structure map with the aide of semblance attribute shows a relatively flat, roll over anticline bounded by two major fault and a major intra-reservoir fault on which the major hydrocarbon accumulation exists[5]. The sag present close to the north bounding fault (Figure 2: in black circle) was managed by applying smoothing process during make and edit process on Petrel, else it will impact on GRV estimation.

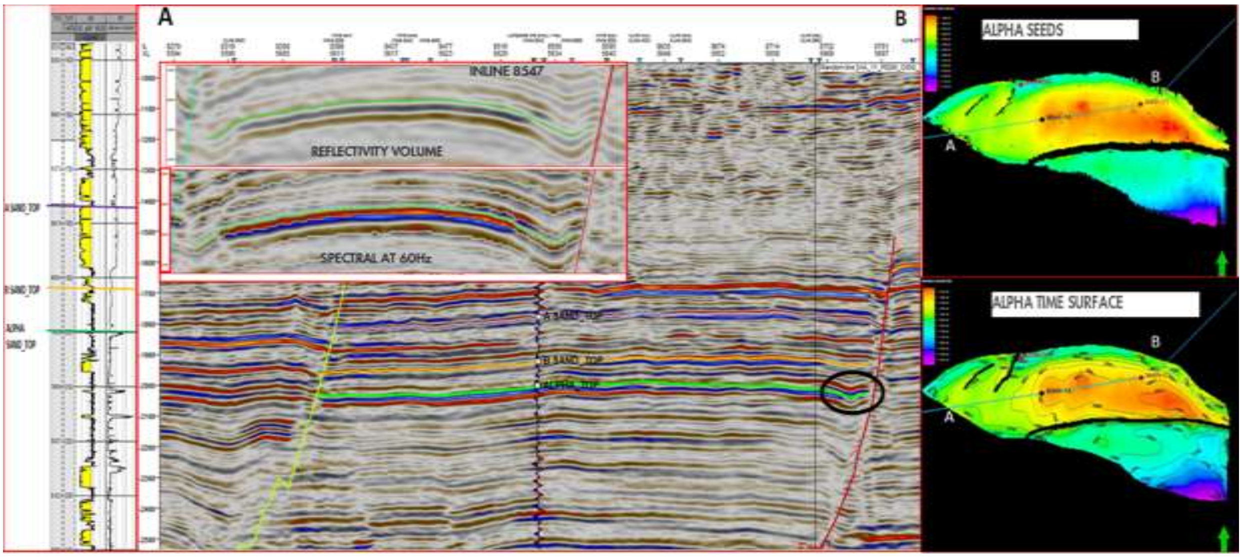

Figure 2: Seismic to well tie and three interpreted reservoir levels including Alpha reservoir

Two shallower surfaces (A Sand and B Sand) were interpreted alongside our reservoir of interest (Alpha reservoir) to test the consistency of both velocity models built for depth conversion (Figure2). The velocity models and depth conversion shows that polynomial method is more optimal for depth conversion than V0-K method due to its lower residual values (Figure 3 a and b). Depth uncertainty of +/-24.7Ft was applied to TVDSS (True Vertical depth subsea) across the interpreted structure after depth conversion to generate the low and high case top structure map.

Vo-K Method

A SAND_Vo-k REPORT

Well	Md	X-value	Y-value	Z-value	Horizon before	Diff befor	AVERAGE	STD
MAR-08	6636.08	433164.6	120110.4	-6506.77	-6562.57	55.79		
MAR-09	6830.66	433485.9	119943.6	-6490.63	-6532.95	42.32		
MAR-01	6398.22	438557.7	119367.1	-6353.89	-6360.4	6.51	32.07	21.54
MAR-1A	6452.43	434029.2	118713	-6410.78	-6434.43	23.65		

B SAND_Vo-K REPORT

Well	Md	X-value	Y-value	Z-value	Horizon before	Diff befor	AVERAGE	STD
MAR-08	7359.93	433205.4	120025.2	-7160.9	-7229.58	68.67		
MAR-09	7535.93	433550.6	119892.9	-7140.56	-7180.38	39.82		
MAR-01	7034.99	438559.8	119338.7	-6983.71	-7000.95	17.24	30.58	30.93
MAR-1A	7096.49	434019.1	118712.8	-7053.95	-7050.54	-3.41		

ALPHA SAND_Vo-K REPORT

Well	Md	X-value	Y-value	Z-value	Horizon before	Diff befor	AVERAGE	STD
MAR-08	7807.51	433233.3	119974.1	-7565.62	-7640.06	74.44		
MAR-09	7991.87	433608.9	119850.2	-7529.79	-7593.15	63.36		
MAR-01	7417.66	438557.6	119321.7	-7362.16	-7406.53	44.38	49.12	26.35
MAR-1A	7435.89	434015.1	118715.2	-7392.98	-7407.23	14.25		

Figure 3a: Results of depth conversion using V0-K method

Polynomial Method

A SAND_POLY REPORT

Well	Md	X-value	Y-value	Z-value	Horizon before	Diff before	AVERAGE	STD
MAR-08	6636.08	433164.6	120110.4	-6506.77	-6516.02	9.25		
MAR-09	6830.66	433485.9	119943.6	-6490.63	-6486.92	-3.71		
MAR-01	6398.22	438557.7	119367.1	-6353.89	-6319.05	-34.84		21.85
MAR-1A	6452.43	434029.2	118713	-6410.78	-6377.75	-33.03	-15.58	

B SAND_POLY REPORT

Well	Md	X-value	Y-value	Z-value	Horizon before	Diff before	Horizon after	AVERAGE	STD
MAR-08	7359.93	433205.4	120025.2	-7160.9	-7173.08	12.18	-7160.9		
MAR-09	7535.93	433550.6	119892.9	-7140.56	-7127.71	-12.84	-7140.56		28.86
MAR-01	7034.99	438559.8	119338.7	-6983.71	-6949.01	-34.69	-6983.71	-22.58	
MAR-1A	7096.49	434019.1	118712.8	-7053.95	-6998.97	-54.97	-7053.95		

ALPHA SAND_POLY REPORT

Well	Md	X-value	Y-value	Z-value	Horizon before	Diff befor	AVERAGE
MAR-08	7807.51	433233.3	119974.1	-7565.62	-7579.59	13.97	
MAR-09	7991.87	433608.9	119850.2	-7529.79	-7531.35	1.56	-10.12
MAR-01	7417.66	438557.6	119321.7	-7362.16	-7350.62	-11.54	
MAR-1A	7435.89	434015.1	118715.2	-7392.98	-7348.51	-44.47	

Figure 3b: Results of depth conversion using Polynomial Method

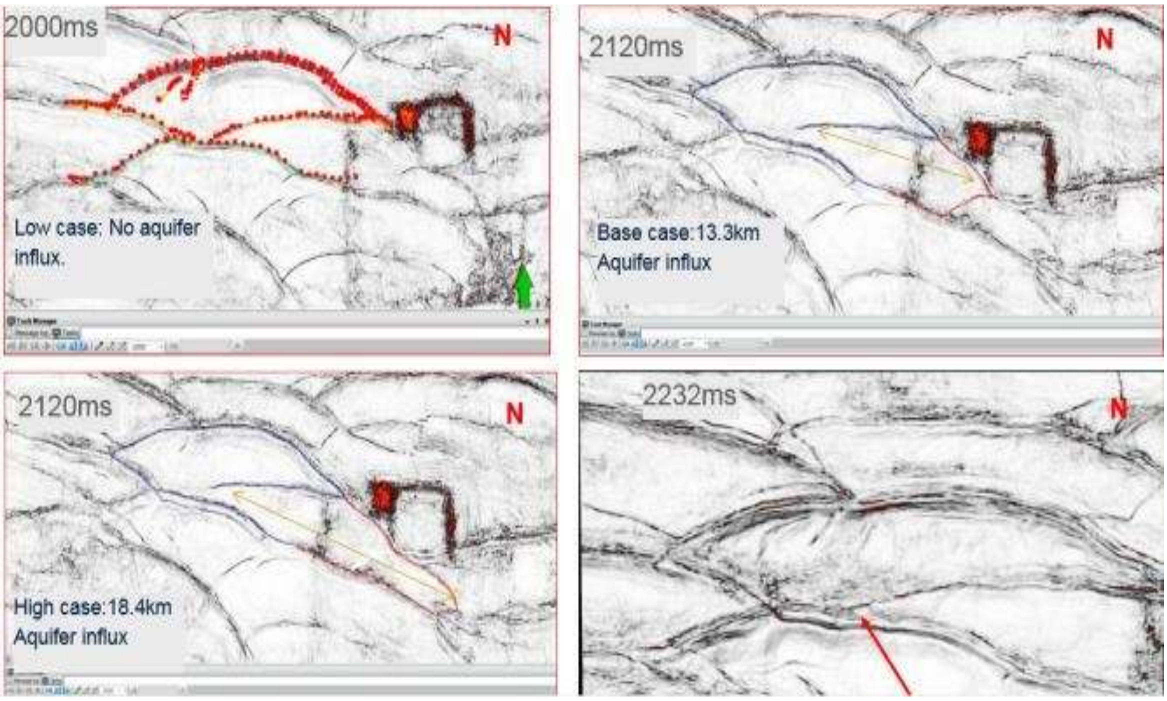

Figure 4: Result of aquifer support analysis and mapping across several time slices

Analyzing the potential aquifer drive, uncertainty was discovered around the intersection of the major intra-reservoir fault and the south bounding fault. This was managed by capturing a low, base and high case aquifer support. At shallower level (figure 4; 2000ms time slice), the faults seem to clearly intersect. In this case, the system is seen to be completely closed, and may have no possible interaction of the aquifer system with that of a neighboring field. Therefore no aquifer influx was mapped and this was taken as our low case aquifer support in the Mar-A structure.

The Alpha reservoir spans across time slice window of 1990ms to about 2130ms (from the crest of the structure to the base of the water leg). Playing through time slices that falls within this time interval of the reservoir, it was discovered that the south bounding fault and the major intra-reservoir fault does not intersect. This could be tied to the fact that the faults were dying off with depth or probably the quality of the semblance volume was not good enough to clearly show the fault behavior with depth[3]. Also, another minor fault (shown in figure 4; 2120ms time slice) seems to be growing with depth and could possibly intersect the south bounding fault. These two observations were a source of uncertainty and captured to create a base and high case aquifer influx from neighboring structure. These results serve as input into the dynamic model simulations for low, base and high case recovery estimation.

Sequence stratigraphic prediction in Figure 5, shows that the reservoir was deposited within a transgressive phase of sea movement (between the 17.4 - 19.4 m.y. sequence), which is an indicator that the prospectivity of the reservoir will continue to diminish distally (petrophysical information confirms this). The petrophysical and geological interpretation of the reservoir revealed a good zone for completion, evidenced by very good reservoir properties in the second zone of the reservoir, and overlaid by a thin streak of shaly heterolithics. Structural uncertainties in the reservoir were managed by building a low to high range of structural models, based on an uncertainty factor of 0.03% of TVDSS of depth. Also, in generating each structural model, a radius of influence around the well penetrations was used, such that the gridded surfaces were constrained by the depth at which each well penetrated the reservoir surface (see Figure 6)

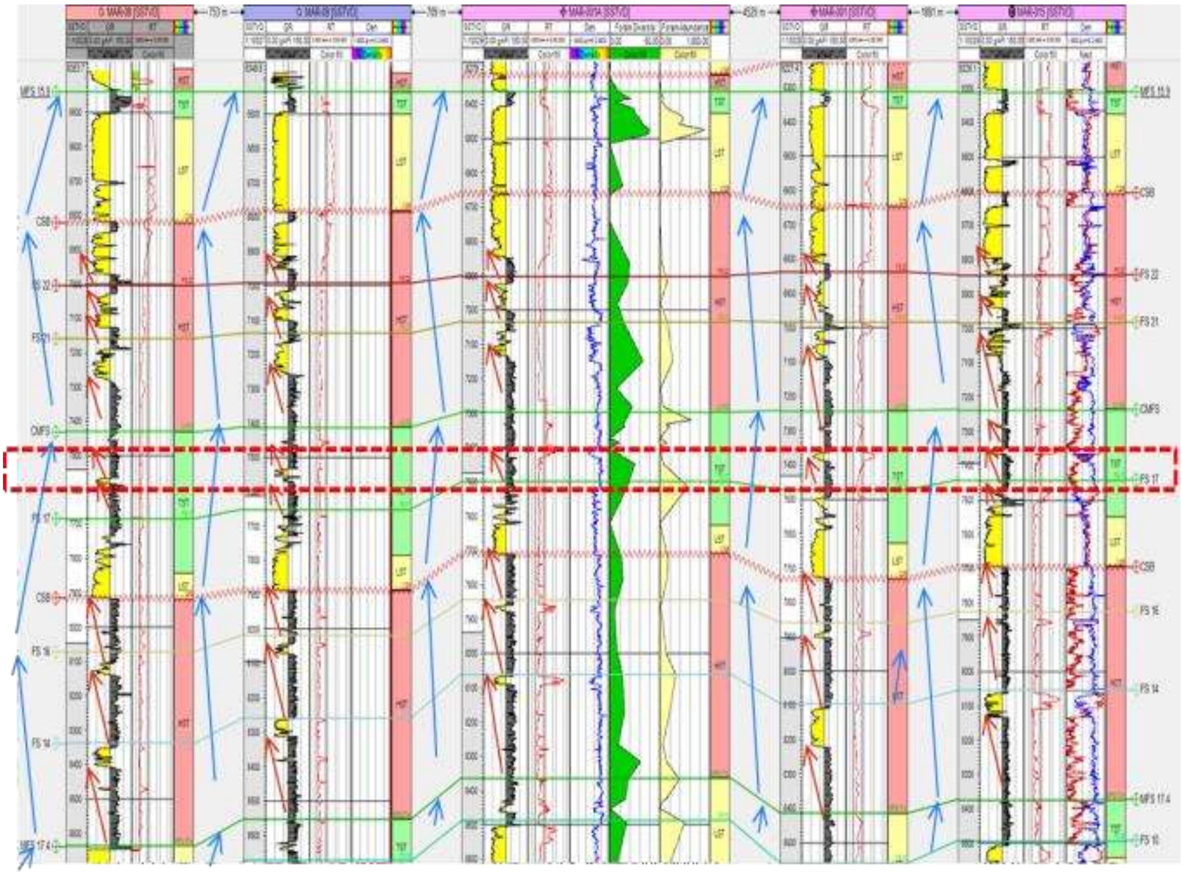

Figure 5: High resolution stratigraphic framework of the field. Red steepled box shows the Alpha Reservoir level

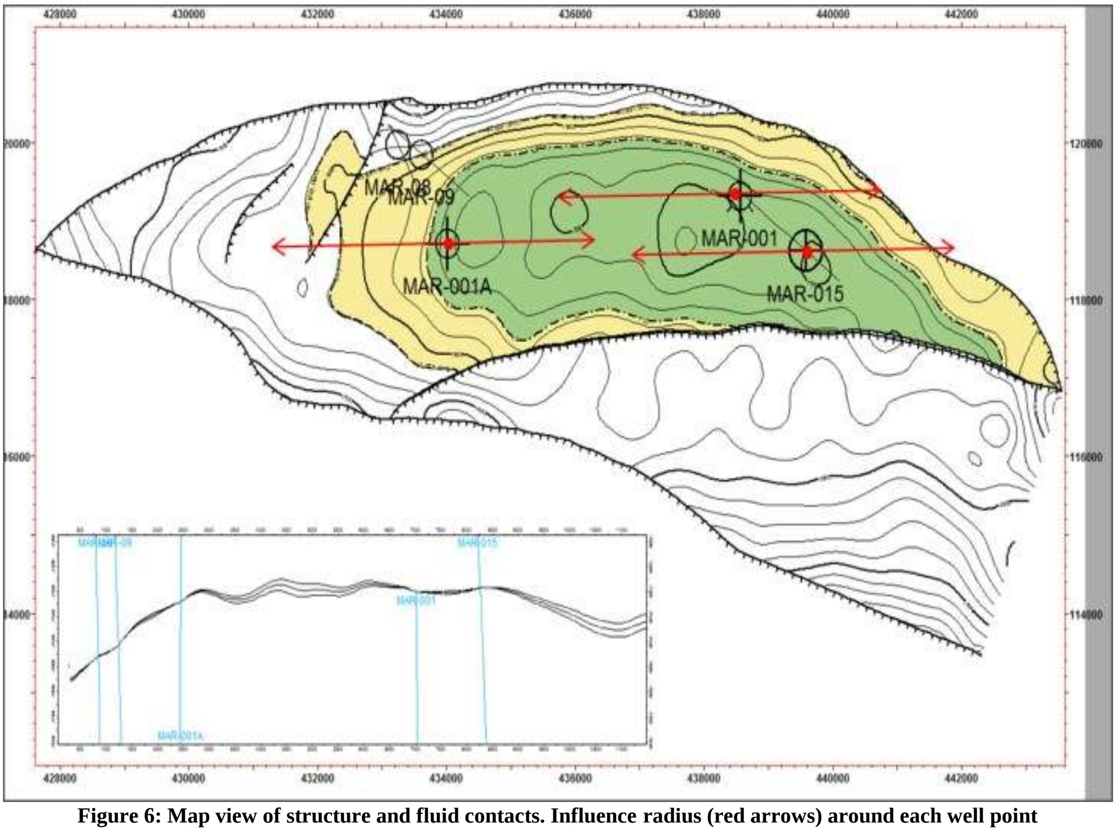

Figure 6: Map view of structure and fluid contacts. Influence radius (red arrows) around each well point

From the oil rim investigation done, the analysis showed that at depths below the GDT up to ca. 20ft above the WUT line, there was no intersection of the oil and water lines above the WUT for any of the possible oil gradients (0.2, 0.29 and 0.38psi/ft.) common in the Niger Delta Basin respectively. The implication is that, within the 103ft. of unknown fluid column, the maximum column of oil-rim possible is just ca. 20ft above the WUT. Even at this depth, only the possible oil gradient of 0.2psi/ft. just intercepts with the hydrostatic line just above the WUT line (Figure 7a). Oil accumulation with such gradients will be very light oil. In addition, the column of possible oil rim of about 20ft. is not economical enough to be developed and as such, is negligible. As a result, the gas gradient line was extended below the Gas-Down-To (GDT) to intercept the hydrostatic line at 7529 ftss. (Figure 7b) This becomes the established Gas-Water-Contact (GWC) and a reference point for reservoir pressure estimation and hydrostatic initialization. With this established, the development strategy adopted was that of a gas reservoir.

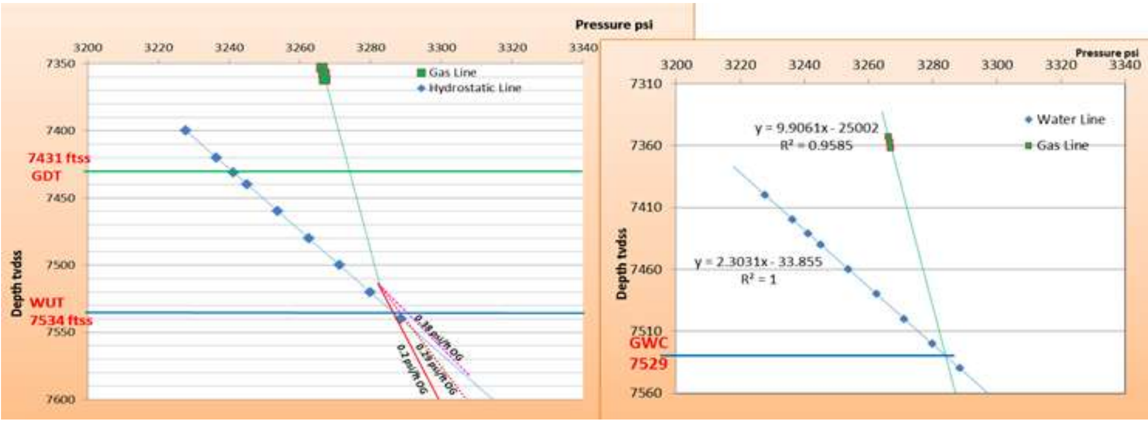

Figure 7: (a) Investigation for possible oil rim within unknown fluid column, (b) Eastablishement of Alpha reservoir fluid contact

In-Place-Volumes

Due to the uncertainties inherent in the data set used for this study, realizations were built to manage these uncertainties. As a result, low, base and high case volumes were determined to account for the possible scenarios of in place hydrocarbon volumes. Below (Table1) is a table summarizing the in-place volumes for the realizations.

Table 1: Volume of Gas Initially in Place (GIIP)

LC	BC	HC
GIPP (BScf)	GIPP (BScf)	GIPP (BScf)
226	263	295

In a bid to ensure that the static model was properly initialized, the gas-in-place volumes of the initialized grid model was compared to that of the static model and from Table 2, it can be seen that the percentage difference in volumes is about 0.4%, signifying that the model was initialized accurately.

Table 2: Volume Comparison of Gas Initially in Place (GIIP)

Initialized (MoRes) Model	Static (Petrel) Model	% Diff
GIPP (BScf)	GIPP (BScf)	
263	262	0.4

Development Concept Selection

In a bid to determine the development concept or strategy to adopt, the following considerations were made;
i. The rate of production from the reservoir.
ii. Number of development well(s) to use for optimal recovery from the reservoir.
iii. The type of well that will optimally drain the reservoir
iv. The best tubing size to use in the well

Sensitivities were carried out on various possible development concepts to understand how they will each affect the total recovery. In considering these development concepts however, it is important to point out that the biggest constraint to the volume of hydrocarbon that will be produced from the well at any given time is the fact that production from the well will be evacuated to a shared surface processing facility, where production from wells in other locations will also be sent. So the rate of production will be constrained by the level of ullage in the processing facility. The study concluded that the optimum subsurface development concept will involve the drilling of one vertical development well (Including pilot hole for further appraisal) and completing same with a 4.5-inch tubing made preferably from chrome and an uptake rate of 50MMscf/Day.

Production Forecast

Deterministic low, base and high case subsurface realizations were built using the selected development concepts to determine the Low, Base and High case expected recoveries. The figures are as shown in the table 3:

Table 3: Low, Base and High Case Recoveries

Recovery	LC	BC	HC
Gas (Bscf)	147	170	190
RF (%)	65.8	64.6	64

Relative to the initial in-place volumes, the volumes recovered from the reservoir give a recovery factor of approximately 65% for the low, base and high case scenarios respectively.

IV. CONCLUSION

No substantial oil rim was established in the reservoir. A new GWC was thus established and the necessity of additional appraisal well(s) eliminated. The development strategy of a gas reservoir was adopted. The key Impacting uncertainties are: Structure and Contact. The Identified uncertainties have been managed by building realizations to adequately capture the possible outcomes. The optimum subsurface development concept is one (1) vertical well with a 4.5-inch tubing size.

The project is therefore recommended for development. However, management of uncertainty around fluid type and contact, using amplitude extracted from reflectivity volume was not possible due to poor amplitude expression on amplitude map. However, this does not invalidate the analysis used in this work but would only have supported results from pressure analysis.

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