



## Facies Analysis, Rock properties and Depositional Environments of 'UQ' Field, Niger Delta, Southern Nigeria

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### Abstract

Despite significant hydrocarbon production in the UQ Field, the reservoir complexity and heterogeneity have made it challenging to accurately characterize the reservoir properties. Hence, the goal of this research was to conduct a complete facies analysis and rock properties characterization of the UQ Field in order to improve reservoir understanding and optimize hydrocarbon production. In this research, petrophysical and facies analyses of the UQ field utilizing well logs were conducted. Porosity, permeability, water saturation, net to gross ratio, and net pay thickness are some of the petrophysical characteristics that were taken into account in this study. Four wells in total were taken into account for the investigation, and four reservoirs were successfully identified. The reservoir sands' depositional facies and environment were distinguished using the gamma ray log.

Each well underwent a thorough investigation of its petrophysical properties, and the reservoir thickness, net pay, net-to-gross ratio, porosity, and water saturation were all computed. The reservoirs had good petrophysical characteristics, with total gross thicknesses ranging from 218.87 to 584.76 feet and net to gross thicknesses varying from 157 to 414 feet due to shale intercalations. The reservoir's N/G ratio of 81% shows that reservoir sands occupy a larger share of the rock's bulk volume. The reservoirs' average water saturations range from 0.17 to 0.41. In general, it is seen that the porosity values within the wells are declining. The four reservoirs' estimated average porosities were between 0.24 and 0.30. The reservoir sands' impacts on particle size and sorting may be primarily responsible for the porosity values. The gamma ray log's form was used to establish the depositional setting for each reservoir. The majority of the basin floor fans and slope fan systems made up the depositional environment for the reservoirs.

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**Keyword:** Well Log; Petrophysics; Facies; Depositional Environment; Sequence Stratigraphy.

## 1.0 Introduction

A sedimentary facies, which is a body of sedimentary rock is identified and set apart from nearby facies by its lithology, fossils, sedimentary structures, geometry, and paleocurrent patterns (Selley, 1970). The sedimentary settings that gave rise to the facies are indicated by these defining characteristics. A delta is one of these sedimentary settings. A delta is a distinct coastline projection of sediments that have accumulated at the mouth of a river as it enters an ocean. They frequently serve as hosts for important petroleum reservoirs (Bhattacharya and Walker 1992).

Exploration wells are those that are drilled to see if a prospect has petroleum accumulation. An oil field is a location where petroleum is discovered by an exploration well. A thorough facies and petrophysical investigation of the sedimentary record at the location of the discovery well is the first step in determining the petroleum accumulations economic worth (Harry *et al.*, 2018). In order to do this, the penetrated geologic Formations must be vertically delineated, and the lithologic units must be linked to the depositional sub-environments.

Identification of reservoir rocks, fluid type, fluid contacts, porosity, hydrocarbon saturation, hydrocarbon pore volume, and reservoir permeability are all part of the petrophysical investigation. This data is used in seismic mapping for post-discovery review to locate appraisal wells for determining the extent of the reservoirs.

The purpose of this research was accomplished by delineating the respective rock intervals penetrated by the wells in the UQ field, characterizing the lithofacies and sedimentary environments of the rock types, analyzing the

distribution of porosity, permeability, and other petrophysical properties and establishing a relationship between rock properties and hydrocarbon saturation in order to optimize production.

## 1.1 Location of Study Area

Nigeria's Niger Delta's onshore region includes the UQ field (Figure 1 and 2). It is an oil and gas field located in Akwa Ibom State, in the southeast of Nigeria. The larger UQ Gas Field Complex, which also includes the UQ, Ukana, and Ebok fields, includes the UQ field as one of its many fields. The UQ field, which Frontier Oil Limited manages, contributes significantly to Nigeria's production of natural gas.

## 1.2 Geology of the Study Area

The Niger delta's thick wedge is said to be made up of three units: the Benin, Agbada, and Akata Formations (Figure 3). These Formations are strongly diachronous and cut across time stratigraphic units that are S-shaped in cross section. Short and Stauble (1967) describe typical parts of these Formations, which are presented in a number of articles (Avbovbo, 1978; Doust and Omatsola, 1990; Kulke, 1995). The following three geologic Formations in the Niger Delta are discussed:

### Benin Formation

The Benin Formation lies on top of the Agbada Formation. The Formation is oligocene in the north and becomes younger as one moves southward. To date, very few hydrocarbon reserves have been discovered in this very porous, mostly freshwater bearing stratum (Short and Stauble, 1967). The Benin Formation, which stretches from west to east throughout the Niger Delta, has been defined as coastal plain sands that outcrop in Benin, Onitsha, and Owerri provinces.

### Agbada Formation

The Agbada Formation is a sandstone and shale paralic series that lies beneath the Benin

Formation. It is made up of sandy sections that serve as the Delta's main hydrocarbon reservoir and shale as the top rock. This sequence is linked to faulting related with syn-sedimentary growth. The Agbada Formation has a maximum thickness of 457.2m in the center (Doust and Omatsola, 1990).

Top sandy unit with minimal shale intercalation and a lower shaly unit that is thicker than the top sandy unit. The Formation was formed in the Eocene and continues until the Recent. The Formation is made up of paralic siliciclastics over 3700 meters thick and represents the sequence's real deltaic phase.

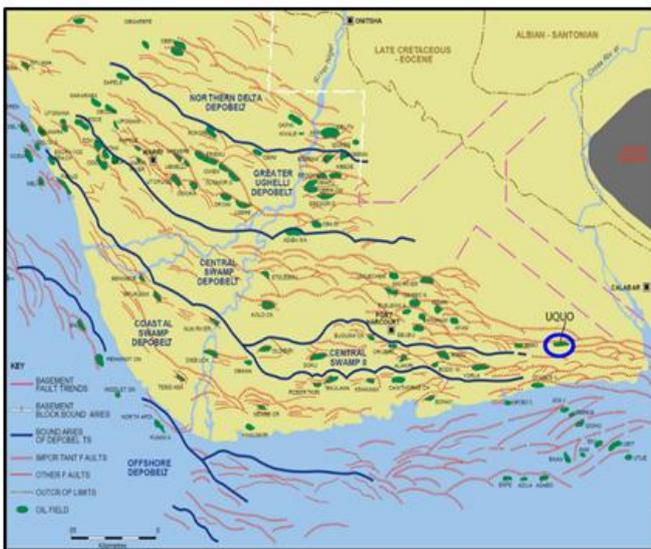


Figure 1: Map of the study area

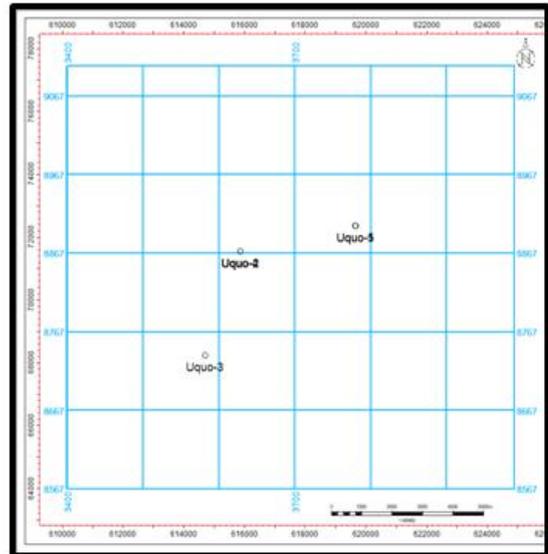


Figure 2: Base Map of the study area

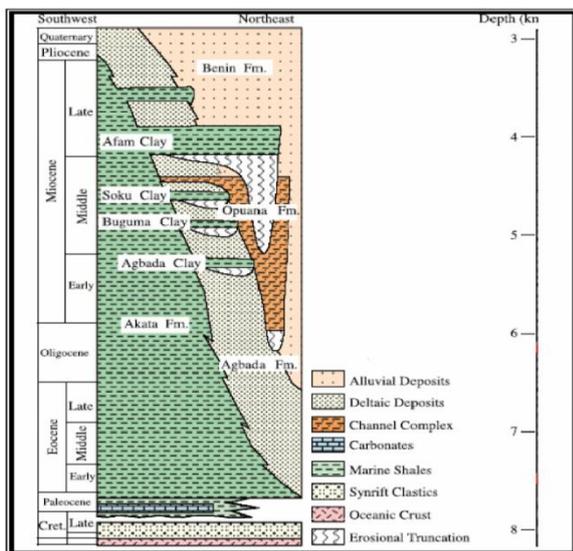


Figure 3: Stratigraphic column showing the three Formations of the Niger Delta (Modified from Shannon and Naylor, 1989; and Doust and Omatsola, 1990)

**Akata Formation**

The Akata Formation, the deepest stratigraphic unit, is made up of deeper marine shale. Plastic,

low density, under-compacted, and high-pressure shallow marine to deep water-shale dominates, with only local inter-beddings of sands and/or siltstones. It is deposited as the high-energy delta moves further into the ocean. The shale is generally overpressured, which supplies the mobile base for future growth faulting associated with the deposition of the overlying paralic sequence. It is the source of hydrocarbons in the Niger Delta. The Formation is expected to be up to 7,000 meters thick (Doust and Omatsola, 1990).

**2.0 Materials and methods**

**Materials**

Frontier Oil and Gas Limited contributed the datasets used in this investigation. A composite log of four wells (UQ-2, UQ-3, UQ-4, and UQ-5) was also obtained, and it had logs for laterolog - deep resistivity, bulk density, gamma ray, and neutron porosity in LAS

format.

### Method of Study

Using the well log data, facies analysis and a petrophysical evaluation were performed. Shale content and recognized lithologies were used to correlate wells. To comprehend the depositional facies better, a sequence stratigraphic study was carried out. Figure 4 presents the workflow that was employed for this inquiry. The primary limitations of this investigation were the lack of core, biostratigraphic, and production data as well as the incompleteness of neutron porosity, density, and some of the wells.

Using the software programs PETREL 2014 and Interactive Petrophysics, the acquired data were analyzed. The well header data, which includes the name, location, and start and finish depths of the wells, was imported first to begin the importation process. The scale ranges for each of the log tracts were determined in order to equalize the wells: the gamma ray log scale was set from 1-150 API, the resistivity log from 0.2-2000 ohm meters, the density log from 1.65-2.65, the neutron porosity log from 0-0.6, and the sonic log from 40-140. Each of the log tracks was assigned a different color. Using GR logs, it was possible to identify the various lithofacies while interpreting well logs. Shales (clay minerals) frequently exhibit a GR response that is quite high. The Gamma Ray log was given a range of 0 to 150. The shale baseline is represented by the maximum GR values, while the sand line is represented by the minimum GR values. The baseline values found for each of the study's wells range from 55 to 70 API. Sand units were assigned to gamma ray curves that deviated to the left of the shale baseline, while shale was distinguished with a deviation to the right. The wells in the Field were all connected along strike lines A to A' in order to create a chronostratigraphic framework for the study region. The wells were organized according to

their number and distance from one another, as seen on the base map (Figure 2). The identification of maximum flooding surfaces (MFS) in well logs was made possible by tracking changes in sedimentary facies and patterns of deposition. These surfaces, which frequently feature a change in lithology, define the transition between transgressive and regressive sedimentary sequences. By examining changes in sedimentary facies and patterns of deposition, system tracks were found in well logs (Harry and Akata 2019). The logs contained descriptions of the Lowstand System track (LST), Highstand System track (HST), and Transgressive System track. System tracks were utilized to analyze the field's depositional history since they show how sedimentary environments change over time (Etesin et al., 2015).

A petrophysical analysis was performed using a combination of well logs from various wells that included gamma ray (GR), resistivity, neutron (NPHI), and density (RHOB) measurements. By using well-to-well correlation, the lithologic units were divided into hydrocarbon-bearing and non-hydrocarbon-bearing intervals inside reservoirs, and the geometry of the reservoirs was established. Porosity ( $\Phi$ ), permeability, gross thicknesses, water saturation ( $S_w$ ), and hydrocarbon saturation ( $S_h$ ), among other petrophysical characteristics of the reservoirs, were all identified.

The first step involves determining the volume of shale from gamma ray log and then calculating the volume of shale using Gamma Ray Index (IGR) as shown in Equation 1:

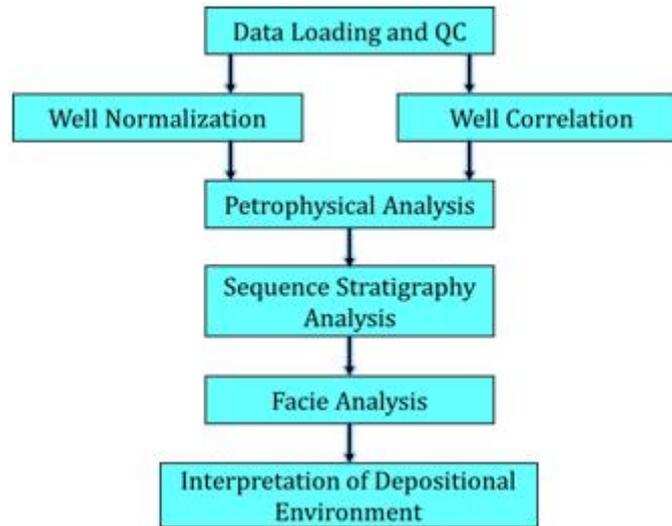
$$IGR = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

where:  $I_{GR}$  = Gamma ray index

$GR_{log}$  = Gamma ray reading of the Formation,

$GR_{min}$  = Minimum gamma ray (clean sand),

$GR_{max}$  = Maximum gamma ray (shale).



**Figure 4:** Workflow for the Facies Analysis and Petrophysical Analysis of UQ Field

The Gross sand thickness (GST) was determined from the difference between the base of sand and top of sand.

$$\text{GST} = \text{Base of Sand} - \text{Top of sand} \quad (2)$$

$$\text{NST (net sand thickness)} = (\text{base} + \text{top of sand} - \text{shale}) \quad (3)$$

Equation is used if shale is present in the Formation. However, if shale is not present, NST will be the same as GST. The Net to gross is then the difference between NST and GST. The Formation density log was used to determine Formation porosity, which is defined as the percentage of voids to the total volume of rock. The porosity was determined by substituting the bulk density readings obtained from the density log within each reservoir into the Equation 4:

$$\phi_T = \frac{\rho_{mat} - \rho_b}{\rho_{mat} - \rho_f} \quad (4)$$

where  $\rho_{mat}$  = Density of Rock Matrix,  $\rho_b$  = Bulk Density and  $\rho_f$  = Fluid Density.

The criteria for classifying porosity given by (Baker 1992) are:  $\phi < 0.05$  = Negligible,  $0.05 < \phi < 0.1$  = Poor,  $0.1 \phi < 0.15$  = Fair,  $0.15 < \phi$

$< 0.25$  = Good,  $0.25 < \phi < 0.30$  = Very good  $\phi > 0.30$  = Excellent. The determination of the water saturation (SW) for the uninvaded zone was achieved using the Archie's (1942) equation for a clean sand model given in Equation 5.

$$SW = \left( \frac{R_o}{R_t} \right)^{\frac{1}{n}} \quad (5)$$

where  $R_o$  = resistivity of rock filled with water,  $R_t$  = resistivity of suspected oil zone,  $n$  = saturation exponent (generally 2). Hydrocarbon saturation ( $S_h$ ), (the percentage of pore volume in a Formation occupied by hydrocarbon) was obtained by subtracting the value obtained for water saturation from 100%. It can be determined from water saturation  $S_w$  using the equation:

$$S_h = (1 - S_w) \quad (6)$$

where  $S_h$  = Hydrocarbon Saturation,  $S_w$  = Water Saturation. The Formation factor was determined from the equation:

$$F = \frac{a}{\phi^m} \quad (7)$$

where  $\phi$  = Porosity,  $a$  = constant (0.62),  $m$  = cementation exponent (2 for sands). The

permeability,  $K$ , (which is the ability of a rock to transmit fluid) is related to porosity but not always dependent on it. It is controlled by the size of the connecting passages (pore throats or capillaries) between pores. It is measured in darcies or millidarcies. The permeability was obtained from the equation:

$$K = \frac{7.0 \times 10^8}{F^{4.5}} \quad (8)$$

where  $F$  is the Formation factor, given by:

$$F = \frac{1.65}{\phi_e^{1.33}} \quad (9)$$

where  $\phi_e$  is effective porosity and  $K$  is absolute permeability in millidarcies (mD). Permeability attribute was categorised as poor to fair, moderate, good, very good and excellent using parameters of (Baker 1992; Okwoli et al., 2015):

1.0 – 14.0 mD: poor to fair permeability, 1.5 – 49.0 mD: moderate 50.0 – 249.0 mD: good, 250.0 – 1000.0 mD: very good, Greater than 1000.0 mD: excellent.

### 3.0 Results and Discussions

The litho-stratigraphic correlation and log interpretation displayed in Figure 5 below provide information on the general stratigraphy of the studied area. The litho-stratigraphic correlation is a visual method that reveals information about an area's general stratigraphy (Amigun1998). Based on the foregoing, the gamma ray log was used to distinguish between the lithologies of sand and shale. According to the lithology log, the intervals colored yellow and black correspond to sand and shale, respectively.

#### 3.1 Well Correlation

Four sand masses were associated throughout the field as reservoirs R\_1, R\_2, R\_3, and R\_4. Each sand unit is found throughout the field and varies in thickness, with some units occurring at a deeper depth than their

neighboring units—possibly indications of faulting—according to the examination of the entire well section. The overall petroleum system of the UQ field as seen on the well correlation panel (figure 5) has its source to be the prolific Akata Formation which is a good source rock, the Akata shale is present in large volumes beneath the Agbada Formation and is at least volumetrically sufficient to generate enough oil for a world class oil province such as the Niger Delta. The Reservoir rock is the Biafra member of the Paralic Agbada Formation which is comprised of sandstone with shale intercalations. The lateral variation in reservoir thickness is strongly controlled faults; the reservoir thickens towards the fault within the down thrown block. The cap rock or reservoir seal is the Qua Iboe member which occurs as a shale body within the Agbada Formation, the shale body extend across the field with varying thickness. The numerous faults which displaced the reservoirs at different depths in the field serve as a migration path for the hydrocarbon.

#### 3.2 Petrophysical Results and Summary

The petrophysical properties of the UQ field was analyzed and computed as shown in Table 1. Based on the lithology and net pay zone of each well, the hydrocarbon-bearing zones were determined. The reservoirs' average water saturation ranges from 0.17 to 0.41. It has been found that the porosity values within the wells generally decrease with depth. The four reservoirs' estimated average porosities were between 0.24 and 0.30. The reservoir sands' impacts on grain size and sorting may be primarily responsible for the porosity values (Chapman, 1983). However, the porosity values are regarded as being particularly favorable for the accumulation of hydrocarbons. Due to the intercalation of shale, the gross sand thickness for the reservoirs ranged from 218.87 feet to 584.76 feet (Table 2).

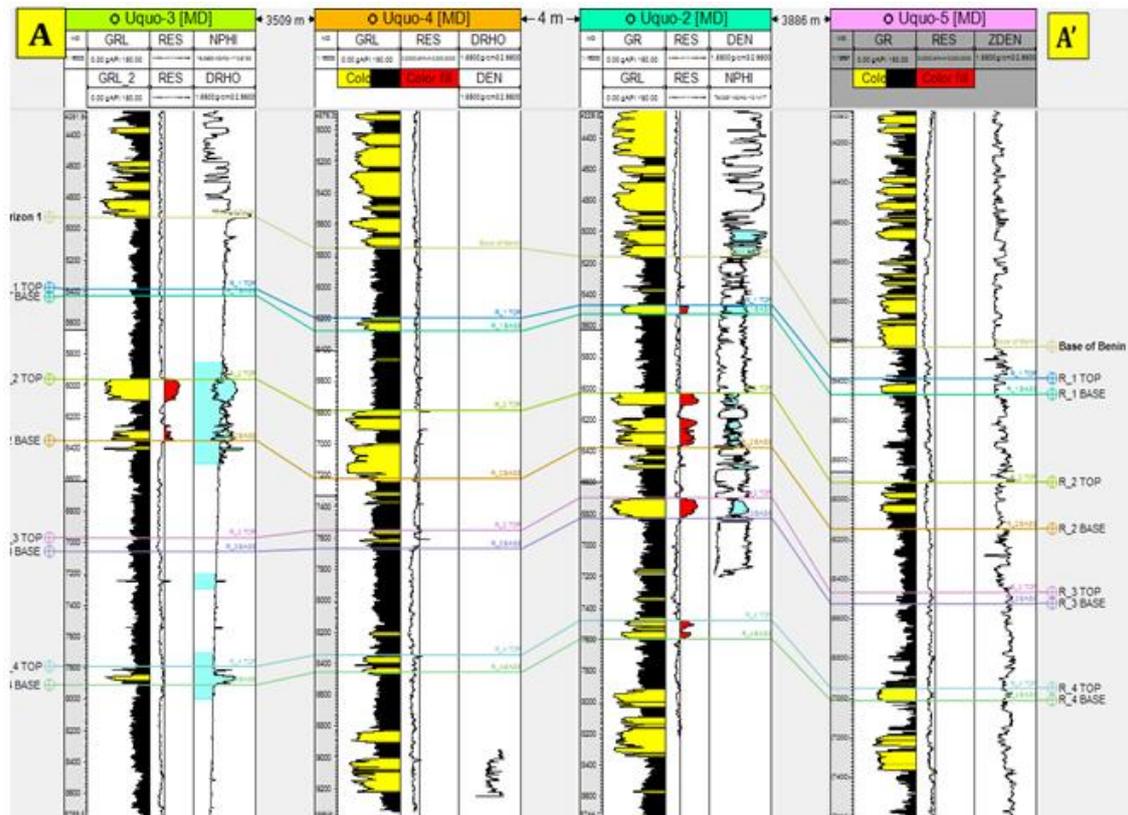


Figure 5: A to A' correlation of hydrocarbon bearing sand across wells in the UQ Field

### 3.3 Pay Summary

According to the calculations done for the reservoirs' net pay summaries, the R\_1 reservoir had a gas net thickness of 55.5 feet in UQ-2, 37.03 feet in UQ-3, and 82 feet in UQ-4 (Figure 6). The Gas net pay for the R\_2 reservoir was 77.5 feet in UQ-2, 143.94 feet in UQ-3, and 112.08 feet in UQ-4 (Figure 7). Oil pay thickness for the R\_2 reservoir was 178 feet in UQ-2, 92 feet in UQ-3, and 144 feet in UQ 4. The Gas net pay for the R\_3 reservoir was 110.4 feet in UQ-2, 59.59 feet in UQ-3, and 75.57 feet in UQ-4. As shown in Figure 8, it also had oil net pay thicknesses of 25 feet in UQ-2, 20 feet in UQ-3, and 36 feet in UQ-4.

Gas net pay thicknesses for the R\_4 reservoir were 113.71 ft in UQ-2, 99.77 ft in UQ-3, and 100.82 ft in UQ-4 (Figure 9). A graphical representation of the rock physics in the UQ field was created using the plotted petrophysical parameters. For reservoirs, the porosity, net to gross ratio, and water saturation

were plotted against one another. To depict the distribution of hydrocarbons in the field graphically, the net oil pay thickness and the net gas pay thickness for each well throughout the reservoirs were plotted against one another (Figures 6 to 9).

### 3.4 Sequence Stratigraphic Analysis

The gamma-ray log patterns from wells UQ-3, UQ-4, UQ-2, and UQ-5 were used to analyze the field's sequence stratigraphy. By connecting well log patterns to particular seismic reflections and vertical variations in seismic facies that could be traced between wells and by matching similar well log patterns inside adjacent wells, sequence boundaries and maximum flooding surfaces were associated between the wells. Retrogradational episodes that depleted the landward shift of sediment during relative sea-level rise made up transgressive facies cycles, which helped explain the rising trend of the gamma-ray log pattern. The progradational, retrogradational,

and aggradational sequences of three major transgressive/regressive facies cycles were interpreted. According to the interpretation, the building-up (Aggradation) and building-out (Progradational) facies make up the majority of the depositional environment. These cause the

gamma-ray log's general increasing trends to coarsen. As a result, it is possible to infer that the sediment was laid down in a deltaic environment during a period of relatively high accommodation space.

**Table1:** Computed petrophysical results for the Reservoirs

Reservoir R 1										
WELL	Top	Base	Gross Sand Thickness	Contact		Pay Thickness		NTG	Porosity	Sw
	ft	ft	ft	Nature	Value(ft)	Net Pay Oil	Net Pay Gas	frac	frac	frac
Uquo-2	5464.5	5522.5	-58	GWC	5520		-55.5	0.93	0.39	0.19
Uquo-3	5381.97	5423.58	-41.61	GWC	5419		-37.03	0.42	0.22	0.18
Uquo-4	6197	6282.53	-85.53	GWC	6279		-82	0.70	0.32	0.15
Uquo-5	5705.4	5741.13	-35.73					0.78	0.27	0.15
Reservoir R 2										
WELL	Top	Base	Gross Sand Thickness	Contact		Pay Thickness		NTG	Porosity	Sw
	ft	ft	ft	Nature	Value(ft)	Net Pay Oil	Net Pay Gas	frac	frac	frac
Uquo-2	6027.5	6374.5	-347	GWC/OWC	6105/6364	-178	-77.5	0.95	0.39	0.08
Uquo-3	5958.06	6350.29	-392.23	GWC/OWC	6102/6343	-92	-143.94	0.68	0.21	0.12
Uquo-4	6785.92	7191.3	-405.38	GWC/OWC	6908/7177	-144	-122.08	0.77	0.25	0.97
Uquo-5	5909.85	6157	-247.15					0.80	0.21	0.45
Reservoir R 3										
WELL	Top	Base	Gross Sand Thickness	Contact		Pay Thickness		NTG	Porosity	Sw
	ft	ft	ft	Nature	Value(ft)	Net Pay Oil	Net Pay Gas	frac	frac	frac
Uquo-2	6693.56	6830.02	-136.46	GOC/OWC	6804/6829	-25	-110.44	0.85	0.37	0.12
Uquo-3	6970.41	7055.55	-85.14	GOC/OWC	7030/7050	-20	-59.59	0.50	0.22	0.37
Uquo-4	7548.43	7665.54	-117.11	GOC/OWC	7624/7660	-36	-75.57	0.67	0.22	0.40
Uquo-5	6486.1	6522.19	-36.09					0.75	0.28	0.37
Reservoir R 4										
WELL	Top	Base	Gross Sand Thickness	Contact		Pay Thickness		NTG	Porosity	Sw
	ft	ft	ft	Nature	Value(ft)	Net Pay Oil	Net Pay Gas	frac	frac	frac
Uquo-2	7476.29	7598.64	-122.35	GWC	7590		-113.71	0.92	0.32	0.12
Uquo-3	7790.23	7903.91	-113.68	GWC	7890		-99.77	0.25	0.21	0.20
Uquo-4	8345.18	8477.09	-131.91	GWC	8446		-100.82	0.23	0.18	0.93
Uquo-5	6914.79	7019.77	-104.98					0.61	0.24	0.21

**Table 2:** Petrophysical summary of UQ Field

PETROPHYSICAL SUMMARY					
Sand	Gross (ft)	Net (ft)	N/G	Phi	Sw
R_1	218.87	157.42	0.71	0.30	0.17
R_2	428.69	333.05	0.81	0.27	0.41
R_3	584.76	414.94	0.69	0.27	0.32
R_4	296.32	175.76	0.53	0.24	0.36

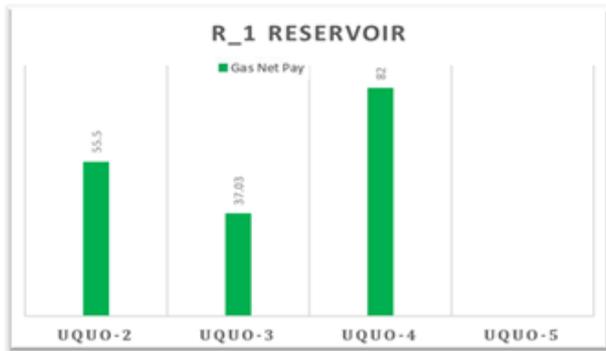


Figure 6: Net Pay plot for R\_1 reservoir

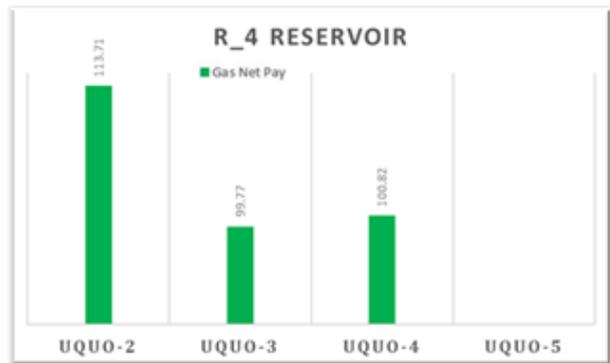


Figure 8: Net Pay plot for R\_4 reservoir

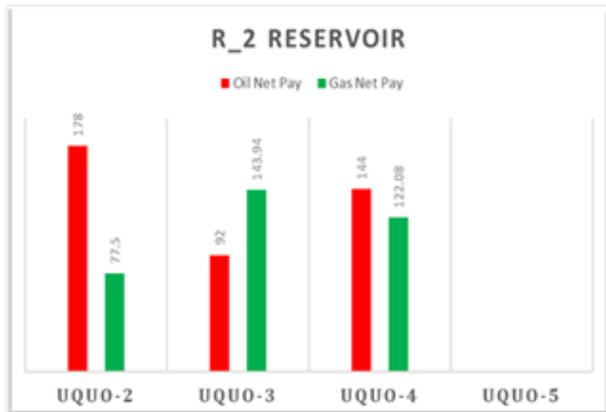


Figure 7: Net pay plot for R\_2reservoir

### 3.5 Identified Gamma Ray Facies

Figure 11 displays the various curves found in the research area's gamma ray logs. Funnel, bell, cylinder, and symmetrical curves were found. These different curves and stacking patterns show that progradation, aggradation, and retrogradation have all been applied to the deepwater. Gamma ray logs are dominated by serrated, blocky or cylindrical curve shapes without abrupt termination.

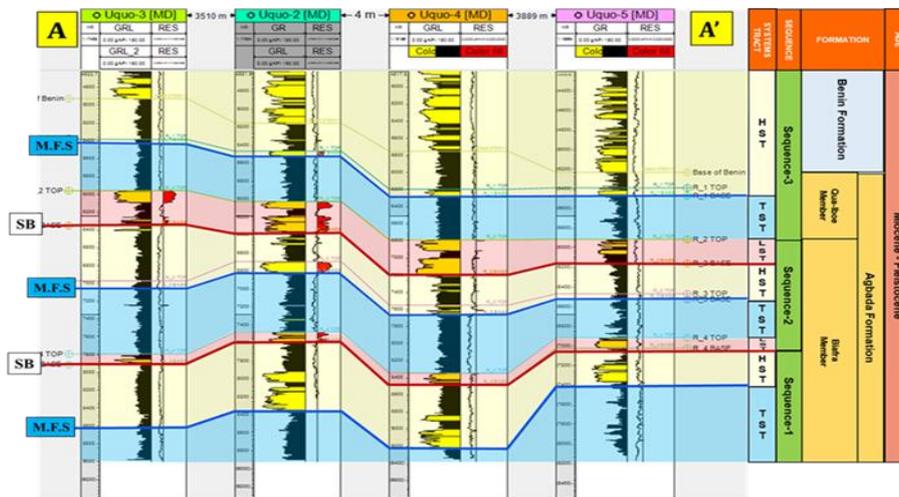


Figure 9: Well correlation, reservoir delineation, Sequences, Maximum Flooding Surface and System Tracts Interpretation of the Field through strike line A to A'

### 3.6 Depositional Environments

The amount of shale in a Formation can frequently be ascertained using the gamma ray log. The shaliness of a Formation progressively decreases with depth rather than abruptly changing. The progressive changes are linked to variations in grain size and sorting and

depend on the litho-facies and environment

where the rock was deposited. Facies and depositional settings typically regulate changes in grain size and sorting.

The internal gross architecture of the depositional environment systems in the study area was described using sand bodies. The

depositional environment was defined using the log patterns of prograding, retrograding, and aggrading structures found in the research area. Basin floor fans and submarine slope fans make up the depositional environment. Slope fans

depositional system, contouritefacies in the basin floor fan depositional system, and basin floor fan depositional system were identified using the recognized log motifs.

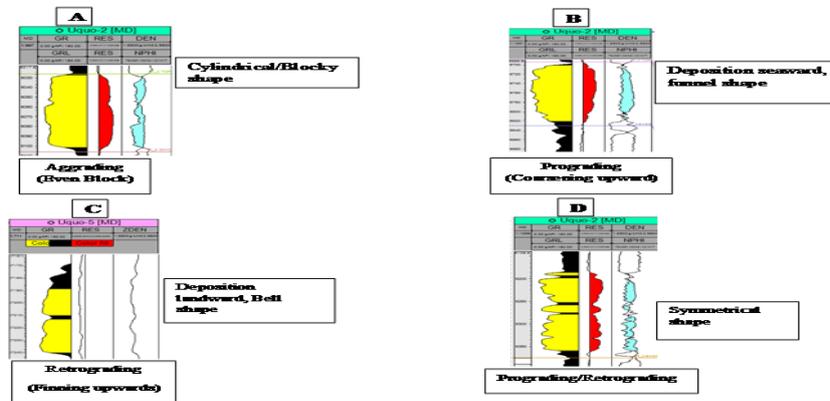


Fig. 10: Gamma ray log signatures observed within UQ Field

#### 4.0 Conclusion

In this study, four wells—UQ-2, UQ-3, UQ-4, and UQ-5—were taken into account, and four reservoirs were successfully identified and associated throughout the field. According to the goals of this study, it used well logs to examine the petrophysical parameters, such as the thickness of the numerous reservoirs under examination, their net-to-gross ratio, porosity, and water saturation. A collection of geophysical well log data, including resistivity, acoustic, gamma, neutron, and density logs, was made accessible for this study. The reservoirs had good petrophysical characteristics, with total gross thicknesses ranging from 218.87 to 584.76 feet and net to gross thicknesses varying from 157 to 414 feet due to shale intercalations. The reservoir's N/G ratio of 81% shows that reservoir sands occupy a larger share of the rock's bulk volume. The reservoirs' average water saturation ranges from 0.17 to 0.41.

It has been found that the porosity values within the wells generally decrease with depth. The four reservoirs' estimated average porosities were between 0.24 and 0.30. The reservoir sands' impacts on particle size and

sorting may be primarily responsible for the porosity values. Since hydrocarbon saturation is expressed by  $(1-S_w)$ , the reservoir has a low  $S_w$  value, indicating a higher hydrocarbon saturation.

#### 4.1 Recommendations

The several petrophysical parameters for the reservoirs under consideration in this work were estimated only using well log data, which can introduce significant computational mistakes in the results. The form of the Gamma ray log signature was the only factor used in the interpretation of the depositional environment of the different reservoirs, which might occasionally produce false conclusions. Therefore, I advise coring the reservoir zones in these wells to increase confidence in these results. Therefore, additional laboratory research should be done on these cores to measure the numerous petrophysical characteristics calculated in this work.

**Conflict of Interest:** Authors declare that there is no conflict of interest.

#### Acknowledgements

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