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The Effectiveness Of Hydrochemical Facies In Delineating Compartmentalized Reservoirs In An X-Field, Niger Delta Basin, Southern Nigeria

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ABSTRACT
This research work was carried out in order to investigate the effectiveness of Hydrochemical facies in delineating compartmentalized reservoirs in an X-field, Niger Delta Basin, Southern Nigeria. In order to achieve the set goal of delineating compartmentalized reservoirs within the field. Five formation water samples were subjected to hydrochemical analysis in order to determine the hydrochemical facies present in the formation water. Five other hydrochemical facies results were obtained from the well completion report. The samples were subjected to standard laboratory analysis and techniques. The results reflects the presence of these ions Cl^- , SO_4^{2-}, $NO3^-$, Ca^{2+}, K^+, *and* Na^+. *Using the chlorine concept, it was observed that there was no significant variation with a range of 8.6 mg/l to 12.4 mg/l for the suite of samples obtained but individually detail as thus, 8.60 mg/l for G18/5, 10.43 mg/l for G18/4, 11.84 mg/l for G51/4, 12.12 mg/l for G51/5 and 12.41 mg/l for G14/5. It can be observed by the precept that guide the Nelon's field study, that except for 8,60 mg/l G18/5 there is no significant difference among the other reservoirs thus they are connected in the light of the observation while G18/5 is separated and compartmentalized. G74 and G84 are also compartmentalized. A synergy of the above denotes compartmentalization.*

Keywords: *Compartmentalization, Hydrochemical, Facies, G-Wells, Formation water.*

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I. INTRODUCTION

Compartmentalization is defined as the existence of petroleum accumulations in discrete individual compartments in the reservoir (Jolley, *et al*, 2010). The two basic types of boundaries that can cause compartmentalization are static and dynamic seals. Static seals can prevent fluid flow over geological time scale, but dynamic seals can prevent fluid flow during production timescale. Dynamic seals include baffles and barriers (Jolley, *et al*, 2010). Overtime as production continues, the characteristic indicators of compartmentalization are fluid contacts, oil saturations, pressure data, biomarker compositional distribution and formation water chemistry (Smalley & Hale 1996).

A variety of compartmentalization has been unraveled, there have been occasions of false negatives, where compartments were assumed absent due to the homogenous nature of the fluid properties while equilibration was possible in the presence of compartments. False positive are where fluid differences were assured as indicator of compartmentalization, while they are still in the process of equilibration as a reservoir process during refilling (Smalley & Muggeridge, 2010).

Reservoir compartmentalization has been attributed to structural configuration, depositional architecture and fault juxtapositions, these are conditions that determine the plumbing system of the reservoir (Ainsworth, 2006, Jolley *et al*, 2007).

AIM AND OBJECTIVES OF STUDY

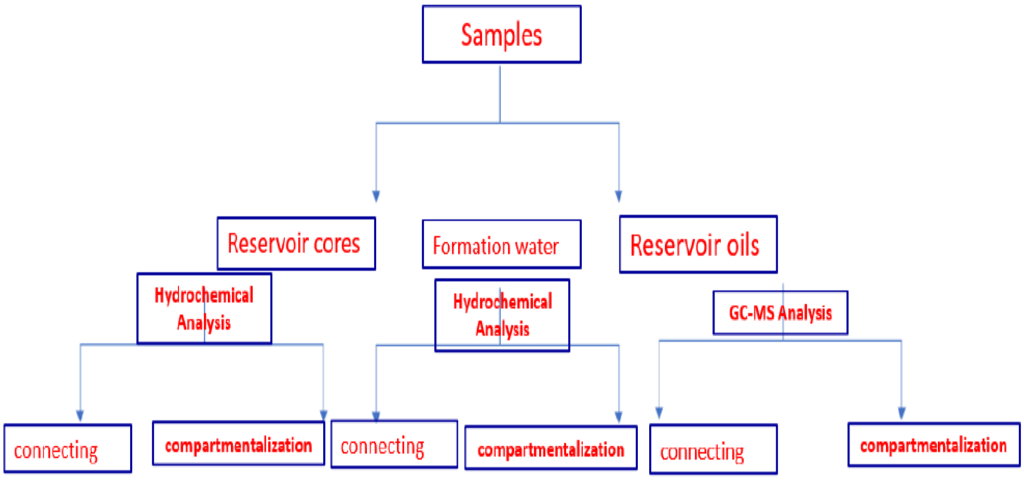
The aim of the study is to use Hydrochemical facies data to delineate potential compartmentalization in an X-field in the Niger Delta Basin.

The objective of the study is to use Hydrochemical facies (formation water chemistry) to determine elemental compositional variation.

II. METHODOLOGY

(Hydrochemical facies from Formation Water).

- *The hydrochemical facies in the formation water*
- The hydrochemical facies in the reservoir rock sample, on the concept that they were in contact with the reservoir formation water, and the elements and compounds in the formation water would have remain within the matrix of sample and can be reconstituted by dissolving the disintegrated sample in D&D (distilled and deionized) water, the precipitated salts and elements in the matrix will redissolve into the solution hence reconstituting the formation water (Mearns & McBride, 1999).
- The use of hydrochemical facies is on the premise that variations in water compositions between reservoirs within a field mostly indicates density inversion and vertical compartmentalization (Warren and Smalley, 1994)



The hydrochemical facies in the formation water

The geochemical fingerprinting of produced water (which prior to is the reservoir formation water) has been identified as a practical tool for operational application in the petroleum industries (Birkle & MaKechnie, 2019; Birkle, 2020; Taha & Amani, 2019.). The hydrochemical facies in formation water refers to the chemical constituents of the formation water in the reservoir, the formation water is the water that was deposited together with the sandstones of the reservoir. It has been the overtime diagenesis will occur and the formation water will be modified by authigenic cements and minerals. However, if the reservoir compartments are connecting or communication by virtue extensive sandstone, fracture or faults, the prior heterogeneous reservoir waters will communication and will undergo homogenization by density driven overturns or mixing and molecular diffusion. The continuity of a reservoir is one of the criteria for reservoir quality assessment (Hartmann & Beaumont, 1999.)

Density driven overturns is the process whereby heterogenous constituents of reservoirs that are vertically or horizontally adjacent homogenizes by mechanism whereby the solution with the light density migrations to replace the solution with heavier density, overtimes (millions of years) the prior to heterogeneous constituents homogenizes (Smalley & Muggeridge, 2010).

Formation waters of reservoirs that are vertically or horizontally adjacent which are communicating via extensive sandstone, faults and fractures will mix to smoothen the differences by the lightly dense formation water migration and displacing the heavily dense formation water and over time the reservoirs formation will be homogenized. The will result in the formation water maintaining an equilibrium which is known as chemical equilibrium. Time for equilibration over a 100m scale reservoir is 5My, that of a 2000m scale reservoirs is about 100My.

III. Results

Client: Solomon Odumoso
Sample Origin: Gabo Field
Project: Reservoir Compact
Date Sampled: NA
Date Received: 26/01/2022

Service Request: MISL/LAB/RES/90
Name of Sampler: Solomon Odumoso
Sample Type: Rock
Date of Reporting: 18/03/2022

PARAMETER	Method	G-88/2320m	G-88/2450m	G-88/2530m	G-12/2190m
Anion, mg/kg					
Chloride	APHA 4500	349.6	382.4	224.8	354
Sulphate	EPA 375.4	47.85	22.99	51.13	35.19
Nitrate	Method 8039	5.08	2.94	4.71	7.11
Cation, mg/kg					
Calcium	EPA 3050B	7.427	8.116	5.197	7.559
Potassium		2.104	3.141	2.265	3.819
Sodium		3.577	5.269	3.087	6.174

PARAMETER	Method	G-12/2420m	G-13/2050m	G-13/2280m	G-13/2309m
Anion, mg/kg					
Chloride	APHA 4500	314	222.8	179.2	248.9
Sulphate	EPA 375.4	10.79	15.95	7.98	11.73
Nitrate	Method 8039	3.16	6.95	2.27	3.887
Cation, mg/kg					
Calcium	EPA 3050B	6.947	5.831	5.057	6.2
Potassium		3.119	2.563	2.489	3.419
Sodium		4.218	2.196	2.874	2.862

Table 4.3. Concentration (mg/L) of hydrochemical facies in Sampled formation water

Ions	OB 24/5 (Gabo 14)	OB 20/5 (Gabo 18)	OB 20/4 (Gabo 18)	OB 38/4 (Gabo 51)	OB 38/5 (Gabo 51)
Cl	12.41	8.60	10.43	11.84	12.12
SO4	0.11	0.27	0.14	0.18	0.40
HCO3	4.80	2.50	3.00	3.00	3.20
Na	0.09	0.13	0.18	0.23	0.27
Ca	0.81	0.58	0.82	0.74	0.69
K	0.03	0.05	0.08	0.11	0.13
Mg	0.87	0.95	1.00	0.89	0.90

Table 4.4.1 Concentration (mg/L) of hydrochemical facies obtained from completion Report.

Ions	Well 88	Well 71	Well 12	Well 84	Well 74
Na	164.37	242.1	199.06	65.23	37.74
Ca	0.2	0.2	0.04	0.9	0.9
Mg	0.02	0.01	0.03	1	1.2
Cl	87.49	115	105.01	27.5	7.51
HCO3	76.8	127	94	35.4	29.2
SO4	0.13	0.14	0.04	0.09	0.13

Table 4.5 Concentration (mg/L) of hydrochemical Facies obtained from reservoir rock samples

Ions	G-88/2320	G-88/2450	G-88/2530	G-12/2190	G-12/2420	G-13/2050	G-13/2280	G13/2309
Cl	0.99	1.08	0.63	1.00	0.89	0.63	0.51	0.70
SO4	0.50	0.24	0.53	0.37	0.11	0.17	0.08	0.12
NO3	0.08	0.05	0.08	0.11	0.05	0.11	0.04	0.06
Ca	0.18	0.20	0.13	0.19	0.17	0.15	0.13	0.15
K	0.05	0.08	0.06	0.10	0.08	0.07	0.06	0.09
Na	0.16	0.23	0.13	0.27	0.18	0.10	0.13	0.12

Figure 4.3 The Stiff diagrams, portraying hydrochemical facies distribution for data obtained from completion report

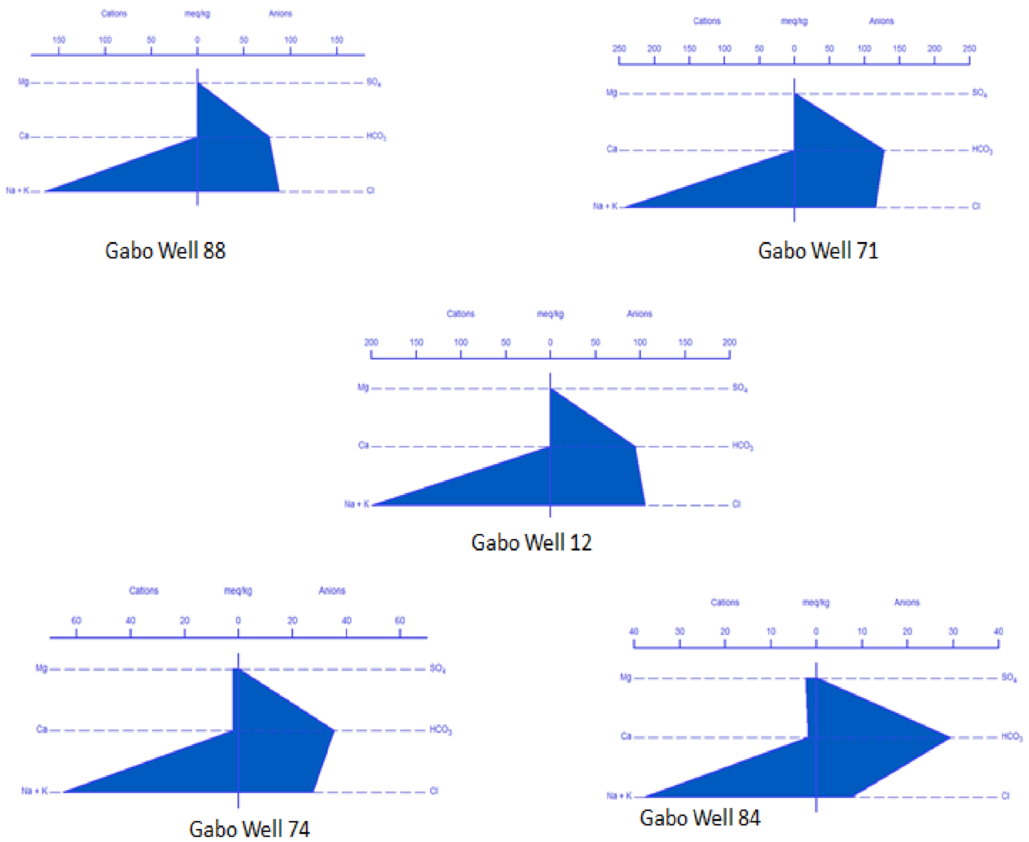


Figure 4.4 Stiff diagrams portraying Hydrochemical facies distribution of formation water of the well studies.

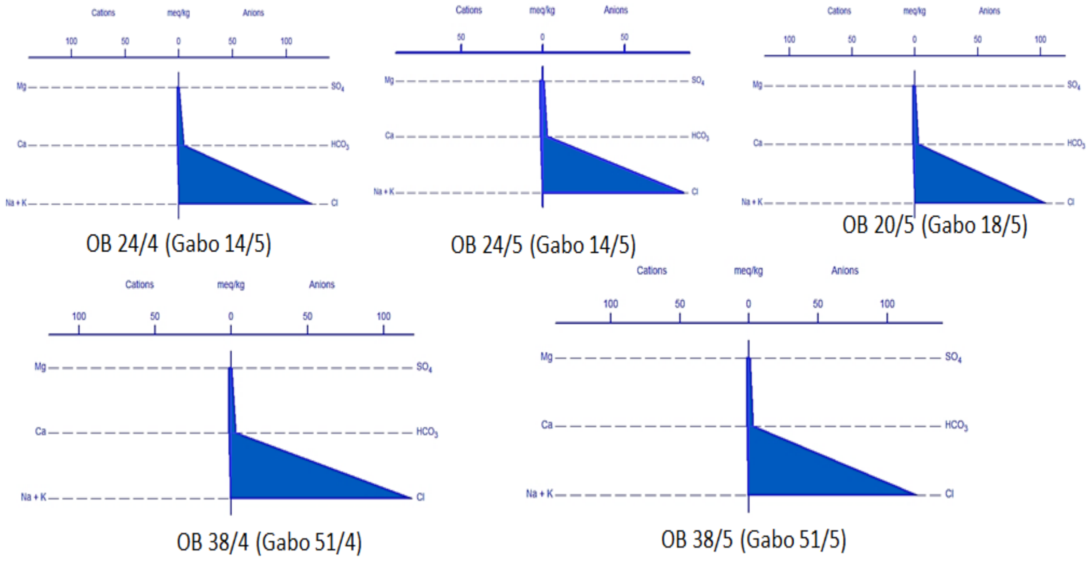


Figure 4.5 Stiff diagrams for hydrochemical facies of reservoir samples of various wells.

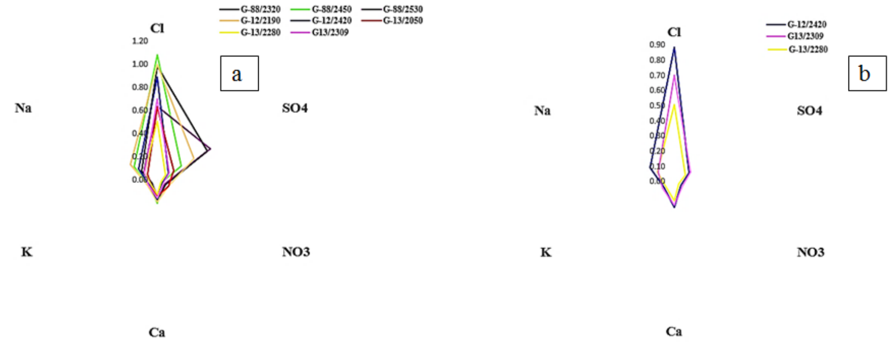


Figure 4.6a and b. Polar plot for hydrochemical facies from reservoir rock samples.

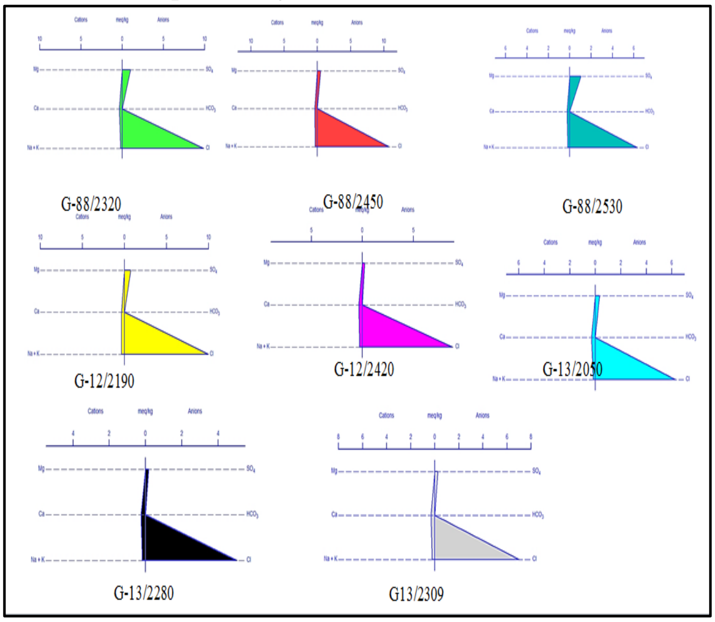
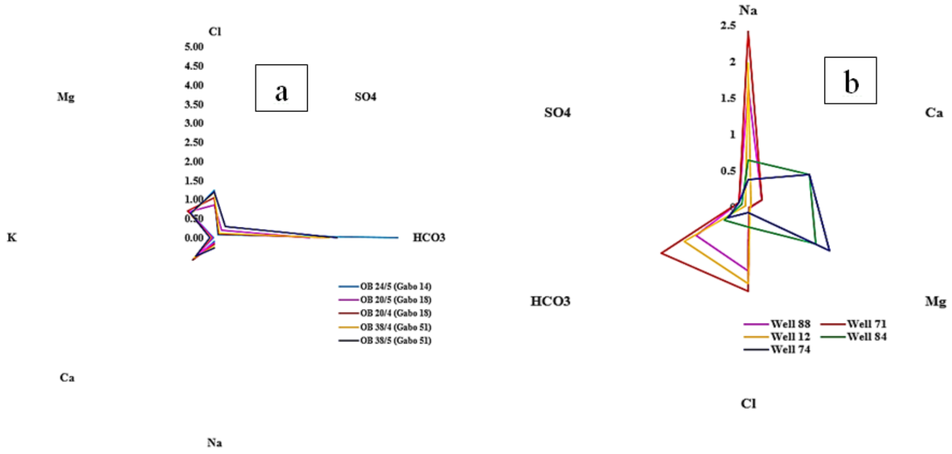


Figure 4.7a and b. Polar plots for hydrochemical facies from reservoir water sample and completion



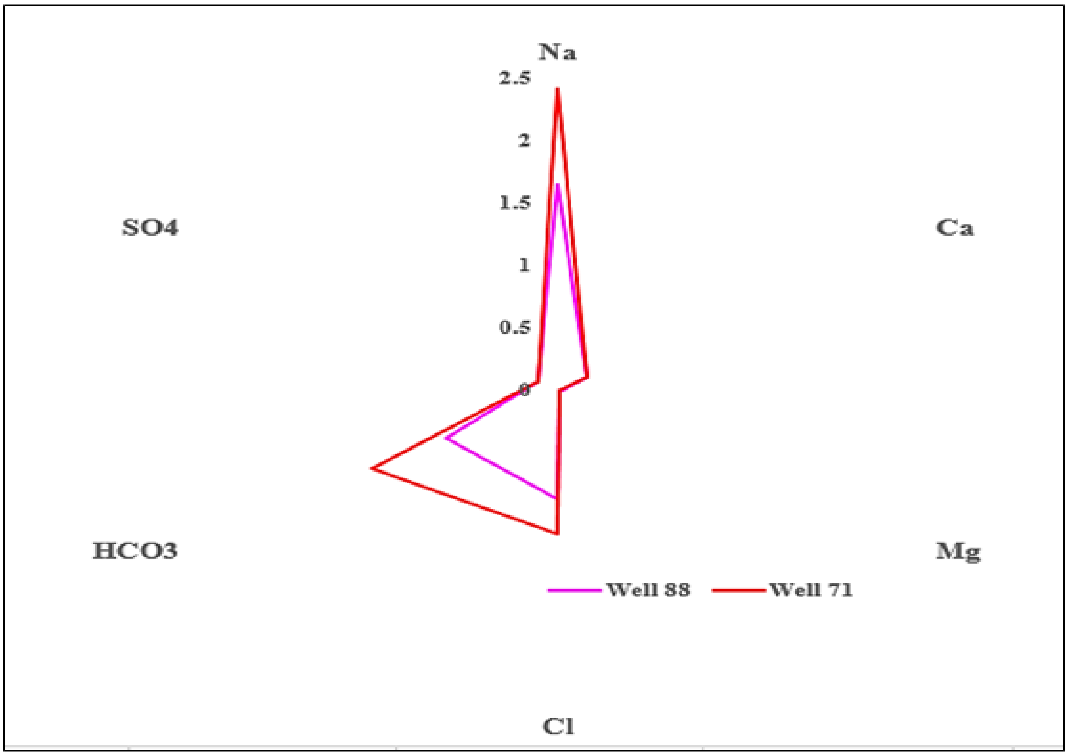
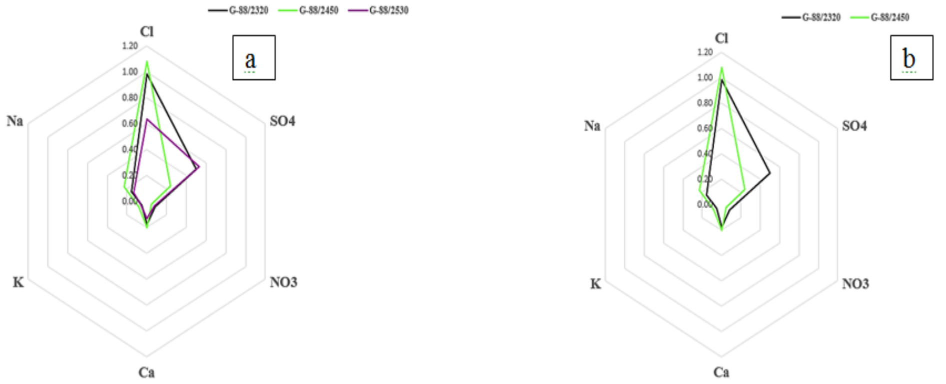


Figure 4.8 Polar plot showing connecting reservoir from the data obtained from completion report

Figure 4.9a and b. Polar plots of some reservoir rock samples, showing vertical compartmentalization in same well reservoir



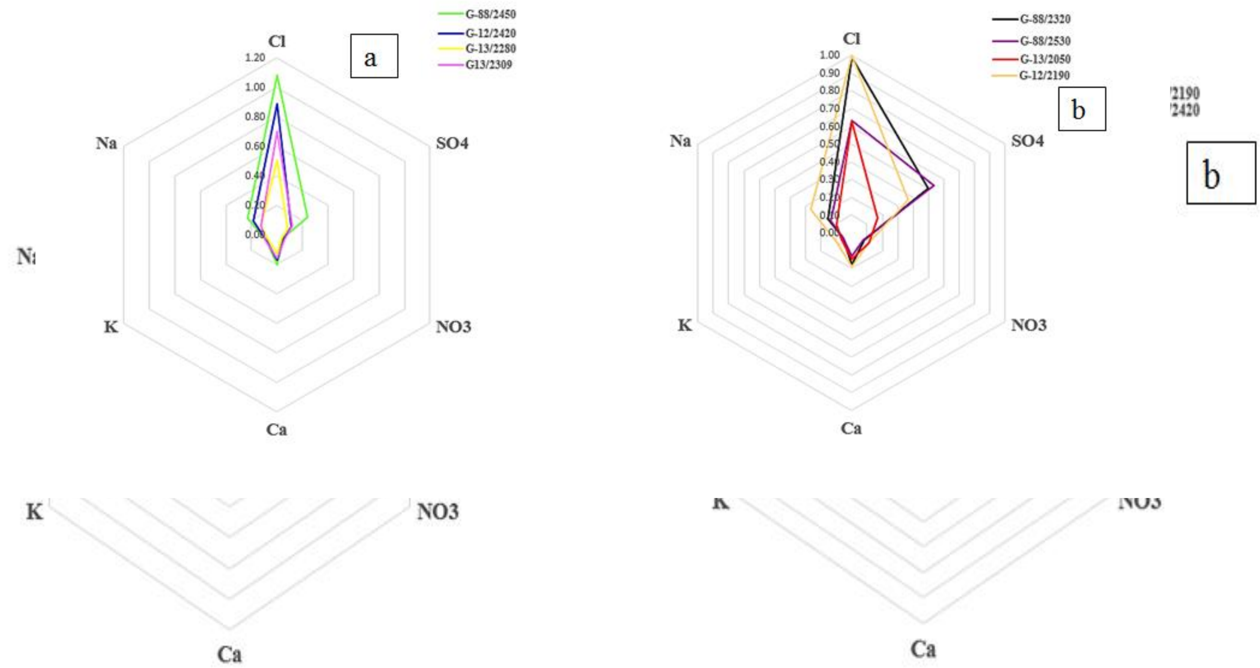


Fig 4.10a and b. Polar plots showing vertically connecting and non-connecting reservoir sections in the same well

IV. Discussions

The implication of this study is that it serves as an answer to the fundamental question that is normally considered during the development of an oil field, which is whether production can be accomplished by a single string or if the reservoir serves as a single large tank of oil. If the reservoir exists as compartments and to consider the number of wells that will be needed to recover an economic value of the oil in place. The degree of compartmentalization will influence the type of facilities needed to develop the field as well as the economics of the project. It is pertinent that compartmentalization be quantified and the features that act as barriers to fluid flow be identified, since the major objective is to minimize cost and maximize production to yield the petrodollars (Smalley *et al*., 1995). The study of compartmentalization of fields should be dynamic because there are occasions of false negatives (where mixing has occurred rapidly in spite of compartmentalization that will affect the production timescale) and false positives (spatial variations are present but relate to insufficient mixing times, no compartmentalization), such corrective redefinition of the fields' structural configuration has brought about new

directions in the development and production of those fields (Nestvold, 1994), an earlier interpreted reservoir structure of the Bay Marchand Oil Field, Offshore Louisiana was re-evaluated and a revised interpretation of the reservoir structure (Nestvold, 1994). A signature of compartmentalization is the detection of variable fluid properties in different part of the reservoir (Muggeridge and Smalley, 2008). Normally, during exploration and earlier appraisal phases various tools such as geochemical fingerprinting, pressure data, hydrochemical facies of formation water can be integrated with geological data to better assess reservoir continuity/or compartmentalization prior to field development. (Elshahawi *et al*., 2009). Reservoir compartmentalization is the most important risk factor in oil field development (Wang *et al*., 2016).
The discussion of results is being approach according to the interpretation scheme.

Hydrochemical facies in the sampled Formation water

Hydrochemical facies refers to the compositional distribution of the anions and cations that consist the reservoir formation water which in some works it is referred to produce water. The use of hydrochemical facies as a reference for fingerpring reservoir formation waters or produce waters has been identified as a practical tool for operational application such as compartmentalization studies in the petroleum industry (Birkle, 2020).

Reservoir formation could evolved from interstitial water to formation water, interstitial water is water contained in the pores grains or units of rocks, it could be syngenetic (deposited at the same time as the rock matrix or epigenetic (originated by subsequent infiltration into rock), this could also be connate water which is also known as fossil water also known as water that has been out of contact with the atmosphere for at a large part of geologic period. Overtime, diagenesis occurs and the water could change chemically and physical, during sediment consolidation which may entails ion exchange, replacement, cementation and dissolution, this water could be formation water which is defined as water present in the matrix of rock immediately before drilling (Collins, 1975). Interstitial waters could migrate or percolate during sediment compaction to more porous environment such as sandstones where it may be accommodated, such may be the formation waters. The formation water becomes produce water during hydrocarbon production, though could be modified in the case of water flooding to sustain the production pressure.

Though produced water refers to the water produced alongside the oils. The hydrochemical facies could serve as the custodian of paleo information and information on the reservoir configuration. Where the compositional distribution show close similarities by comparative graphical expression.

The stiff diagram shows very close similarities for all the samples as in figure 4.4, however, the radar plot or star plot has been the best practiced standard for comparing similarities in reservoir fluid compositional distribution (Hwang and Baskin, 1994). The star plot of the hydrochemical data for the sampled reservoir formation water showed very close similarities, inferring connectivity of the reservoirs for the suite of wells sampled.

The connectivity means that the configuration of the reservoir of the field provides for fluid communication, thus the configuration refers to the network of faults and fractures. This has a near dominant effect on the structure of the reservoir. Where the faults are sealing in nature there is no room for fluid communication, this could be due to clay smearing within the fault. But faults are non-sealing fluid communication occurs providing for the reservoir fluids that were originally heterogenous (having different compositional distribution) to smoothen up, there by mixing either by density driven mixing or molecular diffusion to become homogenous fluid. The study by Hwang and Baskin (1994) represents an example of the use of star plots, the out of phase plots could be clearly seen relative to the matching profiles.

This the depositional architecture which refer to the different pattern in which the sand packages are deposited, can also explain the results. Where the sand packages or bodies are extensive it provides for communication, the sand packages may be stacked such that there is no low permeability interface or high entry capillary pressure interface. The implies that the interface between the packages have high permeability which allows fluid to pass through without undue pressure, such that the pressure needed is very low and this may also be a function of the size of the pore throats which are the inter connecting pores that allow fluid flow. The internal architecture is determined by the pattern of depositions of the sand packages (Jolley *et al*, 2010).

The possibility for a favourable juxtaposition trap may be such that provide a sandstone band to be juxtaposition against another sandstone band providing for a continuity of sandstone formation. Juxtaposition reservoirs are initiated by the advent of faulting and fractures or fissures initiated by over pressure dissipating to equilibrate. Sometimes, extended juxtaposition reservoir provides for sequential infilling of reservoir during accumulation of oil. In this wise reservoir formation water could mix to sustain homogeneity. Thus, the hydrochemical facies which have different compositional distribution could now be smoothened up. This is also reflected in the graphical representations such that similar compositional distribution portrays similar profiles in the graphical representations. Perfectly matching profiles reflects very closely similar formation water, while partially match profiles represents moderately similar formation waters which can be attributed to restriction in mixing as a result of the present of baffles (Rushing *et al*., 2004) which are high permeability seals, that restrict fluid flow but does not prevent fluid flow. Table 1.0 which presents the Concentration of hydrochemical facies in Sampled formation water shows that Mg^{2+} and Ca^{2+} were of highest concentrations for the cations and Cl^{-} and HCO_3^{-} were of highest concentration for the anions this invariably implies that the reservoirs have same water type, hence communication of the reservoirs (Dikkers, 1985; Mearns and McBride, 1999).

In a study Awadh et al (2019) used water types as reflected in the hydrochemistry as a tool for delineating origin of reservoir water in Zubair oil fields in Southern Iraq. Mearns and McBride (1999) also recommended the use of hydrochemical facies are an aspect of integrated approach to reservoir compartmentalization studies.

The concept of use of hydrochemical facies for the reservoir connectivity studies has been applied in the assessment of crosstalks. Crosstalk refer to the linking of induces fractures from adjacent well or reservoirs, when fracturing is performed to enhance production of shale gas or shale oil. When crosstalks occur during fracture propagation, it provides for the reservoir fluid communication, inferring connectivity, hence the flow back fluids are obtained and analysis of the hydrochemical facies (composition) is performed to compare the flow back fluid with the endmember reservoir formation water, where there is connectivity with an adjacent reservoir the flowback fluid with indicate equilibration/modification of the flow back fluid. In a study by Birkle *et al*, (2019) the observed heterogeneities between the formation water hydrochemical facies (composition) was used to infer compartmentalization between the two reservoir blocks of the exploration field.

Hydrochemical Facies obtained from completion Report.

The completion report for G field contained an initial data for hydrochemical facies obtained from wells 88, 71, 12, 84 and 74. The result as in table 4.2 showed that Na and Ca are the most dominant cations while Cl and HCO3 are the most dominant anions for the suite of wells and ions studied. There are significant differences in the profiles of stiff diagrams for the reservoir formation water. The conventional star diagram (figure 4.7) showed that Wells 88, 12 and 74 have same profile whiles wells 71 and 84 has different profile each and are independently out of phase (non–matching) relative to the other wells. This implies that wells 71 and 84 are individually compartmentalized while wells 88, 12 and 74 show some degree of continuity. The continuity of a reservoir is one of the criteria for reservoir quality assessment (Beaumont and Foster,1999). The variations in water compositions between different reservoirs within the same oil field indicates compartmentalization, meaning that the reservoirs exist as different compartments (Warren and Smalley, 1994). The existence of compartmentalized reservoirs are due to reservoir configuration that is based depositional system that fosters the presence of seals which can completely prevent fluid flow over all time periods (Rushing *et al*., 2004). Juxtaposition systems that include clay smearing can also result in occurrence of seals that can completely prevent fluid flow for all time geological periods.

Hydrochemical facies from reservoir rock samples from Wells.

Another aspect of the integrated approach to reservoir compartmentalization studies is the used of reservoir sandstone samples. The hypothesis is that samples bear the remnants of the salts from the formation water within the matrix. The reservoir formation water is reconstituted using D&D (distilled and deionised) water. In this aspect of the study the results in table 4.3 is expressed in graphical formats (stiff and radar diagrams). The reservoir samples are part of the internal structure of the reservoir thus serves as a representative of the internal matrix of the reservoir and will also portray the plumbing configuration of the reservoir. Effectively the discuss reflects the internal structure of the reservoir. The radar plot in figure 4.5 show similar profiles but close examination reveals some significant differences. Significant differences are shown by the profiles of reservoir sections G-88/2320, G-88/2450, G-882530, G-12/2190 and G-13/2050. The difference is very pronounced thus represents a compartmentalized reservoir section. This means that these reservoir sections are not in communication with others and can be attributed to the presence of seals that prevents the reservoir formation waters from mixing and smoothening out of the differences. Since this result is from the matrix samples, it holds that each reservoir section has fluid that is different in composition from others. Mixing of reservoir fluids is initiated by density differences, where there is a high permeability interface (Houston, 2007).

Mearns and McBride (1999) employed the use of reservoir rock samples for the study of vertical continuity in the Middle Jurassic Brent Group reservoir of the Dunbar Oil Field, UK North Sea, also the Upper Jurassic Fulmar Formation sandstone of the Janice Field, Central North Sea, with reference to hydrochemical compositions and strontium isotopic ratios ($^{87}Sr/^{86}Sr$ ratio).

The Brent group reservoir consist the Broom, Rannoch and Etive Formations and where predominantly deposited in the Shore–Shallow marine environments. The Ness Formation is overlain by the Tarbert formation and Upper massive Sandstone, but the pressure data is a single gradient with no evidence of vertical compartmentalization of the reservoir however, the hydrochemical facie (isotopic ratio) showed unequivocal step changes which indicates the presence of a barrier within the reservoir.

In this wise the pressure data did not reflect the reservoir internal configuration which was unravel by the hydrochemical facie data (Mearns and McBride, 1999).

The Leman Field also in the North Sea, has the Upper Permian Zechstein which is dolomitic and the reservoir formation water is exceptionally rich in magnesium and deficient in sodium but significantly different from the formation water of the underlying Rotliegend sandstone reservoir which significantly indicates compartmentalization (Warren and Smalley, 1994).

The Haltenbanken region of the North Sea have a reservoir formation water that are rich in Barium and Strontium. The formation water of the Lower Jurassic reservoir of the Njord Field are Barium rich and different from other Jurassic reservoirs of other fields in the region suggesting lateral compartmentalization (Warren and Smalley, 1994).

The reservoir formation water data from the Beatrice field in the North Sea for seven (7) different wells in the Beatrice field of which six (6) are from the Middle Jurassic Brora Formation and one (1) from the Lower Jurassic Beatrice Formation (Warren and Smalley, 1994). The compositional distribution of the formation waters has no significant variation laterally across the field and even between the Middle and Lower Jurassic reservoirs.

This infers fluid communication laterally across field and vertically down depth, the implications is that hydrochemical facies in water chemistry has been applied in reservoir compartmentalization studies.

The above studies are case studies for which hydrochemical facies (compositional data) has been employed in delineating compartmentalization of reservoirs or connectivity of the reservoir sections. These cited studies above also validate this study on the G Oil Field using hydrochemical facies (compositional data) on the premise that it's a valid and reliable geochemical tool that has been acknowledged as a practical tool for routine operational applications in the oil industries (Birkle, 2020).

The Chloride Concept.

Gill *et al*., (2010) developed a model base on his observation in the Nelson oil Field Central North Sea, in the study Gill *et al*., (2010) observed a large and systemic variation in the formation water composition within the Nelson field. The chloride concentration ranged from 54,000–60,800mg/L. It was observed that water samples from the water leg in the appraisal wells show that average chloride (Cl^-) concentration (60,819mg/L) of the Western block of the field with the range of 60,819mg/L –57,949mg/L was higher than the average chloride (Cl^-) of the Eastern block Channel (56,975mg/L) with a range of 56,975m/L – 54,444mg/L at all reservoir levels. The variation in chloride was interpreted to indicate a level of compartmentalization both laterally and vertically within the Nelson Field. The compartments indicated by the variable chloride ion chemistry represented major sedimentological bodies identified as controlling fluid flow in the Nelson Field. The fluid chemistry did not equilibrate over geological timescale, this is due to the primary depositional architecture which consist inter channel regions that is separated by low permeability sediments which results in sedimentological compartmentalization (Gill *et al*., 2010).

Birkle (2019) stated that geochemical information on flowback water was generally based on the analysis of chloride ($Cl^–$) content during and after fracturing process. The increase in chloride content will indicate that cross talks had occurred during fracturing meaning linking of adjacent reservoir through fracture propagation and eventually infusion of reservoir formation water which is rich in chloride ($Cl^–$) concentration into the fracture fluid. This expresses connectivity and validates the use chloride ($Cl^–$) concentration to assess compartmentalization.

Sampled formation Water.

Samples formation water refers to the formation water that was obtained alongside the reservoir oils during test production and sampling from the well head. The chloride ($Cl^–$) content was observed for variations, it was observed that there was no significant variation with a range from 8.60mg/L to 12.4m/L for the suite of samples obtained but individually detail as thus, 8.60mg/L (G 18/5); 10.43mg/L (G18/4); 11.84m/L (G 51/4); 12.12(G 51/5) and 12.41mg/L (G 14/5). It can be observed by the precept that guide the Nelson's field study, that except for 8.60mg/L (G 18/5) there is no significant difference among other reservoirs, thus (G18/4); (G 51/4); (G51/5) and (G 14/5) can be expressed as connected, in the light of this observation (G 18/5) is a separated and compartmentalized from other reservoirs. This observation is in agreement with the interpretation from the conventional polar/star plot based on the hydrochemical facies. This should be due to the presence of a seal of very low permeability interface.

The reservoir faces are deposited in a delta front complex which consists of tidal flats and channel deposits also foreshore and subaqueous levee.

The sedimentation is constituted by stacking of braided and amalgamated Channels. G field is a roll–over structure induces by the G fault.

The implication of this observation is that the production cost could be low because a single production string could be used to produce from these wells.

Data from Completion Report.

Hydrochemical data (chloride content data) for reservoir formation Water was obtained from the completion report for five (5) wells namely G 88 (87.49mg/L); G 71 (115mg/L); G 12 (105mg/L); G 84 (22.7mg/L); G74 (7.51mg/L). The chloride (Cl^-) content of wells G88, G 71, 12 are relatively higher compare to G 84 and G74. This observation implies that G wells G 88, G 71, and G 12 are connected while the others wells which are G84 and G 74 are compartmentalized being structurally separated from others by the internal partition with a low permeability seal, this observation corresponds to the expression from figure 4.7, showing wells G 74 and 84 as compartmentalized. The occurrence of the low permeability internal partition infers that there is no possibility of cross flow of reservoir fluids, so different production arrangement will be made and it amounts to a higher production cost, while the connected reservoirs will be produced using a single string and it will foster the major objective of most international oil companies (IOCs) which is minimal cost and maximum production.

Reservoir Rock Samples.

The reservoir rock samples were obtained and the formation water was reconstituted following the method of Mearns and McBride (1999) using D&D (distilled and deionized) water. The chloride (Cl^-) content for the samples which is thus: G-88/2320 (0.99m/L); G–88/2450 (1.08mg/L); G–12/2190 (1.00mg/L); G–12/2420 (0.89mg/L); G–88/250 (0.63mg/L); G–13/2050 (0.63mg/L); G–13/2280 (0.51mg/L); G–13/2309 (0.70mg/L).

The result show that samples G-88/2320 (0.99m/L); G–88/2450 (1.08mg/L); G–12/2190 (1.00mg/L); G–12/2420 (0.89mg/L) have higher chloride (Cl^-) content relative to samples G–88/250 (0.63mg/L); G–13/2050 (0.63mg/L); G–13/2280 (0.51mg/L); G–13/2309 (0.70mg/L). This should imply that the reservoirs of samples with higher chloride (Cl^-) concentration are connected and are separated from reservoir of the samples with lower chloride (Cl^-) concentration. Thus, there is a lower permeability partition between these reservoirs. This also has production implication which is that connected reservoirs can be produce by a single production string. This observation unraveled using the chloride (Cl^-) content precept corroborates with the star/polar plots in figure 4.6., validating that reservoirs of samples with low chloride (Cl^-) contents are connecting, while those with high chloride (Cl^-) contents are fairly connecting, this may suggest the presence of moderately permeable barriers as internal partitions in the field.

The reservoir subsurface structure viewed via configurations which refers to the plumbing network of the faults and fractures, and depositional architecture which refers to the mutual contact and communication of the sand body in vertical and lateral orientations. The scale and continuity of reservoirs influences the reservoir effective size and well spacing for development of the oil field (Yu *et al*., 2006).

V. Conclusions

The study on potential compartmentalization of the G Oil field was under taken, based on,
i. hydrochemicalfacies of reservoir formation water,
ii. hydrochemical facie data obtained from completion report
iii. hydrochemical facie from reservoir rock samples

The hydrochemicalfacies in the formation water that came with the reservoir oils unravelled that the reservoirs namely OB 24/5 (G 14), OB 20/5 (G18), OB 20/4 (G 18), OB 38/4 (G51) and OB 38/5 (G 51) are connected both vertically and laterally. Specifically, OB 20/5 (G18), OB 20/4 (G18) and OB 38/4 (G51) and OB 38/5 (G 51) are vertically connected for same well reservoirs. Figure 4.1 the base map infers that the reservoir in G 14 is laterally connected to the reservoir in G 51 Well.

The hydrochemical facies of the formation water data that was obtained from the completion report showed that G 74 and G 84 are laterally compartmentalized, while G 88, G12 and G 71 are laterally connected suggestively due to extensive sandstone deposition.

The hydrochemicalfacies in the reconstituted formation water using the reservoir rock samples also unravelled laterally and vertically compartmentalized reservoirs also vertically and laterally connected reservoirs. Figure 4.6b showed that G 13/2280 and G 13/2309 are vertically connected for reservoir sections in the same well. G 12/2420 is laterally connected to the G 13 reservoirs. However, G 88/2320, G 88/2450, G88/2530, G 12/2190 and also 13/2050 are basically compartmentalized. Specifically, G 88/2320, G 88/2450, G 88/2530 are vertically compartmentalized, while G 12/2190 and 13/2050 are laterally compartmentalized

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