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## **Effects of Temperature and Pressure on Shale Cuttings Dispersion in Water Based Mud WBM Using NaCl, CaCl<sub>2</sub>, KCl Salts as Primary Inhibiting Agents and Polymer XCD Xanthan Gum as Secondary Inhibiting Agent**

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### **Abstract**

The primary cause of wellbore instability is the interaction of water based mud with shales which usually involves the movement of water and ions into or out of shale thereby causing alterations in mechanical property of the shale resulting in dispersion of shale particles into the mud.

This work involves experiments to analyze the effects of chemical osmosis, diffusive flow prior to shale hydration and inhibition, determination of the effects of salt addition on pH and density of mud and also determination of the effect of Temperature and pressure other than just temperature on dispersion of shale cuttings into water based mud. It also shows the behaviour of shale in various inhibitive agents e.g NaCl, KCl, CaCl<sub>2</sub> and Polymer XCD when being hot rolled.

Results from experiment performed in this work confirmed that osmosis and ionic diffusion play a great role in shale hydration and dispersion. It also showed that subjecting the system to temperature and pressure conditions other than just temperature caused more dispersion of shale into mud.

KCl was the best inhibitive agent as more shale cuttings were recovered from the mud while the least shale recovery was from CaCl<sub>2</sub>/salt formulation. A further experiment was performed by adding polymer XCD to the Salt/mud formulations so as to investigate its inhibitive capability; result showed that more shale cuttings were recovered as compared to when only Salt/mud was used.

### **INTRODUCTION**

<sup>1</sup>Wellbore instability encountered while drilling shale formations is a worldwide problem. Despite much experience and considerable research, drilling and completion operations continue to be plagued by various hole problems attributed directly to shale formations. Studies and solutions to shale problems are not a simple matter because of the wide variations in clay chemistry.

Shales are sedimentary rocks which were generally deposited in marine basins. They are composed of compacted beds of muds, silts, and clays. In the soft or unconsolidated shale, mud or clay predominates, in the more consolidated formation it is shale or argillite, and in the metamorphic form, slate, phyllite, or

mica schist. At increased depth the shales become denser due to the compaction caused by overburden weight. Shales may also be subjected to tectonic stresses, producing further alteration. When shales contain sand they are called arenaceous shales. If they contain calcium carbonate they are called calcareous shales. Those that contain iron are termed ferruginous shales and if large amounts of organic materials are present, they are called carbonaceous shales. The drilling fluid engineer is very much concerned with the degree of hydration of shales, and with the cementing materials binding shales together. Equally important are the inclination of the bedding planes and the stresses acting within or upon the shale formation.

Shales contain various clay minerals which differ structurally. The more common of these are montmorillonite, illite, chlorite and kaolinite. Some of these clay minerals will hydrate while others will not. Shales containing montmorillonite will hydrate easily. The montmorillonite clay group has a high base-exchange capacity, where one cation will replace another and can increase or decrease the shales tendency to hydrate. The degree of hydration is also influenced by the type of cation involved and the pH of the fluid. Mass action by a high concentration of salts will suppress the hydration of clays. Illite is another mineral frequently found in shales. The basic structure of illite is similar to montmorillonite but it does not hydrate readily in fresh water. Both are composed of two silica tetrahedral sheets and a central octahedral alumina sheet. Illite, however, develops a charge deficiency (negative charge) from the replacement of silicon by aluminum on the surface of the silica sheet.

Chlorite clay minerals are similar to illite and do not noticeably hydrate. They are composed of the same three layers. Kaolinite is somewhat different from montmorillonite, illite, or chlorite. The clay structure is composed of two layers instead of three: a single silica tetrahedral sheet and an alumina octahedral sheet. There is no charge deficiency and the particles are electrically neutral. Kaolinite does not swell but will readily disperse. The hydrating-type shales containing montmorillonite are found at shallow depths and are often referred to as gumbo shales while at greater depths their ability to hydrate decreases due to modification of the internal lattice structure. They tend to become a more illitic or chloritic type of clay.

### **PROBLEMS CAUSED BY SHALE INSTABILITY**

Terms frequently used to describe troublesome shales are, sloughing shale, heaving shale, running shale, bentonitic shale, mud-making, plastic-flowing and pressured shale. Besides enlarged hole due to shale sloughing, other problems which occur include:

- Improper mud weight
- Hole cleaning difficulties
- Stuck pipe
- Bridges and fill on trips
- Increased mud volume and treating costs
- Poor cement jobs and increased cement requirements
- Well logging problems
- Limited sidewall core recovery
- Tight hole

#### ***Factors Causing Shale Instability***

- Tectonically stressed shales
- Abnormally pressured shales
- Erosion due to high annular velocities
- Drill string whipping, knocking shale off the wall of the hole
- While tripping, the drill string dislodges shale, either by direct contact or swabbing action.
- Dissolving salt within the formation

- Mud filtrate or whole mud invasion of the formation is mechanical. The subsequent effect is chemical.

## **METHODOLOGY**

### **APPARATUS**

The following apparatus were utilized in carrying out the experiments:

Beakers  
Hot roller oven  
Sieve/Marsh funnel  
Mud mixer  
Methyl blue tester/Kit  
Reagent bottle  
Spatula  
PH meter  
Retort stand  
Hot roller plate

### **SHALE CUTTINGS QUANTITY PER TEST**

10 - 15g

### **MUD ADDITIVES**

225ml water  
3.2g Barite  
12.8g Bentonite  
2.5g Polymer XCD (Xanthan Gum)

### **PROPOSED INHIBITIVE AGENTS**

Potassium Chloride, KCl  
Calcium Chloride, CaCl<sub>2</sub>  
Sodium Chloride, NaCl  
Polymer XCD (xanthan gum)

### **SUMMARY OF PROCEDURES PERFORMED**

- Shale Cuttings was dried using the oven at 105°C until a constant weight is obtained.
- The cation exchange capacity (CEC) of shale was determined using methylene blue test method.
- Determined the effect of Osmosis/Ionic Diffusion on shale samples of known weight would be performed as stated in procedure 3.6.2.1 above
- Densities and pH of mud formulations was determined and results were taken.
- 10g -15g of dried shale sample in the various mud formulations were hot rolled for 3hrs and the %weight of shale recovered were recorded with their corresponding temperature and pressure.
- Shale recovered after hot rolling was dried at 270 °F for 12hrs and the dry weight was recorded.

About 85% of the cutting life is spent in the wellbore and subjected to relatively high temperature and pressure in some special cases. It would be desirable to determine the effects of such conditions on the shale cuttings dispersion. Also we can recall that the cuttings are usually in dynamic state when in the wellbore due to rotation of drillstring as well as circulation of mud into and out of the wellbore which aids the carriage of drilled cuttings to the surface.

Therefore, justifying our rationale for hot-rolling the drilled shale for a period of 3hrs, since in the real life situation (dynamic condition) the cuttings would not take more than that to be circulated out of the

wellbore except for situations where connections are being made, tripping or when challenges occur. e.g stuck pipe, faulty mud pump etc.

## RESULTS, DISCUSSION AND OBSERVATION

In order to ensure accurate determination of shale behaviour in water based mud using NaCl, CaCl<sub>2</sub> and KCl, constant water activity of 0.86 was kept by determining the quantity of salt required to be added to the mud for attainment of the desired water activity. 18%wt NaCl, 18%wt CaCl<sub>2</sub> & 24%wt KCl were chosen i.e. 40.5 g of NaCl, 40.5g of CaCl<sub>2</sub> and 54g of KCl were added respectively to the mud samples to achieve 0.86  $a_w$ . Below are the results, observations and discussions of the laboratory experiments conducted.

### CATION EXCHANGE CAPACITY (CEC) DETERMINATION

The CEC of Two different shale samples, Otiba shale and Niger Delta shale were determined by performing Methylene Blue Test. The result of the experiment is shown in [Figure 1.0](#)

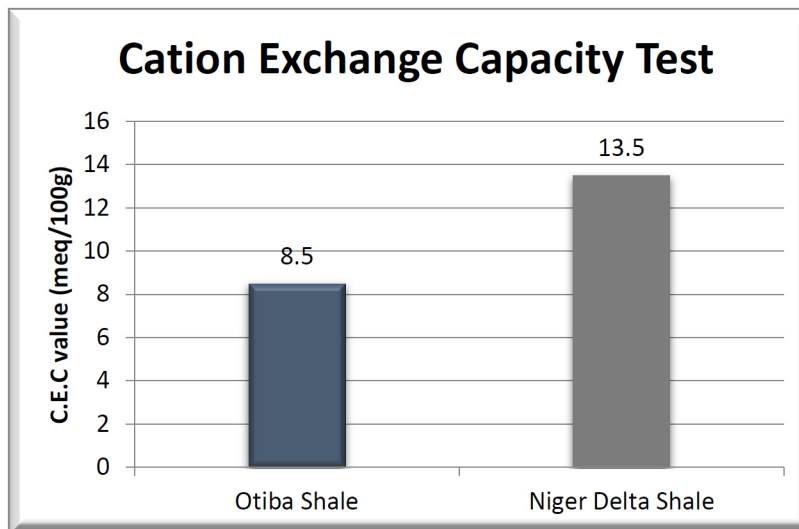


Figure 1.0—Cation Exchange Capacity results

**DISCUSSION** Niger delta shale has more exchangeable cations than otiba shale. This indicates that Niger Delta Shale is more reactive than Otiba shale since the higher the CEC the higher the reactivity. As a result of more exchangeable cations possessed by Niger Delta shale, it makes the shale more vulnerable for dispersion and invasion than the otiba shale.

From the result, it could be deduced that Otiba shale is a low reactivity shale since it falls within the range 3 – 10 meq/100g. While Niger Delta shale could be regarded as a moderate reactivity shale considering the fact that it fall within the range 10 – 20 meq/100g.

We could infer from [Table 1.0](#) above that otiba shale possibly has mainly Kaolinite as the dominating clay mineral while Niger Delta shale could comprise of Illite, kaolinite and chlorite in an unknown proportion since its CEC value of 13.5meq/100g falls within the three categories. This deduction cannot be completely accepted until X-Ray Diffraction analysis is done to accurately to determine the mineralogy of the shale samples. In order words, this table only gives an idea of the possible clay minerals present in the shale samples.

**Table 1.0—Typical CEC values for various clays found in shale and sand**

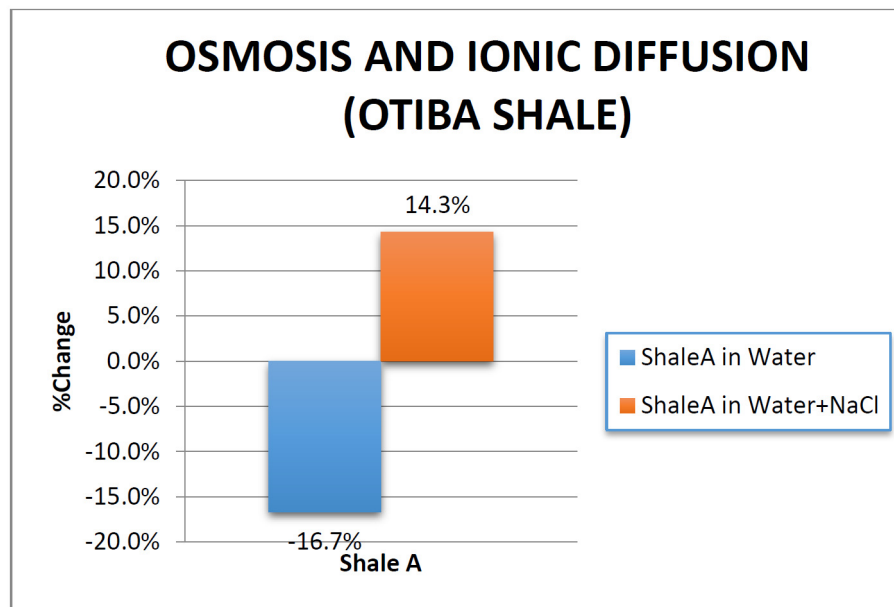
CLAY MINERAL	CEC RANGE OF VALUES
Smectite	80 to 120 meq/100g
Illite	10 to 40 meq/100g
Kaolinite	3 to 15 meq/100g
Chlorite	10 to 40 meq/100g
Sand	<0.5 meq/100g

So therefore, it is expected that the two shale samples having different CEC values should behave differently in the various mud/salt formulations with the shale with higher CEC value (Niger Delta shale) being more reactive.

**EFFECT OF OSMOSIS AND DIFFUSION BETWEEN WATER AND SHALE**

**Table 2.0—shows the result of experiment carried out to confirm osmotic and ionic diffusion effect between shale and water % reduction in weight of shaleA in Beaker1= 16.7%**

DRY SHALE SAMPLES			
Shale A	INITIAL WEIGHT	FINAL WEIGHT	%change
Beaker1	1.2	1	16.7%
Beaker2	0.7	0.8	14.3%



**Figure 2.0—shows osmotic and ionic diffusion effects on shale**

**DISCUSSION** The reduction in weight of shaleA in Beaker1 by 16.7% when immersed in Water confirms the fact that ions diffuse from region of higher concentration (shale) to region of lower concentration (Water).

The increase in weight of shaleA in Beaker2 by 14.3% when immersed in Water+NaCl solution confirms the fact that ions diffuse from region of higher concentration (NaCl solution) to region of lower concentration (Shale) this confirms chenevert’s postulation.

**OBSERVATION** Bubbles in the water (i.e water without any added salt) when the shale was immersed and after a while the shale particles began to fall of indicating that osmosis (i.e water flux into shale) and

ionic diffusion were simultaneously taking place resulting in dispersion of shale particles as well as reduction in weight of shale after being recovered and dried.

While for the Water+NaCl salt solution there were no visible bubbles noticed when shale was immersed. This implies that the salt added prevented flux of water into shale.

**NOTE:** The reason why water and not mud was used was to aid noticeability/observation of any visible interaction between the shale and water/NaCl solution.

## RESULTS OF EXPERIMENT DONE USING MUD FORMULATION 1: HOT ROLLING DISPERSION TEST RESULTS (MUD FORMULATION 1)

***EFFECTS OF TEMPERATURE AND PRESSURE ON SHALE CUTTINGS DISPERSION IN WBM (USING OTIBA SHALE)*** The purpose of this experiment was to confirm if pressure and temperature has significant effects on shale than when only temperature was applied to the system. The tables and charts below show the results of the experiment.

Table 3.0—shows result of hot rolling dispersion test performed on Otiba shale @212degF

HOT ROLLING DISPERSION TEST (212degF)-OTIBA SHALE								
Mud+ salt	Pressure(psi)	Temp. (degF)	Initial shaledry weght(g)	shale recovered(g)		%shale recovery	mud filtrate absorbed	%mud filtrate absorbed
				wet weight	dry weight			
WBM+ 24%KCl	0	212	10	9.6	8	80.0%	1.6	17%
WBM+18%NaCl	0	212	10	9	6.2	62.0%	2.8	31%
WBM	0	212	10	9	5.7	57.0%	3.3	37%
WBM+18%CaCl <sub>2</sub>	0	212	10	1.2	0.8	8.0%	0.4	33%

Table 4.0—shows hot rolling dispersion test for otiba shale subjected to pressure of 35psi @212degF

HOT ROLLING DISPERSION TEST (212degF & 35psi)-OTIBA SHALE								
Mud+ salt	Pressure(psi)	Temperature (degF)	Initial shale dry weght(g)	shale recovered(g)		%shale recovery	mud filtrate absorbed	%mud filtrate absorbed
				wet weight	dry weight			
WBM+ 24%KCl	35	212	15	13.1	10.9	72.7%	2.2	17%
WBM+18%NaCl	35	212	15	11.1	6.3	42.0%	4.8	43%
WBM	35	212	15	9.3	5	33.3%	4.3	46%
WBM+18%CaCl <sub>2</sub>	35	212	15	0.4	0.1	0.7%	0.3	75%

**DISCUSSION** Figure 3.0 above shows comparison between hot rolling shale samples @ 212 degF and when same quantity of shale were subjected to pressure of 35psi and then hot rolled @212degF for a period of 3hrs. The shale samples were recovered from the two cells, weighed, dried and reweighed so as to determine the amount of shale not dispersed. From the results obtained, it was evident that the application of Temperature and Pressure to dispersion test caused further reduction in shale cuttings recovered than when only temperature was applied. It can thus be deduced that pressure plays a role in dispersion of shale into drilling fluid.

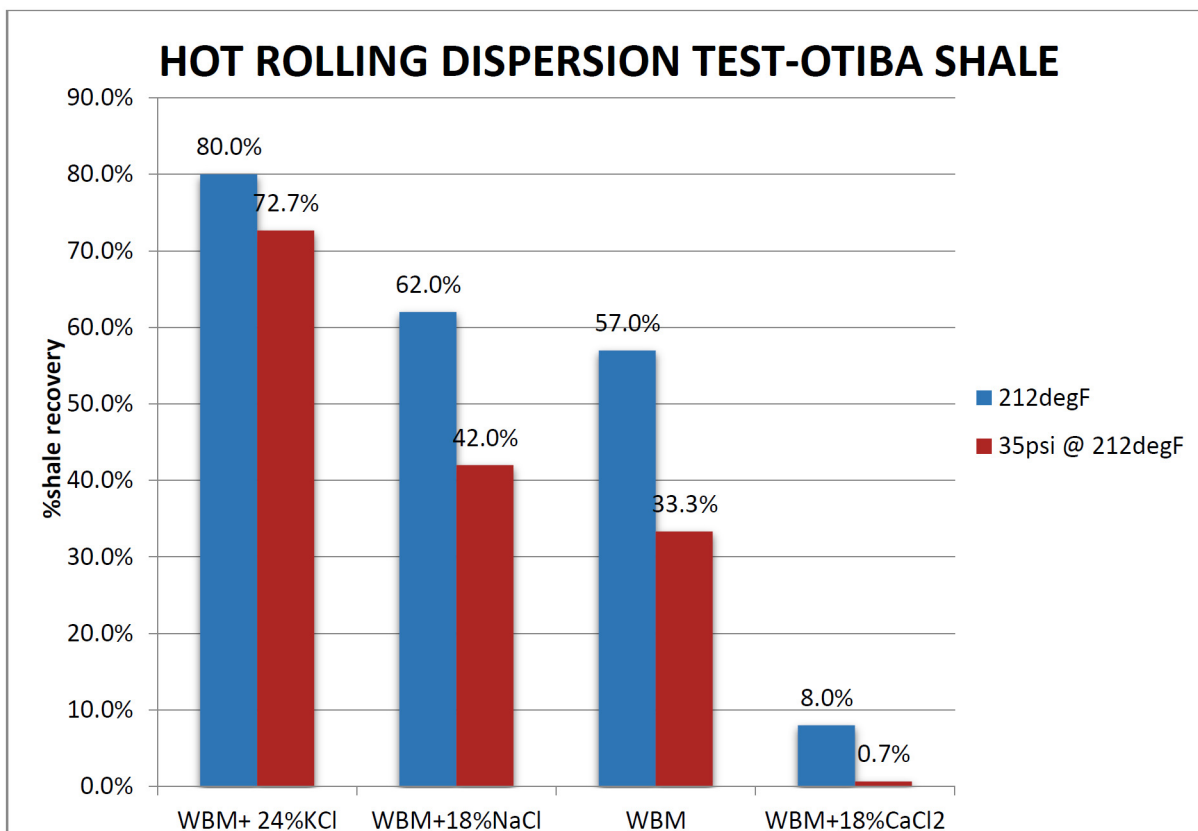


Figure 3.0—shows the effects of Temperature and Pressure on shale cuttings dispersion

***EFFECTS OF TEMPERATURE AND PRESSURE ON NIGER-DELTA SHALE CUTTINGS DISPERSION USING CALCIUM CHLORIDE, SODIUM CHLORIDE AND POTASSIUM CHLORIDE AS INHIBITIVE AGENTS IN WBM***

Table 5.0—shows Hot Rolling Dispersion test when shale was subjected to 35psi @212degF

HOT ROLLING DISPERSION TEST (212degF & 35psi)-NIGER DELTA SHALE								
Mud+ salt	Pressure(psi)	Temperature (degF)	Initial shale dry weight(g)	shale recovered(g)		%shale recovery	mud filtrate absorbed	%mud filtrate absorbed
				wet weight	dry weight			
WBM+ 24%KCl	35	212	10	7.1	4.9	49.0%	2.2	31%
WBM+18%NaCl	35	212	10	3.2	2.3	23.0%	0.9	28%
WBM+18%CaCl2	35	212	10	1.5	1	10.0%	0.5	33%
WBM	35	212	10	0	0	0.0%	0	0%

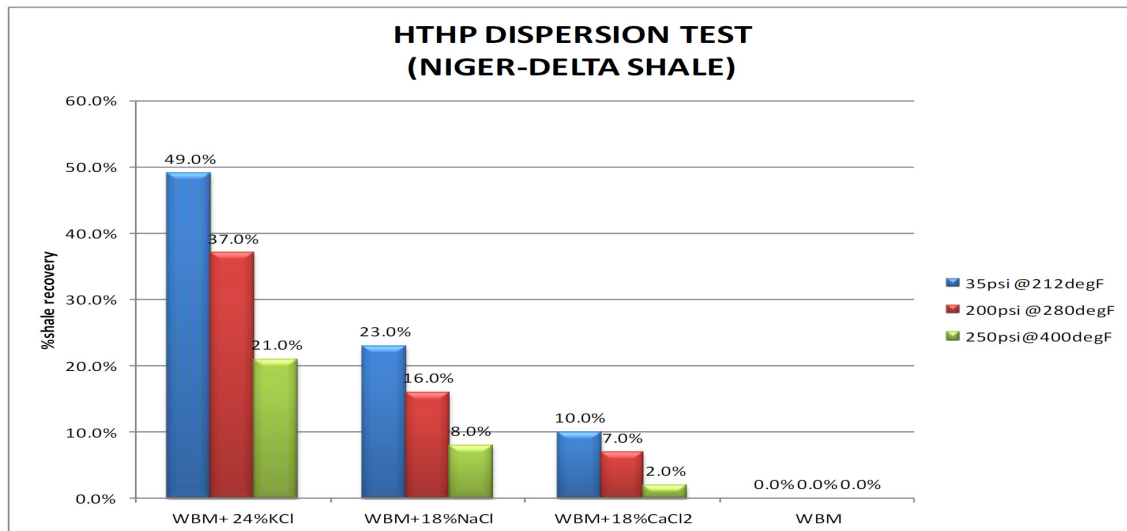
Table 6.0—shows Hot Rolling Dispersion test when shale was subjected to 200psi @280degF

HOT ROLLING DISPERSION TEST (280degF & 200psi)-NIGER DELTA SHALE								
Mud+ salt	Pressure(psi)	Temperature (degF)	Initial shale dry weight(g)	shale recovered(g)		%shale recovery	mud filtrate absorbed	%mud filtrate absorbed
				wet weight	dry weight			
WBM+ 24%KCl	200	280	10	6.1	3.7	37.0%	2.4	39%
WBM+18%NaCl	200	280	10	2.2	1.6	16.0%	0.6	27%
WBM+18%CaCl2	200	280	10	1.6	0.7	7.0%	0.9	56%
WBM	200	280	10	0	0	0.0%	0	0%



Table 7.0—shows Hot Rolling Dispersion test when shale was subjected to 250psi @400degF

HOT ROLLING DISPERSION TEST (400degF & 250psi)- NIGER DELTA SHALE								
Mud+ salt	Pressure(psi)	Temperature (degF)	Initial shale dry weight(g)	shale recovered(g)		%shale recovery	mud filtrate absorbed	%mud filtrate absorbed
				wet weight	dry weight			
WBM+ 24%KCl	250	400	10	4	2.1	21.0%	1.9	48%
WBM+18%NaCl	250	400	10	1.4	0.8	8.0%	0.6	43%
WBM+18%CaCl <sub>2</sub>	250	400	10	0.8	0.2	2.0%	0.6	75%
WBM	250	400	10	0	0	0.0%	0	0%

Figure 4.0—shows hot rolling dispersion results with Temperature and Pressure Variation using NaCl, KCl and CaCl<sub>2</sub>

**DISCUSSION** When Shales come in contact with WBM, negative charges are being developed on their surface. These negative charges developed at clay site help shale surface to act as a selectively permeable membrane thereby repelling movement of negative ions from the mud into shale. Likewise, cations found in the shale readily dissociate themselves when shale comes in contact with mud because they are weakly bonded to the negative charges at the clay sites. This dissociation gives room for cations in the mud+ salt system to invade the shale by fitting themselves snugly into the c-spacing between unit layers/clay platelets. A **unit layer** comprises of one octahedral sheet sandwiched in between two tetrahedral sheets. **C-spacing** is the distance between corresponding planes in adjacent unit layers and its thickness is approximately 9.5 Å (i.e  $9.5 \times 10^{-10}$  m).

The flow of ions into or out of shale results in drastic alteration of the mechanical properties of shale resulting in cohesion degradation and weakening of cementation bonds between clay platelets. This is the mechanism responsible for dispersion of shale. Considering Niger Delta shale behaviour in the various WBM+ salt formulations as shown in the figures above, we can deduce that dispersion occurred most when shale was hot rolled in WBM (i.e containing no salt) and least when hot rolled in WBM+ KCl salt. The proposed reasons are stated below;

For shale behaviour in WBM without salt, dispersion occurred due to simultaneous flux of water from mud into shale (osmosis) and ionic diffusion from the region containing higher concentration of ions (shale) to region containing lower concentration of ions (WBM). The adsorption of water onto shale results in hydration while the diffusion of ions out of shale results in dispersion of shale particles.

For shale behaviour in WBM+ Salt; Because of the addition of salt to mud, water in mud would no longer flux into shale. Instead any water found in shale pore throat would be forced to flux out of shale



due to increased concentration of WBM which is now higher than the concentration of the pore fluid initially in the shale thereby aiding osmotic flow. The resulting effect of this salt addition is that ions would diffuse from region of higher concentration (i.e. WBM + salt) to region of lower concentration (shale) thereby invading the shale and causing alteration in mechanical strength of shale which further leads to shale dispersion when the system is in a dynamic condition (i.e. when agitated).

The cations ( $\text{Ca}^{2+}$ ,  $\text{K}^+$ ,  $\text{Na}^+$ ) diffusing from the salt + WBM into shale respectively all have different impacts upon invasion thereby making shale particles to disperse differently upon contact with the different Salt + WBM formulation. This is as a result of variation in the hydrated ionic diameter of the cations.

Diffusion of  $\text{Ca}^{2+}$  into shale pore throat caused shale to be highly dispersed compared to other cations used because the hydrated ionic diameter of  $\text{Ca}^{2+}$  (i.e.  $19.2\text{\AA}$ ) is larger than shale's default C-spacing of  $9.5\text{\AA}$ . Hence,  $\text{Ca}^{2+}$  tends to force itself in between the unit layers which results in expansion of the distance between the unit layers. This expansion causes increase in the thickness of the shale's c-spacing thus resulting in increased shale size (i.e. swelling) as well as weakening of the cementation bonds between platelets which further leads to shale dispersion.

Diffusion of  $\text{Na}^+$  into shale caused shale dispersion but not as much as that of  $\text{Ca}^{2+}$ . This is because the hydrated ionic diameter of  $\text{Na}^+$  (i.e.  $11.2\text{\AA}$ ) is not as large as that of  $\text{Ca}^{2+}$ . So when  $\text{Na}^+$  fits itself in between unit layers, it results in slight increase in thickness of the c-spacing leading to shale swelling and also slight alteration in mechanical strength thus causing reduction in dispersion of shale.

$\text{K}^+$  behaves in a different manner because its hydrated ionic diameter i.e.  $7.6\text{\AA}$  is smaller than shale's c-spacing. Hence, it fits easily in between unit layers and causes a reduction in thickness of c-spacing which leads to shrinkage in shale size. The process of shrinkage alters the mechanical properties of shale slightly leading to little

***COMPARISON BETWEEN BEHAVIOURS OF NIGER-DELTA SHALE AND OTIBA SHALE IN THE DIFFERENT WBM+SALT FORMULATIONS WHEN SUBJECTED TO PRESSURE OF 35PSI AND HOT ROLLED @212DEGF***

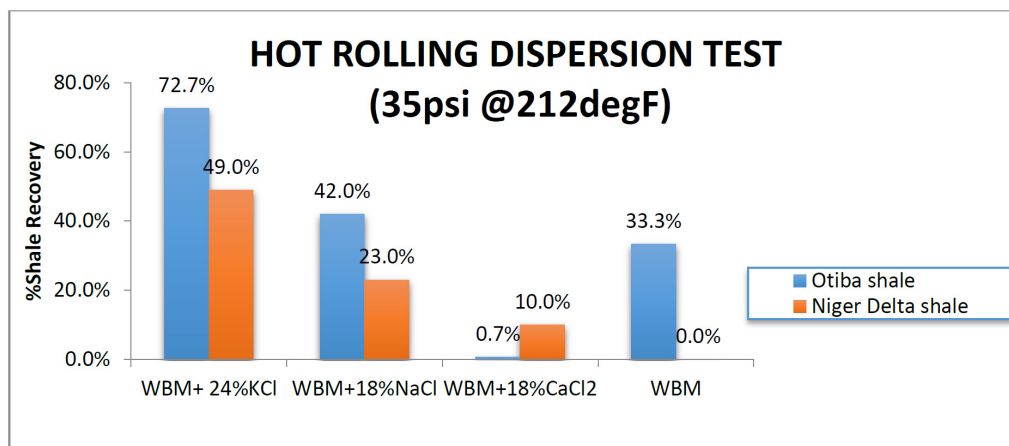


Figure 5.0—shows comparison between Otiba shale and Niger Delta when subjected to pressure of 35psi and Hot rolled @212degF

**DISCUSSION** This plot confirms the result gotten from CEC/MBT values of the shale samples because shale with higher CEC value is expected to be more reactive than one with lower CEC value. Hence from figure 6.0, Niger Delta shale was highly dispersed into the mud/salt formulation than for Otiba shale indicating that Niger Delta shale is more reactive than Otiba shale.

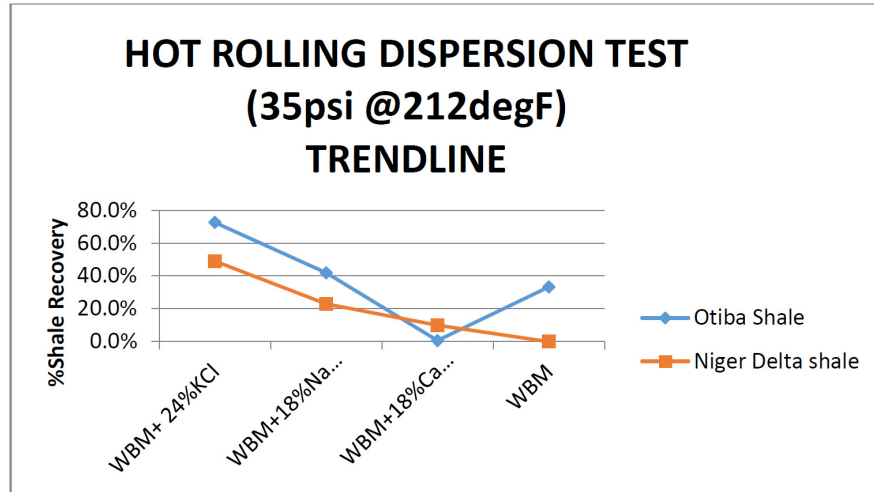


Figure 6.0—shows trendline of how Otiba shale and Niger Delta shale interacted with WBM+ salt when subjected to pressure of 35psi@ 212degF

Also, shale mineralogy determination has a role to play in the behaviour of different shale samples. Looking at the reactivity between the two shale samples in WBM+ CaCl<sub>2</sub>, it is obvious that they do not follow the same trend indicating that calcium ion exchange was more in Otiba shale than in Niger Delta shale. We could deduce that Niger Delta shale had more calcium ions present in its pore throat than in Otiba shale before the immersion into WBM+ CaCl<sub>2</sub> formulation. But we can't draw a conclusion unless the mineral composition of the shale is determined.

**OBSERVATION** Mud flocculated prior to addition of salt, causing bentonite particles in mud to settle out.

**RESULTS OF EXPERIMENT DONE USING MUD FORMULATION 2**

**WBM + SALT + POLYMER XCD (XANTHAN GUM) EFFECTS OF SALT ADDITION ON DENSITY OF WBM**

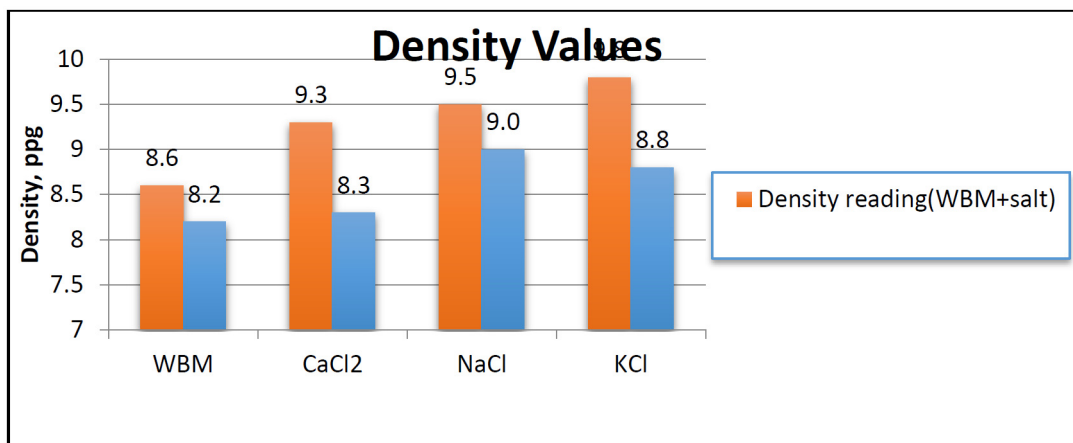


Figure 7.0—shows the effects Polymer XCD addition to WBM + Salt Formulation

**DISCUSSION** A fall in density of the mud occurred as a result of air bubbles entrapped in the mud during mixing with the mud mixer in so as to attain a homogenous mixture.

**HOT ROLLING DISPERSION TEST RESULTS (MUD FORMULATION 2)**

***EFFECTS TEMPERATURE AND PRESSURE ON SHALE CUTTINGS DISPERSION USING THE COMBINATION OF POLYMER XCD & SALT (EITHER NaCl, KCl OR CaCl<sub>2</sub>) AS INHIBITIVE AGENTS IN WBM***

Table 8.0—shows HTHP effect on shale dispersion using WBM+ Salt+ Xanthan Gum

HOT ROLLING DISPERSION TEST (212degF & 35psi)-NIGER DELTA SHALE								
Mud+ salt +polymerXCD	Pressure (psi)	Temp(degF)	Initial shale dry weight(g)	shale recovered(g)		%shale recovery	mud filtrate absorbed	%mud filtrate absorbed
				wet weight	dry weight			
WBM+ 24%KCl+XCD	35	212	10	14	8.8	88.0%	5.2	37%
WBM+18%NaCl+XCD	35	212	10	7.9	4.4	44.0%	3.5	44%
WBM+18%CaCl <sub>2</sub> +XCD	35	212	10	11.8	6.8	68.0%	5	42%
WBM+XCD	35	212	10	2.5	0.8	8.0%	1.7	0%

mass of polymer XCD = 2.5g

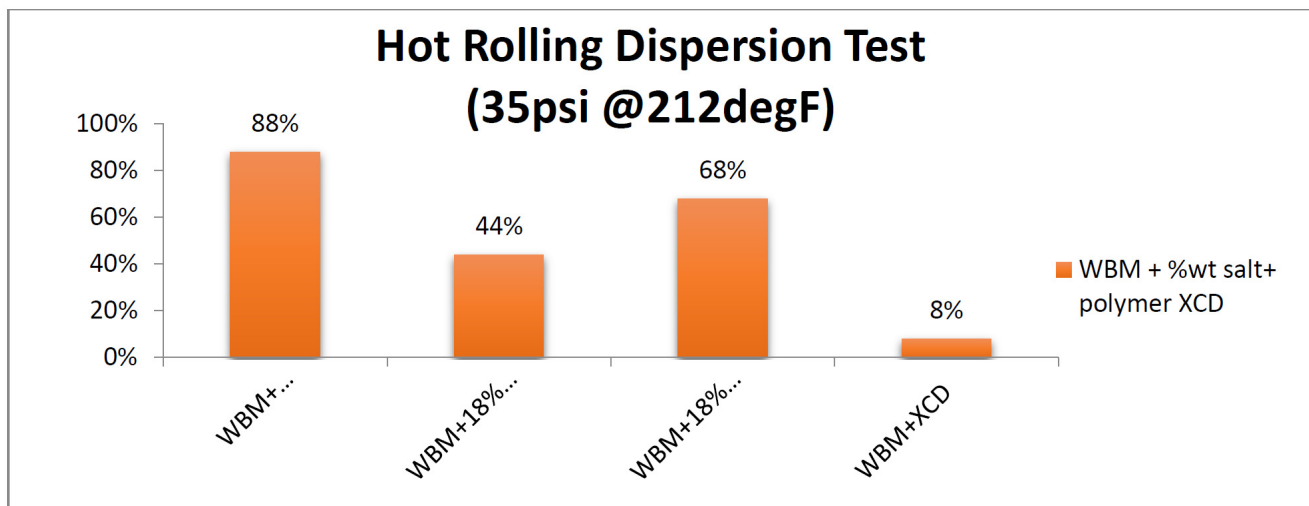


Figure 8.0—Shows Hot Rolling Dispersion test result using Salt+ Polymer XCD +WBM

The addition of polymer XCD (i.e xanthan gum) resulted in more shale recovery indicating that shale dispersion into mud was reduced, thus confirming that polymer XCD is a good encapsulating agent.

***COMPARISON BETWEEN THE EFFECTS OF SALT +WBM FORMULATION & THE EFFECTS OF SALT + POLYMER XCD +WBM FORMULATION ON SHALE CUTTINGS DISPERSION SUBJECTED TO TEMPERATURE AND PRESSURE CONDITIONS***

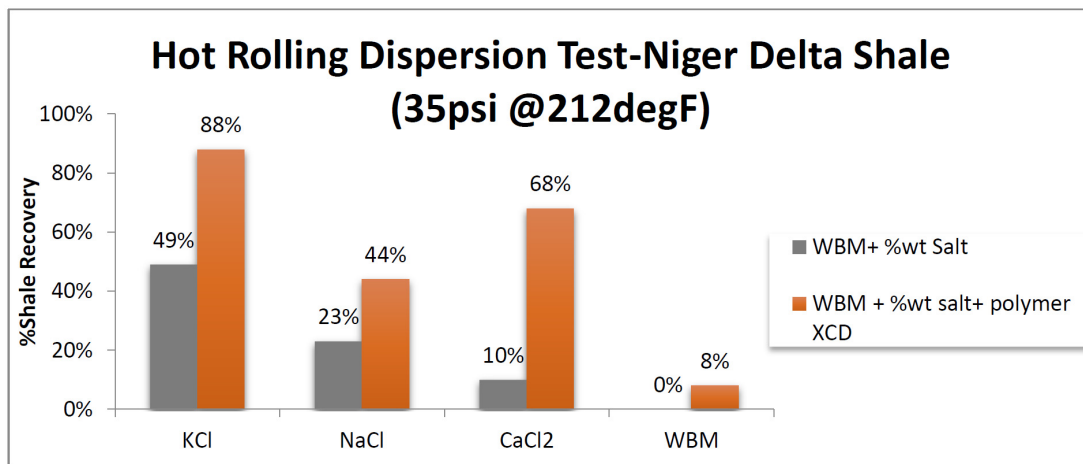


Figure 9.0—shows comparison between effects of (salt +WBM) & (salt +Polymer XCD+WBM) on shale cuttings dispersion subjected to HTHP conditions in the Roller Oven

**DISCUSSION** The addition of polymer to salt +mud formulation resulted into better shale recovery as well as a drastic reduction in the amount of shale dispersed into the drilling fluid than when only salt + WBM formulation was used. This is due to the fact that Polymer XCD coats itself around the shale cuttings acting as an encapsulating agent. There is a possibility that the hydroxyl group present in the polymer XCD adsorb on the shale surface to provide sufficient negative ions thereby aiding a better semi permeable membrane between shale and mud thus improving the characteristic of shale as an ion selective membrane. The adsorption of hydroxide ions onto shale would help shale be more selective and thus would allow only cations with ionic diameter small enough to pass through the pore spaces of the selective membrane or coating formed. Also the reason why shale partially dispersed could be because the quantity of XCD added was not sufficient enough to provide the negative ions needed to completely coat the shale surface.

This justifies the fact that addition of polymer encapsulates the shale cuttings thereby reducing the rate of ionic flux into shale that could have resulted in weakening the mechanical strength of the shale.

#### CaCl<sub>2</sub>+POLYMER XCD

The reason why CaCl<sub>2</sub> + Polymer XCD performed better than when NaCl + Polymer XCD was used could be as a result of hydrated ionic diameter of Ca<sup>2+</sup> which could be larger than the pores of the coating provided by the encapsulating agent thereby preventing the passage of Ca<sup>2+</sup> into the shale.

#### While NaCl +POLYMER XCD

The pore spaces of the polymer coating could be larger than the hydrated diameter of Na<sup>+</sup> thus allowing passage of Na<sup>+</sup> into shale leading to distortion of shale mechanical strength as a result of increase in thickness of c-spacing between the unit layers of the shale.

**OBSERVATION** The addition of polymer to salt/mud formulation reduced the flocculation of the clay minerals present in the mud observed when only Salt+ WBM was used. This therefore improved the rheology of the mud as no obvious settling out of water was noticed compared to the former.

## CONCLUSION

Wellbore instability occurs mostly as a result of shale hydration and dispersion when in contact with water based mud. This dispersion and hydration are due to interaction between shale and the mud, where water from the mud fluxes into shale, causes hydration and weakens the cementation bonds binding the shale platelets together and then result in dispersion into the mud.

Salt was added to the mud to create an osmotic effect between the mud and shale thus preventing flow of water from mud into shale and promoting osmotic flow of shale pore fluid into mud. This in turn

resulted in diffusion of ions from the mud to the shale due to the presence of large amount of cations in the salt added to the mud. This diffusion resulted in simultaneous hydration and dispersion of shale as they were being rolled.

Potassium Chloride, Calcium Chloride and Sodium Chloride were the salts added to the mud. The least shale recovered after hot rolling dispersion test was from the addition of Calcium Chloride to Water based Mud while the most and highest percentage shale recovery were from the addition of Potassium Chloride to Water Based Mud.

Further comparison was made on the hydrated ionic diameters of these cations compared to the C-spacing between unit layers of the shale could be probably be the reason why the cations have different behaviours when they diffuse into shale.

Addition of Polymer XCD (Xanthan Gum) to WBM containing substantial amount of salt resulted into a better recovery of shale indicating that Xanthan Gum was a good encapsulating agent.

From the experiment conducted, it showed that not only temperature plays a role in dispersion of shale but pressure also play a substantial role by resulting into further dispersion of the shale samples that were hot rolled. This therefore indicates that the effect of pressure other than only temperature be put into consideration so as to have an idea of the effectiveness of our newly developed/proposed inhibitive agents.

In conclusion, Osmosis, Ionic diffusion and Temperature are not the only factors that cause dispersion and hydration of shale but also the pressure differential between the wellbore pressure and the formation pressure as well as hydrated ionic diameters of the cations present in the salt being utilized in the mud. Hence, all these factors should be put into consideration when drilling mud is being prepared.

## RECOMMENDATIONS

- Slake Durability Test should be performed to help give a better understanding of shale dispersion in drilling mud when subjected to Temperature and Pressure condition. Here is a description of what slaked durability test is all about:  
The Slake Durability Test is similar in design to the hot rolling dispersion test, but provides a harsher, more abrasive environment. This test is designed to simulate exposure of cuttings to the fluid in a well annulus, and subsequent removal at the shaker screens.  
The evaluation consists of placing a weighed quantity of sized shale pieces in a round cage semi-immersed in the test fluid. The cage with cuttings is rotated through the fluid for a 3hr period at room temperature. During rolling, any sensitive shale will tend to hydrate, break up, and disperse, passing through the cage screen. The shale pieces remaining in the cage after the test period are recovered, washed, weighed, dried overnight at 210°F and re-weighed. The moisture content of the shale and the percentage recovery of the shale are determined. The results would give an idea of the ratio of actual size been scraped by the bit during drilling to the size of the cuttings recovered at the shale shakers when the cuttings get to the surface.
- When a newly formulated mud is to be tested for shale inhibitive abilities, effects of pressure must be put into consideration. Since from the experiment performed, it was evident that pressure exerted on drilling fluid causes further reduction in shale cuttings dispersion than when subjected to only High Temperature.
- X-Ray Diffraction (XRD) test should be performed on shale to aid determination of shale mineralogy. XRD determines the crystalline structure of the minerals being tested by determining the angles at which the XRay beam is diffracted. This results in a pattern that is unique to a particular mineral. Analysis of the patterns from a formation sample can help identify the minerals present and semi-quantify them.
- It is recommended that chloride free sources of  $K^+$ ,  $Na^+$ ,  $Ca^{2+}$  be used to carry out same experiment to see whether it would yield a better result

- Good information and knowledge about shale mineralogy from offset core data be attained for fields to be explored provided it is not an exploratory well. This would assist in knowing the appropriate cations/salts to be used as additives when preparing the water based mud.
- Encapsulating agents e.g Xanthan Gum, Carboxy Methyl Cellulose(CMC) be utilized at all times during preparation of Water Based Mud as it does not only reduce the rate of shale dispersion but also serves as a filtration agent thus preventing fluid loss in to the formation

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## NOMENCLATURE

WBM	= Water Based Mud
NaCl	= Sodium Chloride
CaCl <sub>2</sub>	= Calcium Chloride
KCl	= Potassium Chloride
NH <sub>4</sub> Cl	= Ammonium chloride
POAM	= Polyoxyalkyleneamine
MEG	= Methyl Glucoside
PHPA	= Partially Hydrolyzed Polyacrylamide
HPWBM	= High Performance Water Based Mud
$P_s$	= Vapor pressure of water in the substance, m/L-t <sup>2</sup>
$P_0$	= Vapor pressure of pure water at the same temperature, m/L-t <sup>2</sup>
$A_w$	= Water Activity, dimensionless
ERH	= Equilibrium Relative Humidity
T	= Temperature, t
P	= Pressure, m/L-t <sup>2</sup>
$\mu_i$	= Chemical potential of a particular component at temperature T and pressure P
$\mu_i^0$	= Chemical potential of the particular component at standard condition
R	= Gas constant
$P_\pi$	= Osmotic pressure, m/L-t <sup>2</sup>
$\alpha_m$	= Membrane efficiency, dimensionless
$\bar{V}_w$	= Molar volume of water, 0.018 m <sup>3</sup> /mol
$\alpha_{w^o}$ shale	= Water activity of shale, dimensionless
$\alpha_{w^o}$ mud	= Water activity of mud, dimensionless
J	= Mass flux of ith ion, mol/L <sup>2</sup> -t
$C_{i, \text{shale}}$	= Concentration of ith ion in pore fluid
$C_{i, \text{mud}}$	= Concentration of ith ion in mud
$D_{si}$	= Diffusion coefficient of the ith ion, L <sup>2</sup> /T
$\Delta x$	= Length of shale, L
BHA	= Bottom Hole Assembly
H <sup>+</sup>	= Hydrogen ion
OH <sup>-</sup>	= Hydroxide ion
CEC	= Cation Exchange Capacity
MBT	= Methyl Blue Test