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Experimental Model for the Determination of Hydration Potential of Niger-Delta Shales for Drilling Mud Design

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Abstract

Maintaining stability between shale-mud interaction is a key factor towards improving safety and drilling efficiency while minimizing costs associated with drilling and production operations. The use of conventional Water Base Mud in drilling shale formation results in the adsorption of water associated with the drilling mud by the shale. Depending on the shale type, water adsorption may lead to various reactions such as swelling, cuttings dispersion, and increase in pore pressure creating wellbore instability to varying degrees. This research provides information on shale characterization of two Wells, A and B in Niger/delta region Nigeria and proposes the development of inhibitive Water based drilling fluids for the shale samples. It also provide results of the shale mineralogy, native moisture content, total organic carbon content, cation exchange capacity and the adsorption isotherm of the shale samples. From the analysis, the X-Ray Diffraction (XRD) results indicate that the shales are dominant of kaolinite. The result of the CEC falls within the Kaolinites group of 3 Meq/100g - 10 Meq/100g according to Boulding and Ginn (2003). Polymeric fluids composed of varying Polymer/salt (KCl, NaCl and $CaCl_2$) concentrations was prepared and evaluated for the shales samples using dispersion test. The result of the analysis was used to design a mud selection template for drilling through shales. Recommendations for improving shale stability were described, based on the current understanding of shale stability.

Key Words: Shale · Wellbore Stability · Adsorption Isotherm · Water Base Mud · XRD · CEC · TOC · Dispersion

INTRODUCTION

The interest in the issue of wellbore instability has become paramount concern to drilling operators in Niger-Delta in the sense that the shale formation is very abundant and gives the most problem during drilling operations due to the interaction of the drilling mud and the shale formations. Shales are fine-grained, sedimentary rocks which are primarily composed of fissile layers of mud, silt and clay materials. They can also be defined as fine-grained sedimentary rocks which are characterized by low permeability, medium to high clay content, and medium porosity (Oleas et al., 2008). These characteristics results to issues such as hydration, swelling, shrinking, strength reduction and ultimately failure. As a result of this, interests in the design of water-based muds (WBM) that will inhibit shale swelling encountered drilling through troublesome shales have arise. As the depth increases, the shales become denser as a result compaction which is caused by overburden pressure. The compaction results to interaction which causes problem of wellbore instability through shale properties like the mineral composition, its negative surface charge, its low permeability and its laminated structure. Shale experiences alteration due to tectonic stresses. Shale formations consist over 75% of all the formation drilled during drilling operations and over 90% of wellbore instability problems encountered during drilling are caused by it resulting into massive yearly expenses.

Most of the prevalent problems encountered in the use of water based mud during drilling operatios in Niger-Delta are mostly in the shaly formations. The conventional water based muds used in drilling the shale formations results to water adsorption of shale with associated drilling mud. Base on the shale type, water adsorption may lead to different reaction and increase in pore pressure resulting to varying degrees of wellbore instability. The non-productive time (NPT) recorded from these problems are eminent as a result of these failures and may further compound into mud treatment costs, difficulties in running casing and poor cement jobs. The use of Oil base muds has been limited due to the difficulties in disposing the cuttings, environmental impact, high handling cost and safety conditions.

This study focused on the Characterization of Niger-Delta shale hydration capacity through comprehensive review on the fundamentals of shales, its adsorption isotherm and the development of a water based mud. The water base mud developed was used for shale-drilling fluid interactions and the observed results were applied in designing Drilling mud Template.

LITERATURE REVIEW

Clay swelling has been there since the inception of well instability during drilling operation. So many works has been done regarding issues surrounding shale-fluid interactions which is either experimental, modeling or field trial in order to account for the behavior of shale when in contact with a drilling fluid.

O'Brien and Chenevert (1973) characterized shales with major laboratory procedures. X-Ray Diffraction analyses revealed the shale composition while adsorption isotherms generated showed hydrational tendencies. Various fluids tested using the swelling and dispersion tests showed the advantage of potassium muds in limiting swelling and instability to other salts. Chenevert and Osisanya (1989) investigated and improved established laboratory techniques in shale studies and it's applications at wellsites. The six major techniques evaluated in their works were swelling, dispersion, cation exchange capacity, capillary suction time, adsorption isotherm tests, and the X-Ray diffraction analysis. Testing equipment required for these tests were adjusted to favour their simple application at wellsite locations. This is necessary as shale problems are time dependent. It was observed that the more time they spent studying the shale, diagnosing it's problem and developing an inhibitive drilling fluids, the higher the severity of the wellbore instability they encountered.

Al-Awad and Smart (1996) utilized the adsorption isotherm obtained for native and re-compacted shales to find their equilibrium activity and restore them back to their native moisture content. This was followed by experimental investigations with four fluids including distilled water and their effects on these shales. Unconfined linear swelling and dispersion tests were carried out to evaluate shale-fluid interactions. Van Oort et al. (1996) studied water and ion transfer between shales and drilling fluids for better designs of Water Based Mud. Membrane efficiency, solute coefficient, and pore pressure buildup were measured using pressure transmission tests, osmosis tests, and Downhole Simulator Cell tests (DSC) for various salt solutions. The role of modifying the aqueous activity of the fluid using salts was once again confirmed.

Chenevert and Pernot (1998) investigated the development of swelling pressures resulting from interactions between various water based fluids in contact with problematic shales from the North Sea. They observed that swelling or shrinkage recorded in the shales was a function of the ionic concentration and salt type. Furthermore, strength reduction was outstanding with some of the fluids used. Lower swelling pressure values even to a negative value were observed through lowering fluid activity by addition of salt. The membrane efficiency of the shale was found to depend on chemicals dissolved in the water.

MATERIALS AND METHODS

The aim of study is to develop a water based mud that will be able to reduce the dispersion and swelling of shale samples obtained. Several water based fluid systems have been developed and tested for various shale samples in other Regions as discussed in the literature review but much has not been done in Niger-Delta region. However, each shale formation requires a unique drilling fluid for effective inhibition.

Two major experimental methods were used in this study. The first is shale characterization and second is shale-drilling fluid interaction experiments. The characterization test gives us an overview on the composition and properties of the shale while the shale-drilling fluid interaction tests provide information on the shale's reactivity in various fluids through dispersion and swelling tests.

In achieving this stability between the shale/mud interactions, the following procedures were carried out for different Shale samples:

1. X-Ray Diffraction Analysis (XRD Analysis) of the shales
2. Shale Tests through:
   - Determination of total organic carbon content
   - Native moisture content and Cation exchange capacity
3. Adsorption isotherm tests for the various shale samples
4. Development and evaluation of various water-based fluids against shale samples which involves Dispersion and Swelling tests

RESULTS AND DISCUSSION

This part presents the data analysis, results and discussions from the experiments that was carried out. It also provides detailed analysis of the outcomes observed.

SHALE CHARACTERIZATION

This is to determine qualitative mineral content. Mineral identification and interpretation is performed by matching the diffraction pattern of the sample with patterns of reference materials. The study of crystalline structure characteristic and its clay mineralogical determination is technically determined by X-ray diffraction.

The XRD analysis was done at the National Geosciences Research Laboratory (NGRL) Kaduna State Nigeria and results as shown in Appendix A. The percentage of clay minerals present in the Shale samples is as stated below.

Table 1—Shale Characterization (Mineralogy analysis)

Mineralogy	Shale Samples												
Minerals		A_1	A_2	A_3	A_4	A_5	A_6	A_7	B_1	B_2	B_3	B_4	B_5
Carbonate		10	8	17	13	9	9	13	8	7	6	8	8
Quartz		6	6	5	8	5	6	8	5	4	3	5	6
Feldspar		2	2	2	1	0	1	0	1	0	1	1	1
Diaspore		0	1	3	2	1	0	4	3	2	2	4	2
Iron Minerals		9	10	9	10	6	7	9	5	9	5	5	10
Rutile		5	4	4	3	7	2	3	2	3	1	2	4
Pyrite		3	8	3	8	5	3	9	0	5	3	6	5
Gibbsite		0	2	3	1	1	1	1	2	0	0	2	2
Halite		3	4	4	3	1	0	2	0	5	0	1	6
Others		12	10	11	8	9	10	17	4	7	8	6	10
Clays	**Kaolinite**	17	13	16	18	11	8	12	4	12	4	8	13
	Smectite	3	5	5	3	4	3	5	2	1	3	3	5
	Illite	3	0	0	0	0	0	2	1	2	0	1	1
	Chlorite	4	5	6	6	7	5	4	1	6	1	2	11
	Mixed layers	2	2	2	1	1	4	6	2	1	3	2	2

Table 2—Clay mineralogical Content of WELL A

	Shale Sample						
Clay Minerals	**A_1**	**A_2**	**A_3**	**A_4**	**A_5**	**A_6**	**A_7**
Kaolinite	17	13	16	18	11	8	12
Smectite	3	5	5	3	4	3	5
Illite	3	0	0	0	0	0	2
Chlorite	4	5	6	6	7	5	4
Mixed layers	2	2	2	1	1	4	6
Total	**29**	**25**	**29**	**28**	**23**	**20**	**29**

Table 3—Clay mineralogical Content of WELL B

	Shale Sample				
Clay Minerals	**B_1**	**B_2**	**B_3**	**B_4**	**B_5**
Kaolinite	4	12	4	8	13
Smectite	2	1	3	3	5
Illite	1	2	0	1	1
Chlorite	1	6	1	2	11
Mixed layers	2	1	3	2	2
Total	**10**	**22**	**11**	**16**	**32**

Table 4—Percentage Clay content from Well A and B

Depth (m)	Shale Sample	% Clay	Depth (m)	Shale Sample	% Clay
2250-2300	**A1**	**36.71**	2600-2650	**B_1**	**72.50**
2300-2350	**A_2**	**31.25**	2650-2700	**B_2**	**34.34**
2350-2400	**A_3**	**32.22**	2700-2750	**B_3**	**27.50**
2400-2450	**A_4**	**32.94**	2750-2800	**B_4**	**28.57**
2450-2500	**A_5**	**34.33**	2800-2850	**B_5**	**37.21**
2500-2550	**A_6**	**33.89**			
2550-2600	**A_7**	**30.53**			

NATIVE MOISTURE CONTENT (NMC)

Native moisture content is the amount of water present in shale as received in the laboratory after the removal of coatings for preservation. It is unique to each type of shale and the environment in which it is located. The average NMC of the two wells A and B are determined by adding up the NMC of the different depths divided by the total number of the samples from that well.

Table 5—NMC for WELL A

Shale Sample	Cuttings Depth (m)	Weight before drying (g)	Weight after drying (g)	Moisture Content	Percentage Moisture Content (%)
A_1	2250 – 2300	50.0	45.65	4.35	**8.70**
A_2	2300 – 2350	50.0	44.05	5.95	**11.90**
A_3	2350 2400	50.0	45.36	4.64	**9.28**
A_4	2400 – 2450	50.0	44.43	5.57	**11.14**
A_5	2450 – 2500	50.0	44.99	5.01	**10.02**
A_6	2500 – 2550	50.0	45.41	4.59	**9.18**
A_7	2550 - 2600	50.0	42.81	7.19	**14.38**

Table 6—NMC for WELL B

Shale Sample	Cutting Depth(m)	Weight before drying (g)	Weight after drying	Moisture Content	Percentage Moisture Content (%)
B_1	2600 - 2650	50	43.97	6.03	**12.06**
B_2	2650 – 2700	50	44.77	5.23	**10.46**
B_3	2700 -2750	50	45.08	4.92	**9.84**
B_4	2750 -2800	50	44.56	5.44	**10.88**
B_5	2800 - 2800	50	44.48	5.52	**11.04**

Based on the calculation, the average NMC in Well A and Well B are 10.66% and 10.86% respectively. Most likely, high value of moisture content is point toward the existence of stretch clays with the ability to store moisture by adsorption. This result implies that the NMC of the shale sample varies at different depths.

CATION EXCHANGE CAPACITY (CEC)

This evaluates the reactivity of drilled cuttings. The methylene blue test (MBT) method was recommended by API 13I (2003). The CEC was calculated from the methylene blue test result with the formular below

$$\text{CEC} = \frac{C_x \text{ x } V_{mb} \text{ x } C_{mb}}{V_{fd} \text{ x } M_{ds}}$$

Where,

C_x = Volume constant (3500)

V_{mb} = Volume of methylene blue solution titrated (ml)

C_{mb} = Concentration of methylene blue solution (M)

V_{fd} = Volume of fluid dispersed (ml)

M_{ds} = Mass of dispersed shale (g)

The values of CEC of Well A and Well B calculated from the above equation are 7.86 Meq/100g and 4.38 Meq/100g respectively. Increase in shale reactivity implies higher CEC. This implies that well A has reactive clay materials compared to well B based on their CEC values. It means that well A contains more of the smectite clays than well B. The result of the CEC falls within the Kaolinites group of 3 Meq/100g - 10 Meq/100g according to Boulding and Ginn (2003).

TOTAL ORGANIC CARBON CONTENT (TOC)

Total organic carbon (TOC) is a measurement of the organic richness of sedimentary rocks. TOC analysis is the first step in screening a formation for its hydrocarbon potential. The TOC values are reported in weight percent of carbon.

Table 7—TOC Result

S/No	Shale Sample	Titre Value(ml)	TOC (%)
1	A_1	7.85	**2.91**
2	A_2	8.85	**2.31**
3	A_3	9.30	**2.04**
4	A_4	8.85	**2.31**
5	A_5	8.85	**2.31**
6	A_6	9.40	**1.98**
7	A_7	8.95	**2.25**
8	B_1	8.25	**2.67**
9	B_2	8.40	**2.58**
10	B_3	8.30	**2.64**
11	B_4	8.40	**2.58**
12	B_5	8.75	**2.37**
13	BLANK	12.70	

The TOC result ranges from 2.0% – 3.0% which indicates adequate and good generational potential in the shale samples according to Jarvie (1991). The average TOC value for each well are Well A = 2.30% and for Well B = 2.57%..

CONCLUSION

The objective of this study was achieved by obtaining the mineralogical compositions, cation exchange capacities, native moisture content and total organic carbon content of the shale samples from Niger-Delta region. A water-based mud that reduces shale dispersion was formulated and a mud selection template was designed from the results of the shale-drilling fluid interaction. The XRD result indicates that the shale samples are majorly composed of the kaolinite group. It was observed that:

1. The characterization and evaluation of the behavior of shale formations with drilling fluids are the basic steps needed in solving wellbore stability problems.
2. Shale water activity varies with depth and their mineralogy content.
3. The clay type and adsorption of water by the shale may lead to various reaction ranging from cutting dispersion, and swelling which can result to shale instability to a varying degree.

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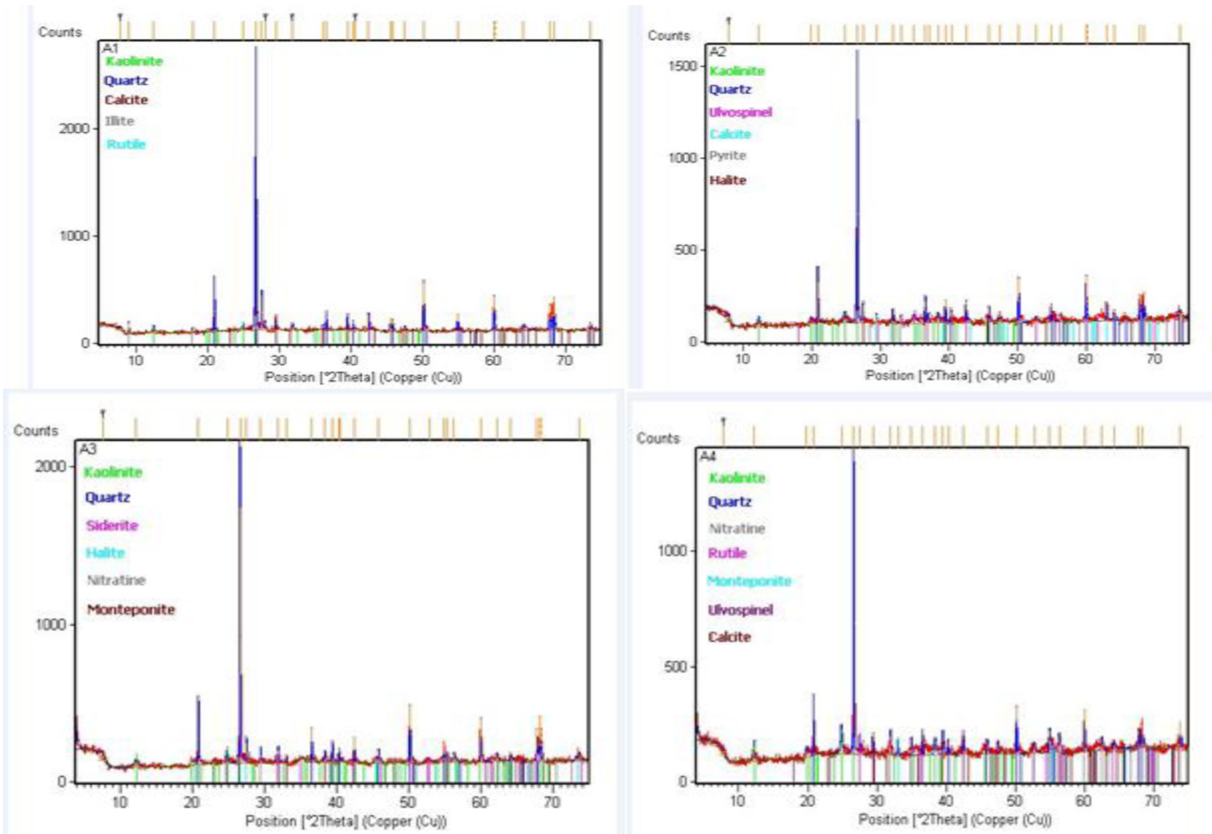
APPENDIX A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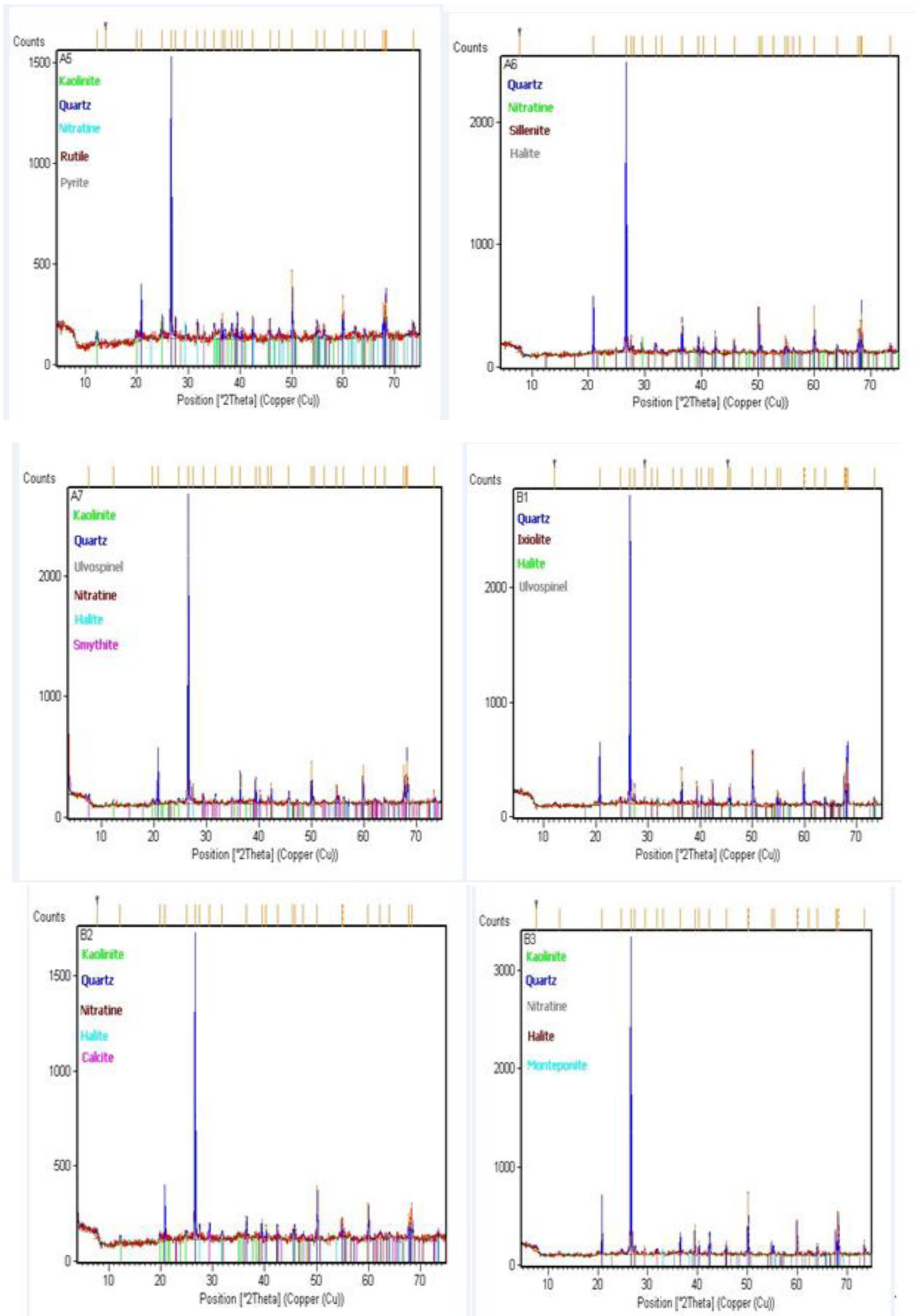
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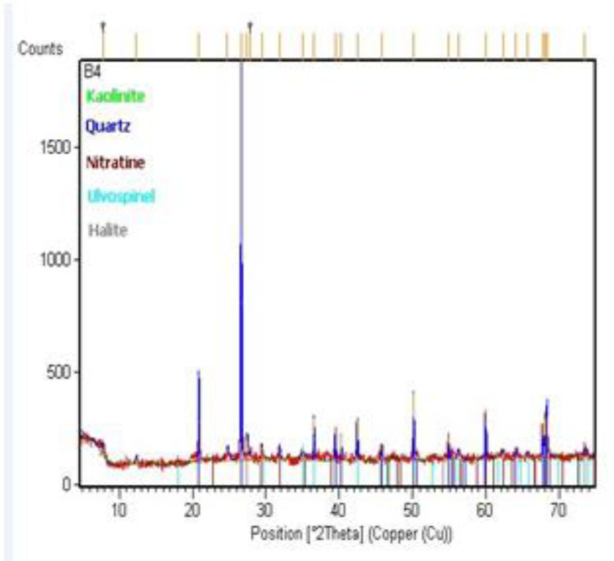
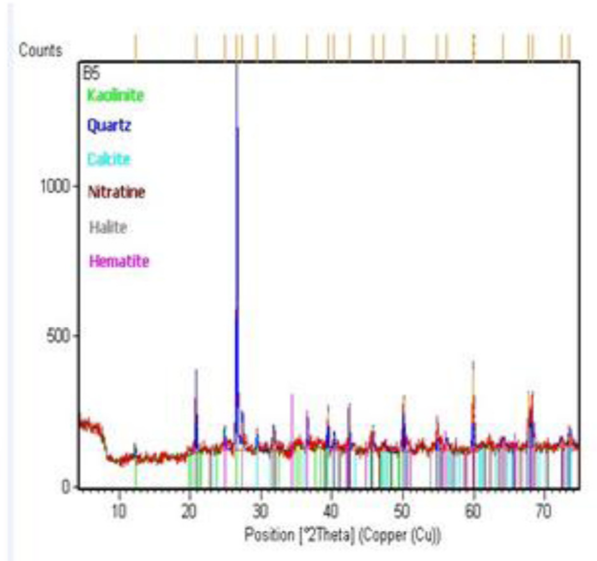
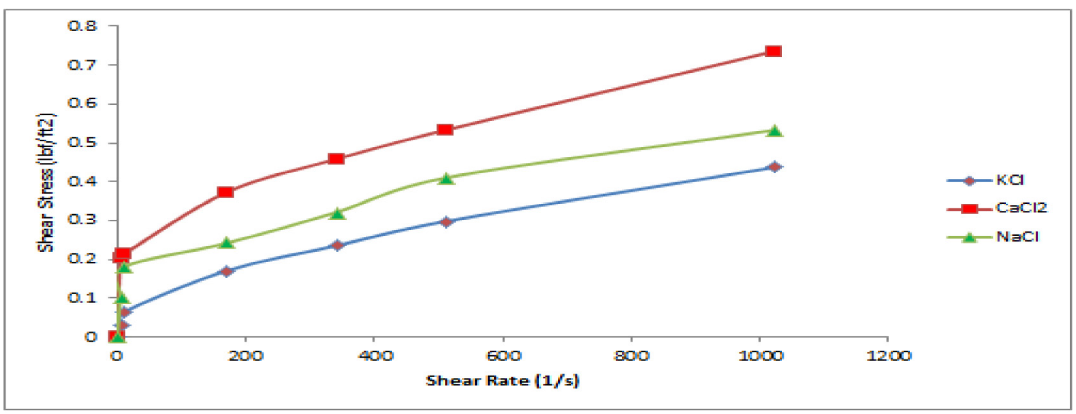
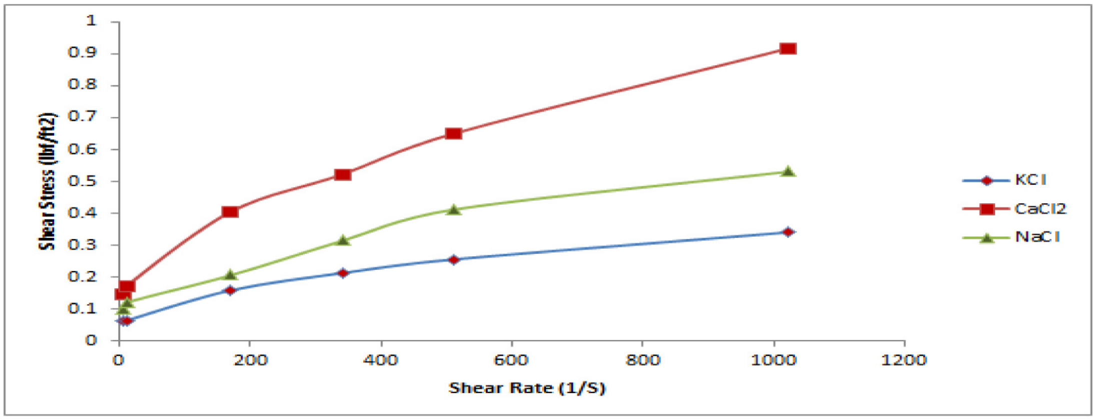




APPENDIX TWO



Rheogram of Polymer fluid before hot rolling at 250⁰ F



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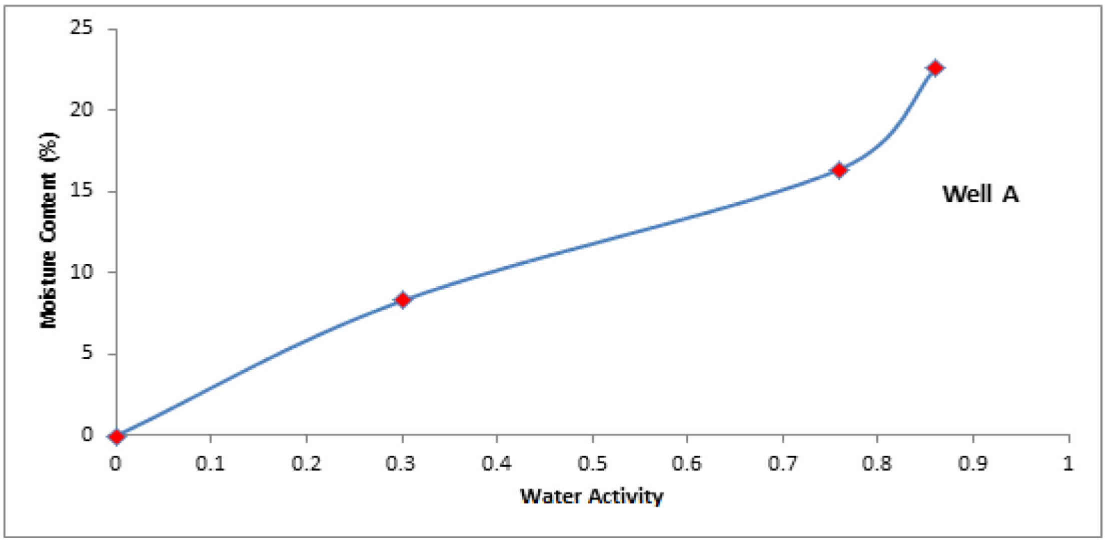
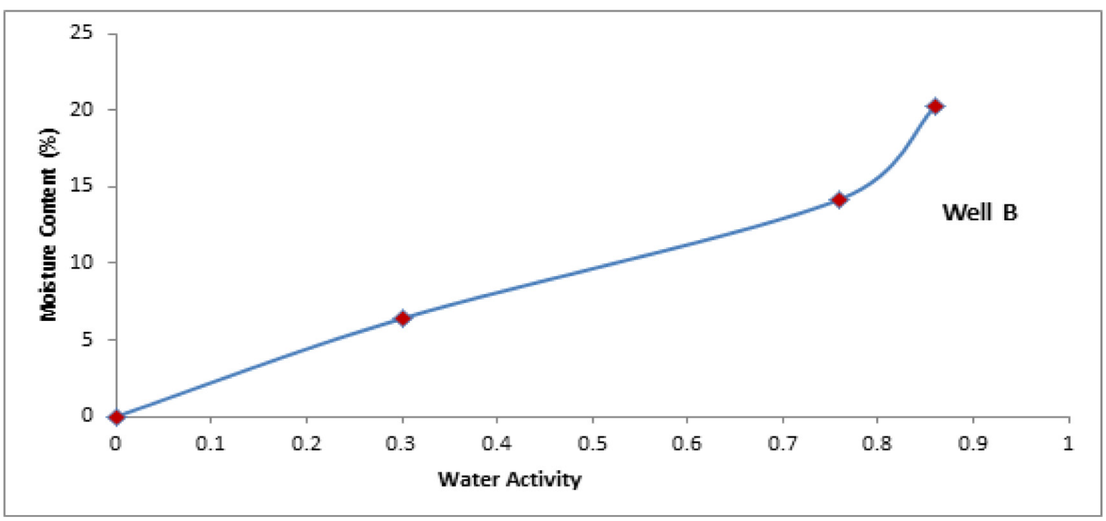
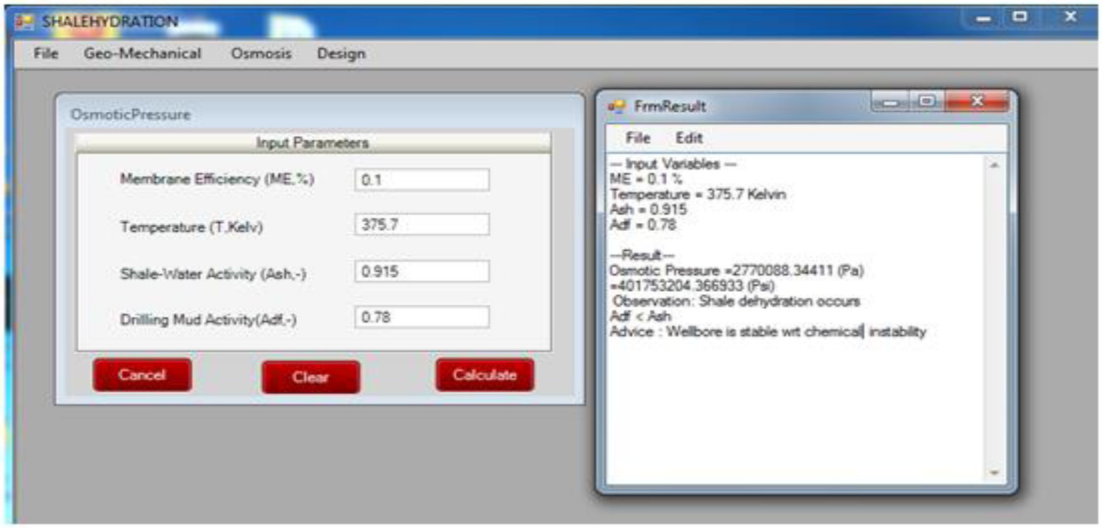


Adsorption Isotherm of Well A



Adsorption Isotherm of Well A



Shale Hydration Determination using chemical properties