

UNIVERSITI
TEKNOLOGI
PETRONAS

FINAL YEAR PROJECT 2

FINAL REPORT

TITLE:

**The Effectiveness of Different Water-Based Mud Systems in
Controlling Swelling and Dispersion of Shale in Malaysia Water.**

SUPERVISOR:

MR. ISKANDAR B DZULKARNAIN

CO-SUPERVISOR:

MR. M SOLEHUDDIN BIN A RAZAK

MUHAMMAD SYAFIQ BIN MOHD ARIFFIN

10228

PETROLEUM ENGINEERING PROGRAM

CERTIFICATION OF APPROVAL

The Effectiveness of Different Water-Based Mud Systems in Controlling Swelling
and Dispersion of Shale in Malaysia Water.

by

Muhammad Syafiq Bin Mohd Ariffin

10228

Dissertation submitted in partial fulfillment of
the requirements for the
Bachelor of Degree (Hons)
(Petroleum Engineering)

Approved by,



(Mr. Iskandar Bin Dzulkarnain)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

January 2011

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MUHAMMAD SYAFIQ BIN MOHD ARIFFIN

ABSTRACT

The main objective of this research is to propose the most suitable type of water-based mud (WBM) to be used in Malaysia Water for controlling the swelling and dispersion of shale. There are several types of drilling muds used in drilling oil and gas wells for these purposes such as oil-based mud (OBM), water-based mud (WBM) and synthetic-based mud (SBM). Out of these choices, WBM are used in drilling operations due to its environmental friendly nature and low cost. The justification of conducting the project is due to the importance of selecting the right WBM, if proper investigation is not made, this will lead to drilling problems such as washout, stuck pipe and hole enlargement. The purpose of this study is to determine the most excellent performance of WBM in order to minimize the shale problem while drilling offshore in Malaysia Water. Shale from Field A, which is located in Malaysia Water, is selected to go through a series of x-ray diffraction, cation exchange capacity, capillary suction time test and linear-swell meter test to achieve the objective. X-Ray Diffraction (XRD) and Cation Exchange Capacity (CEC) Tests were carried out to determine the mineralogy and reactivity of that particular shale formation. Meanwhile, Capillary Suction Time (CST) and Linear-swell Meter (LSM) Tests were conducted to observe shale behavior upon being tested with different mud systems. This investigation will solely be based on the comparison of the outcome of test results where KCL PHPA and Salt Polymer Amine systems are investigated. At the end of the project, the Salt Polymer Amine system is proposed to be used in the drilling campaign for Field A and fulfill the objectives of the project.

TABLE OF CONTENTS

ABSTRACT	02
TABLE OF CONTENT	03
LIST OF FIGURES & TABLES	05
CHAPTER 1: INTRODUCTION	06
1.1. PROJECT BACKGROUND	06
1.2. PROBLEM STATEMENT	09
1.2.1. PROBLEM IDENTIFICATION	10
1.2.2. SIGNIFICANT OF PROJECT	10
1.3. OBJECTIVE	11
1.4. THE RELEVANCY OF PROJECT	11
1.5. THE FEASIBILITY OF PROJECT WITHIN SCOPE & TIME FRAME	12
1.6. SCOPE OF STUDY	13
CHAPTER 2: LITERATURE REVIEW	14
2.1.1. MALAYSIA WATER	14
2.2. FORMATION STABILITY	17
2.3. WATER BASED MUD SYSTEM	19
2.4. MEASUREMENT OF SWELLING STRESS	25
CHAPTER 3: PROPOSED METHODOLOGY	26
3.1. RESEARCH METHODOLOGY	26
3.2. LAB EXPERIMENT	26
3.2.1. MINERALOGY TEST	26
3.2.2. PERFORMANCE TEST	27
3.3. SELECTING SAMPLE	28
3.4. DESIGNING DRILLING FLUIDS- WATER BASED MUD	28
3.5. PROJECT ACTIVITY FLOW	29
3.6. KEY MILESTONE	30
3.7. GANTT CHART	31

CHAPTER 4: RESULT AND DISCUSSION	33
4.1 MINERALOGY TEST	33
4.1.1 LABORATORY TEST RESULT	33
4.1.1.1 FIELD 1	34
4.1.1.2 FIELD 2	35
4.2 PERFORMANCE TEST	44
4.2.1 CAPILLARY SUCTION TIME (CST) TEST	44
4.2.2 LINEAR-SWELL METER	51
CHAPTER 5: CONCLUSION	57
REFERENCE	58
APPENDICES	61

LIST OF FIGURES & TABLES

Figure 1: Malaysia's Basin	14
Figure 2: Malay Basin	15
Figure 3: Location of Sarawak and Sabah Basin	16
Figure 4: Project Activity Flow Chart	29
Figure 5: Key Milestone	30
Figure 6: Gantt Chart	31
Figure 7: Comparison of CEC Value and Clay Content from XRD Test	36
Figure 8: Sample 1A from Field A @ 120909 ft	37
Figure 9: Sample 1A (Core Sample) from Field A at 6182 ft	37
Figure 10: Salt Polymer Amine & KCl PHPA Performances in Different KCl Concentration Against Field A Core	45
Figure 11: Comparison CST tests result of Sample 2A from Field A cutting samples at different KCl concentration (% wt.) in artificial seawater as base fluid.	46
Figure 12: Comparison CST tests result of Sample 2A from Field A cutting samples at different KCl concentration (% wt.) in artificial seawater as base fluid with 3.0% v of Salt Polymer Amine.	48
Figure 13: Comparison of Drilling Mud Systems against Sample 2A from Field A core sample using Linear-Swell Meter (LSM) Test.	53
Figure 14: Figure 14: Shale Recovery AHR 190F @ 16 hr, %	54
Figure 15: Pellet Expansion in swell meter, %	54
Figure 17: Steps of Analysis of XRD Test.	61
Figure 18: Linear-Swell Meter Devices	62
Table 1: Summary of CEC Test (meq/100g), moisture content (%) and XRD analysis total minerals (wt%) for tested cutting samples Field A	34
Table 2: Summary of CEC Test (meq/100g), moisture content (%) and XRD analysis total minerals (wt%) for tested cutting samples Field B	35
Table 3: Summary of XRD and CEC Tests (meq/100g), moisture content (%) and XRD analysis total minerals (%wt) for Sample 2A at depth 6182 ft.	38
Table 4 : CST Tests Result of different KCl concentration (% wt.) in artificial sea water as base fluid.	47
Table 5: CST Tests Result of different KCl concentration (% wt.) in artificial sea water as base fluid with 3.0% v. of Salt Polymer Amine.	49
Table 6: Detail result of comparison of shale stability and pellet expansion of different drilling fluid system against Sample 1B from Field 1 core sample.	52

CHAPTER 1 INTRODUCTION

1.1 PROJECT BACKGROUND

Swelling can be defined as a type of damage in which formation permeability is reduced because of the alteration of clay equilibrium. Clay swelling occurs when water-base filtrates from drilling, completion, workover or stimulation fluids enter the formation. Clay swelling can be caused by ion exchange or changes in salinity. However, only clays that are directly contacted by the fluid moving in the rock will react; these include authogenic clays, some detrital clays on the pore boundaries and unprotected clay cement. The nature of the reaction depends on the structure of the clays and their chemical state at the moment of contact. The most common swelling clays are smectite and smectite mixtures that create an almost impermeable barrier for fluid flow when they are located in the larger pores of a reservoir rock. In some cases, brines such as potassium chloride, KCL is used in completion or workover operations to avoid clay swelling. Meanwhile, dispersion of shale is the act of breaking up large particles into smaller ones and distributing them throughout a liquid or gaseous medium. For example, in water-base drilling mud, dispersion is the act of degrading clay materials, starches, carboxymethylcellulose, biopolymer, synthetic polymers or oils into submicroscopic particles by applying mechanical energy, heat or chemical means. In oil-mud emulsion terminology, dispersion is the act of forming a fine-grained emulsion of an aqueous phase into oil¹.

¹ www.glossary.oilfield.slb.com

It is well known that one of the methods to prevent the swelling and dispersion of shale is by using oil-based mud. The inhibitive action of oil-based mud happens from the emulsification of brine in oil, which acts as a semi-permeable barrier that materially separates the water molecules from being in direct contact with the water-sensitive shale molecules. Water molecules may flow through this semi-permeable barrier when the water activity of the oil-based drilling fluid differs from that of the shale formation. To prevent water molecules from being osmotically drawn into shale formations, the water activity of the oil-based mud is usually adjusted to a level equal to or less than that of the shale. Oil-based mud offers superior shale stability, excellent lubricity, high rate of penetration (ROP) and less risk of stuck pipe. However, the application of water-based mud is traditionally based on concerns associated with the use of oil-based mud, such as environmental compliance, logistical problems in remote locations, gas solubility in fluids, and the cost associated with makeup of fluid and anticipated lost circulation risk. Over the time, environmental policies and concerns have increasingly restricted the use of oil-based mud worldwide. These increasing environmental demands have resulted in a keen interest in the development of highly inhibitive, high-performance water-based drilling fluid systems, which would have similar drilling advantages to oil-based mud².

Water-based drilling fluid or drilling mud has several components. One of them is a shale stabilizer. This component inhibits the absorption of water by the shale. Shale is made of several different types of material. When the clay components such as sodium montmorillonite absorb water, they swell. Swelling by one of the shale components but not the others weakens the entire shale structure and can cause large pieces of the shale to cave into the well bore. Thus, by preventing clay components from absorbing water, the entire shale formation is stabilized. Otherwise, numerous drilling problems, such as bit balling, stuck pipe, and dispersion of drilled cuttings, will be encountered while drilling the unstabilized formations.³

² Arvind Patel, Emanuel Stamatikas, James E. Friedheim and Eric Davis, M-IL.L.C.: Highly Inhibitive Water-Based Fluid System Provides Superior Chemical Stabilization of Reactive Shale Formations, 2001

³ Melbouci, Mohand & Sau, Arjun C., Water Based Drilling Fluids, Wilmington, DE, US July 22, 2004.

Since water-based mud have been developed remarkably in times, it is essential to perform tests in favor of analyzing the result of using several types of water-based mud on a sample of shale. Furthermore, how data from each method may be used to assess shale behavior and help selecting shale inhibitive water-based mud systems is briefly discussed. One observation is that methods that treat shale as a uniform bulk material without internal structure tend to be more quantitative while methods that treat shale as a non-isotropic material with internal structure tend to be more qualitative. The result will be used to compare which of them has high ability to minimize the problem and has high compatibility with the shale composition. Eventually, the study is aims to recommend which water-based mud system is the most effective in controlling the swelling and dispersion of shale.

1.2 PROBLEM STATEMENT

Although there are many known drilling mud compositions that can achieve requirements to inhibit the swelling and dispersion of shale, obtaining such a drilling mud in the field can be difficult. Choosing the right selection of water-based mud system will result in optimum production of well. Selecting the right type of drilling fluids can be tough due to the wide range of choices and diverse condition of the region of interest. One cannot afford to make mistake in order for a drilling operation to be success. Failure to do so will result in many problems such as bit balling, mud rings and tight hole. The stability of shale depends on the type of drilling fluids used. In this case, the significance type of drilling fluids in focus is water-based mud.

Shale can swell and disperse due to mechanical effects and chemical effects. The usage of water-based mud on shale can result in chemical effects where water will hydrate the clay minerals in shale. This can lead to swelling, softening and dispersion in softer types, or rock failure (fracturing) in the harder materials. If the shale is physically constrained so that it cannot swell, significant swelling pressures can develop. It is crucial to minimize the reaction with water (one of the way is by creating good inhibition) utilizing appropriate drilling fluids. For water-based mud, this is done using combination of mud additives such as salts and polymers. Salts, such as KCL, reduce clay swelling and dispersion, and polymers may encapsulate the shale to hold it together (for example PHPA) or have a chemical strengthening effect (such as glycols)⁴. The interaction between shale rock materials and drilling fluids is an important consideration when analyzing many drilling problems. In order to perform meaningful tests that may help in selecting drilling muds compositions that are less reactive with a particular shale interval, laboratory analysis of rock samples from interval of interest is useful⁹. With no data and information to compare, it is desirable to have one in order to propose fine criteria of water-based mud that required for to be used based on shale requirement.

⁴ <http://www.scribd.com/doc/34410470/Shale-Problems>

⁹ Mike Stephens, Sandra Gomez Nava, Marc Churan; Laboratory Methods to Assess Shale Reactivity With Drilling Fluids; 2009.

1.2.1 PROBLEM IDENTIFICATION

Drilling mud plays a major role in drilling operation. Choosing the right option will be beneficial and vital for a success of a project. This study aims to conduct tests to analyze the mineralogy of shale in Malaysia Water that would eventually determine the proper water-based mud system to be used. Furthermore, the study aims to propose selection matrix/design that works for water-based mud usage in this region. The problem to choose from the selection of water-based mud is crucial. The project tackles how PHPA in KCL PHPA mud system and amine in Salt Polymer Amine control the clay from swelling and disperse. The method to measure and observe the shale reaction is one of the identified problems to ensure that the accuracy and compatibility of data will be used to get most favorable findings.

1.2.2 SIGNIFICANT OF THE PROJECT

By performing this study will ultimately assisting the engineer in selecting the correct water-based mud system in Malaysia's Basin region, which can optimize the cost, time and safety in drilling operation. The result of study also significantly helps in term of research in future as reference for improvement. The usage of water-based mud will minimize the environmental impact of the drilling process in a highly important part of drilling operations that comply with environmental regulations that have become stricter throughout the world. Besides, selection the area of study in Malaysia Water is to conduct more tests in that particular region where our very own national oil company, PETRONAS has huge oil and gas fields to be produced.

1.3 OBJECTIVE

The objectives of this project are as follow:

- 1) To study feasibility of water-based mud effectiveness in controlling the swelling and dispersion of shale in Malaysia's Basin area.
- 2) To compare the ability of different types of water-based mud system to inhibit swelling and dispersion of shale. Ability by means the capability to minimize the shale problem and its ability to maintain the shale stability by using several options of water-based mud.
- 3) To propose the water-based mud that has high compatibility with shale in Malaysia Water area. High compatibility can be referred as high inhibiting performance and able to maintain shale stability.

1.4 THE RELEVANCY OF THE PROJECT

This study is an attempt to observe shale behavior upon the exposure with different type of water-based mud. The result would be useful for comparative measurement on the water-based mud potential on controlling the impact on shale in Malaysia's Basin region. This project also might be useful to a better understanding on reaction of shale upon tested with water-based mud in future.

1.5 FEASIBILITY OF THE PROJECT WITHIN THE SCOPE AND TIME FRAME

The timeline for this project is to be completed until April 2011. The approach that the author used is by starting with the collection of related materials such books, journals and technical papers specifically on water-based mud and shale studies. Research will be done from time to time to get a better understanding on the subject. The research will develop and focus on lab experiments, which consists of two tests which are Mineralogy Test and Performance Test. Based on the activities stated above, given seven months for the researches to be done as well as experiment activities and for the rest of five months for the finalization of the design, the author believes the project can be completed within time frame. Time management is crucial aspect that the author believes this study can be completed in time. Besides, consulting supervisor and engineers will help the author to speed up the research and finish in time.

1.6 SCOPE OF STUDY

The scope of study will develop around the literature review and lab experiments. Learning on the method for conducting the tests is essential, as the results are required to be used for comparison. Overall, the project scope can be divided into two phases whereby the first phase is the study of the background environment and theories related to the project. At this stage, research, understanding the fundamental of clay chemistry, drilling fluids, and gathering data and facts, which are vital to have a strong base of familiarization and preparing for the next stage. The method choose to analyze the shale behavior will be in the second phase of the study. The second phase would be focused on lab experiments where two stages of tests will be conducted which are Mineralogy Test and Performance Test. This is where the shale behavior is examined prior to being tested with various drilling fluids. It is crucial to decide which type of water-based mud are to be included in this study. The selected drilling mud systems to be studied are KCL PHPA and Salt Polymer Amine. The justification of selecting these two type of mud systems in the project is due to KCL PHPA is widely used in Malaysia Water operation and Salt Polymer Amine is the newly developed technology of water based system. The method to determine the result will be a comparative measurement on the ability of these water-based mud that can minimize the swelling and dispersion of shale. The justification of using these types of water-based systems is due to their criteria that meet the requirements on drilling operation in Malaysia.

CHAPTER 2

LITERATURE REVIEW / THEORY

2.1 MALAYSIA WATER



Figure 1 – Basins in Malaysia

Malaysia's continental shelf is made up of six major sedimentary basins. The favourable geological conditions affecting these basins provide ideal conditions for the creation of hydrocarbons - that is petroleum and natural gas. The six basins are grouped into three main regions: Peninsular Malaysia, Sabah and Sarawak. Within Malay Basin, which is located offshore east of Peninsular Malaysia, it is the most prolific oil and gas-producing basin in Malaysia, with more than 12,000 metres of sediments. To the south, the Penyu Basin covers an area of 5,000 square kilometres. Tjia (1994) have reported that The Malay Basin Province (Figure 1) is entirely offshore and is composed of the Malay Basin (primarily in the waters of Malaysia, with smaller portions in the waters of Thailand, Indonesia and Vietnam. This province lies from north of the Malaysian Peninsula to the south of Cambodia and Vietnam and straddles the Gulf of Thailand and the South China Sea. Water depth is less than 200m¹⁰.

¹⁰ Tjia, H. D., 1994, Inversion tectonics in the Malay Basin: evidence and timing of events: Geol. Soc. Malaysia, Bull. 36, p. 119-126.

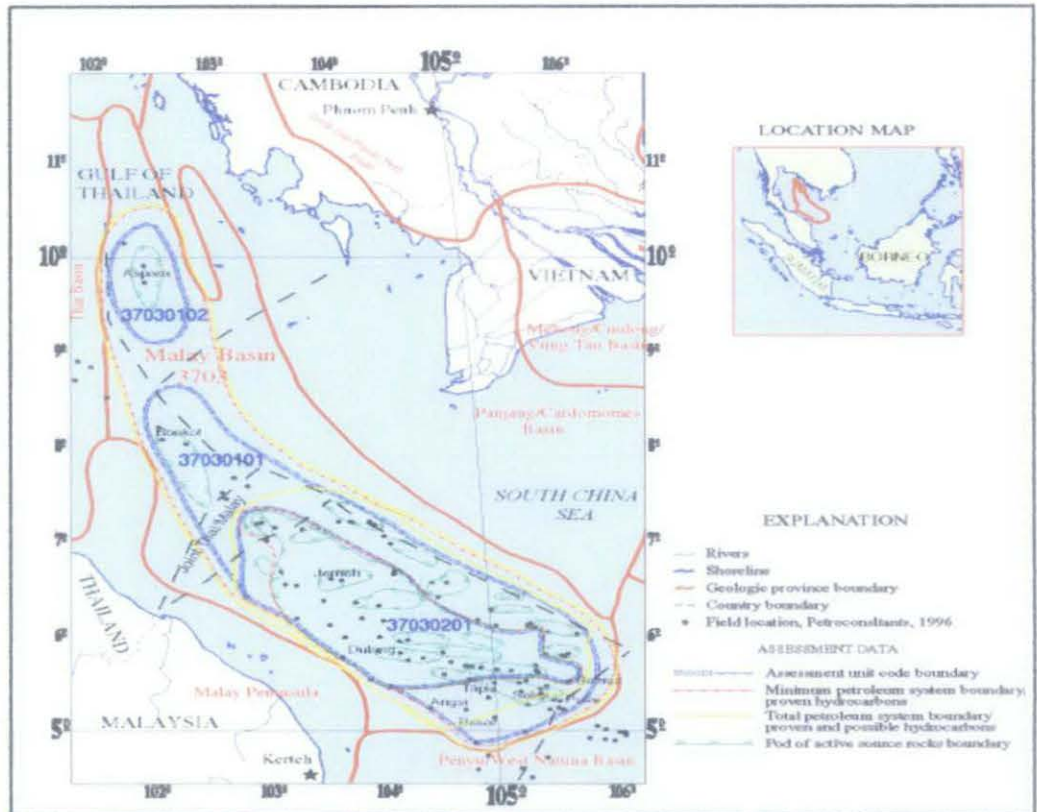


Figure 2 – Malay Basin

Breeden, D., and Shipman, J. (2004) reported that the shale formations in the Malaysian sectors of the Malay Basin are mostly non-reactive, dispersive claystones, which have very low rock strengths but may be tectonically stressed by current day active stress (location refer to Appendix I). For that reason, the causes of borehole instability can either be a fluid shale interaction or unbalanced stress against the weak formations.

The Sarawak Basin is a prolific oil and gas-producing basin. Seven geological provinces have been identified in the basin, namely the West Baram Delta, Balingian, Central Luconia, Tinjar, Tatau, West Luconia and North Luconia¹³. Exploration activities have been carried out in all seven provinces and commercial hydrocarbons

¹³ www.petronas.com.my/our_business/.../sedimentary_basins.aspx

have been found in three provinces: West Baram Delta, Balingian and Central Luconia. More exploration activities are being undertaken in the West and North Luconia provinces including the deepwater area to the north of these province¹⁴.

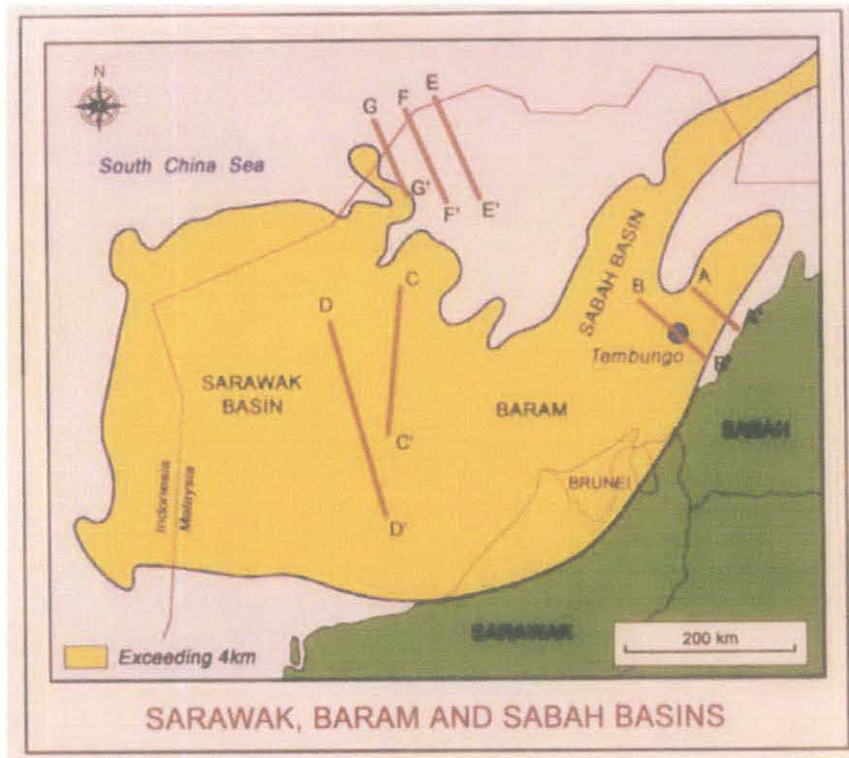


Figure 3: Location of Sarawak and Sabah Basin.

There are three major basins in Sabah namely the Sabah Basin, Northeast Sabah Basin and Southeast Sabah Basin. The Sabah Basin, which is located in Northwest Sabah, is mainly offshore while the other two basins cover some onshore areas in Northeast and Southeast Sabah. Significant recent oil discoveries in the deepwater areas have made Sabah a prolific deepwater region¹⁵.

¹⁴ http://www.ccop.or.th/epf/malaysia/malay_petroleum.html

¹⁵ Allagu Balaguru, 2001, Tectonic Evolution and Sedimentation of the Southern Sabah Basin, Malaysia

2.2 FORMATION STABILITY

Jansen (1997) has classified formation instability problems that have been known attributed to strong interaction between the shale and water-based mud into five basic problem areas that can be distinguished¹⁸:

- (1) Drilling through naturally fractured shale.
- (2) Drilling through a brittle shale and inducing fragmentation through drillstring vibrations.
- (3) Causing shale failure with too high a mud weight (tensile fracturing).
- (4) Causing shale failure in a compressive mode through insufficient mud-weight support.
- (5) Causing shale failure in a tensile mode through hydration stress.

One of the main shale instability mechanisms that occur with water-based drilling fluids is that the wellbore pressure breaks through into the shale pore space. This increases the near-wellbore pore pressure and reduces the true overbalance. This reduction of true overbalance, which acts like a support pressure for the hole, can cause shale failure and wellbore instability. The pressure penetration cannot be prevented with standard filtration additives, because shale pores are extremely small (~0.01 micron) and shale permeability is extremely low (typically ~0.01 microdarcy or less). In this project, the shale problems on focus based on the following interrelated factors: shale swelling and dispersion of shale cuttings.

P. Simpson and T.O. Walker (1997) have suggested that shales have been thought of as being impermeable, with destabilizing hydration caused only by reactions at the borehole surface. Studies in recent years have indicated that shales are not only permeable to water but, to a lesser extent, permeable to hydrated solutes. This suggests two fundamental driving forces controlling the transfer of water between drilling fluid and shale. One is the hydraulic differential between the Milling fluid pressure in the borehole and the pore pressure in the shale formation (AP). The second is an osmotic pressure customarily calculated using the ratio of water activity of the shale to that of the drilling fluid. Transfer of water into the shale should cause an increase in shale pore pressure near the borehole surface, weakening of the shale, and a reduction in borehole stability. Transfer of water in the opposite direction (from the shale to the drilling fluid) should improve borehole stability, although an ionic water-base drilling fluid might allow ion diffusion as a counter flow into the shale to cause some detrimental changes in the clay structure. Effective design of drilling fluids to maintain borehole stability in shale requires meaningful data on drilling fluid/shale interactions and the resulting effects on borehole stability¹⁶.

The problems of shale stability are related to many factors, one of them is drilling fluids properties. Many of the problems related with the use of water-based fluids in drilling and completion operations are caused by incompatibilities between the fluids and the shales. Such incompatibilities may result in washouts, increased drilling costs and shale sloughing during the drilling operation. Based on claims from previous study, this information contributes in this study in term of fundamental understanding on how wellbore stability works and factors that contributes to its instability. Engineers used to apply oil-based mud in drilling campaign but over time, water-based mud has replaced oil-based mud as the technique to prevent swelling and shale dispersion.

¹⁶ P. Simpson and T.O. Walker, O'Brien-Goins-Simpson and Assocs. Inc., and J.K. Aslakson,* Amoco Production Co. Studies Dispel Myths, Give Guidance on Formulation of Drilling Fluids for Shale Stability, Texas, March 1998.

2.3 WATER-BASED MUD SYSTEM

According to American Petroleum Institute (API), drilling fluid is defined as a circulating fluid used in rotary drilling to perform any or all of the various functions required in drilling operations¹⁷. The main purposes of the drilling fluid are to:

- (1) cool, clean and lubricate the drill bit
- (2) suspend the drill cuttings from the drilling operations
- (3) carry them to the surface and remove them from the bottom of the borehole
- (4) prevent loss of excessive amounts of fluids from flowing from the hole into surrounding formations by forming on the wall of hole a thin and impervious filter cake
- (5) serve as a fluid column to exert sufficient hydrostatic pressure to counterbalance the formation pressure (water, gas, oil or other earth fluid)
- (6) prevent caving or other intrusions into the drill hole. The three main categories of drilling fluids are water-based muds (which can be dispersed and non-dispersed), non-aqueous muds, usually called oil-based mud, and gaseous drilling fluid, in which a wide range of gases can be used.

¹⁷ J.L Lummus and J. J. Azar, in "Drilling Fluids Optimization: A Practical Field Approach"; Penn Well Publishing Company: Tulsa Okla., pp. 19-27, 1986

Historically, conventional water-based mud contains water as the continuous phase. Water may contain numerous dissolved substances such as salts, alkalis and surfactants, various insoluble substances, such as barite, clay and cuttings in suspension. According to Melbouci Mohand (2004), the composition of mud is selected for use usually dependable on dissolved substances in the most economically available makeup water or on the soluble or dispersive materials in the formations to be drilled. A number of mud systems are accepted and depicted in the literature such as inhibitive potassium muds, lime muds, gypsum muds, non-dispersed polymer muds, cationic muds³. Despite their ability to minimize environmental impact during drilling process, conventional WBM shows major deficiencies in performance relative to Oil Based Mud with regard to their relatively poor lubricity, shale inhibition and the characteristics of thermal stability. To overcome those deficiency, WBM is developed by adding specific additives into the compositions to improve WBM performance, though not as good as OBM performance. As a result, new invention of WBM also called inhibitive drilling mud was developed to compete against OBM. In addition, the development of new types of non-damaging drilling fluids, called "drill-in-fluid" has been designed to minimize the formation damage and to drill the pay-zone formations.

Appropriate selection of the drilling fluids to be used on a particular well site is a fundamental phase of any carefully planned drilling operation. Water is the most essential component of most drilling fluids. Many wells are begun to consider using the natural available in the area. As drilled solids become entrained in the water, a natural mud is formed. Some clays hydrate readily in water and greatly increase the viscosity of the mud. This increase in viscosity boosts the ability of the drilling fluid to carry the rock cuttings to the surface, particularly in the larger hole sizes where the annular velocity developed by the pump is relatively low. The clay particles also form a mudcake on the hole wall opposite permeable formations. This significantly reduces the amount of water loss to these zones and helps to prevent the hole wall from caving into

³ Melbouci; Mohand & Sau; Arjun C. , Water Based Drilling Fluids, Wilmington, DE, US July 22, 2004 .

hole. Because of these beneficial effects, clays that will hydrate readily with the available water often are added at the surface if they are not present in the formation drilled. A presence of hydrated clays in the water has undesirable as well as desirable effects on the rotary drilling process. A reduction in penetration rate and an increase in frictional pressure losses are observed when the clay content of the drilling fluid increases. When drilling relatively small holes in hard, competent formations, these undesirable effects may be more important than the beneficial effects. When this is the case, water alone can be used as the drilling fluid. Equipment capable of removing finely divided solids must be used continually to prevent the formation of a natural mud¹⁸.

When this drilling is predicted to encounter water-sensitive shale zones, the selection of the fluid becomes even more crucial. Despite oil-based mud has broad applicability, high performance and capacity for reuse, they also carry a higher unit cost, which are more difficult to mix, more likely to lost circulation and less environmentally acceptable than water-based mud. These disadvantages have led to the development of water-based drilling fluids that attempt to duplicate oil-based performance without the limitations. The starting point for these water-based fluid designs is typically control of clay/shale hydration and swelling. To maintain a stable borehole through such zones, an inhibitive drilling, mud will often be required. Besides low in cost, it is also environment friendly which cause this type of mud is more preferable than the other one.

¹⁸ Adam T. Bourgoyne Jr., Keith K. Millheim, Martin E. Chenevert, F.S Young Jr, "Applied Drilling Engineering Text Book", Texas,1991.

According to Clark RK (1976), KCL PHPA mud system is a class of muds that contain potassium ion (K^+) dissolved in the water phase that use partially-hydrolyzed polyacrylamide (PHPA) as a functional additive, either to control wellbore shales or to extend bentonite clay in a low-solids mud. Potassium chloride, KCL, is the most widely used potassium source. Potassium muds are the most widely accepted water mud system for drilling water-sensitive shales, especially hard, brittle shales. K^+ ions attach to clay surfaces and lend stability to shale exposed to drilling fluids by the bit. The ions also help hold the cuttings together, minimizing dispersion into finer particles. In other word, potassium ions are believed to be able to displace sodium ions in the shale, making the shale more stable.

As a shale-control mud, partially hydrolyzed polyacrylamide polymer or PHPA is believed to seal microfractures and coat shale surfaces with a film that retards dispersion and disintegration. KCL is used as a shale inhibitor in most PHPA mud designs⁵. PHPA has been included in a number of fluid formulations to provide shale encapsulation. It is believed that the PHPA formed a coating over the shale in the well bore wall to encapsulate the shale particles in the mud stream. This PHPA coating or encapsulation, as the case may be, has several effects. First, it prevents further hydration of the shale formation or cuttings by direct contact with the drilling mud. Second, it seals the fractures and pores in the surface of the shale formation and cuttings, closing the shale to capillary movement that would allow mud filtrate into the formation. When the PHPA coats the shale cuttings in the mud, it lubricates them and prevents them from sticking to one another. This prevents the cuttings from collecting or "balling" on the bit or the stabilizers. Preventing the cuttings from sticking to drill string components lessens the chances that the components will become stuck in the well bore and simultaneously makes it more likely that the cuttings themselves will be circulated out of the well bore with the mud so they can be removed at the surface. The PHPA coating also inhibits the dispersion of the shale cuttings by preventing them from breaking into small pieces,

⁵ Clark RK, Scheuerman RF, Raath H and van Laar H: "Polyacrylamide-Potassium Chloride Mud for Drilling Water Sensitive Shales," *Journal of Petroleum Technology* 28, no. 6 (June 1976): 719-726.

which are often difficult if not impossible to remove from the mud. Also, by lubricating the cuttings, the PHPA helps to prevent them from scouring the well bore wall as the mud flows through the bore. These were traditionally used in conjunction with KCL as effective shale encapsulating polymers. However, KCL/PHPA does not provide all of the benefits of emulsion muds.

One group of chemicals that can be added to drilling and completion fluids to increase their shale stabilizing properties is salts. Salts work by providing cations for swelling inhibition, increasing viscosity, and lowering water activity to promote osmotic back-flow. Salts known to have shale stabilizing properties are [1]: KCl, NaCl, CaCl₂, ZnCl₂, MgCl₂, MgBr₂, ZnBr₂, Na formate, K formate, Cs formate, Na acetate, K acetate, Cs acetate. Both the anion and cation of the monovalent formate brines provide all of the beneficial properties listed above (strong swelling inhibition from Cs⁺ and K⁺, high filtrate viscosity, and very low water activities). Thus there is nothing to achieve if non-formate salts to formate fluids is added. The addition of some of these salts can contribute to the deterioration of other fluid properties, such as reservoir compatibility and corrosion. The shale stabilizing properties of formate brines can however be optimized by adjusting the balance of monovalent cations in the fluid. When sodium formate brine is being used, it could be beneficial to provide some K⁺ ions in the fluid to improve its shale-swelling inhibition properties. This can be accomplished by adding some potassium formate. Similarly a sodium and potassium formate brine blend may have better shale stabilizing properties than diluted single-salt potassium formate brine due to its increased filtrate viscosity. Certain types of polymers (e.g. cations, amines, PHPA) are also believed to have shale-stabilizing properties. These are polymers with functional groups that adsorb onto clay surfaces at multiple sites, and are matched for providing cuttings stability.

Salt Polymer Amine delivered a higher level of performance than is currently attainable using conventional WBM. Researchers and engineers often focus on delivering a single, specific performance attribute when designing water-based alternatives to emulsion-based muds. For example, partially hydrolyzed polyacrylamide (PHPA) polymer is an excellent additive for cuttings encapsulation; however, PHPA does not provide all of the benefits of emulsion muds. The addition of rate of penetration (ROP) enhancer to a water-based mud may deliver drilling rates equivalent to those of an oil-based mud (OBM) or synthetic-based mud (SBM). However, it is unlikely that it alone will match the overall drilling performance of emulsion muds. Salt Polymer Amine is a reformulated polymer systems containing system-specific products to deliver shale stability, clay and cuttings inhibition, lubricity and high ROP, while minimizing bit balling/accretion and downhole torque problems. Salt Polymer Amine is use borehole stabilizing products to reduce pore pressure transmission similar to oil-based muds. Therefore, Salt Polymer Amine is suitable to use whenever environmental liabilities and associated waste management costs limit the application of OBM/SBM⁶.

⁶ Authors William Dye, Ken Daugereau, Nels Hansen, Michael Otto, Larry Shoults, Richard Leaper, Dennis Clapper, Tao Xiang, Baker Hughes Drilling Fluids Source, Title New Water-Based Mud Balances High-Performance Drilling and Environmental Compliance, SPE/IADC Drilling Conference, Amsterdam, Netherlands, 2005.

2.4 MEASUREMENT OF SWELLING STRESS

Shale that has a high tendency to absorb water can swell and disperse upon contact with water. Previous studies have found a reliable way to validate the osmotic theory is by direct measurements of true swelling stresses on shales contacted by various brines. Steiger (1993) has conducted tests for such purpose give an excellent database. Steiger used Pierre shale samples conditioned at different activities between 0.92 and 0.98 and contacted them with various fluids - Deionized water, NaCl, $MgCl_2$, CaCl₂ and glycerol based fluids- under the same initial pressures and stresses. Steigner measured the confining pressure increase required in each case to suppress the expansion of the specimens and therefore performed a direct measurement of the swelling stress in the specimens. For each test, it is therefore possible to compare the measured swelling stress. The coefficient of correlation is then extremely low -i.e. 0.395- revealing an almost statistically valid independence between the two variables. When on the other hand, the measured swelling stress is correlated to the shale activity alone, the coefficient of correlation becomes excellent -i.e. 0.938. From this set of experimental data, the swelling of shales seems to depend only on the activity of shales and not on that of the mud, which is in complete contradiction with the theory of osmosis¹⁹. This model of experiments can be used in this study to understand the swelling of shale measurements. In fact, this also can be used for explanation how the swelling occurred.

¹⁹ Steiger R. P.: "Advanced triaxial swelling tests on preserved shale cores", In. J. Rock Mech. Min. Sci. & Geomech. Abstr, 30, (1993)

CHAPTER 3

PROPOSED METHODOLOGY

3.1 RESEARCH METHODOLOGY

In order to achieve the objectives and relevant outcomes of the project, several researches had been done on numerous resources from books, technical papers and Internet. The first step is to collect information on shale behavior, how to control swelling and dispersion of shale's and other relevant topics.

3.2 LAB EXPERIMENTS

After the studies has completed, the next stage will be lab experiments, which consists of two different stages of tests: Mineralogy Test and Performance Test.

3.2.1 MINERALOGY TEST

Mineralogy Test consists of two type of test which is XRD Test and CEC Test. XRD Test also known as X-Ray Diffraction (XRD) Test is conducted to examine the mineralogy of shale. This is essential to understand the formation of shale because different mineralogy has different effect on behavior of shale. The mineralogy of clay has played an important role in determining the effects of using Water Based Mud on shale. The mineralogy analysis was carried out by combining data from X-ray Diffraction, which give the main minerals present in the rock and the chemical composition of each mineral in shale. Hence, it is important to know the mineralogy first before the next stage of test is run. In this test, x-rays will bombarded the finely ground sample, ensuing reflection. The reflection will be measured and the result will provides a semi quantitative

analysis of the mineral constituents of the sample ²⁰. Alternatively, the mineralogy of this particular area can be determined by data and sample from the previous studies which can be correlated to the samples of this research. Meanwhile, the CEC is the abbreviation for the cation exchange capacity of the soil. Positive charge is named as cation. The amount of these positively charged cations a soil can hold is portrayed as the CEC and is expressed in milliequivalents per 100 grams (meq/100g) of soil.

3.2.2 PERFORMANCE TEST

Performance Test is a test to observe the behaviour of shale. The test consists of two parts, Capillary Suction Time (CST) Test and Linear-swell Meter (LSM) Test. The CST device measures the time it takes for a given amount of free water from slurry to travel radially between two electrodes on thick and porous filter paper. The test measures the hydrating and dispersion properties of shales by simulating the chemical and shear forces exist during drilling. Meanwhile, LST device (image attach in Appendices section) is used to determine shale hydration or dehydration. This will be done by measuring the length over time of a reconstituted or intact shale core whether it increase or vice versa. This test can determine the recommended mud system for drilling through a specific shale formation ²⁰.

²⁰ Susan Abbott, et.al, Baroid Fluids Handbook, 1998

²⁰ Susan Abbott, et.al, Baroid Fluids Handbook, 1998

3.3 SELECTING SAMPLES

The sample is taken from Malaysia's Basin area namely from well in Malaysian Water. First, the shale samples were collected from PETRONAS Core Warehouse. The sample from various fields in basin around Malaysia Water region will be selected and the depth of the samples taken will be decided.

3.4 DESIGNING DRILLING FLUIDS – WATER BASED MUD

Water Based Mud can be prepared by specific formulae given by Petroleum Engineer from PCSB. In this study, the author has chosen to compare KCL PHPA and Salt Polymer Amine systems. In KCL PHPA system, partially-hydrolyzed polyacrylamide (PHPA) particles will act as preventer those serious wellbore problems because the PHPA will form bonding around the reactive shale. With this chemical mechanism, the formation solid cannot be dispersed into the water base mud. Meanwhile, in Salt Polymer Amine, which contains amine, is group of organic chemicals that are analogs of ammonia (NH_3), in which either one, two or three hydrogen atoms of ammonia are replaced by organic radicals. Amine salts capable of cation exchange, which stabilize the formation due to its ability as shale inhibitor.

3.5 PROJECT WORKFLOW

The project activities flow is shown in Figure 2.

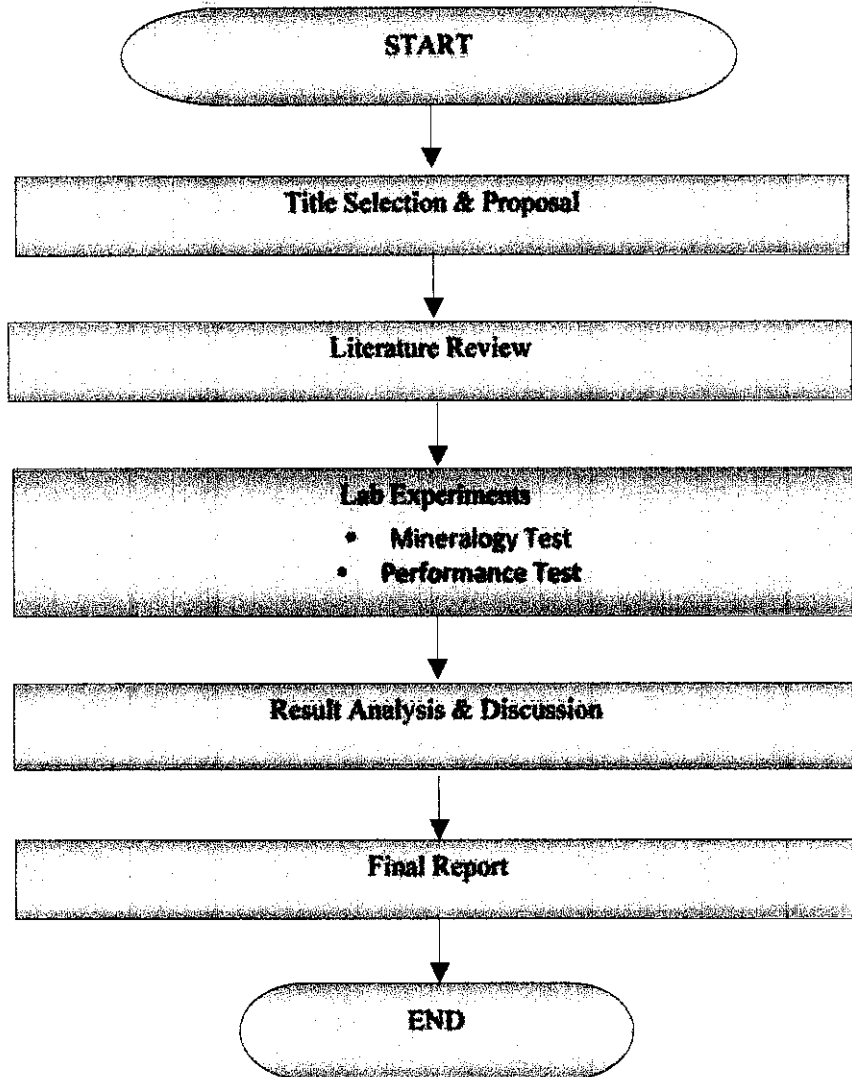


Figure 4: Project Activities Flow Chart

3.6 KEY MILESTONE

Figure 5 illustrates the key milestone for the whole activities conducted throughout FYP 2. The purpose of this semester project is to focus on experimental work and finalize the literature review of project before submitting final report. Figure 6 is the Gantt Chart for the whole FYP.

No	Action Item	Action By	Date	Note
1	Briefing & update on students progress	Coordinator / Students / Supervisors	8 February 2011	Week 3
2	Project work commences	Students		Week 1 -8
3.	Submission of Progress Report	Students	16 March 2011	Week 8
4.	PRE-EDX combined with seminar/ Poster Exhibition/ Submission of Final Report (CD Softcopy & Softbound)	Students / Supervisor / Internal Examiner / Coordinator	4 April 2011	Week 11
5.	EDX	Supervisors / FYP Committee	11 April 2011	Week 12
6.	Final Oral Presentation	Students / Supervisors	20 April 2011	Week 13
7.	Delivery of Final Report to External Examiner / Marking by External Examiner	FYP Committee / Coordinator	20-27 April 2011	Week 14
8.	Submission of hardbound copies	Students	04 May 2011	Week 16

3.7 GANTT CHART

No		Week/Month																																			
		Year 2010 (FYP 1)																Year 2011 (FYP 2)																			
		August				September				October				November				December				January				February				March				April			
		1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
1	Introduction	■																																			
2	Selection FYP Topic		■																																		
3	Preliminary			■	■																																
4	Prelim Report				■																																
5	Literature Review					■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
6	Progress Report																																				
7	Interim Report / Final Draft																																				
8	Presentation																																				
9	Planning for Sample																																				
10	Collect sample																																				

CHAPTER 4

RESULT & DISCUSSION

4.1 MINERALOGY TEST

4.1.1 LABORATORY TEST RESULT

XRD TEST & CEC TEST

In this project, the author studies the mineralogy of two different fields by conducting XRD and CEC Tests. Field A and Field B are located in Malaysia Water. Most of the drilling problems, which can be solved by the choice of drilling muds are due to the presence of clay minerals. By properly applied tests to evaluate the extent of the clay problem in shale, the appropriate choice can be made. A fluid which counteracts its tendency to damage a given shale formation is called an “inhibitive” fluid. Field A is to be selected to the next stage of the project. Sample from Field 1 was going through CST and LSM Tests.

4.1.1.1 Field A

The cutting sample is taken from Field A named as Sample 1A, received from previously drilled Field 1 well. To determine the mineral and clay composition proposes, we run X-Ray Diffraction (XRD) and Cation Exchange Capacity (CEC) Tests and the result were analyzed. For Sample 1A from Field 1, the XRD Test and CEC Test results are below.

Sample Depth, ft	CEC, meq/100g	Moisture content, wt %	Bulk Mineralogy (Whole Sample), wt%											Clay Mineralogy, wt%						
			Quartz	K-Feldspar	Plagioclase	Fe Dolomite	Pyrite	Calcite	Banite	Hailite	Sylvite	Siderite	Mica	Clay Mineral	Illite	Kaolinite	Chlorite	Smectite	Mixed-layer	
9510	9.5	13	79		3					1	1	1			15	10	3	2		
12090	11	26	53	1	3			1	1	2	7				32	21	5	5		1
12510	5.0	10	74	<1	2			2		1	8				14	9	2	2		

Table 1: Summary of CEC Test (meq/100g), moisture content (%) and XRD analysis total minerals (wt%) for tested cutting samples Field A.

From the result, at depth 12090 ft the illite contains is high with 21%, followed by kaolinite and chlorite both with 5%. At all depth, smectite does not exist. The mineral clay of mix layer of illite-smectite is 1% with percentage of illite as high as 90%. For CEC Test, Sample 1A, at depth 12090, the CEC value is highest at 11.0 meq/100g indicating at this particular depth, the sample shows higher total clay mineral compared to other samples.

4.1.1.2 Field B

Sample Depth, ft	CEC, meq/100g	Moisture content, wt %	Bulk Mineralogy (Whole Sample), wt%											Clay Mineralogy, wt%					
			Quartz	K-Feldspar	Plagioclase	Fe Dolomite	Pyrite	Calcite	Banite	Halite	Sylvite	Siderite	Mica	Clay Mineral	Illite	Kaolinite	Chlorite	Smectite	Mixed-layer
2217	7	4.8	47		3.8			3.5	2.5	1.0	2.0			40	21	11	8.1		
3414	6	13.2	41	3.9	4.7	2.4			3.7	1.3				43	19	11	8.7		4.4
5658	4	9.8	28		7.3		9.0	18.0	6.1		2.4			29	10	14	5.0		

Table 2: Summary of CEC Test (meq/100g), moisture content (%) and XRD analysis total minerals (%wt) for tested cutting samples Field B.

For sample from Field B, based on data in table above, the amount of total clay minerals varies widely in Field B, cutting samples, which is between the ranges of 29 wt to 43% wt. As shown by total clay minerals breakdown, Illite is the dominant clay minerals for sample depth at 2217 ft and 3414 ft. Smectite clay is absent in all tested samples but this does not preclude swelling of bulk shale following cation exchange by sodium ion.

The total clay minerals contents in the sample indicate the reactivity of the formation. Clay is natural occurring material composed primarily of fine-grained minerals. For this project, clay can be classified into four different groups, which are Illite, Smectite (Montmorillonite), Kaolinite and Chlorite. The presence of Smectite and Mix-Layer Illite-Smectite in the sample will affect the reactivity of the formation. The higher percentage of both minerals in clay, the more reactive the formation is.

From XRD and CEC analyses, we can conclude that Field A and B are non-reactive formations due to a very small percentage of both minerals contain in the sample. In sample from Field A, Smectite shows no existence and Mix-Layer Illite-Smectite is less than one percent. Due to its low percentage, we can conclude that Field A is not reactive.

Same pattern occurred in Field B where Smectite is not present and Mix-Layer Illite-Smectite is only 4.4 %wt. As both Fields are non-reactive shales, the author decided to select Sample 1A from Field A to be proceeded to the next stage.

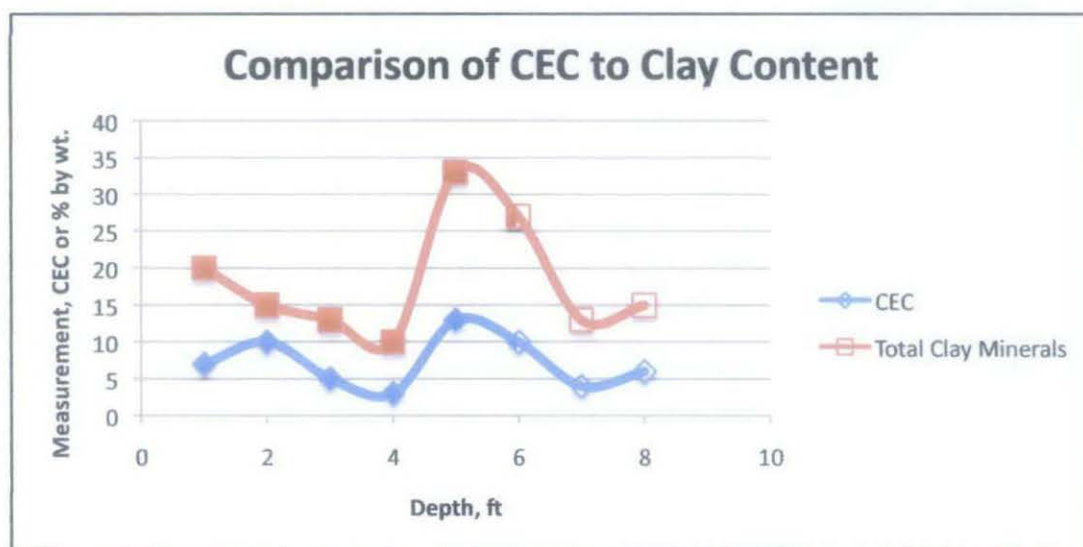


Figure 7: Comparison of CEC value and clay content from XRD Test for Field A.

By referring to XRD result data, the amount of total clay differs extensively and the range is between 9% to 32%. Consistently illite is the main clay in all of the samples. Meanwhile, in the entire of samples swelling smectite clay is not present but a very small amount ($\leq 1\%$) of mixed-layer illite-smectite was detected in half of the quantity of cutting samples analyzed by XRD.

The mixed layer clay contains $\geq 90\%$ illite layers and shows negligible expansion after being treated with ethylene glycol vapour. Samples at depth 12090 ft exhibit higher total clay mineral compared to the other samples. Proven by CEC test, the value of CEC is highest which is 11.0 meq/100g at depth 12090.



Figure 8: Sample 1A from Field A @ 12090 ft

Sample 1A at depth 12090 ft is selected as the cutting sample to be used for inhibition test. However, the sample is not suitable to perform the swelling and dispersion tests due to its physical properties, which is soft, malleable and has high moisture content. Co-supervisor, Mr. Solehuddin (PCSB) recommended to use core sample at depth 6182 ft named as Sample 2A from the exact well for this study.



Figure 9: Sample 2A (Core Sample) From Field A at 6182 ft

Field 1 (Sample A) Sample Depth, ft		6182
Moisture content, %		1.5
Average CEC, meq/100g		16
Bulk Mineralogy, % wt	Quartz (silicone dioxide)	52
	K-Feldspars	2
	Plagioclase (plagioclase feldspar)	7
	Fe Dolomite (Iron-Ca-Mg Carbonate)	<1
	Calcite (calcium carbonate)	1
	Barite (Barium sulfate)	2
	Halite (sodium chloride)	<1
	Sylvite (potassium chloride)	1
	Siderite (Iron (II) carbonate)	ND
	Total Clay Minerals	35
Clay Mineralogy, % wt (total Clay Minerals)	Illite	7
	Kaolinite	5
	Chlorite	14
	Smectite	0
	Mixed-Layer Clay Illite/Smectite	9
Mixed-Layer Clay	Smectite	25
Illite/Smectite, %	Illite	75
Free Energy of Hydration (KCAL/MOLE)		137
Equivalent Shale Activity Index (HI)		0.239

Table 3: Summary of XRD and CEC Tests (meq/100g), moisture content (%) and XRD analysis total minerals (%wt) for Sample 2A at depth 6182 ft.

Based on XRD and CEC Tests Data in Table 3, the quantity of total clay minerals is 35% wt. Swelling smectite clay is not exist in the sample. Meanwhile, mixed-layer illite/smectite shows it is made of 75% of illite layers. At the table, free energy of hydration is used to detect the expansion capacity of cutting samples. Here, it is calculated as much as 137 Kcal/mole. In general, free energy of hydration ranges between 100-200 Kcal/mole generally regarded to very low activity of clay in freshwater-based system with moderate expansion.

X-Ray Diffraction (XRD) is an instrument that is able to identify the minerals exists in shale samples. The sample is placed into the instrument and rotated through a series of angles while being illuminated with the X-ray beam. As the sample is rotated in the instrument, the crystalline structures of the individual minerals present diffract the X-ray beam. This results in an X-ray diffraction pattern that is unique for each mineral in the sample. The software identifies the minerals present and determines semi-quantitative amounts of each (the analysis steps is attached in Appendices Section).

X-ray diffraction can be carried out on cuttings, cavings, or cores. Preferably, samples should be washed to remove drilling fluids at the well site before being sent to the lab. Once at the lab, samples from water-based fluids may require some further washing to remove any residual drilling fluid. If the cuttings are not solid and rather soft and mushy, the sample is dried as received without washing. Conversely, samples from non-aqueous fluids are cleaned with organic solvents to remove hydrocarbons and dried. Once the samples are dry they are ground to a fine powder and placed in a sample holder for analyses. The time required for the instrument to complete the X-ray diffraction pattern is two minutes. The dry powder analyses, or bulk samples analyses, can be supplemented by a clay fraction analysis, which is achieved by separating the clay fraction from the bulk sample. A dispersion of the powder in water is prepared, the coarse non-clay fraction is allowed to settle, and the resulting clay suspension is filtered. While still wet, the filter cake of the clay fraction is transferred to a glass slide and air-dried. X-ray diffraction of the clay slide results in an enhanced analyses of the clays present. Treating the clay slide with glycol can further enhance the presence of smectite clays.

An X-ray diffraction analysis requires expensive instrumentation and a knowledgeable analyst trained in the operation of the instrument and interpretation of the data. Owing to limitations of obtaining pure standards and the crystalline nature of some samples, the X-ray diffraction data is only semi-quantitative for the mineralogical composition of shale. The non-reactive minerals seen typically in shale samples are quartz, feldspars, calcite, dolomite, pyrite, hematite, and siderite, while the reactive clay minerals seen are illite, kaolinite, chlorite, smectite and mixed layer clays. The smectite and mixed-layer clays are the most reactive and are prone to swelling. The higher the clay content, the more likely the shale will be reactive to swelling. Therefore, the X-ray diffraction data can be used in conjunction with other considerations when formulating a drilling fluid for specific sections of the well. When it is known that a section of the well will have high clays present, a more inhibitive drill fluid should be considered²¹.

The cation exchange capacity (CEC) of a soil refers to the amount of positively charged ions a soil can hold. When dissolved in water, the nutrients are either positively charged or negatively charged. Examples of positively charged ions (cations) include: calcium (Ca^{++}), magnesium (Mg^{++}), potassium (K^{+}), sodium (Na^{+}), and ammonium (NH_4^{+}). Soils have a slight negative charge due to the presence of clay particles and organic matter. The amount of these positively charged cations a soil can accommodate is described as the CEC and is expressed in milliequivalents per 100 grams (meq/100g) of soil. The larger this number, the more cations the soil can hold. A clay soil will have a larger CEC than a sandy soil. For example, the dominant clay type of kaolinite has very little capacity to hold cations. Clays are aluminosilicates in which some of the aluminum and silicon ions have been replaced by elements with different valence, or charge. For example, aluminum (Al^{+++}) may be replaced by iron (Fe^{++}) or magnesium (Mg^{++}), leading to a net negative charge. This charge attracts cations when the clay is immersed in an electrolyte such as salty water and causes an electrical double layer. In formation evaluation, it is the contribution of cation-exchange sites to the formation electrical properties that is important.

²¹ Mike Stephens, Sandra Gomez Nava, Marc Churap; Laboratory Methods to Assess Shale Reactivity With Drilling Fluids; 2009.

Numerous techniques are used to measure CEC in the laboratory, such as wet chemistry, multiple salinity and membrane potential. Wet chemistry methods, such as conductometric titration, usually involve destruction or alteration of the rock. Although quicker and simpler to perform, they are less representative of electrical properties in situ. The multiple salinity and membrane potential methods are more direct measurements of the effect of CEC on formation resistivity and spontaneous potential.

From the XRD and CEC tests, the results can be used to analyze the mineral contain in that particular area. The presence of Illites and Montmorillonites (Smectites) is directly related to bit balling. As the clays swell, they stick to the bit body, stabilizers and other tools. Kaolinite is the main constituent of kaolin where it is formed by rock weathering. It is white, grayish-white, or slightly colored. It is made up of tiny, thin, pseudohexagonal, flexible sheets of triclinic crystal with a diameter of 0.2–12 μm . It has a density of 2.1–2.6 g/cm^3 . The cation exchange capacity of Kaolinite is considerably less than that of Montmorillonite, in the order of 2–10 meq/100 g, depending on the particle size, but the rate of the exchange reaction is rapid, almost instantaneous²². Small molecular substances were adsorbs by Kaolinite such as lecithin, quinoline, paraquat, and diquat, but also proteins, polyacrylonitrile, bacteria, and viruses²³. The adsorbed material can be easily removed from the particles because adsorption is limited to the surface of the particles (planes, edges), unlike the case with montmorillonite, where the adsorbed molecules are also bound between the layers²⁴. Upon heating, kaolinite starts to lose water at approximately 400 °C, and the dehydration approaches completeness at approximately 525 °C²²The dehydration depends on the particle size and crystallinity.

²² Grim RE Clay mineralogy, 2nd ed. New York, McGraw-Hill, 596 pp., 1968

²³ Lipson SM & Stotzky G :Adsorption of reovirus to clay minerals: Effects of cation-exchange capacity, cation saturation, and surface area. Appl Environ Microbiol, 46: 673–682., 1983

²⁴ Weber JB (1970) Adsorption of s-triazines by montmorillonite as a function of pH and molecular structure. Soil Sci Soc Am Proc, 34: 401–404.

*Illite, together with chlorite, is the main component of common clay and shale. It is also an important impurity in limestone, which can affect the properties and thus the value of the stone for construction and other purposes*²⁵. Despite the extensive occurrence of illite in nature, large deposits of high purity are quite rare. Illite usually occurs as very small (0.1–2 μm), poorly defined flakes commonly grouped into irregular aggregates. Lath-shaped and ribbon-shaped illite particles up to 30 μm in length and 0.1–0.3 μm in width have also been described²⁷. But their existence is controversial. Velde (1985) stated unqualifiedly that these so-called filamentous illites are mixed-layer structures²⁶. Srodon & Eberl (1984), however, drawing on the same references plus their own data, concluded that these filaments in some cases are mixed-layer structures but in other cases are composed only of illite, and they further supported their view with scanning electron microscopic photographs of lath-shaped crystals of what they identified as illite.

The special properties of illite are derived from its molecular structure. The balancing cation is mainly or entirely potassium, and charge deficiency from substitutions is at least twice that of smectites (i.e., 1.3–1.5 per unit cell layer) and is mainly in the silica sheet and close to the surface of the unit layer rather than in the octahedral layer as in smectites. These differences from smectites produce a structure in which interlayer balancing cations are not easily exchanged and the unit layers are relatively fixed in position and do not permit polar ions such as water to readily enter between them and produce expansion. Illite reacts with both inorganic and organic ions and has a cation exchange capacity of 10–40 meq/100 g, a value intermediate between those of montmorillonite and kaolinite²⁷.

²⁵ Carr DD, Rooney LF, & Freas RC (1994) Limestone and dolomite. In: Carr DD ed. Industrial minerals and rocks. Littleton, Colorado, Society for Mining, Metallurgy, and Exploration, pp 606–629.

²⁶ Velde B ed. (1995) Composition and mineralogy of clay minerals. In: Origin and mineralogy of clays. Berlin, Springer-Verlag, pp 27–33 (Clays and the Environment, Vol 1).

²⁷ Grim RE Clay mineralogy, 2nd ed. New York, McGraw-Hill, 596 pp., 1968

Wilken & Wirth (1986) stated that fithian illite from Illinois, USA, adsorbed hexachlorobenzene suspended in distilled water with a sorption partition coefficient of 2200–2600 and that more than half of this adsorbed hexachlorobenzene could be desorbed by further contact with distilled water. However, the fithian illite used in the experiment had a composition of 30% quartz, 19% feldspar, 11% kaolinite, 1% organic carbon, and 40% illite, making it impossible to know how much of the measured adsorption could be ascribed to illite²⁸. The dehydration and other changes in illite with heating have been studied by several investigators, with inconsistent results. Some of the inconsistency in findings may result from differences in the period at which samples were held at a given temperature, since dehydration is a function of both time and temperature²⁹. It is also probable that small differences in particle size, crystal structure, and molecular composition among samples of what were ostensibly the same minerals contributed to the inconsistencies. Dehydration takes place either smoothly or in steps between about 100 and 800 or 850 °C for both biotite and muscovite illites. Loss of structure by the various illite minerals occurs between about 850 and 1000 °C. Montmorillonite clay minerals occur as minute particles, which, under electron microscopy, appear as aggregates of irregular or hexagonal flakes or, less commonly, of thin laths²⁷. Differences in substitution affect and in some cases control morphology.

²⁸ Wilken RD & Wirth H (1986) The adsorption of hexachlorobenzene on naturally occurring adsorbents in water. IARC Sci Publ, 77: 75–81.

²⁹ Roy R (1949) Decomposition and resynthesis of the micas. *J Am Ceram Soc*, 32: 202–210.

4.2 PERFORMANCE TEST

4.2.1 CAPILLARY SUCTION TIME (CST) TEST & LINEAR-SWELLMETER (LSM) TEST

Cutting samples from Field A, Sample 2A is chosen to be proceed for the second stage. To determine shale behavior upon contact with water-based mud systems, Capillary Suction Time (CST) Test and Linear-swell Meter (LSM) Test have to be performed. CST Test, which involves measuring the time of a filtrate volume to move over a specific distance due to the capillary suction pressure of dry filter paper. This test gives information about the ease of separating water portion from the solid portion of clay.

The measurement of time interval is dependable to the amount of free water in the permeability of the filter cake deposited as well as the amount of free water in fluid slurry. Hypothetically, the less dispersed the fluid slurry is, the more permeable the filter cake. Thus, the shorter the time interval is. Mineral that is sensitive to water in formation will adsorb free water and disperse. Consequently, impermeable filter cake is formed and capillary suction time will be longer.

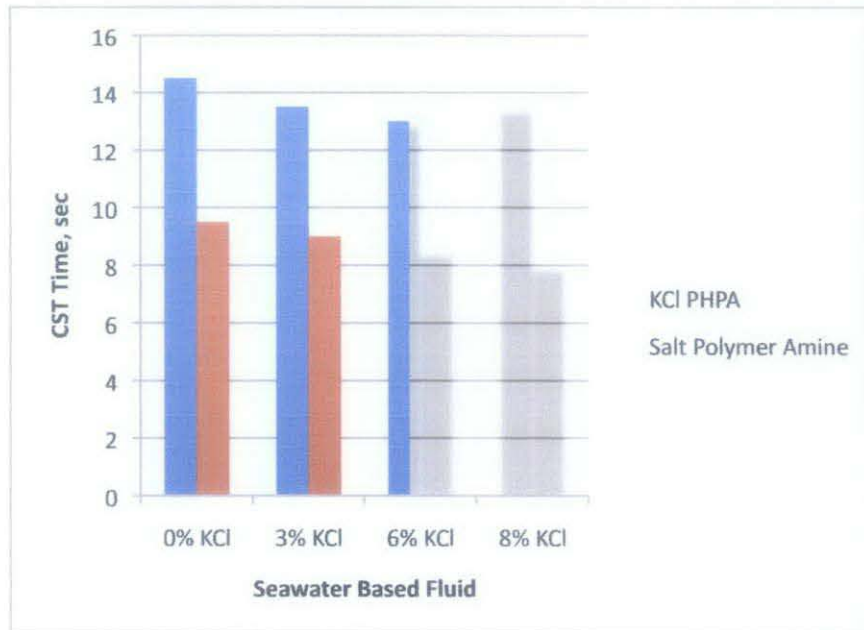


Figure 10: Salt Polymer Amine & KCL PHPA Performances in Different KCL Concentration Against Field A Core Samples.

To determine the Salt Polymer Amine performance and optimum KCL concentration for Salt Polymer Amine systems against Sample 2A from Field A, several tests were performed. The fluid system tested were 0 to 8% wt. of KCL concentration in artificial seawater and another system is with additional of 3.0% of Salt Polymer Amine to the tested fluid. From the above data, KCL concentration with additional Salt Polymer Amine has lower CST value compared to KCL without Salt Amine Polymer.

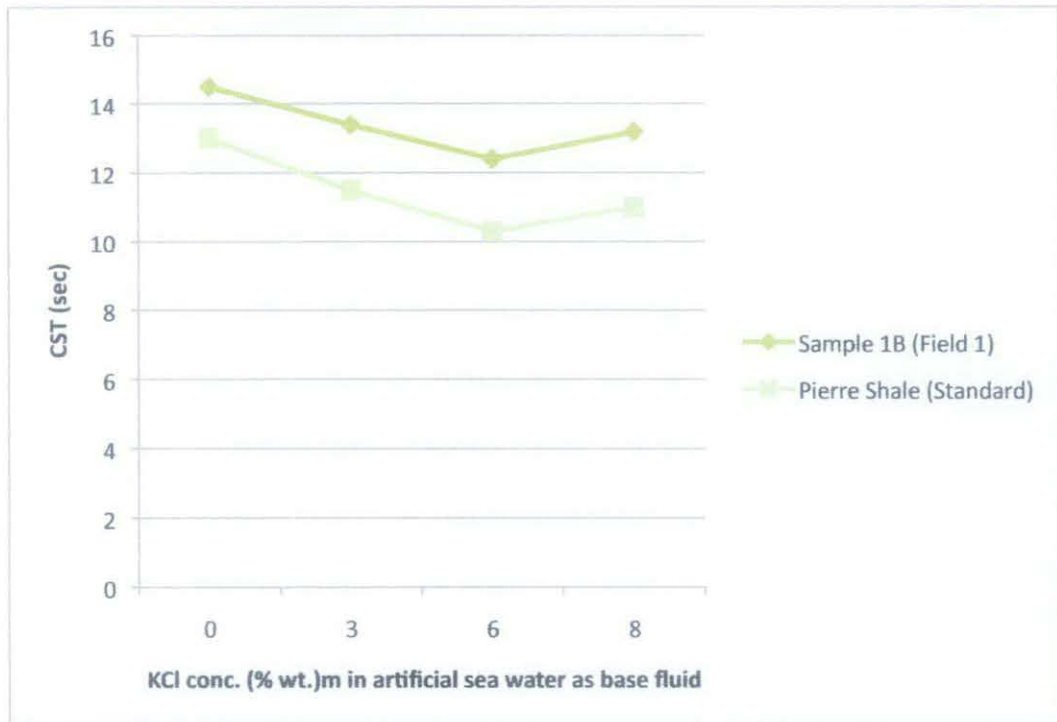


Figure 11: Comparison CST tests result of Sample 2A from Field A cutting samples at different KCl concentration (% wt.) in artificial seawater as base fluid.

Sample ID	Base Fluid	Seawater			Seawater			Seawater			Seawater		
	KCl conc. % wt.	0			3			6			8		
	Test	1	2	3	1	2	3	1	2	3	1	2	3
Sample 1B from Field 1	CST Value, sec	14.5	14.9	14.2	13.2	13.9	13.1	12.2	12.3	12.6	12.2	13.3	13.0
	Average CST value, sec	14.5			13.4			12.4			13.2		
	CST variation changes, %				-7.8			-14.9			-9.4		
Pierre Shale (Standard)	CST Value, sec	12.8	13.0	13.3	11.1	11.6	11.8	10.4	10.1	10.3	11.0	11.2	10.9
	Average CST value, sec	13.0			11.5			10.3			11.0		
	CST variation changes, %				-11.8			-21.2			-15.3		

Table 4: CST Tests Result of different KCl concentration (% wt.) in artificial sea water as base fluid.

The laboratory result of CST test shows that without addition of Salt Polymer Amine, the fluid with 6.% wt. of KCl in 6182 ft core sample delivers maximum inhibiting effects by giving 15% decrement of CST value compared to base fluid with 0% KCl concentration. However, CST value tends to increase at 8.0% wt. of KCl with both tested samples.

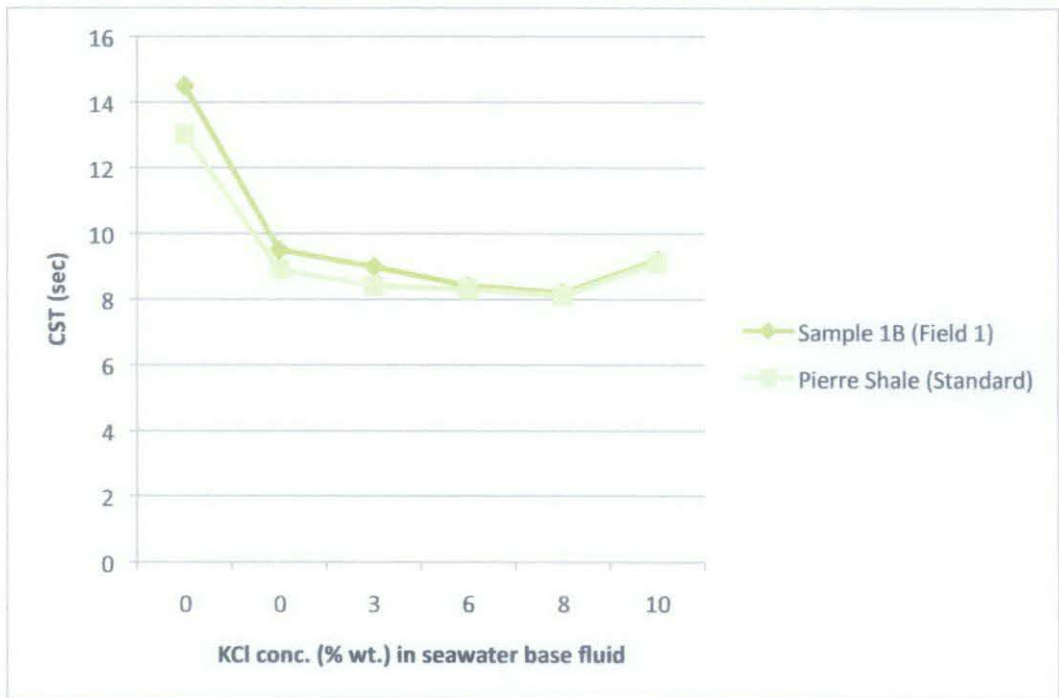


Figure 12: Comparison CST tests result of Sample 2A from Field A cutting samples at different KCl concentration (% wt.) in artificial seawater as base fluid with 3.0% v of Salt Polymer Amine.

Sample ID	Base Fluid	Seawater			Seawater			Seawater			Seawater			Seawater					
	KCl conc. % wt.	0			0			3			6			8			10		
	SPA conc. % v.	0			3			3			3			3			3		
	Test	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
Sample 1B from Field 1	CST Value, sec	14.5	14.9	14.2	9.3	9.8	9.4	8.8	9.1	9.0	8.4	8.8	8.1	8.1	8.4	8.2	9.3	9.1	9.3
	Average CST value,	14.5			9.5			9.0			8.4			8.2			9.2		
	CST variation				-34.6			-38.3			-42.0			-43.3			-36.5		
Piersi Shale (Standard)	CST Value, sec	12.8	13.0	13.3	8.9	8.8	9.1	8.4	8.1	8.7	8.7	7.9	8.2	8.1	8.3	8.0	9.0	8.9	9.3
	Average CST value,	13.0			8.9			8.4			8.3			8.1			9.1		
	CST variation				-31.5			-35.5			-36.6			-37.6			-30.4		

Table 5: CST Tests Result of different KCl concentration (% wt.) in artificial sea water as base fluid with 3.0% v. of Salt Polymer Amine.

After the addition of 3.0% v. of Salt Polymer to the base fluid containing different concentration of KCl, it is observed that fluid with 8.0% wt. of KCl gives the maximum inhibiting effect with 43% of reduction of CST value compared to the fluid without addition of Salt Polymer Amine. However, it is observed that CST value tends to increase at 10% wt. of KCl with both tested samples.

Capillary Suction Time (CST) Test has been adapted to measure the capillary suction time of clay or shale slurries. Basically, a small amount of shale is mixed with water, brine, or mud filtrate in a small commercial blender cup. The CST requires 3 g of dry cuttings, cavings, or core material per test. CST result are graphed to show the CST value (time) against test fluid type and it is depend on solid type and slurry content, degree of mixing, pH salinity, deflocculant or dispersant type and concentration, and polymer type and concentration. The CST value used as an indicator of cake permeability. For highly dispersed particles, the result would be low cake permeability with high CST values. Meanwhile, flocculated particles will gives the other way around. The result shows the inhibitive effects of various salts and their concentration on the dispersion of shale.

Typically, several tests are run at different salt concentrations, and it is common to run repeat tests with the output comprising of numerical results in seconds. In many cases, a “flocculation” concentration of salt or KCl that dramatically reduces CST can be determined. If the salt concentration in the fluid is lower than the flocculation concentration, particles of shale will disperse into the fluid. Reactive shale with high smectite clay content usually has a high CST value less reactive shale lacking smectite clay tends to have a significantly lower CST value. In addition, capillary suction time can be used to evaluate the effect of salinity on shale dispersion tendencies for specific shale formations².

² Arvind Patel, Emanuel Stamatakis, James E. Friedheim and Eric Davis, M-I L.L.C. Highly Inhibitive Water-Based Fluid System Provides Superior Chemical Stabilization of Reactive Shale Formations, 2001

4.2.2 LINEAR-SWELL METER (LSM) TEST

Investigating the swelling characteristics of shale formations is vital in selecting a proper drilling fluid to give maximum inhibition and wellbore stability. While drilling a well, a shale formation will immediately begin to swell if the drilling fluid is not completely compatible with the formation. This swelling can cause many problems, such as bit balling, pipe drag, hole sloughing and other related problems. Hence, selecting the proper drilling fluid prior to, or during the drilling operation, can be very beneficial in achieving a stable wellbore.

Several controls were established for this project. Fresh water bentonite polymer mud system (Control 1) is used as a projection of non-inhibitive system. Three additional different systems were added and used as a direct comparison on Optimized Salt Polymer Amine system (Control 2). Meanwhile, synthetic-based mud system is used as a projection of a very inhibitive system (Control 3). Below is detail of base fluid for each system tested using linear-swell meter.

- Fluid 1: Synthetic-based mud – Base fluid is Saraline 185SV with 25% wt. CaCl_2
- Fluid 2: Optimized Salt Polymer Amine – Base fluid is SW + 6% KCl + 3% v. Salt Polymer Amine + 3% Chemical A + 3 lb/bbl Chemical B + 3% v. Chemical C + 3% v Chemical D.
- Fluid 3: Base Fluid is SW+3% wt. KCl + 3% wt. KCl + 2% Chemical A + 2 lb/bbl Chemical B + 3% v. Chemical C + 2% v Chemical D.
- Fluid 4: Base Fluid is SW + 8% wt. KCl + 2 lb/bbl Chemical B + 3% v. Chemical D.
- Fluid 5: Base Fluid is SW + 6% wt. KCl + 1 lb/bbl Chemical B + 3% v. Chemical D.
- Fluid 6: Bentonite Polymer System – Base Fluid is Fresh Water

Note: Chemical A, Chemical B, Chemical C and Chemical D are products of Scomi Oiltools

Tested Fluid	Shale Recovery AHR 190F @ 16 hr, %	Pallet Expansion in swell meter, %
Fluid 1: Synthetic-based mud – Base fluid is Saraline 185SV with 25% wt. CaCl ₂	98.9	0.4
Fluid 2: Optimized Salt Polymer Amine (HPWBM) – Base fluid is SW + 6% KCl + 3% v. Salt Polymer Amine + 3% Chemical A + 3 lb/bbl Chemical B + 3% v. Chemical C + 3% v Chemical D.	97.0	5.3
Fluid 3: Base Fluid is SW+3% wt. KCl + 3% wt. KCl + 2% Chemical A + 2 lb/bbl Chemical B + 3% v. Chemical C + 2% v Chemical D.	94.3	7.6
Fluid 4 : Base Fluid is SW + 8% wt. KCl + 2 lb/bbl Chemical B + 3% v. Chemical D.	93.0	8.4
Fluid 5: Base Fluid is SW + 6% wt. KCl + 1 lb/bbl Chemical B + 3% v. Chemical D.	76.0	8.1
Fluid 6: Bentonite Polymer System – Base Fluid is Fresh Water	1.6	15.0

Table 6: Detail result of comparison of shale stability and pellet expansion of different drilling fluid system against Sample 1B from Field 1 core sample.

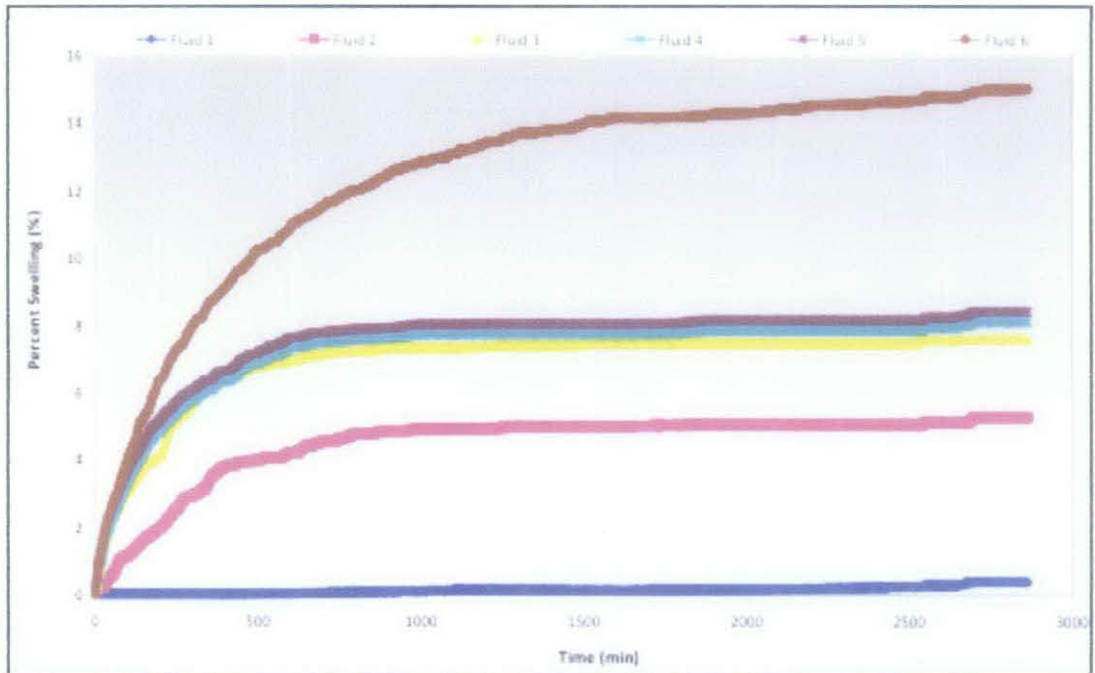


Figure 13: Comparison of Drilling Mud Systems against Sample 2A from Field A core sample using Linear-Swell Meter (LSM) Test. (picture courtesy of Scomi Oiltools)

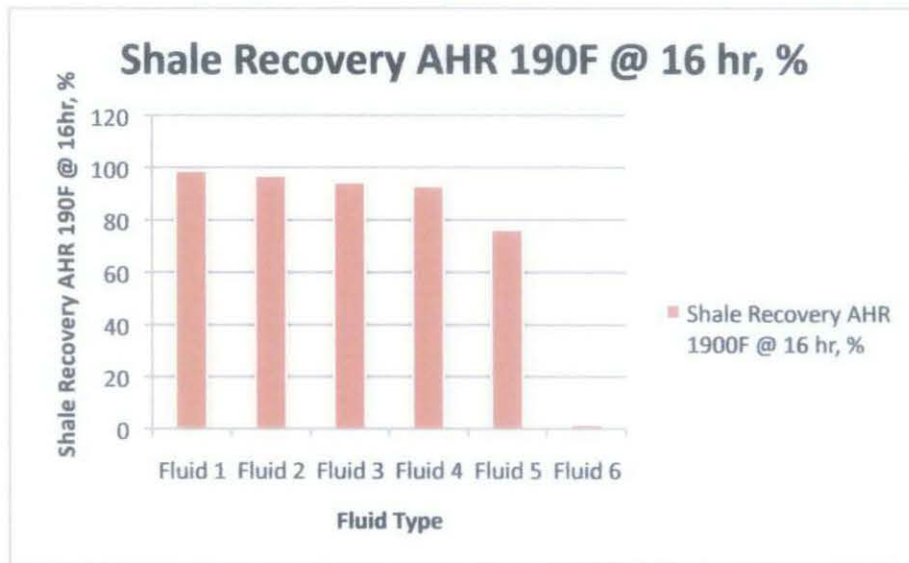


Figure 14: Shale Recovery AHR 190F @ 16 hr, %

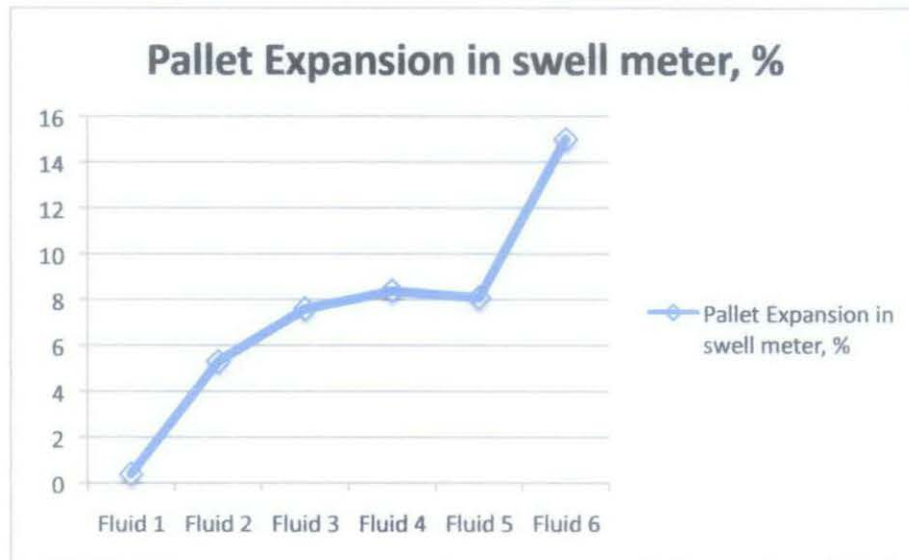


Figure 15: Pallet Expansion in swell meter, %

Observing the data above, it is concluded that Optimized Salt Polymer Amine system has the ability to imitate synthetic-based mud qualities followed by Fluid 3, Fluid 4, Fluid 4 and Fluid 6. Based on the above finding, the tested systems against Sample 1B from Field 1 has demonstrates as per below:

- a. Provides shale recovery with 97% of cutting samples retains on 2.36mm and 600 μ after hot rolled at 190⁰F at 16 hours.
- b. Gives maximum shale among WBM system with 94% of cutting samples retain on 2.36mm and 600 μ after hot rolled at 190⁰F at 16 hours.

The swelling test is conducted using the linear swelling tester. The device measures free swelling of a reconstituted shale pellet after the shale has been in contact with a drilling or completion fluid. The amount of swelling the shale undergoes after it is in contact with the fluid is a measure of the reactivity of the shale to the fluid. The device consists of a fluid reservoir, a shale chamber, a linear variable differential transformer (LVDT), A/D converter, and computer. The fluid reservoir holds the fluid until the test is ready to start. The shale pellet, which is prepared by compressing dry ground shale under 25,000 psi, is placed in the shale chamber that confines the pellet between a pair of screens and confines swelling to the vertical direction. The fluid is released from the reservoir and fills the shale chamber, thus coming into contact with the shale as the test begins. The swelling of the shale causes the LVDT sensor to rise, altering the inductance of the transformer and generating a voltage change that is sensed by the A/D converter. The A/D converter status is monitored by a computer at short intervals and the results, in terms of percent volume expansion of the shale, are recorded for the duration of the test. This test is a good indication of the reactivity of the shale sample to the fluids being tested.

For comparison, a shale pellet is exposed to water in order to determine the worst-case scenario. The more swelling observed with water, the higher the content of swelling and highly water-sensitive clays (smectite and mixed-layer clays). This test can be performed on cuttings, cavings, sidewall core, and full-diameter core, providing the amount of sample is sufficient to prepare one pellet for each fluid to be tested. It is important to note that the preparation of the sample implies disintegration and reconstitution of the sample into a pellet. Formation samples with massive structures and homogeneous composition are most suitable for this test. The results of the test are associated mainly with a chemical interaction and some physical effects, such as fracturing, dispersion and cracking, are not detected due to the elimination of the natural structure of the rock. Concentration in the fluid is lower than the flocculation concentration; particles of shale will disperse into the fluid. Reactive shale with high smectite clay content usually has a high CST value less reactive shale lacking smectite clay tends to have a significantly lower CST value. In addition, capillary suction time can be used to evaluate the effect of salinity on shale dispersion tendencies for specific shale formations².

² Arvind Patel, Emanuel Stamatakis, James E. Friedheim and Eric Davis, M-I L.L.C. Highly Inhibitive Water-Based Fluid System Provides Superior Chemical Stabilization of Reactive Shale Formations, 2001

CHAPTER 5

CONCLUSION

In summary, this research builds the case that reasonable, correct diagnosis and other reliable efforts accompany technology to achieve ideal operational performance. Rapid increase in using Water Based Mud for environmental concern has lead to the development in drilling fluids technology and knowledge. Based on these tests, we can conclude that Salt Polymer Amine mud system has a better performance in term of shale inhibition, shale stability or recovery compared to KCl PHPA system. The performance of optimized mud system is proved to gives substantial impact based on testes conducted. Therefore, Salt Polymer Amine system is recommended in Field A Drilling Campaign in order to control the swelling and dispersion of shale. The suggestion is for improvement in for any drilling campaign in one of many fields in Malaysia Water. As for conclusion, this project has meets its objectives.

REFERENCE

1. www.glossary.oilfield.slb.com
2. Arvind Patel, Emanuel Stamatakis, James E. Friedheim and Eric Davis, M-IL.L.C :Highly Inhibitive Water-Based Fluid System Provides Superior Chemical Stabilization of Reactive Shale Formations, 2001
3. Melbouci; Mohand & Sau; Arjun C., Water Based Drilling Fluids, Wilmington, DE, US July 22, 2004 .
4. Clark RK, Scheuerman RF, Raath H and van Laar H: "Polyacrylamide-Potassium Chloride Mud for Drilling Water Sensitive Shales," Journal of Petroleum Technology 28, no. 6 (June 1976): 719-726.
5. Steven Devereux: "Practical Well Planning and Drilling Manual", Tulsa, Oklahoma, USA, 1998.
6. Guichard, Bertrand (Villemecresnes, FR), Wood, Barry (Hornchurch, GB), Vongphouthone, Patrick (Sceaux, FR) : Fluid loss reducer for high temperature high pressure water based-mud, 2008.
7. Authors William Dye, Ken Daugereau, Nels Hansen, Michael Otto, Larry Shoults, Richard Leaper, Dennis Clapper, Tao Xiang, Baker Hughes Drilling Fluids Source, Title New Water-Based Mud Balances High-Performance Drilling and Environmental Compliance, SPE/IADC Drilling Conference, Amsterdam, Netherlands, 2005.
8. <http://www.scribd.com/doc/34410470/Shale-Problems>
9. Mike Stephens, Sandra Gomez Nava, Marc Churan; Laboratory Methods to Assess Shale Reactivity With Drilling Fluids; 2009.

10. Tjia, H. D., 1994, Inversion tectonics in the Malay Basin:evidence and timing of events: Geol. Soc. Malaysia, Bull. 36, p. 119-126.
11. Robinson, K., 1985, Assessment of undiscovered conventionally recoverable petroleum resources in Tertiary sedimentary basins of Malaysia and Brunei: Geol. Soc. Malaysia, Bull. 18, p. 119-131
12. Hutchison, C. S., South-East Asian Oil, Gas, Coal and Mineral Deposits: Oxford Monographs on Geology and Geophysics, 36: Clarendon Press, Oxford, 1996.
13. www.petronas.com.my/our_business/.../sedimentary_basins.aspx
14. http://www.ccop.or.th/epf/malaysia/malay_petroleum.html
15. Allagu Balaguru, 2001, Tectonic Evolution and Sedimentation of the Southern Sabah Basin, Malaysia
16. P. Simpson and T.O, Walker, OBrien-Goins-Simpson and Assocs. Inc., and J.K. Aslakson,* Amoco Production Co. Studies Dispel Myths, Give Guidance on Formulation of Drilling Fluids for Shale Stability, Texas, March 1998.
17. J.L Lummus and J. J. Azar, in "DrillingFluids Optimization: A Practical Field Approach"; Penn Well Publishing Company: Tulsa Okla., pp. 19-27, 1986
18. Adam T. Bourgoyne Jr., Keith K. Millheim, Martin E. Chenevert, F.S Young Jr, "Applied Drilling Engineering Text Book", Texas, 1991.
19. Stejger R. P.: "Advanced triaxial swelling tests on preserved shale cores", In. J. Rock Mech. Min. Sci. & Geomech. Abstr, 30, (1993)
20. Susan Abbott, et.al, Baroid Fluids Handbook, 1998

21. Mike Stephens, Sandra Gomez Nava, Marc Churan; Laboratory Methods to Assess Shale Reactivity With Drilling Fluids; 2009.
22. Grim RE Clay mineralogy, 2nd ed. New York, McGraw-Hill, 596 pp.,1968
23. Lipson SM & Stotzky G :Adsorption of reovirus to clay minerals: Effects of cation-exchange capacity, cation saturation, and surface area. Appl Environ Microbiol, 46: 673–682., 1983
24. Weber JB (1970) Adsorption of s-triazines by montmorillonite as a function of pH and molecular structure. Soil Sci Soc Am Proc, 34: 401–404.
25. Carr DD, Rooney LF, & Freas RC (1994) Limestone and dolomite. In: Carr DD ed. Industrial minerals and rocks. Littleton, Colorado, Society for Mining, Metallurgy, and Exploration, pp 606–629.
26. Velde B ed. (1995) Composition and mineralogy of clay minerals. In: Origin and mineralogy of clays. Berlin, Springer-Verlag, pp 27–33 (Clays and the Environment, Vol 1).
27. Grim RE Clay mineralogy, 2nd ed. New York, McGraw-Hill, 596 pp.,1968
28. Wilken RD & Wirth H (1986) The adsorption of hexachlorobenzene on naturally occurring adsorbents in water. IARC Sci Publ, 77: 75–81.
29. Roy R (1949) Decomposition and resynthesis of the micas. J Am Ceram Soc, 32: 202–210.

APPENDICES

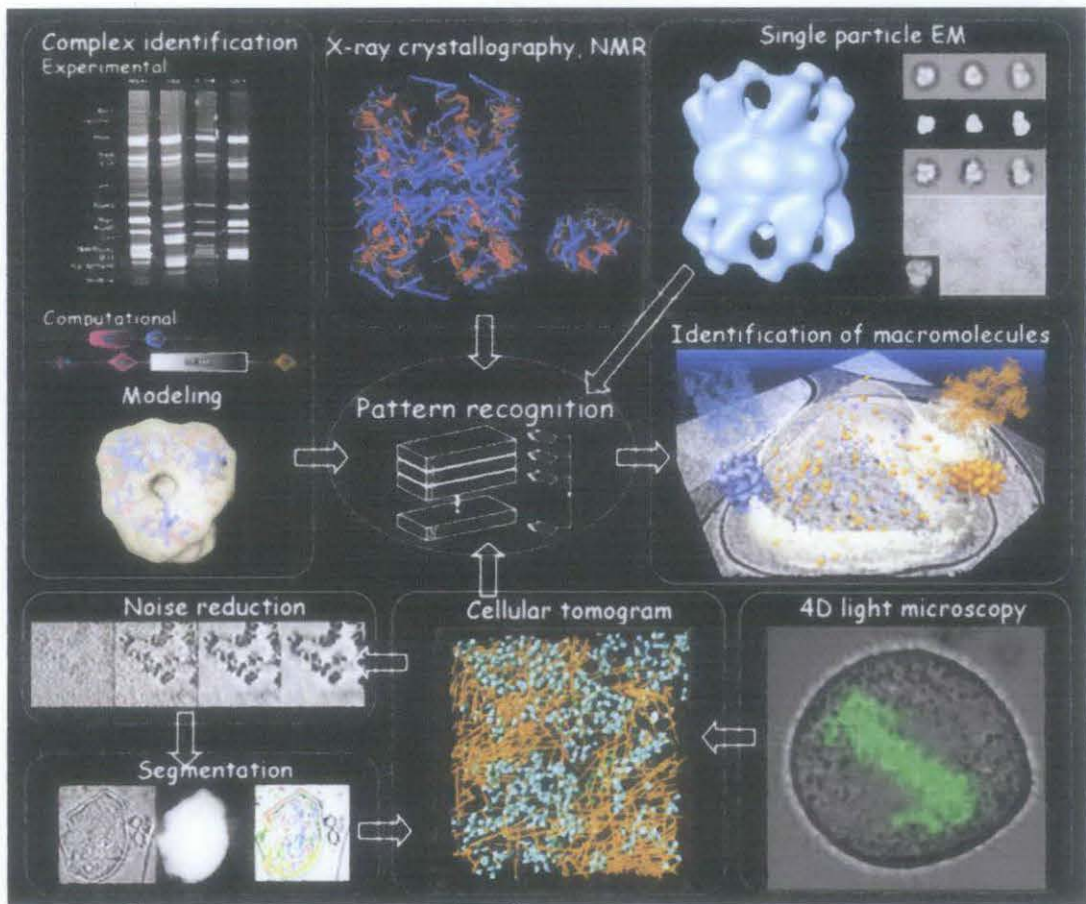


Figure 16: Steps of Analysis of XRD Test.



Figure 17: Linear- Swell Meter Device