

**THE EFFECT OF ECCENTRIC DRILLING ON FORMATION DAMAGE
TO BEREA SANDSTONE FORMATION**

TEOW KET SEANG

**A thesis submitted in fulfilment
of the requirements for the award of the
Degree of Master of Engineering (Petroleum)**

**Faculty of Chemical and Natural Resources Engineering
Universiti Teknologi Malaysia**

APRIL, 2003

ABSTRACT

Formation damage caused by particles and filtrate invasions has been identified as one of the major problems that cause serious damage to the formation, thus it results in reduction of oil and gas productivity. It occurs throughout the life of an oilwell, especially during drilling a horizontal well. In a horizontal well, drill string eccentricity phenomenon tends to occur mostly due to the gravitational effect and this phenomenon would contribute to formation damage. A formation damage rig with 6" hole and 3.5" drill string simulating a slim-hole drilling had been designed to facilitate the investigation of damage on Berea sandstones caused by oil-based mud in dynamic condition at various differential pressures, drill string rotations, and exposure times. The rig was also used to investigate the damage of Berea sandstones in horizontal and vertical wells. The experimental results showed that the drill string eccentricity did contribute to the permeability reduction and became critical as differential pressure, drill string rotation speed, and exposure time were increased. The effect of drill string eccentricity at 250 psi induced differential pressure encountered lesser permeability impairment compared to 200 psi. SEM studies showed the presence of micro fractures in the cores when exposed to differential pressure of 250 psi, which increases the permeability of the Berea sandstones (*improved permeability*). SEM visualization revealed that the particles plugging and deposition in pore spaces in horizontal well was found to be more severe than vertical well, thus it induced higher damage in the former well.

ABSTRAK

Kemasukan partikel dan bendalir gerudi ke dalam formasi ialah punca berlakunya kerosakan formasi. Seterusnya, gejala ini mengakibatkan terjadinya pengurangan produktiviti minyak. Kerosakan formasi berlaku secara berterusan sepanjang hayat telaga minyak, terutama semasa mengerudi telaga mendatar. Lazimnya, fenomena keesentrikan rentetan gerudi di dalam telaga mendatar yang disebabkan oleh kesan daya graviti akan mendorong kepada berlakunya kerosakan formasi. Rig kerosakan formasi dengan lubang telaga 6" dan rentetan gerudi 3.5" telah direka bentuk bagi menyelaku keadaan sebenar ketika mengerudi lubang kecil di medan. Rig ini bertujuan untuk mengkaji kesan keesentrikan rentetan gerudi terhadap kerosakan formasi Berea dengan menggunakan lumpur dasar minyak dalam keadaan dinamik apabila keesentrikan digabungkan dengan tekanan kebezaan, masa dedahan, dan kadar pemutaran rentetan gerudi. Di samping itu, rig ini juga digunakan untuk membandingkan kerosakan sampel batu pasir Berea yang dialami telaga mendatar terhadap telaga menegak. Keputusan eksperimen menunjukkan bahawa keesentrikan rentetan gerudi mengakibatkan kerosakan formasi. Tahap kerosakan bertambah teruk apabila tekanan kebezaan, kadar putaran rentetan gerudi, dan masa dedahan ditingkatkan atau dipanjangkan. Pada tekanan kebezaan 250 psi, kerosakan sampel batu pasir Berea berkurang apabila dibandingkan dengan tekanan kebezaan 200 psi. Kajian dengan menggunakan kaedah SEM menunjukkan wujudnya retakan halus pada sampel batu pasir Berea yang didedahkan kepada tekanan kebezaan 250 psi. Kehadiran retakan harus telah meningkatkan ketertelapan sampel batu pasir Berea. Analisis SEM juga menunjukkan bahawa penyumbatan lubang pori oleh partikel yang dialami telaga mendatar lebih ketara berbanding telaga tegak. Ini menunjukkan bahawa kerosakan formasi yang dialami oleh telaga mendatar adalah lebih serius.

CONTENTS

CHAPTER	TITLE	PAGE
	TITLE	i
	DECLARATION	ii
	DEDICATION	iii
	ACKNOWLEDGEMENT	iv
	ABSTRACT	vi
	ABSTRAK	vii
	TABLE OF CONTENTS	viii
	LIST OF TABLES	xii
	LIST OF FIGURES	xiv
	LIST OF ABBREVIATIONS	xviii
	LIST OF APPENDICES	xix
I	INTRODUCTION	
1.1	General Background	1
1.2	Problem Statement	5
1.3	Objectives of Study	5
1.4	Scope of Study	6
1.5	Organization of Thesis	7

II LITERATURE REVIEW

2.1	An overview of Formation Damage	9
2.2	Formation Damage due to Field Operations	11
2.3	Causes of Formation Damage	16
2.4	Formation Damage Mechanisms	19
2.4.1	Solid Invasion	22
2.4.2	Filtrate Invasion	26
2.4.3	Clay Swelling	33
2.4.4	Fines Migration	34
2.4.5	Precipitation from Incompatible Fluids	36
2.4.6	Emulsion Block	37
2.4.7	Surface Adsorption/Wettability Alteration	37
2.4.8	Mechanical Near Wellbore Damage	38
2.4.9	Biologically Induced Formation Damage	38
2.5	Comparison of Damage in Horizontal and Vertical Wells	39
2.6	The Possible Effect of Drill String Eccentricity on Formation Damage	41
2.7	The possible Factors that Tend to Enhance Wellbore Damage	46
2.8	Formation Damage Identification	56
2.8.1	Quantification of Formation Damage	59
2.8.2	Techniques for Evaluating Formation Damage	61
2.9	Formation Damage Prevention and Minimization	65
2.10	Summary	70

III EXPERIMENTAL PROCEDURE AND MEASUREMENT

3.1	Sample Preparation	73
3.1.1	Preparation of Berea Sandstones	73
3.2	Drilling Fluid Formulation	76
3.2.1	Based Oil-Sarapar 147	77

3.2.2	Drilling Fluid Additives	77
3.2.3	Drilling Fluid Mixing Procedures	80
3.3	Hydraulic Calculation	81
3.3.1	Reynold's Number	82
3.4	Formation Damage Rig	82
3.4.1	Tank Construction	83
3.4.2	Flowline System	86
3.4.3	Valve Types	86
3.4.4	Pump Types	87
3.4.5	Flexible Hoses	88
3.4.6	Filtrate Collecting System	89
3.4.7	Multi Angles Rotating Rig	89
3.4.8	Testing Unit	90
3.5	Permeability Measurement	99
3.5.1	Measurement of Initial Permeability (K_i) and Damaged Permeability (K_d) procedures	101
3.6	The Operational Procedures of The System	102
3.7	Summary	106

IV RESULTS AND DISCUSSION

4.1	Rock Properties Measurement and Analysis	110
4.2	Drilling Fluid Preparation and Analysis	113
4.3	The Study of Drill String Eccentricity on Formation Damage	116
4.3.1	Eccentricity Calculation Diagram	116
4.3.2	Mud Flow Pattern in Annulus	118
4.3.3	Effect of Drill String Eccentricity on Formation Damage	119
4.3.4	Filtrate Loss due to The Drill String Eccentricity	125
4.3.5	Effect of Differential Pressure on	

	Formation Damage	129
4.3.6.	Effect on Differential Pressure on Filtrate Loss	134
4.3.7	Effect of Drill String Eccentricity Against Exposure Time on Formation Damage	137
4.3.8	The Influence of Exposure Time on Filtrate Loss	139
4.3.9	Effect of Drill String Eccentricity Coupled with Drill string Rotation Speed on Formation Damage	143
4.3.10	Effect of Drill String Rotation Speed on Filtrate Loss	145
4.4	The Effect Drill String Eccentricity in Horizontal and Vertical Wells	147
4.4.1	Filtrate Loss in Horizontal and Vertical Wells	154
4.5	Verification of Improved Permeability	157
4.6	Summary	162
V	CONCLUSIONS AND RECOMMENDATIONS	
5.1	Conclusions	163
5.2	Recommendations for Further Studies	164
	BIBLIOGRAPHY	170
	APPENDICES	183

LIST OF TABLES

TABLE	TITLE	PAGE
2.1	A list of particle sizes that cause formation damage by calculation method	55
2.2	Basic appraisal method and practical prevention measures to overcome formation damage	71
3.1	Chemical composition and properties of Sarapar 147	77
3.2	Chemical characteristics of drilling fluid additives obtained from Product Data Sheet of Kota Minerals and Chemicals Sdn Bhd (KMC)	78
3.3	Function of mud additives	79
3.4	The detail of OBM drilling fluid formulation (oil water ratio= 75/25)	80
4.1	The breakdown of studied parameter	112
4.2	Rock permeability before and after damage	112
4.3	The required of the based oil and mud additives	114
4.4	The rheological properties of the mud	115
4.5	Required shifted value for the drill string eccentricity	117
4.6	PVI for the core sample at different drill string eccentricity	120
4.7	Comparison of the PVI in horizontal well for upper and bottom parts of the hole	123
4.8	Final collected filtrate for different drill string eccentricity	126
4.9	PVI for the core sample at different differential pressures	129
4.10	Final collected filtrate at vary differential pressures	135

4.11	Classification of core samples for exposure time	138
4.12	Filtrate loss against different exposure times	141
4.13	Classification of core sample for drill string rotation speed	143
4.14	Filtrate loss for different drill string rotating speed	146
4.15	Classification of core samples for horizontal and vertical wells	148
4.16	Filtrate loss for horizontal well @ various Induced differential pressure	155
4.17	Filtrate loss for vertical we @ various Induced differential pressure	156
4.18	The breakdown of studied parameters (verification)	158
4.19	Rock permeability before and after damage (verification)	158

LIST OF FIGURES

FIGURE	TITLE	PAGE
2.1	Mud filtrate invasion in the near wellbore formation	22
2.2	Particle invasion and bridging phenomenon in formation	26
2.3	Depth of invasion data by Simpson (1974) plotted against the square root of time for different muds	31
2.4	Comparison of dynamic and static filtration	31
2.5	Eccentricity of rotating drill string in horizontal wells	44
2.6	Flow profile in horizontal and vertical well	45
2.7	Invasion profile in horizontal and vertical wells	45
2.8	The relationship between filtrate loss against time	48
2.9	The relationship between differential pressure and damage ratio	48
2.10	The effect of annular velocity in damage ratio	50
2.11	The effect of exposure time on damage ratio	52
2.12	The effect of temperature on damage ratio	53
2.13	Life cycle approach used to identify formation damage	59
3.1	Berea core cutting equipment	74
3.2	Schematic diagram of core saturation unit	76
3.3	Tank construction sectional detailed diagram	84

3.4	Platform to support the mixing tank	85
3.5	Rotating rig holder detailed diagram	90
3.6	Related component attached to the testing unit	91
3.7	Sectional diagram of the top bore assembly	93
3.8	Sectional diagram of the center bore	94
3.9	A core sleeve	95
3.10	Sectional diagram of the core holder	96
3.11	Sectional diagram of the lower bore assembly	98
3.12	Sectional diagram of drill string	99
3.13	Schematic diagram of the equipment set-up for the measurement of K_i and K_d	102
3.14 (a)	Schematic diagram of the experiment set up	107
3.14 (b)	Labeling of the schematic diagram	108
3.15	Completed system set-up	109
4.1	Calculation model of drill string eccentricity	117
4.2	Mud Flow pattern in Annulus	118
4.3	The effect of drill string eccentricity on permeability variation index	123
4.4	Fractures occurs in core sample at 75% drill string eccentricity	124
4.5	Filtrate collected for different drill string eccentricity conditions at differential pressure of 100 psi	127
4.6	Filtrate collected for different drill string eccentricity conditions at differential pressure of 150 psi	127
4.7	Filtrate collected for different drill string eccentricity conditions at differential pressure of 200 psi	128
4.8	Filtrate collected for different drill string eccentricity conditions at differential pressure of 250 psi	128
4.9	The effect of differential pressure on permeability variation index	131
4.10	Pore spaces before exposing to drilling mud at 100x	132

4.11	Pore space was severely plugged by mud particles after exposing to drilling mud at differential pressure of 150 psi	133
4.12	Micro fractures occurred at induced pressure of 250 psi for drill string eccentricity conditions	135
4.13	Filtrate collected for different differential pressures and 0% drill string eccentricity	135
4.14	Filtrate collected for different differential pressures and 25% drill string eccentricity	136
4.15	Filtrate collected for different differential pressures and 50% drill string eccentricity	136
4.16	Filtrate collected for different differential pressures and 75% drill string eccentricity	137
4.17	Permeability variation index against exposure time	139
4.18	Filtrate loss against exposure time	142
4.19	Permeability variation index for different drill string rotation speed at 200 psi	144
4.20	Micro fractures occurred at induced pressure of 200 psi @ 50% for drill string rotation of 150 rpm	145
4.21	Filtrate loss at vary drill string rotation speed at 200 psi	147
4.22	Micro fractures in horizontal well at 50x	149
4.23	Micro fracture in vertical well at 50x	150
4.24	Comparison of formation damage in horizontal and vertical wells	152
4.25	Drilling mud invasion in vertical well	152
4.26	Drilling mud invasion in horizontal well	153
4.27	Mud cake formed in horizontal well	153
4.28	Mud cake formed in vertical well	154
4.29	Filtrate collected in horizontal well	156
4.30	Filtrate collected in vertical well	157
4.31	Micro fractures occurred at induced pressure of 250 psi @ 75% drill string eccentricity no drill string rotation	159

4.32	Micro fractures occurred at induced pressure of 250 psi @ 75% drill string eccentricity for drill string rotation of 120 rpm	160
4.33	Micro fractures occurred at induced pressure of 250 psi @ 75% drill string eccentricity for drill string rotation of 150 rpm	161

LIST OF ABBREVIATIONS

API	-	American Petroleum Institute
HPHT	-	High Temperature High Pressure
PVI	-	Permeability Variation Index
K_i	-	Initial Permeability, md
K_d	-	Damaged Permeability, md
SEM	-	Scanning Electron Microscope
SPE	-	Society of Petroleum Engineer

LIST OF APPENDICES

APPENDIX NO.	TITLE	PAGE
A	Berea cores report from Cleveland, USA	188
B	Reynold's number calculation	189
C	Initial and damaged permeability calculation	191
D	Mud quantity required	192
E	XRD analysis	193
F	Detail calculation of core permeability before and after exposed to mud	195
G	Mud rheological properties checked during experiment	203
H	Schematic diagram of Drill String Eccentricity	210

CHAPTER I

INTRODUCTION

1.1 General Background

In the petroleum industry, one of the important objectives of oil companies is to obtain optimum oil and gas recovery from reservoir. One of the constraints in achieving this objective is formation damage. Laboratory and field studies indicate that almost every operation in the field such as drilling, completion, production etc. is a potential source of damage to well productivity (Krueger, 1986). Formation damage also known as wellbore damage, can cause major problems to oil production and should be given special attention by the reservoir and drilling engineers.

Since the advent of energy crisis and Arab embargo, serious attention has been given for preventing formation damage and maximization of the well productivity. Formation damage may result either from physical or chemical mechanisms. The physical mechanism comprises drill string eccentricity, pipe sticking etc., while the chemical mechanism includes emulsion blocked, wellbore sloughing etc. Formation damage becomes more severe when it is coupled with physical parameters such as differential pressure, annular velocity, mud weight, particles size, temperature etc. (Guota and Civan, 1994; Di Jiao and Sharma, 1992).

Differential pressure is one of the important parameters that has significant influence on the formation damage (Rahman and Marx, 1987). Higher differential pressure would permit more filtrate and solid particles from drilling fluid to invade into the formation (Byrne *et al.*, 2000). The invasion of these particles will block the pore space and cause the formation damage.

Higher annular velocity creates higher hydrodynamic forces to the fluid, thus it forces more fluid particles to flow into the formation. Sharma *et al.* (1991) confirmed that the annular velocity was a critical criterion of fine release, which could plug the formation and reduce productivity. Peden *et al.* (1982) found that the dynamic filtrate loss was significantly influenced by the annular velocity and permeability of a core. Generally, higher permeability and annular velocity would permit more fluid to pass through the pore space, thus it would cause damage to the wellbore.

The greater the density of a hydrostatic fluid column and resulting downhole pressure generated in comparison to the net effective reservoir pressure, the greater the tendency for losses of both fluids and mud solids to the formation. Overbalance pressure in excess of 7000 kPa (1000 psi) is generally considered to be severe and may cause serious losses to the formation, particularly in highly permeable production zone (Bennion *et al.*, 1996).

Temperature is an important variable but is often ignored when conducting laboratory studies on formation damage under the reservoir condition. A severe damage may occur at higher temperatures (Guota and Civan, 1994). This is due to thermal degradation of the mud especially polymer mud system. The ability of fluids to transport the fines decreases with the increase in temperature. As a result, this will increase the potential of physical bridging and colloidal trapping, which will lead to physical damage of the wellbore. According to Chambers *et al.* (2000), it is more viable to use the oil-based mud compared to water-based mud as drilling fluid in severe temperature condition (170°F), as it has several advantages such as avoid damage to water-sensitive reservoirs, better control of water-sensitive shale, ability to withstand high bottom temperature, extent bit life, improve drill string

lubricity, eliminate pipe sticking, and subsequent sidetracks caused by water-based mud etc.

The invention of the latest technologies in the oil and gas industries has led to the introduction of horizontal drilling. This method has proved its value for both the unprecedented increase in production for the operators and to allow the operators to increase reserves by developing resources that might not otherwise be tapped. By realizing this fact, horizontal drilling is burgeoning with it tremendous opportunities and challenge (Shaw, 1993). Ishak *et al.* (1995) in their field application studies on horizontal drilling discovered that, horizontal drilling has significant benefits of increased production rates, oil recoveries from existing producing fields, and previously uneconomic oil accumulation reservoir. Generally, the oil production rates of most horizontals wells are three to five times higher than vertical wells (Yan *et al.*, 1998). According to Pendleton (1991), in 1986, only 50 horizontal wells were drilled worldwide. By 1989, the number had climbed to 265. In 1990, activity soared with the number of wells drilled increasing fourfold to over 1000 wells. From the expected forecast, by the year of 2005, the number of horizontal year drilled will range from 10,000 to 50,000 worldwide.

Field experience has proven that horizontal drilling is more susceptible to formation damage than vertical wells in the same formation due to many factors (Reed, 1989). One of the factors is that most of the time the horizontal section of the well is completed as barefoot completion, and the drilling time for horizontal well is usually greater than the vertical wells. Fluid exposure time at the heel of the well may be significant if drilling mud with poor rheological properties is utilized in an overbalanced condition, or if the mud filter cake is continuously disturbed by a poorly centralize drill string or multiple tripping operations which would provoke more filtrate to invade into the formation. The depth of invasion of damaging mud filtrate and solids into near wellbore region may be substantially greater than in a conventional vertical well (Bennion *et al.*, 1996).

Drill string eccentricity is a phenomenon where the drill string moves away from the center of the hole and is found to be critical when drilling a horizontal well. The eccentricity of drill string may occur due to the gravitational effect especially in horizontal holes. This phenomenon is believed to have some effects on formation damage especially in horizontal well. The formation damage caused by this phenomenon becomes more serious when it is coupled with physical parameters such as differential pressure, drill pipe rotation speed, exposure time etc.

At higher eccentricity, the increase in differential pressure would create more forces in the drilling fluid. It is believed that higher differential pressure when coupled with drill string rotation speed will induce greater hydrodynamic forces in the mud system. Thus, the combination of those mechanisms enables the laden fluid to possess additional energy to invade deeper into the formation and causes severe wellbore damage.

Formation damage is a critical issue in horizontal wells. However, to the best of our knowledge, rare experimental measurement has been made on the effect of drill string eccentricity on formation damage in horizontal well. To evaluate the effect of drill string eccentricity on formation damage in a horizontal well, an extensive experimental rig was designed and constructed in order to execute the research study.

1.2 Problem Statement

In the petroleum industry, the main objective of oil companies is to achieve optimum oil and gas productivity. The use of the state-of-the-art technology has led to horizontal drilling with the anticipation of providing higher production rate compared to vertical drilling. However, the drill string in horizontal well tends to lie down on the formation, which could cause serious wellbore damage during drilling, especially in the vicinity beneath the drill string. The wellbore damage becomes more severe when it is coupled with the physical parameters such as differential pressure, exposure time, drill string rotation speed etc. The effect of rotating drill string eccentricity on the severity of formation damage in horizontal well when coupled with the physical parameters has been chosen as the research topic for this Master of Engineering program.

1.3 Objectives of Study

The objectives of this study were:

- (i) To determine the degree of wellbore damage, caused by the eccentricity of rotating drill string under dynamic conditions.
- (ii) To investigate the effect of drill string eccentricity on formation damage when coupled with differential pressure, exposure time, and drill string rotation speed.
- (iii) To investigate the damage in horizontal and vertical wells caused by the drill string eccentricity (for comparison).

1.4 Scope of Study

A formation damage rig was designed and constructed in order to conduct the experimental work. The rig comprised testing unit, mud tank, supporting structures, flowline system, pump etc.

The parameters investigated were the effect of 0-75% eccentricity of the rotating drill string from the center of the hole, coupled with differential pressure of 100-250 psi, exposure time of 30 minutes to 4 hours, drill string rotation speed of 0-150 rpm at constant mud weight and annular velocity of 10.3 ppg and 60 ft/min, respectively.

The Berea sandstones purchased from the Cleveland Quarries, United States of America were used in this study. The Berea cores had to undergo several processes prior to conducting the experiment. Core samples preparation included core cutting, washing, saturation, and preservation. Drilling mud formulation, and determination of mud rheological properties were the others important task to be carried out. A permeability measurement rig was set-up to assist the determination of initial and damaged permeability, which were vital in computing the damage ratio.

1.5 Organization of Thesis

Followed by a brief introduction presented in this chapter, the outline of this thesis is as below:

- Chapter I : This chapter introduces the general background concepts, indicates problem statement, objectives of the study, and outlines the scopes of this work.
- Chapter II : General review on formation damage includes a review of the damage mechanisms, factors enhancing the formation damage, the effect of drill string eccentricity, severity of formation damage in a horizontal well compared to a vertical wells, and prevention of the formation damage.
- Chapter III : Describes in detail the apparatus, experimental rig set-up, and experimental procedures of this study.
- Chapter IV : Discusses the results and explains the findings.
- Chapter V : Presents the conclusions and recommendations of this research study.

CHAPTER II

LITERATURE REVIEW

This chapter describes the relevant aspect of formation damage either in vertical or horizontal wells during field operations or laboratory studies. The detail breakdown of the literature review is as follow:

- Section 2.1 discusses the general idea of formation damage,
- Section 2.2 briefly reviews the occasions when formation damage may occur,
- Section 2.3 discusses the causes of formation damage,
- Section 2.4 discusses the significant mechanisms that affect oil productivity,
- Section 2.5 discusses the comparison of damage in horizontal and vertical well,
- Sections 2.6 discusses in detail of the possible effect of rotating drill string eccentricity on formation damage,
- Section 2.7 discusses and the possible factors that enhance wellbore damage,
- Section 2.8 briefly discusses the formation damage identification, quantification, and techniques for evaluation,
- Section 2.9 briefly outlines the formation damage minimization and prevention, and
- Section 2.10 gives a summary of the chapter.

2.1 An Overview of Formation Damage

Formation damage is normally indicated by the lower productivity than expected and fast declined of the production rate that due to reduced permeability near the wellbore.

It is very challenging to drill a high angle or horizontal well, but the present state-of-the-art technology has performed a satisfactory degree of confidence to drill the horizontal or high angle wells (Ezzat, 1993). Horizontal and highly deviated wells have been drilled through hydrocarbon zones throughout the world in an ever-increasing fashion since 1990 in attempts to increase production rates. These activities target multiple zones, maximizing reservoir pressure, reducing drawdown to avoid premature water or gas coning problems. According to Ezzat (1993), the production rate of a horizontal well is several folds higher than the vertical well even without stimulation treatments.

Formation damage in horizontal wells is of a great concern as the horizontal section is open-hole completed (Saintpere, 2000). According to Fraser and Polnaszek (1991), any near wellbore damage in horizontal wells does not bypassed by the perforation tunnels, therefore this near wellbore damage can cause an adverse effect on well productivity.

Formation damage is the impairment to the productivity of hydrocarbon bearing formation and it can be caused by the combination of mechanical and chemical activities required in the process of to drill, complete, or stimulate and occurs in reservoirs in almost every field operation (Hanssen *et al.*, 1997). Physical mechanisms include eccentricity of the drill string especially in drilling horizontal wells, pipe sticking, pore deformation, collapse etc. The eccentricity of the rotating drill string when coupled with differential pressure, temperature, and drill string rotation has great tendency of reducing oil productivity. On the other hand, chemical mechanisms that may induce wellbore damage includes emulsion blockage, wellbore-sloughing, chemical precipitation, and organic deposition. The possibility of formation damage may occur during the entire life of the well when

changes occur in the reservoir, pressure, stress, temperature, fluid chemistry etc. (Vidick and Reid, 1997).

Laboratory studies indicate that operations in a field such as drilling, completion, workover, production, and stimulation are the potential sources of formation damage (Al-Marhoon *et al.*, 1998; Abu Azam Md. Yasin *et al.*, 1991; Krueger, 1982). The possibility of damaging a producing zone by exposed to drilling fluids has been recognized since the 1930's (Gill, 1932). Since the advent of the energy crisis and the Arab embargo, most of the oil companies started to realize the importance of understanding formation damage that should not only focus on the prevention of formation damage but also in maximizing well productivity.

Remedial works of formation damage such as acid stimulation and water flooding are usually difficult and costly and the basic approach should be of damage prevention. To achieve this goal, the process of drilling, completion, and production need to include extensive preplanning, execution, and follow-up. Failure to effectively control treatment, operating procedures, and chemicals such as adding excessive mud additives in drilling fluid may negate the effectiveness of well-designed and well-executed operations. Severe damage to productivity may result from a single mistake during well development.

The manner in which the producing zones may be damaged varies from operation to operation such as drilling and completion. Investigation and diagnosis of the specified problems indicate that the reasons are typically attributed to pore plugging from migration of native clay, formation of precipitate, transport of fine solids during drilling of wellbore, emulsion blockage due to incompatible of drilling filtrate etc. (Vidick and Reid, 1997).

Vidick and Reid (1997) explained the importance of increasing the industry awareness of formation damage. This is due to the increase in small and marginal field developments (drilling only a small number of wells that must produce to their full potential), and an increase in the number of wells that are completed

without casing and perforation. In these completions, near wellbore damage is not bypassed by perforating tunnels, hence formation damage problem has to be minimized. Finally, stimulation treatment can reduce formation damage, but prevention of formation damage is of utmost important as it could reduce the overall cost of developing an oil well.

To prevent permeability damage or to stimulate well effectiveness, it is vital to accurately diagnose the damage mechanisms. Having a vast knowledge in formation damage is the first step in the prevention of well damage. Besides, each operation should be studied in detail in order to achieve the production goal of the company. Generally, avoiding formation damage is not possible and non-damaging fluid does not exist. The question is to find out what level of formation damage is acceptable by taking into account the number of wells, type of formation, type of completion etc. (Vidick and Reid, 1997).

2.2 Formation Damage due to Field Operations

Formation damage begins when a bit penetrates into a permeable formation, and it can occur at any time throughout the useful life of the formation (Krueger, 1988). For the example, when the oil well encounters the tremendous production decline, the remediate job such as fracturing job may be imposed to increase the oil productivity. During the fracturing job, it may cause the formation damage by generating the debris that can block the pore throat of formation and cause formation damage.

This section describes the origins of potential formation damage problems during various well operations such as drilling activities, casing and cementing, completion, well servicing, well stimulation, production, enhanced oil recovery etc.

(I) Drilling Activities

The formation damage problems associated with drilling is mostly due to prolonged contact of drilling fluid with the exposed formation. From the time when the drill bit penetrates the pay zone until the well is put on production; the zone is exposed to a series of fluids and operations that will greatly affect the productivity capacity of the well. Two types of damage commonly occur during drilling are mud solid and mud filtrate invasions (Tovar *et al.*, 1994). The damaging solids may come directly from the fluid system or from the formation itself. The intrusion and deposition of these mobile particles lead to the blockage of pore throat by formation of internal filter cake, which will reduce the permeability of the rock.

The solid phase of drilling mud can be categorized into two basic types; commercial solids and drilled solids. Commercial solids are the solids introduced into the mud system to achieve the desired rheological properties. Drilled solids are solids that enter into the mud system in the form of drill cuttings or caving from the formation being drilled.

Generally, the depth of the damage during drilling depends on the condition near wellbore, characteristic and composition of the rock, and mud filtrate and solids that flow with it under dynamic condition (Nowak and Krueger, 1951).

(II) Casing and Cementing

Potential formation damage problems during casing and cementing includes solid invasion, spacer fluids invasion (chemical), and cement filtrate invasion.

The pore blockage caused by the solid invasion occurs when the cement and mud solids push ahead of the cement, particularly during squeeze cementing operations and when lost circulation occurs during cementing operation.

Chemicals pumped ahead of the cement can interact adversely with the formation fluids and minerals resulting in the destabilization of the clay, fines migration, and saturation changes problems. Cement filtrate with rich Ca^{2+} when it reacts with silica will form calcium silicate hydrate that can plug effective flow paths. Hydroxyl ions present in filtrate could destabilize clays, release fine particles and would increase migration of fines and react with crude oil to form emulsion.

The formation damage due to the cementing process can be minimized or eliminated when a non-damaging fluid loss additives such as *hydroxyethylcellulose* (HEC) is used in the water based mud system to minimize filtrate leak off from the cement slurry (Jones *et al.*, 1991).

(III) Completion

An excessive hydrostatic pressure during the completion work would force both solids and fluids into the formation. Thus, will cause the incompatibility between the circulating fluid and the formation resultant in occurrence of pore plugging.

According to Bennion *et al.* (1995), formation damage occurring in completion works is always related to the perforating process. Perforation damage appears to be inherent result of the conventional perforating process. Even under the best of conditions of perforating process, immediately after perforation, the compacted rock and charge debris will block the natural pore spaces in the formation. The perforating process will also create a channel of low conductivity in already damaged formation if the perforating job does not carefully taken into account of drilling procedures and fluids. Wettability alteration may occur due to the completion fluid additives during the completion job.

(IV) Well Servicing

Formation damage problems are similar to those that can occur during the completion job. Formation plugging is caused by the solids in unfiltered fluid during well killing of economic wells (Adair and Gruber, 1996).

(V) Well Stimulation

The objective of well stimulation is to improve existing well productivity. Generally, it consists of stimulation effect of a particular treatment and productivity damage associated with various quality control problems. Oil productivity of the wells will improve to a satisfactory economic payout if the well's problems are accurately diagnosed and the treatment is well designed and executed. If the damage aspects dominate and the treatment didn't bring changes in productivity or even decline, the treatment process is not optimize/unsuccessful.

According to Yost (1994), formation damage related to the stimulation process is usually associated with fluid selection and the nature of producing reservoir rocks. Acidizing is one of the well stimulation processes and in some instances, can be damaging to the formation mainly due to plugging of formation pores by loose fines generated during acidizing, precipitation of iron reaction products, and organic sludge (Adinathan Venkitaraman *et al.*, 1994). Acidizing process may also has the tendency to release fines and collapse the formation if excessive concentration of acid is used for the unconsolidated reservoir. It is expensive and difficult to handle in horizontal wells, where large section of open hole needs to be treated with large acid volume. Generally, well stimulation process can bring disaster to the oil productivity if it is incorrectly implemented.

(VI) Production

Every well drilled must be cleaned-up before being put on production. Subsequently during injection or production, the near wellbore region becomes “damaged” if its permeability is reduced from original value (Al-Marhoon *et al.*, 1998). However, in reality, this near wellbore area is a complex zone, consisting of the wellbore casing, a cement annulus, and a perforated zone, which is gradually affected by formation damage (Economides *et al.*, 1994; Golan and Whitson 1986)

According to Bennion and Thomas (1995), production rates normally decline with the natural depletion of a field. Accelerated decline from formation plugging is a common problem during production operation and it must be dealt with to maintain an adequate return on investment. Formation damage in production wells can be detected by implementing historical comparison of decline curves, pressure built up test etc.

Diagnosis of the cause of declining productivity is a critical problem in designing an effective well treatment. Some of the common sources of well plugging during production are formation fines, waxes, asphalt, and inorganic scales.

(VII) Enhanced Oil Recovery

The formation problems always associated in this process are fines migration, clay swelling, and silica dissolution initiated by contact of high pH steam generator effluents with the formation rock during thermal recovery. Inorganic scaling problem also occur due to the changes in thermodynamic conditions during steam injection (Hayatdavoudi, 1999).

2.3 Causes of Formation Damage

Formation damage has been well known as the mechanism that can cause the reduction of oil productivity. There are many causes of formation damage includes organic deposition, inorganic scaling, microbial, high-density completion fluid etc. The causes of formation damage are also depending on the various well operations (completion, drilling, production etc). The most common formation damage causes encountered in the field are organic deposition, inorganic scaling, microbial etc. (Leontaritis *et al.*, 1994).

(I) Organic Deposition/Damage

Organic damage may occur naturally or through various well intervention practices used in oilfield. It is an ongoing process that decreases permeability and subsequent oil production (Newberry and Barker, 2000). Paraffin, asphaltene, and resin are the typical sources of organic deposition in well, pipelines, and reservoir during production. Paraffin and asphaltene could precipitate as organic scales near the wellbore and impair permeability.

Organic deposition can occur both on the surfaces of well tubing and formation pores to reduce the flow efficiency and eventually to clog the flow paths completely (Civan, 2000). The paraffin deposition primarily occurs due to temperature decrease, whereas asphaltene and resin deposition occur because of a number of complicated phenomena, including aggregation, electro-kinetic deposition process etc (Mansoori, 1997).

The most frequently occurring organic near-wellbore formation damage during oil production is due to the asphaltene deposition and the asphaltene induced damage may occur many feet inside the reservoir depending on the drawdown pressure (Leontaritis *et.al*, 1994). Asphaltenes can reduce the hydrocarbon effective mobility by blocking pore throats, thus it reduces the rock

permeability, absorbs onto the rock and alters the formation wettability from water wet to oil wet. Hence, these phenomena would diminish the effective permeability to oil initial permeability (K_o), and increase the reservoir fluid viscosity (μ) by forming the water-in-oil emulsion if the well is producing oil and water simultaneously (Leontararitis, 1998). The most frequently encountered case of asphaltene induced formation damage is the blockage of pore throats by asphaltene particles causing a reduction in rock permeability, followed by wettability alterations, and viscosity increase.

(II) Inorganic Scaling

Inorganic scaling is a process of deposition of scales from aqueous solution of minerals, referred to as brine, when they become supersaturated as a result of the alteration of the state of their thermodynamic and chemical equilibrium (Amaefule *et al.*, 1988). Inorganic scaling can occur in the tubing and near wellbore formation of producing and injection wells. Scaling caused mainly by the mixing of incompatible fluids during well development operations, such as drilling, completion, and workover due to decrease of pressure and temperature especially during production of the reservoir fluids. According to Jordan *et al.* (1998), the most effective way to deal with the problem of oilfield scale formation is through the use of chemical crystal growth modifiers-scale inhibitors that can prevent or delay scale formation.

Generally, the removal of mineral scale is carried out by mechanical or chemical methods. Mechanical methods of scale removal may involve re-perforation and pipeline drill outs. These treatments are extremely expensive to perform. Furthermore, the success of mechanical scale removal techniques cannot be guaranteed, especially if the near wellbore region has suffered from significant scale formation (Carrel, 1987). Chemical treatments method is usually less expensive than mechanical methods and in addition, they may help to remove scale

from the near wellbore formation. Barium sulfate has been recognized as the most difficult to remove chemically due to its thermodynamic stability.

(III) High Density Completion Fluid

The use of high-density can effectively reduce formation damage during the completion operations. However, recent studies have suggested that high density brines such as $\text{CaBr}_2/\text{CaCl}_2$ (> 14.2 ppg) were found to be potentially damaging and reduce core permeability from 25 to 29% due to the precipitation of calcium hydroxide and calcium carbonate (Houchin et.al, 1991). Baijal *et al.* (1991) from their research studied also confirmed that the calcium based completion/workover brines of equal or greater than 14.2 ppg have the greater potential for formation damage compared to the lower density brines. The permeability impairment due to calcium precipitation also increases with the increase in temperatures.

(IV) Microbial

The microbes and their role in oilfield formation damage is less understood. Microbes can be classified as aerobic bacteria that require oxygen, anaerobic bacteria that do not need oxygen, and facultative bacteria that can grow either with or without oxygen. Microbes usually grow about 5 times faster in the presence of oxygen. Formation damage in terms of physio-chemical reactions such as asphaltene deposition, scale precipitation, and fines migration for example is relatively well understood.

Oilfield microbes, especially the S.R.B. (sulphate reducing bacteria), have been identified as the most troublesome microbes in oilfields worldwide and have been isolated from drilling mud (particularly water-based muds) and other downhole chemicals and injection water. This is due to the combination of these

various process with microbial populations often results in the precipitation of insoluble metal sulphides, biopolymer, and hydrogen sulphide production, that cause loss in production and injection rates (Wood and spark, 2000). Johnson *et al.* (1999) recommended to use *anthrahydroquinon disodium* salt in caustic to control the growth of S.R.B. combined with the traditional biocide treatment for controlling other types of bacteria. For example, bacteria-induced formation damage in injection well can be treated using a highly alkaline *hypochlorite* solution, followed by a HCL overflush for neutralization of the system (Thomas *et al.*, 1998).

Temperature is one of the major controls on the growth of bacteria and their byproduct. The greatest risk of microbial formation damage within the reservoir would occur in those areas at 30°C (Wood and Spark, 2000). Temperature above 30°C will be unfavorable to the microbes growth, therefore an understanding of the microbes growth behavior is vital in preventing the formation damage caused by microbial.

2.4 Formation Damage Mechanisms

The implementation of horizontal drilling throughout the world is to increase well productivity. Production results from many horizontal wells have been disappointing, and it is believed that near wellbore formation damage effects is the major contributor to the restriction of the fluid flow (Bennion, *et al.*, 1996). Generally, most of the horizontal wells are barefoot completion; therefore relatively shallow invasion near wellbore may substantially impede flow of the hydrocarbon that might cause the oil productivity below the expectation.

During drilling, the formation is exposed to several types of fluids from drilling mud or formation itself that have tendencies to reduce and impact productivity. The basic cause of drilling induced damage may include invasion of mud solid and filtrate into formation, fines mobilization, phase trapping or

chemical reactivity between invading fluids and the formation matrix or in-situ fluid (Bennion *et al.*, 1996). The solid invasion mainly occurs at the spurt loss stage, while the filtrate can dissipate into formation before and after building of mud cake (Zhang *et al.*, 1998). These damage mechanisms can seriously reduce the pore throat size and relative permeability.

The mechanism that reduces the pore size includes mud solid invasion, clay swelling, filter cake plugging, formation fines migration, polymer precipitation etc., whereas the damage mechanism that causes the reduction of relative permeability includes emulsion, fluid saturation and, wettability changes etc. (Vidick and Reid, 1997). Civan *et al.* (1989) showed that the degree of permeability impairment could be quantified by considering the combined effects of foreign fines invasion, in-situ fines mobilization, and clay swelling.

Many authors have documented their finding on formation damage in horizontal well that often outweigh those observed in vertical wells (Bennion *et al.*, 1991). According to Bennion and Thomas (1994); Shaw (1993), generally mechanisms of damage to both horizontal and vertical wells would include:

- (a) solids invasion from the artificial solids contained in the drilling fluid,
- (b) emulsion blocking due to the incompatibility of the drilling and formation fluids,
- (c) reduction of near wellbore permeability caused by the rock-fluid incompatibility,
- (d) phase trapping/blocking due to high oil and water saturation in the near wellbore region,
- (e) fines migration due to internal movement of the formation fines or loosely attached in-situ formation particulates,
- (f) biological activity that can influence porosity and reduce permeability, and
- (g) chemical adsorption/wettability alteration that reduces the rock permeability.

Yao and Holditch (1993) described the drilling process in Figure 2.1, where the drilling mud is pumped from the mud pit and out of the drill string. The mud is continuously circulated in order to remove the friction heat that generated as the drill bit penetrates the rock, to provide a lubricant for reduction of the frictional effects, and to transport the cuttings produced during drilling. However, during this process the mud particles and filtrates tend to invade and damage the near wellbore formation as depicted in Figure 2.1 (invaded and uninvaded zones). Typical drilling mud may be water-based, oil-based, or water-emulsion types.

The invasion of mud particles and filtrates has been well documented as a most potential source of formation damage (Browne and Smith, 1994; Donovan and Jones, 1995). In dynamic condition, the quality of the external mud cake plays an important role in determining the extent of the damage. The quality of the external cake is a function of particles size, solids concentration, and mud additives (Jiao and Sharma, 1992).

Mud particles invasion only occurs during the mud spurt loss. Once the external cake has formed, very few particles invade into the formation. Without an external cake or weak external cake, the particle invasion would continue for a long period of time and may cause large reduction of permeability. To minimize damage caused by these particles, a mud must exhibit low fluid loss, low fine solids concentration, enable to form a thin and permeable cake, and exhibit suitable rheological properties.

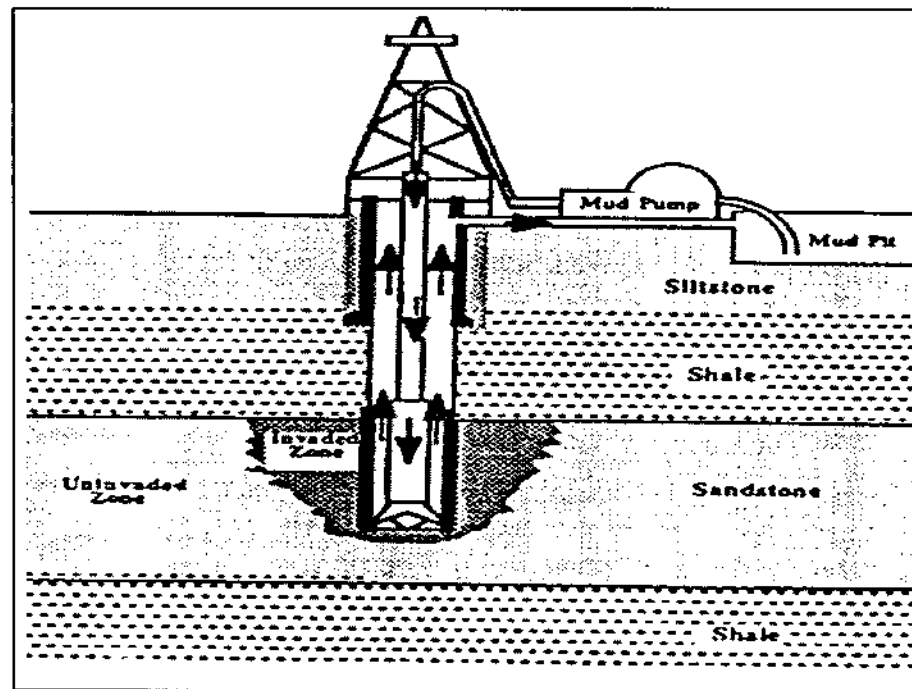


Figure 2.1: Mud filtrate invasion in the near-wellbore formation (after Yao and Holditch, 1993)

2.4.1 Solid Invasion

Solid invasion is a common occurrence phenomenon, which happens during overbalanced drilling and completion operations due to hydrostatic pressure in the circulating fluid system is usually greater than formation pressure. The invasion of solid particles into formation has been well recognized as one of the primary formation damage mechanisms caused by weighting agent or artificial bridging agent in drilling mud (Bailey *et al.*, 1999). These solid particles may also come from the formation rock itself during the milling action of the bit in the formation (Wojtanowicz *et al.*, 1987). According to Civan (2000), the various particles contribute to the formation damage include: the foreign particles introduced externally into the wellbore, the indigeneous particles existing in the porous formation, and the particles generated inside the pore space by various processes which include the wettability alteration. The solids invasion into the rock pore space is commonly referred to as mechanical damage (Krilov *et al.*, 1991).

Nabzar *et al.* (1996) in their research found that the permeability damage caused by the particles proceeds according to more or less overlapping process occurring at the grain/pore openings. First, particles are deposited on the grain surface, giving a progressive and moderate decrease in permeability, followed by the reduction in gaps of grains opening caused by the particles deposition. Deposition of the particles will allow the mono or multi-particle bridge formation. Once the bridge formed and consolidated, the arriving particles accumulate upstream from the bridge formation (pores), thus it would decrease drastically fluid flow rate through these pores (Chauveteau *et al.*, 1998). Internal cake formation will start as soon as the non-percolation threshold reached near the core entrance, and finally the formation of external filter cake when the internal cake formation is completed. External filter cakes are used to minimize fluid loss and solids invasion to formation from drilling and completion fluids.

During the initial stage of filter cake growth, mud solids are forced into the formation, building an internal filter cake that plugs the near wellbore pores. The removal of this internal cake is difficult and leads to the permeability reduction (Bailey and Meeten, 1998). Some of the filter cake will be removed through the action of a drill bit and circulating mud, but most of the internal bridge solids might be trapped. The permanent entrapments of these solids in the formation can severely reduce the permeability if they are not flushed out completely when the well is put on production.

The importance of minimizing internal filter cake is widely recognized. And most attention has focused on the selection of an appropriately size agent to bridge across surface pore to minimize spurt loss. Some alternative bridging approaches such as the use of structured fluids (for example mixed metal hydroxide-bentonite systems) were explored to minimize the spurt loss and were found to give better properties of filter cake formation (Fraser *et al.*, 1995).

Invasion of drilling mud particles into the formation and their abilities to bridge the pore throats and seal the passages in the formation are strongly

dependant on porosity, pore size distribution, induced differential pressure, amount of solid particles, porous media, etc. (Yeager, 1998; Kumar, 1991; Kumar and Todd, 1988; Burnett, 1996; Krueger, 1982). Tovar *et al.* (1994) found that higher the initial permeability of the rocks, higher and much deeper the permeability impairment were. To enable the solid particles from drilling fluids enter into the formation, the solid particles size must be smaller than the pore opening. Bennion *et al.* (1995) found that if extremely high permeability formation is encountered, or if drilling and completion in highly overbalanced conditions in a pressure depleted formation, the invasion of solids particles into the formation is serious.

Tovar *et al.* (1994) and Zhang *et al.* (1998) discovered that the severity of the particulate invasion also depends on the mud typed used in drilling. Both water-based and oil-based muds reported to cause damage in various extents. Generally, the solids concentration in oil-based mud is higher than water-based mud and solids invasion is expected to be higher in oil-based mud. Therefore, the usage of the oil-based mud in a drilling operation must have certain rheological properties that meet the API drilling fluid standard such as low fluid loss, low concentration of fine particles, able to form a thin and impermeable filter cake, suitable mud weight and rheological properties etc. Kumar and Todd (1988) in their simulation works also found that the increase of particles concentration in drilling mud would increase formation damage. Liu and Civan (1993) in their studies about the solid concentration that involved simulation and experimental works also discovered the same outcome as mentioned by Kumar and Todd (1988).

Solid invasion is not considered as a serious problem compared to the filtrate invasion and normally the depth of the solid invasion is from few millimeters to few centimeters (Reed, 1989; Krueger, 1982). Different researchers have different findings about the depth of the solid invasion. Jiao and Sharma (1992) in their laboratory studies discovered that solid invasion of more than 8 " was measured. According to Farina (1984), the depth of particle invasion is relatively shallow (6" or less) and can be solved by perforating process or fracturing the formation.

Francis (1997) reported significant damage from shallow invasion even after removal of the internal and external filter cake, therefore a better understanding of the properties of both internal and external cake is needed for improvement in drilled in fluid. An average reduction of 50% to 80% of initial permeability was found in the case of Berea sandstones when exposed to various muds caused by particles invasion due to decrease or plug pore channels (Kumar, 1991).

Abram (1977) proposed an empirical criterion for rock permeability impairment from the suspended solid particles:

- (a) particles larger than $1/3$ of the pore diameter can bridge pore entrances at the formation face to form an external filter cake,
- (b) particles smaller than $1/3$ but larger than $1/7$ of the pore diameter invade the formation and are trapped, forming an inter filter cake, and
- (c) particles smaller than $1/7$ of the pore diameter cause no formation damage, because they are carried through the formation.

The rule proposed by Abram (1977) was found to be unsatisfactory by several researchers (Eylander, 1987; Kumar and Todd, 1988; Todd *et al.*, 1990). This is due to the fact the $1/3$ to $1/7$ rule cannot be rigorously applied to predict the particle invasion as in some instances the internal invasion occurred with particles outside this range. Van Velzen and Leerlooijer (1992) proposed a new rule of $1/3$ "- $1/4$ " for solid particles plugging in a porous medium and it is more acceptable by other researchers.

According to Farina (1984), the solid invasion can be avoided by appropriate design of fluid system with the appropriate size and distribution of granular bridging agents to create an effective sealing impermeable filter cake very rapidly upon the face of formation, thereby inhibiting continual losses of small solids and potentially damaging mud filtrate into the formation. A proven method to reduce damage caused by particles invasion is flowing the well back with low drawdown rates and gradually increasing to maximum rate.

Figure 2.2 shows the solid particles and filtrate invading process. The upper arrow shows the direction of the solid invasion. The particles from the drilling fluid will invade into the formation during the initial spurt loss before the external cake is formed (top diagram). After a certain period, mud particles accumulated and trapped in the formation will form bridge which is called as bridging process (bottom diagram). Bridging process reduces pore size and consequently induces formation damage.

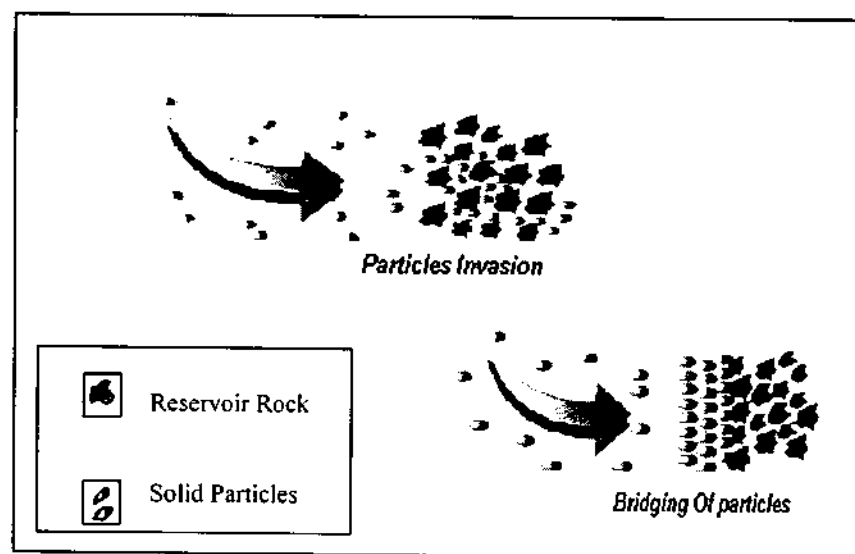


Figure 2.2: Particle invasion and bridging phenomenon in formation (Internet, 2000)

2.4.2 Filtrate invasion

The solids that accumulate on the wellbore, which formed the mud cake, restrict filtrate flow into the formation, but allow some fine particles to move with the filtrate into pore channels. These fine particles blocked flow channel and reduced productivity. The invasion of mud filtrate associated with fine particles may impair rock permeability around the wellbore. The intrusion of potential damaging filtrates into formation can occur during drilling, completion etc. Many researchers found that filtrate from drilling fluid invade much deeper than solids

into the formation. Permeability damage by mud filtrate may extend from few inches to a few feet (Di Jiao and Sharma, 1992; Reed, 1989; Krueger, 1982).

Different researchers have different findings about the depth of filtrate invasion. The depth of the filtrate invasion depends on initial rock permeability, mud types, mud composition, experimental condition, and experimental time (Di Jiao and Sharma, 1992; Marx and Rahman, 1984; Krueger, 1982; Krueger and Vogel, 1954; Record, 1976; Simpson, 1974). Zhang *et al.* (1993) in their laboratory studies found that the first 1" of the core surface exposed to the most severe damage due to filtrate invasion.

Initial rock permeability is dependant on the grain sizes. Generally larger pore grain will allow more filtrate invade deeper into the formation. Simpson (1974) found that the depth of filtrate invasion strongly depends on the type of muds. Figure 2.3 shows the depth of invasion of three mud systems plotted against time reveals that the depth of the invasion is less with oil-based mud, more with water-based mud, and in between with emulsion mud. This scenario only applicable to a water wet formation. Mud composition also contributes to the depth of the filtrate invasion; for example, *versatro* is used as the filtrate control agent in oil-based mud. Inadequate amount of it in the oil-based mud will cause higher filtrate loss that might cause severe filtrate invasion to the formation. According to Di Jiao and Sharma (1992), higher filtration rate does not necessary cause severe damage to the formation and it is depending on the size of the invading particles to the formation.

Different experimental conditions also contribute to different depth of filtrate invasion. When water-based mud is used at high temperature (above 300°F), it tends to degrade and change its mud rheological properties, especially viscosity. Generally, the viscosity changed will cause cutting transportation problem where the cutting from the formation is difficult to be transported out from the hole to surface. When this phenomenon occurs, the cutting may swept away the mud cake formed in the formation. Therefore, more filtrate will invade into the formation due to the bad mud cake formation.

Generally, longer exposure times will result in higher cumulative filtrate loss. According to Di Jiao and Sharma (1992), filtrate from the drilling fluid will never stop from invading into the formation during the experiment as well as actual drilling activities.

Different experiment conditions are also contributes to the depth of filtrate invasion. For example, when the experiment is conducted at higher annular velocity condition, it will cause deeper filtrate invasion. This is due to higher shear stress between the drilling fluid and the mud cake compared to at lower annular velocity condition.

Filtrate invasion can reduce the permeability of a formation by causing clays to swell or migrate, alter the salinity of pH, change the wettability, transport salts which may deposit in pore throats, and transporting fines which can seal off formation pores (Jones and Carpenter, 1991). This leads to pore throat plugging and adverse fluid-fluid interaction resulting in either emulsion/water block.

(I) Types of Fluid Filtration

During drilling, the drilling fluid is subjected to a differential pressure effect that causes filtration occurs in porous and permeable formation. The deposits of the solids causes formation of mud cake that is vital for borehole stability and limit the invasion of liquid phase into the permeable zones

(Vaussard *et al.*, 1986). During the well development, the estimation and prediction of the filtration properties under borehole condition is important to ensure less drilling problem and improved productivity.

Xinghui and Civan (1993) in their investigation found that filtrate loss to the formation occurred at high flow rate in the early stages (surge period), followed by the period of decreasing flow rate with time, which is also known as non-uniform cake formation period. The constant flow rate at the later stage is known as constant filtration period. There are many parameters that might affect the dynamic filtration such as annular velocity, temperature, hole angle etc. (Sharma *et al.*, 1991; Peden *et al.*, 1982).

Generally, down hole filtration can be categorized into three separate phenomenas, namely dynamic filtration through permeable well, dynamic filtration beneath bit, and static filtration (Vaussard *et al.*, 1986). There was no filter cake formed on the surface beneath the bit, but some experiments have shown that pore plugging could occur some distances ahead the bit (Ferguson and Klotz, 1953).

Dynamic filtration occurs above the bit while the drilling mud is circulating. The rate of filtrate loss during this period is higher than static condition. This is due to the shear stress between the drilling fluid and the mud cake, and also erosion process of the mud cake in dynamic condition is higher. The dynamic filtration rate will eventually reach a constant value when the optimum filter cake is achieved. According to Liu and Civan (1994), under dynamic filtration, the rate of the mud cake built-up is the difference between the rate of the mud particles deposition and the rate of particle erosion by the circulating mud.

Filtration beneath the bit causes no formation of mud caker. Filtration beneath the bit is controlled by formation properties, whereas static and dynamic filtration is controlled almost entirely by mud rheological properties.

Static filtration prevails when the fluid is not circulating. The pressure differences between the hydrostatic pressure of the mud column and pore pressure

lead to increase filtration. Under this condition, the thickness of the mud cake increases as filtration continues (Liu and Civan, 1994).

Generally, the filtration is in dynamic condition in most of the drilling activities, but static filtration is also important from both an experimental and a practical point of view. For example, deep holes require long periods of time to make trips when it is necessary to change drilling bits. During this trip, the mud is not circulated and the filtration is occurs due to the hydrostatic pressures induces in the formation.

Hassen (1980) found that from first 6 to 15 hours of dynamic filtration, equilibrium has not yet been accomplished, as filter cake being deposited would be eroded away by the fluid circulation. This is referred to as the period of “*dynamic non-equilibrium*”. When the filtration rate becomes constant, this period is referred to as the period of “*dynamic equilibrium filtration*”. In more typical conditions, dynamic invasion rate is greater than static.

An additional parameter is the volume of the spurt loss, which is always greater under dynamic condition than static condition (Argillier *et al.*, 1999). Figure 2.4 shows the comparison of dynamic and static filtrations by Argillier *et al.* (1999). The cumulative filtrate volume for dynamic filtration (either 1000 S^{-1} or 500 S^{-1}) is found to be higher than the static filtration at a given experimental period.

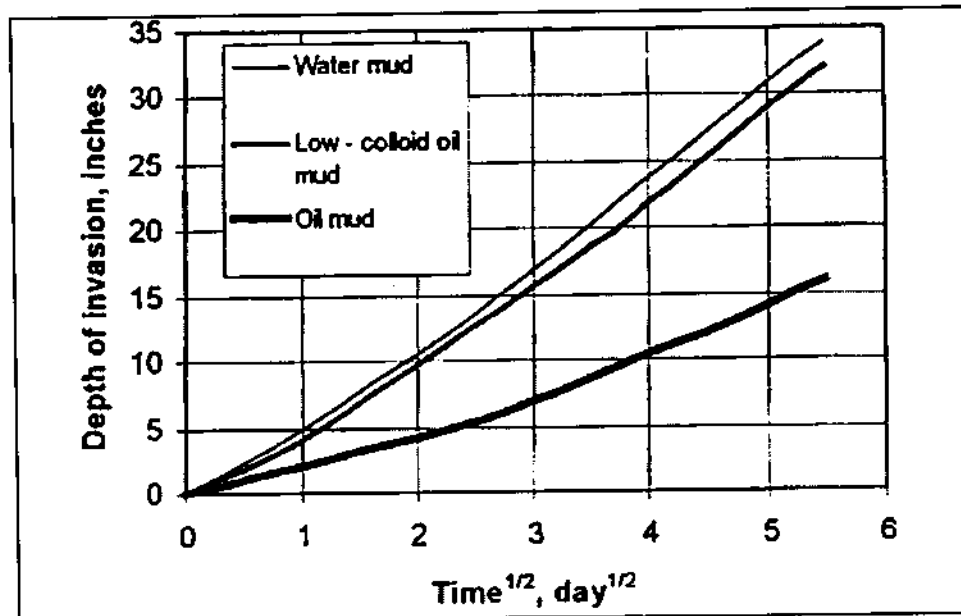


Figure 2.3: Depth of invasion data by Simpson (1974) plotted against the square root of time for different muds

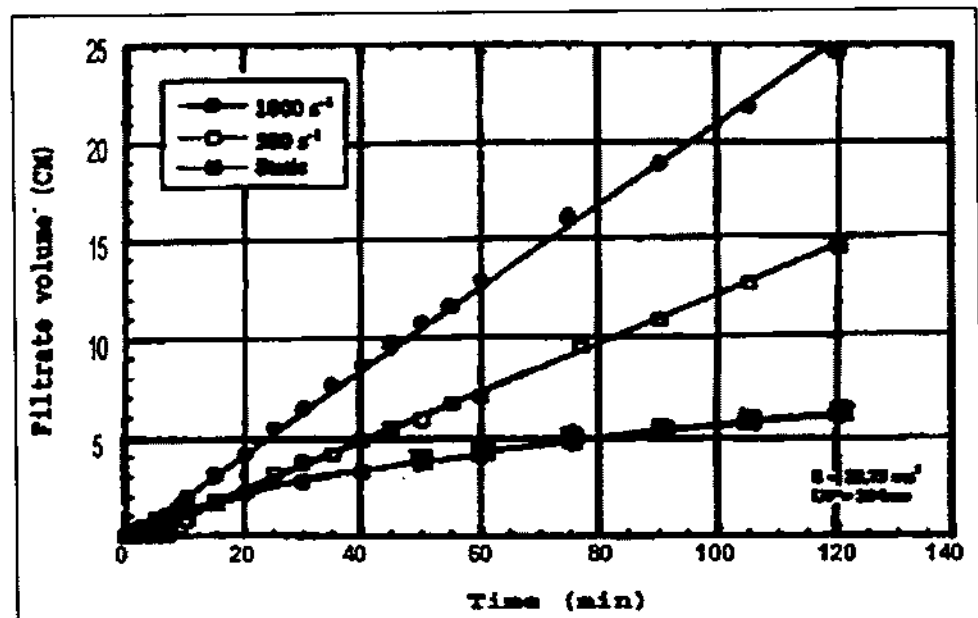


Figure 2.4: Comparison of dynamic and static filtrations (after Argillier *et al.* 1999)

(II) Reasons for Attempting to Quantify and Reduce Filtrate Volume

To exploit the advantage offered by a horizontal well for achieving higher oil productivity is to minimize damage to the formation caused by filtrate. The consequences of filtrate invasion are numerous and have been identified in many field operations such as drilling, completion, enhancing oil recovery etc (Ferguson and Moyes, 1997; Dairymple *et al.*, 1990; Krueger, 1982; Krueger and Vogel, 1954). The possible effects of foreign fluid invasion are:

- (a) emulsification with formation fluids resulting in highly viscous mixtures,
- (b) precipitation of solids such as insoluble salts and asphalt,
- (c) reduction of relative permeability to gas due to the presence of third immiscible fluid,
- (d) reduction of relative permeability to oil due to an increase of irreducible water saturation, and
- (e) shale swelling and wellbore sloughing.

(III) Techniques for Reducing Filtrate Damage

Filtrate from the drilling and cementing fluids can cause serious damage to formation and damage ratio is ranged from 0.3 to 1.0. The most effective way to control the filtrate damage from water-based mud or oil-based mud is by having higher concentration of Ca^{+} and Mg^{+} divalent in the mud system. This is due to clays, shales, and clayer rocks are found to be more stable exposed to drilling mud containing these ions (Krueger, 1982). Hassen (1980) also suggested some useful measures that can be used to reduce filtrate damage as follow:

- (a) reduce exposure time of prospective formation,
- (b) penetrate formation quickly using high bit weight as opposed to high rpm,

- (c) avoid stabilizer rotation and bits trips past through the formation,
- (d) avoid turbulent and high annular velocity at the formation,
- (e) extreme reduction in the value of API fluid loss is expensive and may lead to increase in dynamic filtration. Increased availability of dynamic filtration test equipment would greatly facilitate the proper selection of filtrate control agents and drilling fluid types,
- (f) spurt loss and high temperature pressure filtration data should be checked for most of the mud systems,
- (g) mud solid size data should be used along with formation pore size data to ensure that solid plugging is limited within one hundred millimeters, and
- (h) avoid using diesel prior to formation penetration.

2.4.3 Clay Swelling

Many formations contain potentially reactive materials in-situ in the matrix, including reactive swelling clays such as smectites or mixed layer clays, or deflocculatable materials such as kaolinite. Expansion or motion of these materials within the pore system will block pore throat, reduce the fluid flow, decrease effective porosity, and consequently reduce the fluid flow channel. According to Yost (1994), when the swelling clays are activated may destabilize the associated non-expanding clays and cause them to migrate. Mohan and Fogler (1997) explained that there are three processes lead to permeability reduction in clayey sedimentary formations:

- (I) Under favourable colloidal conditions, non-swelling clay, such as kaolinites, and illites can be released from the pore surface and then these particles migrate with the fluid flowing through porous formation.
- (II) Swelling clays such as smectites and mixed layer first expand under favorable ionic condition, and then disintegrated and migrated.

- (III) Fines attached to swelling clays can be dislodged and liberated during clay swelling, the phenomenon of which is referred to as fines migration.

Drilling the water sensitive zones with the presence of reactive clays such as smectite is the most troublesome. Smectite is considered to be the most hydratable and will swell many times of its normal size when it is exposed to the filtrate from the drilling fluid due to the rock-fluid incompatibility. This will reduce the radius of flow in the pore where is located and also facilitates the migration of particles by weakening the internal bond strength holding particles together. The rock-fluid incompatibility problems can prevent by using brines (NH_4Cl , KCl , CaCl_2 , NaCl) rather than fresh water for drilling and completion processes at clayer formation (Donovan and Jones, 1995). According to Keelen and Koepf (1977) 5% of the brine solutions are normally sufficient to retard clay damage caused by the filtrate from water-based drilling mud. Besides, oil-based mud can be used as drilling fluid for water sensitivity formation due to it lower fluid loss compared to water-based mud. Furthermore, the small amount of fluid loss from the oil-based mud is mostly oil and therefore inhibitive to water sensitivity formation.

Zhou (1995) stated “ clay swelling is a result of the increase in interlayer spacing in clay particles.” Clay swelling occurs when the clay is exposed to aqueous solution having a brine concentration below the critical salt concentration (Khilar and Fogler, 1983). Therefore, Zhou concluded, “ Clay swelling is controlled primarily by the composition of aqueous solutions that contact with clay.

2.4.4 Fines Migration

Formation damage can occur as a result of particle migration in producing wells. The particles can bridge across the pore throats in the near-wellbore region

and reduce well productivity. Fines migration is the internal movement of the formation fines or loosely attached in-situ formation particulates. It has been identified as the main contributor to permeability impairment in the porous media (Mueke, 1979). This phenomenon may occur during drilling process due to high fluid leak off rates of water based or oil-based mud filtrate into the near wellbore region caused by elevated hydrostatic overbalance pressures or excessive underbalanced pressure (Eng *et al.*, 1993). The fine particles may either come directly from drilling mud or formation itself during the fracturing process etc. The effect of fines migration is a major concern in drilling and production operations as well as subsurface contamination. The reduction in the conductivity of the porous media due to fines migration is well documented (Sarkar and Sharma, 1988; Miranda and Underdown, 1993).

According to Bennion *et al.* (1995), fines migration is controlled by a number of factors including wettability of the porous media (fines generally tend to migrate exclusive in the phase that wets the rock), pore size distribution, size of fines, and velocity of fluid flowing in the interstitial spaces.

The migratable fines including the non-expanding authigenic clay minerals (kaolinite, illites and chlorites), expanding authigenic clay minerals (smectite montmorillonite, and attapulgite) were identified earlier (Mueke, 1979). These fines loosely released due to colloidal/hydrodynamic forces exerted by the invading fluids to the formation. The release fines if present in sufficient quantities in the flowing fluid, will plug the pore throats thereby reduce the permeability of the rock.

Other loose fines such as quartz or feldspar can cause permeability impairment by migrating just as clay. Chemical clay stabilizer can be used to control fines migration, and gradually increasing the production rates may prevent fines plugging in the pore throats (Farina, 1984).

2.4.5 Precipitation from Incompatible Fluids

Oil-based or water-based mud filtrates invading into the near wellbore region during overbalanced drilling processes can react adversely with in-situ hydrocarbons or water in the matrix. This phenomenon may reduce permeability such as formation of insoluble precipitate, scales etc. Precipitation includes inorganic precipitate and organic precipitate. Typical inorganic precipitate includes anhydrite (CaCO_3), barite (BaSO_4) etc. originating from the mixing seawater with brine, and rock brine interaction (Oddo and Tomson, 1994, Atkinson and Mecik, 1997). On the other hand, the organic precipitates encountered in petroleum production are paraffin and asphaltene. Paraffin is an inert substance while asphaltene is reactive substance. They are sticky, thick, and deformable precipitates (Chung, 1992; Ring *et al.*, 1994)

If the injected fluids are not compatible with the formation fluid, they may form precipitates, scale, stable emulsion etc. Precipitation is the most serious mechanism due to the fluid-fluid incompatibility and may seriously cause permeability damage. For example, to kill a well that is having connate water with high concentration of bicarbonate by using calcium chloride will cause calcium carbonate to precipitate and consequently cause the damage to the wellbore. Precipitates cause damage by moving with the flowing fluids, lodging in pore throats, and plugging flow channel.

According to Ziadi Yaacob and Azmeer (2000), senior drilling engineer from Exxonmobil-Esso Production Malaysia Inc. (EM-EPMI), precipitation caused by the incompatibility of drilling fluid and formation fluid brings serious problem to well. This problem is permanent and difficult to overcome by remedial jobs such as stimulation.

2.4.6 Emulsion Block

According to Bennion *et al.* (1995), emulsion is a problem that always associates with heavy oil operations where both oil and water are simultaneously being produced. The water-in-oil emulsion tends to be the problematic as it exhibits very high viscosity. It can be generated due to turbulence flow, the presence of sand, silt or dispersed fines, paraffin, iron sulphide etc. Emulsion can impair fluid flow towards the wellbore and it is a serious formation damage problem.

According to McKinney and Azar (1988), emulsifier is required for the inverted-emulsion drilling mud in order to maintain a good quality and a stable emulsion system. However, excessive concentration of emulsifier will develop a high shear emulsion system when they contact with the formation fluids. The high shear and presence of the emulsifier can lead to the formation of an emulsion blocked.

Emulsion blocked leads to reduction in the mobility of reservoir fluids and reduces the effective permeability of the formation. This emulsion can be very stable and has viscosity of up to 2000 cP (Peden, 1982).

2.4.7 Surface Adsorption/ Wettability Alteration

Most drilling fluid contains a variety of chemical additives to improve the mud rheological properties, emulsion control, corrosion inhibition and compounds which can be preferentially absorbed on the surface of the rock. The physical adsorption of these compounds can cause reduction in permeability by blocking of the pore system. Besides, in some cases, these additives may be incompatible with the formation fluids or rock, or exhibit a high tendency for physical adsorption. This can result in a number of undesirable phenomena such as permeability reductions

due to the physical adsorption or wettability alteration due to surfactant adsorption (Bennion *et al.*, 1996).

2.4.8 Mechanical Induced Damage

Mechanical action of the bit, combined with cuttings, poor hole cleaning, and a poorly centralized drill string may result in the formation of a thin “ glaze” of low permeability surrounding the wellbore. This problem is aggravated by straight gas drilling operation, where a large amount of heat is generated at the rock bit interface due to poor heat transfer capacity of gas-based drilling fluid. An openhole completion in horizontal wells tend to be the most probable candidates for this type of damage (Bennion *et al.*, 1996).

2.4.9 Biologically Induced Formation Damage

Both aerobic and anaerobic bacteria can be introduced into the formation at any time during drilling, completion, stimulation, and workover operations when aqueous phase fluids are utilized. Bacteria produce polysaccharide polymer slimes as waste product, which can influence porosity and reduce permeability in near wellbore region. According to Yeager (1998), microbes also caused precipitation of iron sulfides or generation of microbial corrosion product. According to Bennion *et al.* (1995) there are three major problems associated with the introduction and propagation of bacteria in porous media as follows:

(1) Plugging:

Bacteria produce extremely high molecular weight polysaccharide polymer and form a biofilm upon the surface of the formation to protect them from fluid shear effect. The physical adsorption of this biofilm can cause a

significant reduction in injectivity or productivity of a given well over an extended period of time.

(2) Corrosion problem:

Bacteria, when colonized on metal surfaces, formed small electrochemical cell which result in a hydrogen reduction reaction and causes the corrosion and pitting problems on surface such as downhole tubing, pumps and surface facilities.

(3) Toxicity concern:

Sulphate reducing bacteria, is a troublesome family of anaerobic bacteria present in naturally occurring formation water or injection water and create toxic hydrogen sulphide gas as a byproduct. This H_2S gas is highly soluble in oil or water and can be potentially toxic or lethal to human if its concentration greater than approximately 1000 ppm.

Biological damage problems are extremely difficult to remediate, particularly with sour gas once this gas has propagated to a considerable distance into the reservoir. Therefore, the best technique associated with biologically induced damage is to ensure continuous monitoring of surface and downhole bacteria levels. This can be performed by using rapid detection field kits and an aggressive biocide and treating program for not only continuously injected fluids such as injection water, but also fluid used for drilling, completion, workover or stimulation operations.

2.5 Comparison of Damage in Horizontal and Vertical Well

Horizontal well has become importance as it can increase the oil productivity by four times compared to the conventional vertical well. According to Bennion *et al.* (1996), even though the horizontal well can increase the oil productivity, but it is more susceptible to damage compared to vertical well. There

are number of reasons why horizontal wells appear to be more susceptible to formation damage as follows:

- (I) The completion practices for most of the horizontal well is barefoot completion, or with some types of slotted or prepacked liner. Therefore, a shallow damage caused by the particles or filtrate invasion is more significant in horizontal wells due to the need to produce through the zone of impaired permeability during ultimate production compared to a cased completion in vertical well. Whereas, the shallow particles and filtrate invasion in vertical well can be penetrated by a typical perforation charge.
- (II) Drilling time for horizontal well is usually greater than vertical wells. Therefore, the mud invasion is deeper and severer due to longer exposure time. Fluid exposure time at the heel of the well may be significant if poor mud rheological properties is present in an overbalance condition, or if the mud filter cake is continuously disturbed by a poorly centralized drill string or multiple tripping operations. Invasion depth of damaging mud filtrate and solids into the near wellbore region may be substantially greater than in a conventional vertical well. In addition, the fluid flow for a horizontal well is affected by anisotropy of permeability.
- (III) The large exposed area of a horizontal well often results in zones of highly variable reservoir quality being penetrated. High permeability streaks preferentially clean up upon drawdown resulting in minimal drawdown pressure being applied to more heavily damaged and invaded portion of the well, making it difficult to obtain an effective cleanup.
- (IV) Damaged vertical wells may effectively stimulated by using variety of penetrative techniques such as hydraulic fracturing or acid treatments, heat treatment etc. These types of processes are not readily

economically applied to horizontal wells due to cost and technical considerations associated with attempting to simulate a section of hundreds meters in length (instead of only a few meters in length as often in a vertical well). Therefore, stimulation treatment of sandstones in horizontal well tends to be relatively non-invasion such as acid wash and may only effective in penetrating shallow near wellbore damage.

2.6 The Possible Effect of Drill String Eccentricity on Formation Damage

Permeability impairment of the formation can occur during any stages of well development and reservoir exploitation due to the adverse chemical or physical reactions between reservoir rock and formation fluid (Ohen and Civan, 1991). Drill string eccentricity in horizontal hole is believed to be one of the physical mechanisms that can cause formation damage. In this research study, focus will be given on the effect of the drill string eccentricity on formation damage and also its effects when coupled with differential pressure, drill string rotation, and exposure time.

Drill string eccentricity in this study is defined as the phenomenon where the drill string moves away from the center of the hole towards the bottom part of hole in horizontal hole due to gravitational effect. The eccentric condition of drill string that measured from the center of the hole towards the bottom part of the hole is depicted in Figure 2.5. From Figure 2.5, higher drill string eccentricity will bring the smaller annular; for example at 25%, 50%, and 75% drill string eccentricity conditions, the remaining annular space at the bottom part of the hole is 23.8 mm, 15.9 mm, and 7.9 mm respectively.

At 0% drill string eccentricity condition, it is believed that the mud flow behavior in the annulus was turbulent at the both sides (upper and bottom parts of a hole) and the rotation of drill string will generate additional forces that might cause the swirling effect to occur. When the drill string eccentricity increased from 0% to

25%, 50%, and 75%, the flow pattern presence at the bottom part of the hole (drill string moved close to the bottom part of hole) would change from turbulent to laminar. This was due to the formation of smaller annulus at bottom part of the hole when the drill string eccentricity increased. It is believed that at higher drill string eccentricity condition, the induced differential pressure and forces generated by drill string rotation acting on the flowing mud at smaller annulus is higher compared to the upper part of the hole. Therefore higher drill string eccentricity conditions would cause higher damage due to more filtrate or mud particles were invaded into it.

Generally, when the rotating drill string eccentricity coupled with higher induced differential pressure (<200 psi) at certain exposure time will cause more severe damage due to the forces that generated in the wellbore is stronger. Therefore it will push solid and filtrate particles invade deeper into the formation and cause severe formation damage. Conversely when higher rotating drill string eccentricity (150 rpm) coupled with higher induced differential pressure (>250 psi), it is believed that it may cause the micro fractures to the Berea sandstones (test samples) due to these forces had exceeded the fracture limit of the Berea cores.

Generally, longer exposure time will permit more solid and fluid particles invade into test samples and caused severe internal plugging of pore space that causes severe formation damage. It is believed that, the invasion of fluid and solid particles into test samples become higher whenever the exposure time for the experiment is increased.

The drill string rotation speed could bring certain degree of formation damage. The drill string rotation would generate extra forces that push the particulates from drilling mud into the test samples. Generally, at higher drill string rotation speed condition, it would generate higher forces, which could push more mud particles into the formation and cause severe formation damage. In addition, higher drill string eccentricity condition in a hole would result in large radial variation in annular flow velocity, where higher velocity in wide side (upper part) and lower in annular low side (bottom part). Therefore, the increase of drill

string rotation speed especially at higher drill string eccentricity would push more particulates invade into the lower part of formation. This is due to the accumulated force generated by the drill string rotation and induced differential pressure in annular low side is greater. Thus they might push the particulates invade easily into formation and cause severe damage.

The effect of rotating drill string eccentricity in horizontal well is believed to be more severe compared to the vertical well. This is believed due to the anisotropic flow effect in horizontal well is completely different compared to vertical well.

The fluid flow in vertical well is uniform strata of crossed bedded planes as depicted in Figure 2.6. Whereas in horizontal well, sources of the fluid flow are from the both vertical and horizontal direction as depicted in Figure 2.6. In addition, the invasion damage profile for vertical well is one direction (x-direction, Figure 2.7), but the invasion profile for horizontal well is elliptical in nature where the invasion damage is dominated in x and y direction as depicted in Figure 2.7.

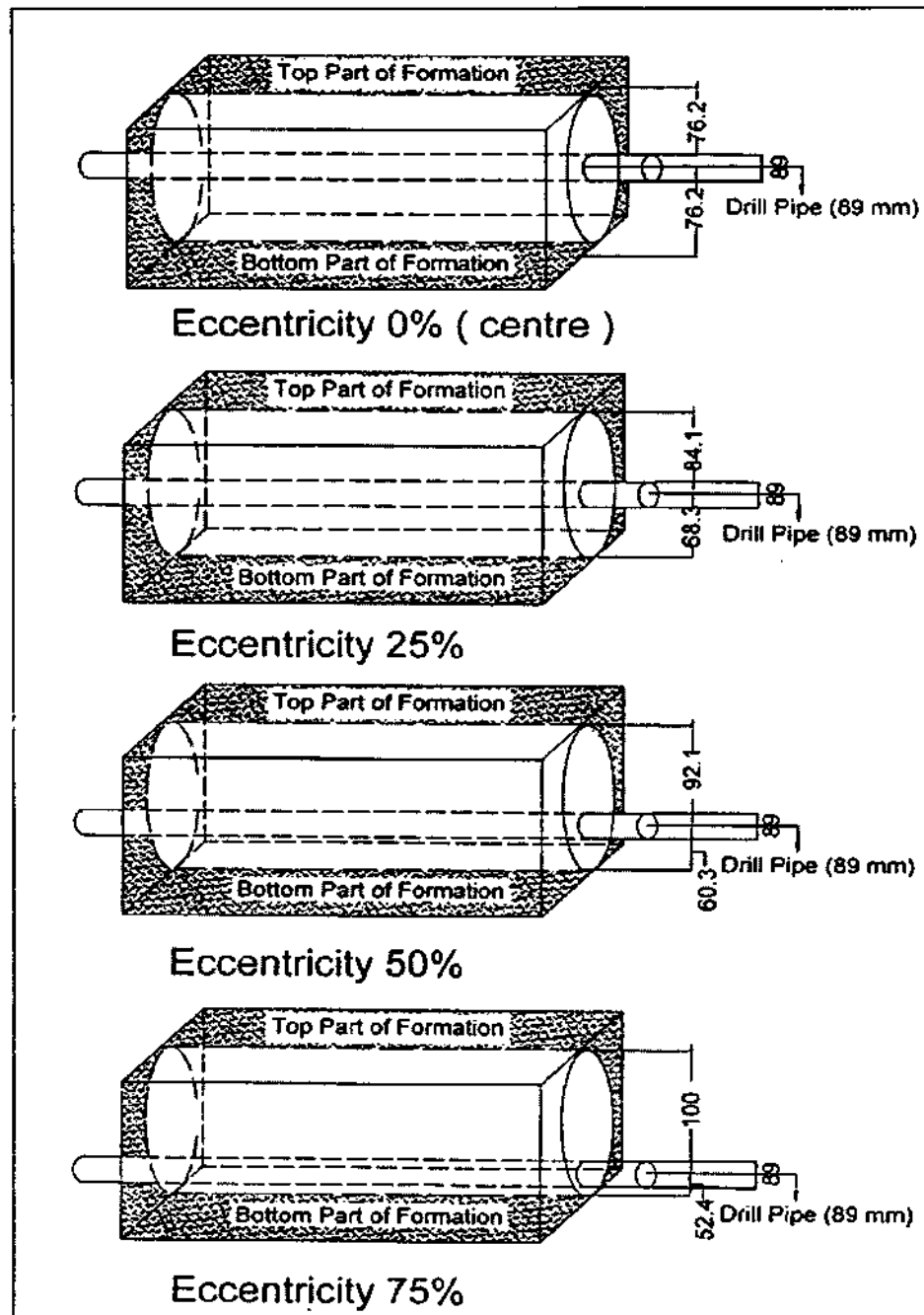


Figure 2.5: Eccentricity of the rotating drill string in horizontal wells

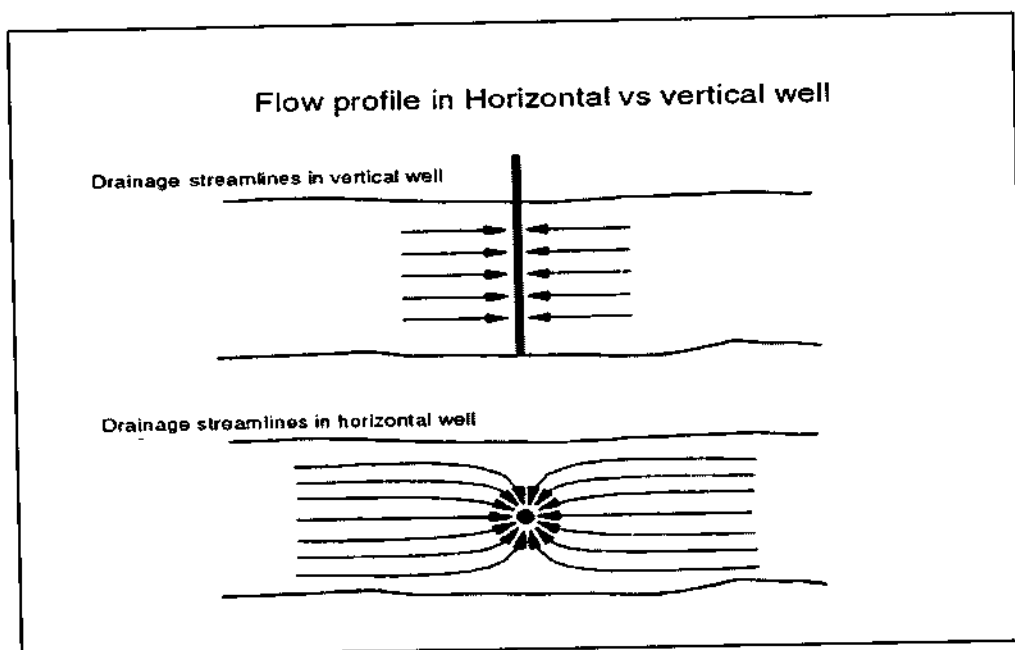


Figure 2.6: Flow profile in horizontal and vertical wells

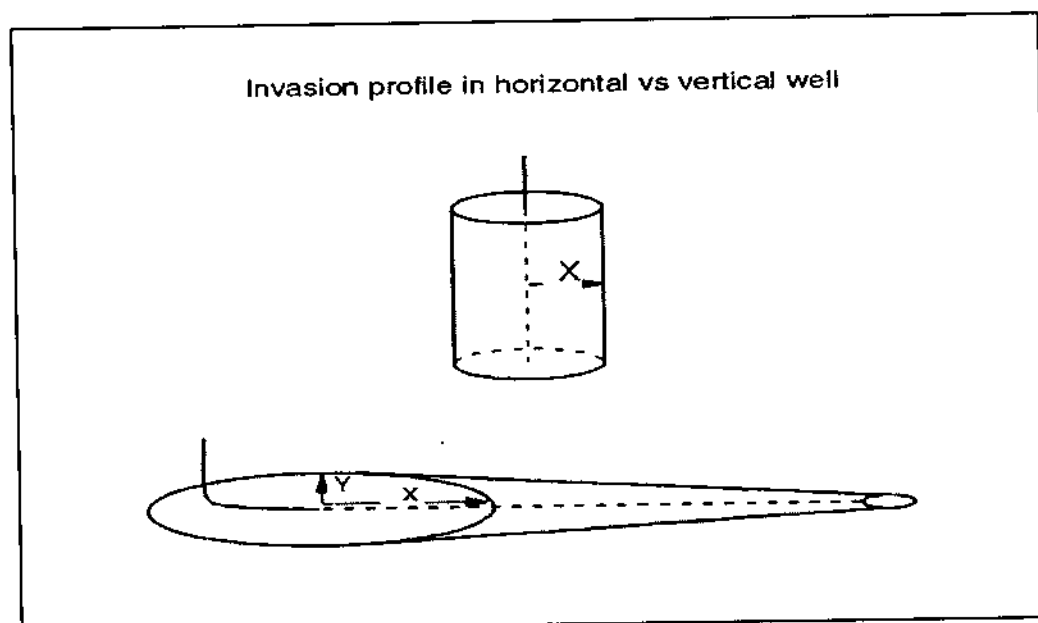


Figure 2.7: Invasion profile in horizontal and vertical wells

2.7 The Possible Factors that Tend to Enhance Wellbore Damage

There are many physical parameters that can enhance the damage mechanisms such as differential pressure, exposure time, temperature, annular velocity, particles size, drill string rotating speed, overbalanced pressure, mud composition etc. (Guota and Civan, 1994; Di Jiao and Sharma, 1992; Shaw and Chee, 1996; Marx and Rahman, 1984; Krueger, 1982; Records, 1976; Krueger and Vogel, 1954). All the mentioned parameters that had been previously studied by the researchers were for vertical drilling. According to Bennion (1996) the same physical parameters would also contribute to the wellbore damage. Besides, high solid contents, poor fluid rheology, and presence of zones of extreme permeability etc. also contribute to the wellbore damage.

(I) Differential Pressure

Differential pressure or overbalanced pressure is one of the most important physical parameters that is significant influence the formation damage. Generally, higher induced differential pressure could cause severe formation damage. This is due to the presence of strong force pushing the filtrate and solid particles into pores space at higher induced differential pressure and consequently cause formation damage (Zulkeffli *et al.*, 2000)

Differential pressure between the wellbore and formation is an important parameter that governs the damage and clean-up phases of the operation especially damage caused by solid invasion. It is also important for the mud cake compaction and once the formed, it is use to prevent the mud cake to be flushed out by the higher formation pressure. Marx and Rahman (1984) in a laboratory studies on formation damage, found that unfavorable increase in differential pressure would cause the infiltration of mud solid due to lack of formation of the external cake and would cause the damage to the formation.

Higher differential pressure leads to severe formation damage for the first two inches of the core samples. Different researchers have different findings about the depth of the solids or filtrate invasion due to the induced differential pressure. It depends on the initial permeability of the rock and mud system used in the experiment (Marx and Rahman, 1987; Krueger, 1982; Peden *et al.*, 1982; Gray and Darley, 1982).

Figure 2.8 shows the filtrate volume (ml) plotted against time(s) for formation damage studies carried out by Teow, (1999) by using oil-based mud. It is obviously showed that at the initial stage (early 5 minutes) a tremendous filtrate loss occurred and this phenomenon is called as surge period. When filtrate loss increases gradually at a very low rate (approximately less than 1 ml per minute) shows that mud cake started to form (after 15 minutes). The filtrate loss continued to occur for the subsequent period even after 30 minutes as shown in the Figure 2.8. It is found that higher induced differential pressure caused higher filtrate loss due to the stronger force created by increased differential pressure would push more solids and filtrate particles into test samples.

Damage ratio can be defined as damage permeability divided by initial permeability (K_d/k_i). The lower the damage ratio reflects severe the wellbore damage. Figure 2.9 shows the damage ratio (%) plotted against time(s) and the experimental was conducted at constant annular velocity (120 ft/min) by using water-based mud at two different induced differential pressures. Higher differential pressure (200 psi) caused lower damage ratio than lower differential pressure (100 psi) as depicted in the Figure 2.9. This is due to the higher force generated by the higher differential pressure permit more solids or filtrate invade deeper into the formation and consequently causes severe formation damage.

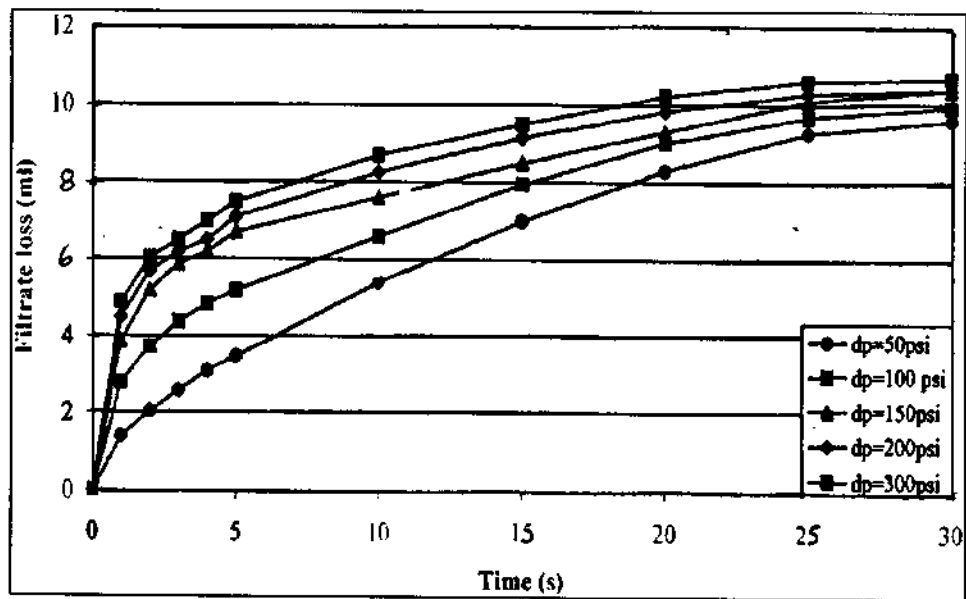


Figure 2.8: The relationship between filtrate loss against time (Teow, 1999)

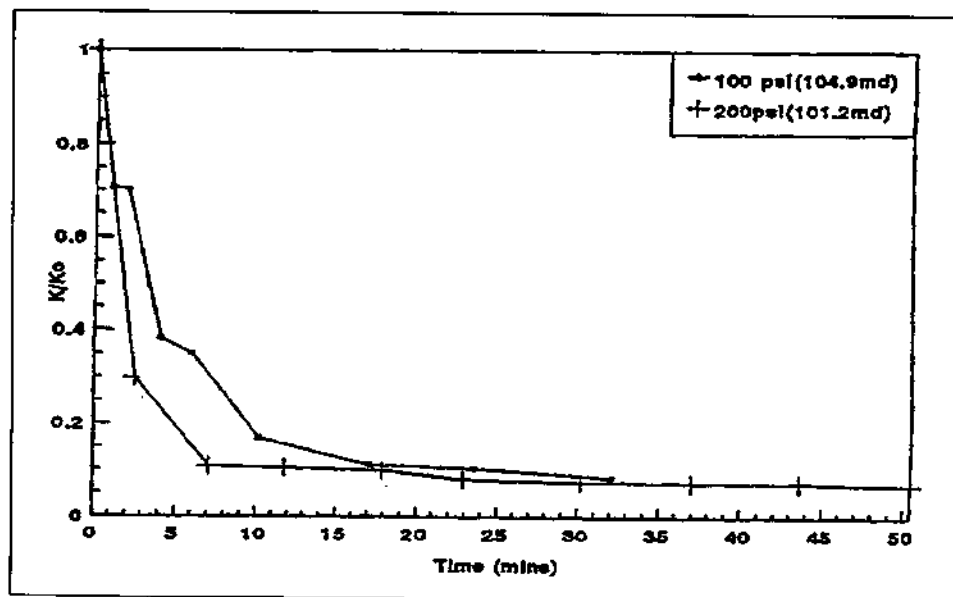


Figure 2.9: The relationship between differential pressure and damage ratio

(II) Annular Velocity

In horizontal drilling, annular velocity is an important parameter for cutting transportation and wellbore cleaning processes. Inappropriate applies of annular velocity during drilling horizontal well will initiate formation damage.

According to Rahman (1984), higher annular velocity will provoke higher filtration rates due to the higher hydrodynamic forces exerted to drilling mud, thus it leads to severe formation damage. Higher annular velocity cause higher cumulative filtrate loss, thus it provokes the filtrate to invade deeper into the formation. This phenomenon leads to formation damage, which is also known as fines/particles plugging.

Figure 2.10 shows the damage ratio plotted against the annular velocity for formation damage studied for the duration of one hour and at constant reservoir temperature of 70°C. Figure 2.7 shows that higher annular velocity (87×10^{-2} m/s) would give lower damage ratio compared to lower annular velocity (25×10^{-2} m/s). This is due to the filtrate or solid particles invade deeper into the formation at higher annular velocity. It is found that, the damage ratio for annular velocity at 25×10^{-2} m/s and 87×10^{-2} m/ at 90 bars were 80%, 60% respectively.

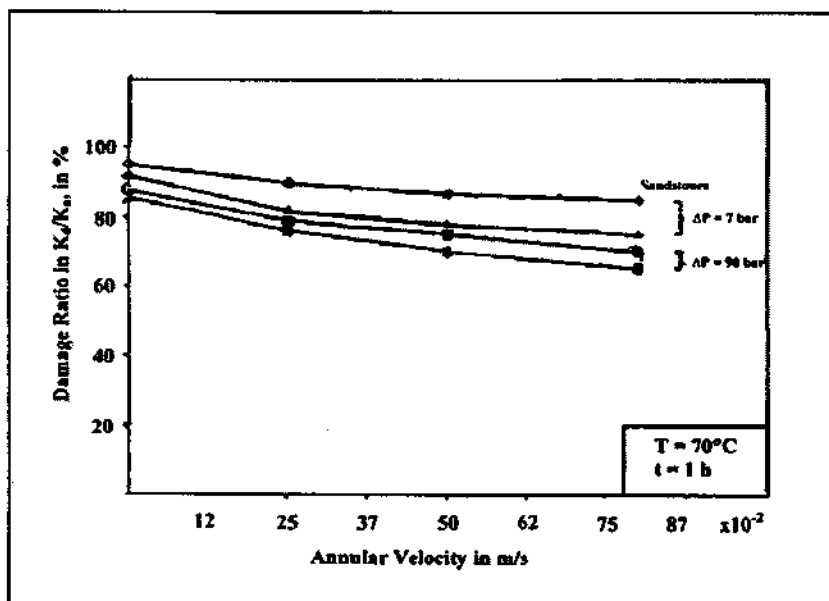


Figure 2.10: The effect of annular velocity in damage ratio
(Marx and Rahman, 1987)

(III) Mud Weight

One of the importance functions of drilling fluid is to provide sufficient hydrostatic pressure across the wellbore. In drilling activities, it is difficult to achieve balanced drilling condition that will not damage the formation. Therefore, an overbalanced hydrostatic pressure of 200 psi to 300 psi is implemented for typically drilling activities.

Higher overbalance pressure can be achieved by adding more weighting agent such as barite into the drilling fluid. An excessive mud weight condition is considered severe and would provoke formation damage especially in horizontal hole, as more solid particles tend to invade into the formation.

(IV) Exposure Time

According to Ray *et al.* (1998) the filtration or invasion of mud into formation, both are dependent on the duration of exposed formation to drilling fluid and the amount of pressure differential operating at the sand face. Exposure time is important when drilling through unstable zone such as shale formation. This is due to the tendency of shale formation to absorb the filtrate from drilling fluid or formation fluids, thus it tends thus it tends to cause wellbore sloughing that may result pipe sticking and wellbore collapse.

Generally, an oil well needs to be completed at short time. This is to reduce damage caused by completion fluid. If any completion work requires longer time especially in shale formation, wellbore sloughing may happen and it may cause pipe sticking. Tovar and Azar (1996) in their investigation found that the degree of formation damage increased with the increased of exposure time at certain differential pressure and annular velocity. Therefore, it is vital to employ lower exposure time for drilling and completion works at the pay zone in order to achieve higher productivity.

Figure 2.11 shows the result of damage ratio plotted against exposure time for the experiment carried out by using the water-based mud for 60 minutes. Figure 2.11 obviously shows that higher exposure time give lower damage ratio for all different cores used in the experiment. For example, the limestone core registered damage ratio of 90% after 30 minutes but damage ratio reduced to 70% after 40 minutes and Berea cores registered damage ratio of 70% at the end of first 5 minutes but tremendously reduced to 15% after 30 minutes. Figure 2.11 shows that the longer the exposure time, more filtrate would invade farther into formation thus it leads to severe formation damage. In horizontal well, drilling time is a critical criterion that needs to give serious consideration while drilling. This is due to the exposure area in horizontal well is larger than vertical wells. Thus it may cause severe damage to the wellbore if the longer drilling time required to drill a hole.

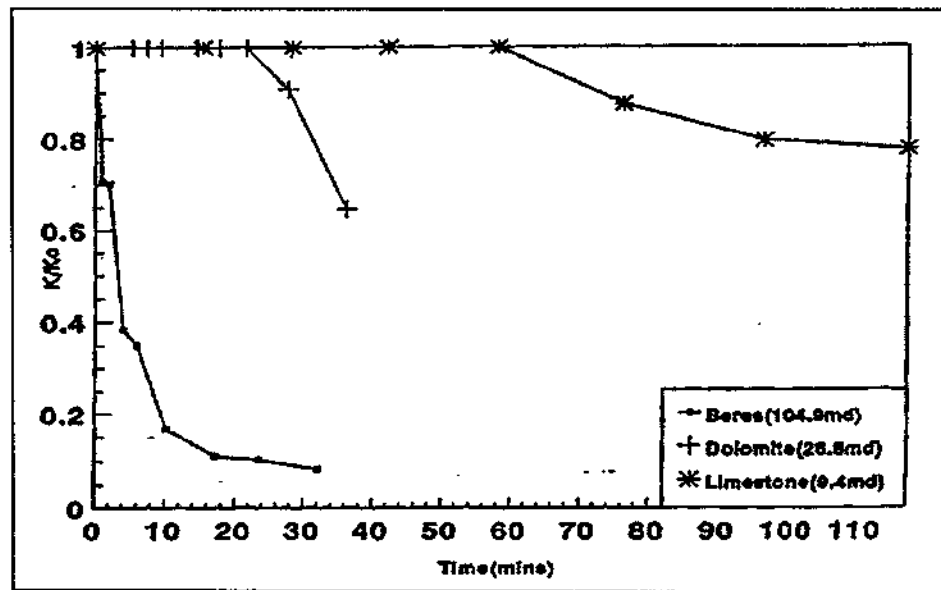


Figure 2.11: The effect of exposure time on damage ratio
(Tovar and Azar, 1996)

(V) Temperature

Drilling fluid viscosity is very sensitive to temperature especially water-based mud at high temperature. The temperature has great influence on hydrodynamic and thermodynamic forces in drilling fluid that play critical role in releasing, migration, and retention rate of fines in reservoir rock. Allen and Riley (1988) in their studies found that temperature effect on formation damage was severe and could cause up to 50% reduction in initial permeability. The damage ratio found to be decreased with temperature; for example 51% initial damage observed at 75°F compared to 41% damage at 350°F. Temperature effect on formation damage is often ignored, but in reality it is a parameter that can cause formation damage especially when drilling through a high temperature reservoir by using water-based mud where the mud properties tends to degrade.

Rahman (1984) found that water-based mud was very sensitive to temperature above 158°F due to the thermal degradation of mud. Generally, thermal degradation changes the drilling mud viscosity and gel strength.

For highly temperature reservoir, it is advisable to use oil-based mud as it is thermally stable. Figure 2.12 shows the damage ratio plotted against temperature. As temperature increase, core samples with higher porosity experienced severe damage than the lower porosity core samples. This is due to the fact that at higher temperature condition, the thermal expansion on rock pore space is increase, thus leads to the invasion of solid particles to the formation.

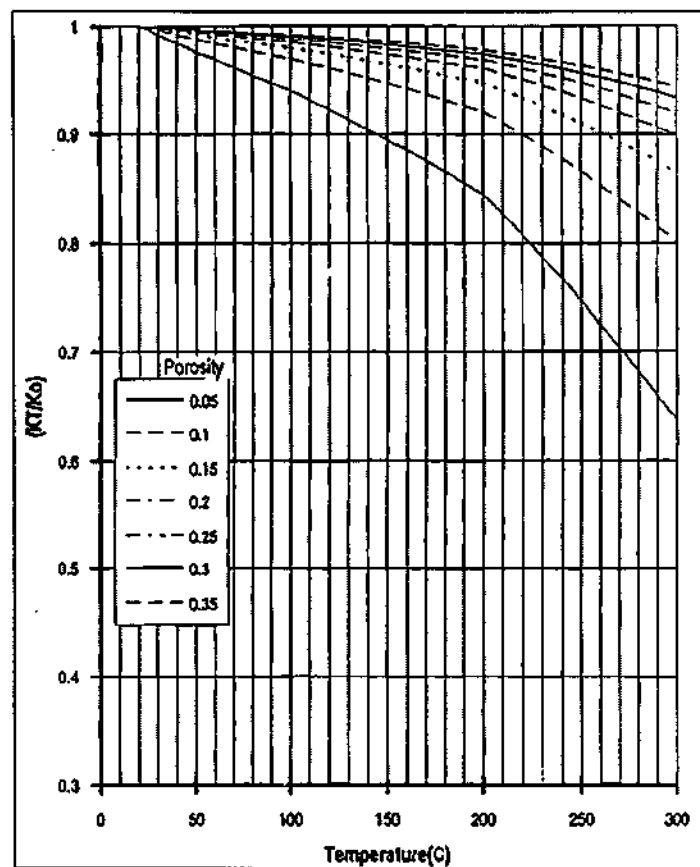


Figure 2.12: The effect of temperature on damage ratio
(Gupta, A. and Civan, F., 1994)

(VI) Particle Size

Generally, mud spurt loss occurs before the filter cake is established and a good drilling mud is required to reduce the mud spurt loss. Since the mud cake forming process is largely dependent on the solid size, therefore solid particle size larger than pore opening cannot enter the pore and are continuously circulating in the annular mud system. Generally the size of the particles in most of the mud system is relatively small and will diminish as mud is circulated through bit, wellbore, and surface facilities and some of them may invade into the pore of permeable formation.

According to Byung Lee *et al.* (1989), particles that are less than one-sixth ($1/6$) of the average pore size of the formation will probably flow freely into the formation and will be produced back; thus they are less likely to cause problems than larger particles. Mud particles that are between one-sixth ($1/6$) and one half ($1/2$) the average pore throat size will invade some distance into the formation and may form bridge or become trap. This particle size can potentially damage the formation by plugging the fluid flow channels. Whereas particles larger than one half ($> 1/2$) of the average pore throat size will stop at the borehole and form mud cake.

The pore throat size of the formation can be determined by taking the square root of rock permeability (\sqrt{K}) (Byung Lee, *et al.* 1989). Table 2.1 shows a list of particle sizes that can cause formation damage. By knowing and understanding the pore throat size calculation, the formation damage caused by particles can be controlled or minimize effectively.

Table 2.1: A list of particle sizes that can cause formation damage by using calculation method (Byung Lee *et al.*, 1989)

Formation Permeability (K in md)	Pore Sizes (Microns)	Particles That Invade (Microns)	Particles That Bridge (Microns)	Particles That Plug (Microns)
1000	31.6	<5.4	5.4-15.8	>15.8
500	22.4	<3.8	3.8-11.2	>11.2
100	10.0	<1.7	1.7-5.0	>5.0
50	7.1	<1.2	1.2-3.6	>3.6
10	3.2	<0.5	0.5-1.6	>1.6
5	2.2	<0.4	0.4-1.1	>1.1
1	1.0	<0.2	0.2-0.5	>0.5

(VII) High Solids Content

High concentration of artificial or natural solids of inappropriately size in the mud system will either invade into the rock matrix or screen off on formation face to form porous, high permeability, thick filter cake. This phenomenon may result in long term filtrate seepage and stuck pipe if the number of solids particles accumulated is significant (Bennion *et al.*, 1996). In open hole completion practice, an appropriate size distribution of particulate in mud system is essential to establish a low permeability filter cake to minimize solids invasion directly at near wellbore region.

(VIII) Poor Fluid Rheology

The use of high API fluid loss and low viscosity fluids will generally increase the potential for filtrate losses to the formation. Consideration is often given to the use of “clear” fluid with no added solids with the anticipation that the

based fluid is compatible with the formation fluid and no damage will occur even if significant fluid losses occur during drilling. The presence of naturally generated solids in clear fluid system often result in near wellbore mechanical damage as large volume of the based fluid together with inappropriately generated solids are carried off into the formation (Bennion *et al.*, 1996).

(IX) Presence of Zones of Extreme Permeability

Fluid losses and potential damage will generally be more significant in zones of high permeability such as fractures or interconnected vugular porosity, which may be penetrated by the horizontal drilling. Conversely, if invasion depth is not too significant, these zones may be the most easiest to clean up in some respects due to more favorable capillary pressure relations and larger pore size (Bennion *et al.*, 1996).

2.8 Formation Damage Identification

When a well is producing below its optimum productivity, the source of the problem must be identified before corrective measures can be taken (Schaible, 1986). The identification of formation damage in oil field is difficult, particularly for an oil field with multiple formation damage mechanisms. Tague (2000) proposed a logical and comprehensive method to identify potential damage mechanisms while stepping through the life of a well. This is called "Life-Cycle Approach." This approach provides a template for categorizing various forms of formation damage likely to be encountered as depicted in Figure 2.13. The life-cycle approach begins with the deposition of the reservoir and concludes with the abandonment of the well. By following this approach, all possible mechanisms of formation damage can be identified and classified by types and potential impact on production.

(I) Deposition

Generally, formation damage is inherently determined by the composition of reservoir. Thus an understanding of the depositional environment provides a basis for identifying many forms of formation damage. Depositional analysis requires mineralogical studies and compositional analysis of oil, gas, and formation fluid.

Mineralogical studies of core samples, sieves analysis, SEM photomicrographs, and XRD reveal the reservoir composition such as quartz, feldspar, and clay. Sieves analysis provides information of the formation, whether it is a consolidated or poorly sorted reservoir. Depositional analysis can identify several basis damage mechanisms that include clay swelling, fines migration, organic deposition, and scale precipitation.

(II) Drilling

Formation damage is a fundamental concern in drilling. Research works have identified many damage mechanisms caused by drilling and numerous procedures have been designed to prevent formation damage from occurring. Despite this, it is still important to identify all potential damage mechanisms related to drilling and to review the procedures used in the field. This is due to different fields are having different wellbore damage problems. Generally, the potential forms of damage during drilling are:

- (a) clay swelling due to fresh water invasion from mud if a well drilled by using water based mud in water sensitive zone,
- (b) filtrate invasion from the mud system,
- (c) drilling fluid contamination, and etc.

(III) Completion

Once an oil well is drilled, proper completion practice becomes paramount. Again, formation damage is a fundamental concern and is usually avoidable. Yet, most of the completion procedures inherently cause formation damage. Generally, the formation damage caused by the completion procedures is inability to remove the mud cake, near wellbore damage, and perforating damage (Tague, 2000).

(IV) Production

Once an oil well is completed, it is put on production. Production itself can lead to many types of formation damage that capable of drastically reducing productivity. The typical form of formation damage due to production includes paraffin or asphaltene deposition, sand and fines migration, wettability alteration, and emulsion blocked. Identifying the damage mechanisms caused by production is difficult and always relies extensively on data gathered from analyzing the depositional environment (Tague, 2000).

(V) Well Intervention

During production, well intervention is often necessary for a variety of reasons when high volume of sand production and shorter downhole pumps life are encountered. Well intervention itself, if improperly conducted can cause numerous forms of formation damage. Identifying the damage mechanisms related to the well intervention can improve remediation jobs and make prevention much easier. The commonly found causes of formation damage during the well intervention are particulates plugging while killing the well and precipitates due to the poorly designed well stimulation treatments (Tague, 2000).

(VI) Abandonment

Abandonment is not a normal source of formation damage. Failure to adequately isolate the presence of fresh water, high-pressure aquifer above the production well during well abandonment could lead to unwanted dump of flooding. The damage mechanism during well abandonment is most likely due to the fluid incompatibility near wells (Tague, 2000).

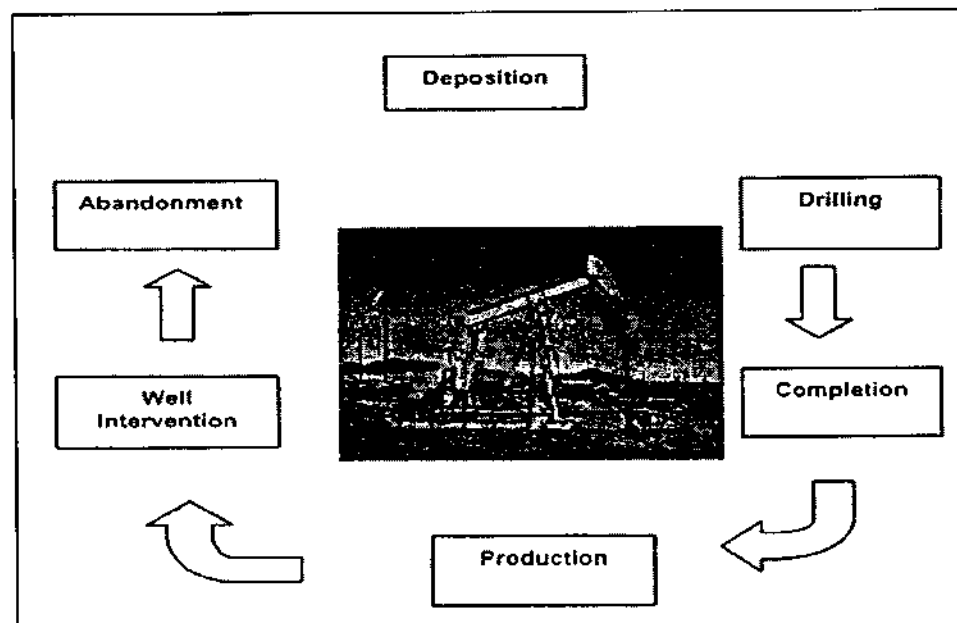


Figure 2.13: Life cycle approach used to identify formation damage by (Tague, 2000)

2.8.1 Quantification of Formation Damage

The typical indication of formation damage is when the well does not respond as expected on initial production or after workover, or an excessive pressure buildup at injection wells. It is also suspected when a well is producing below predicted productivity index/or experiencing higher than expected rate of production decline. However, the others operational mechanical factors such as limited perforation density, partial penetration, inadequate cement bonding, and

compressive strength may also adversely affect productivity. Therefore, a systematic approach is required for proper recognition or quantification of the problem at any stages of well development and reservoir exploitation (Leontaritis *et al.*, 1994).

Quantification is perhaps the most difficult step in overcoming multiple formation damage mechanisms. However, it is also the most necessary step. In quantification of formation damage, the goal is to accurately assess the amount, location, extent, and impact of formation damage on oil productivity. Without quantifying formation damage, it is almost impossible to determine which damage mechanism is the most detrimental. Generally, formation damage can be quantified by using comparative analysis of production data, pressure transient analysis, nodal analysis, laboratory analysis, and field analysis, and etc.

The most common method used of quantifying the impact of formation damage is comparative analysis of production data. A comparison is made on the producing data from a well that suspected of having formation damage with other wells located in the vicinity. Comparative analysis can also be used to identify damaged wells by matching production data with predicted decline curves. Perhaps the most effective used of comparative analysis is when it is utilized with pressure transient analysis and nodal system analysis.

Pressure transient analysis can determine skin factors. Nodal analysis is a powerful tool for detection of formation damage, quantify the effect of the damage on the production rate of a well, and evaluation of effective stimulation procedures. Brown *et al.* (1985) defined the nodal analysis as a system approach to optimize oil and gas wells by thoroughly evaluating of complete producing system. Nodal analysis relates the production rate to bottom hole pressure.

Pressure transient analysis, nodal analysis, and comparative analysis are sufficient to provide information on a particular field that is having a primary damage mechanism such as plugging due to solid particles. For field field with multiple formation damage mechanisms, comparative analysis and pressure

transient data can only provide a qualitative picture due to their inability to differentiate damage mechanisms.

All field techniques discussed earlier can only identify the probable existence of damage but none of them can either pinpoint at what operational stage the damage may have occurred or quantify the relative contribution to damage from various well operations. According to Adair and Gruber (1996), more comprehensive laboratory methods for evaluating drilling mud damage were introduced in 1994 and are often used to compliment the initial analysis. It is commonly used to quantify damage by exposing cores to damaging fluids or muds at downhole conditions. Laboratory studies can also be used to test the severity of produced fluids to form scale. Despite the relative sophistication of these studies, they still do not provide the complete picture of the in-situ or wellbore environment. However, the introduction of state-of-the art technologies, including the downhole video camera have made it possible to actually identify the quality, location, and extent of formation damage in the wellbore.

Downhole video camera allows the engineer to obtain visual images of scale, organic deposit, sand entry, plugging etc. Combination of downhole video and production logs can accurately assess the impact of formation damage on production. These techniques must be performed in a systematic manner to provide a complete understanding of the problem, establish the mechanism, and determine optimum preventive/treatment procedures.

2.8.2 Techniques for Evaluation of Formation Damage

Visualization through the core flood testing has been seen as an important step in understanding the mechanisms of permeability impairments (Francis *et al.*, 1997). However, Van Der Swaag *et al.* (1997) observed that, quantitative analysis of invasion is much more powerful tool for assessing formation damage and giving information which can be ultimately used to develop predictive models. A number

of different approaches have been pursued ranging from X-Ray Fluoroscopy, X-Ray CT Scanning, X-Ray Diffraction (XRD), Scanning Electron Microscopy (SEM), Core Photography, Petrographic Image Analysis (PIA), Energy-Dispersive X-Ray Diffraction Tomography to Thin Section Petrography (TSP) etc. (Francis *et al.*, 1995; van der Zwaag, *et al.*, 1997; Fordam, *et al.*, 1991; Amaefule *et al.*, 1988 and Longeron *et al.*, 1995; Unalmiser and Funk, 1998; Durand and Rosenberg, 1998).

All these approaches have their advantages and disadvantages, some are destructive and some are non-destructive. Therefore, an evaluation of reservoir sensitivity to formation damage by using these quantitative methods requires the integration of various techniques in order to give better results.

(I) X-Ray Fluoroscopy (XRF)

The degree and extent of drilling fluid invasion either in consolidated or unconsolidated cores can be observed by X-Ray Fluoroscopy method (Amaefule *et al.*, 1988). The X-ray technology being used is similar to that used in airports for security screening of luggage. X-Ray Fluoroscopy is a technology suited for the examination of unconsolidated sleeved cores. Unconsolidated cores can be examined in their liner such as rubber sleeve and fiberglass to delineate presence of drilling fluid. It is possible to see radial invasion patterns as well as selective invasion along the bedding planes and fractures.

(II) X-Ray CT Scanning (XRCT)

X-Ray-CT Scanning (computer-assisted tomography) of consolidated and unconsolidated cores can provide three dimension analysis of drilling fluid invasion and the uniform and non-uniform invasion patterns are clearly recognized

in CT images. It is a non-destructive technique. Formation damage analysis using CT Scanning provides data on fluid saturation, bulk density, and porosity (Unalmiser and Funk, 1998). CT Scanning of sidewall core provides valuable information on the drilling mud invasion and sample compaction. CT Scanning can also be used to monitor invasion of drilling mud with a strong photoelectric absorber at reservoir condition during formation damage tests.

(III) X-Ray Diffraction (XRD)

The powder XRD analysis is a non-destructive technique and the most accepted technique that can determine accurately and quickly the mineralogy of the bulk and clay (less than 4 microns) fraction of sedimentary rock samples (Amaefule *et al.*, 1988). The XRD technique is not particularly sensitive for non-crystalline materials, such as amorphous silicates, and therefore integrated applications of various techniques, such as SEM-EDS analysis are required (Braun and Boles, 1992). Recent advances in XRD technology have made this analytical technique a rapid and reliable method to determine bulk mineralogy and it is the best technique available to determine clay mineralogy.

(IV) Scanning Electron Microscopy (SEM)

SEM analysis is a destructive technique that provides observational information on the mineralogy, amount, size, and pore-filling materials present in the pore throats, which causes reduction in permeability. It is the best technique available to study the mineralogy of the pore system. This analysis is very rapid and can be completed within an hour after cleaning the test samples.

Recent advancement in instrument technology by the development of reliable backscatter detectors enable the examine samples in the SEM without

having to follow the normal gold or carbon coating procedures. Uncoated samples can be examined before and after fluid sensitivity tests in order to monitor types and degree of formation damage. SEM has also been employed to great advantage in visualization studies of filter cake and formation damage when it is coupled with Energy-Dispersive-X-ray-Spectroscopy (EDS). The cryo-scanning electron microscopy has been used to visualize the distribution of fluids in regard to the shape and a spatial distribution of the grain and clays in the pore space (Durand and Rosenberg, 1998). Coupling of both these methods will allow better visualization study to quantitative mapping of solid invasion.

(V) Core Photography

Formation damage resulting from oil-based drilling mud invasion can be visualized by photographing cores in white and UV light. Modern UV light systems make it possible to photograph fluorescence associated with oil-based mud (blue) and fluorescence associated with native crude oil (yellow).

(VI) Petrographic Image Analysis (PIA)

PIA uses high speed image analysis system coupled with a petrography microscope to measure geometrical characteristics of pores including porosity, permeability, and capillary pressure etc. (Rink and Schopper, 1997; Oyno *et al.*, 1998). PIA is very useful in assessing the degree of formation damage in sidewall cores and it is also very useful in choosing correct sizing agent for difference mud systems. By conducting the image analysis of thin section (cutting) of a reservoir interval will provide accurate measurement of minimum, maximum, and average pore and pore throat size. These data can then be used to choose correct sizing agents.

(VII) Energy-Dispersive-X-Ray Diffraction Tomography

It is a novel quantitative method for investigating particles invasion using the synchrotron source (synchrotron EDD-T). The essential difference between this technique and conventional X-ray Tomography (CAT) is that CAT only provides attenuation data, whereas EDD-T detects bragg-diffracted photons, which when sorted by energy-dispersive detectors, provides analytical powder diffraction data.

(VIII) Thin Section Petrography (TSP)

Thin Section petrography technique can be used to examine the thin sections of core samples to determine the texture, sorting, fabric, and porosity of the primary, secondary, and fracture types, as well as the location and relative abundance of the detrital and authigenic clay mineral and the disposition of matrix minerals, cementing materials, and porous structure (Amaefule *et al.*, 1988)

2.9 Formation Damage Prevention and Minimization

For many years ago, individuals and companies have recognized that the wells throughout the world are not producing at capacities indicated by the natural permeability of their productive formation. Millions barrels of oil and cubic feet of natural gas are left behind as wells prematurely reached their economic limits (Simpson, 1974).

Well productivity is critically important if oil and gas reserves are to be developed economically. With the change in economic climate and the maturation of many existing fields has come an emphasis on reduced production costs, optimized productivity. In addition, the trend to the openhole completion places

additional emphasis on damage avoidance. Near wellbore permeability impairment from drilling and completion fluid can have substantial, yet potentially avoidable, impact on well productivity. The proper design and engineering of fluid systems to minimize productivity impairment is therefore important.

First Formation Damage Symposium held by the Society of Petroleum Engineer in February 1974 officially recognized the importance of preventing formation damage. After this symposium, a study was carried out at Gulf Coast and results indicated that production rates could be improved by utilizing or practicing good drilling and completion techniques. After this studied, people have paid more attention to prevent the well from damage and lots of formation damage prevention tools and techniques have been created.

Formation damage tends to be more significant in horizontal or in an extended-reach well if the fluid used for drilling and completion is not compatible with reservoir rock. This situation will have substantial impact on productivity of a well by impeding the fluid flow of near wellbore regions (Gaurina-Medjimurec *et al.*, 2000). Although in many cases, this can be bypassed by perforation, but recent trend towards non-perforated completion has resulted in an increased emphasis on damage mechanisms rather than implementing costly perforation process. According to Yan *et al.* (1996), whether the flow efficiency of a horizontal well is greater or smaller than vertical wells, the production loss of the horizontal wells due to formation damage is greater than that vertical wells and the formation damage control for horizontal well is more critical compared to vertical well.

Although “*skin damage*” numbers may be calculated for producing oil and gas wells, these calculated values are sometimes misleading and confusing. Experience shows that stimulation treatments provide significant increase in well productivity from well that have zero or negative “*skin effects*”. This result can be explained by the fact that stimulation treatments removed or bypassed some forms of formation damage.

There are many parameters that lead to damage of permeability of a susceptible reservoir during drilling and the key to attain production efficiency is to prevent damage rather than using remedial treatments. Reed (1989) suggested some measures, which are useful in preventing formation damage such as:

- (a) maintaining an adequate concentration of salt (preferably potassium salt) in drilling and completion fluids, especially in water sensitive zone,
- (b) using minimum amount of oil wetting agents and surfactant in oil-based drilling mud and deflocculants in water-based drilling fluids,
- (c) drill and complete well with minimum safe overbalanced pressure, and
- (d) use clean completion fluids that do not form precipitation when mixed with formation water.

The formation damage problems mostly associated with drilling process and well completion are formation plugging caused by solid particles. This problem is unavoidable since some degree of filtration is needed in drilling operation for filter cake forming in order to reduce filtrate loss. The basis concern of the reservoir and production is to ensure that such damage is at minimum level. An understanding of the basis damage during well development operation is the key to minimize formation damage. Vidict and Reid (1997) found in their studies that, some importance and useful criteria for minimizing formation damage during drilling as below:

(1) Fluid loss control

The fluid loss control (measured under the right conditions) for both drilling fluid and cement slurries should be reduced as low as possible to minimize the spurt loss.

(2) Filtrate compatibility

In water-based muds, the aqueous chemistry of the filtrate should be formulated to ensure its compatible with formation water to prevent any scale precipitation. Some potentially damaging additives such as

deflocculents should be ruled out if the formation appears susceptible to be damage by these materials. For the oil-based muds, if wettability changed is considered to be a potential source of damage, the formulation of a stable low surfactant system should be given priority.

(3) Mud solids invasion

Invasion of mud solids is a problem in openhole completion where severe damage will not be bypassed by perforations. Properly controlling the size of additives will enhance the filter cake forming outside the rock surface and subsequent cake cleanup will restore the initial permeability to almost its original value.

Recommended drilling and completion a practice is vary somewhat according to the particular formation and well conditions. However, some basis principles can be applied in most instance cases to prevent formation damage such as (Lacey and Wells, 1979):

- (a) operate with the lowest overbalanced drilling condition necessary to satisfy safety requirement,
- (b) avoid pressure surge whenever possible,
- (c) enforce the proper hydraulic program to alleviate hole instability program and prevent breakdown of formation,
- (d) check drilling mud rheological properties frequently to ensure proper weight, filter cake thickness, and pH,
- (e) maintain good solids controls to minimize fine particles build-up,
- (f) avoid hole deviation (if possible) and pipe whipping,
- (g) minimize exposure of the pay zones to drilling and completion fluids, and
- (h) after perforating, the well in put on production as soon as possible.

According to Ezzat (1993), careful preplanning and utilization of the laboratory test data will help to minimize wellbore damage, thus they would help to optimize the drilling cost and performance especially in horizontal drilling. The control of formation damage induced by drilling mud has long been recognized as part of good drilling practice. Utilizing the muds with improved filtration loss control characteristics provides an efficient method that limit the excessive filtrate loss, improve drilling muds properties to form an impermeable mud cake quickly, thereby reducing the spurt loss and cake thickness. According to Helio and Queiroz (2000) underbalanced drilling also can minimize the invasion of mud solids and filtrate into the permeable and fracture formation that cause the wellbore damage.

The best damage prevention rule are to use high quality drilling fluids that is compatible with formation fluids, look into details the particular jobs that potentially can damage the formation, and understanding operating damage mechanisms. A philosophy, which has been widely implementing is “prevention of damage is better than cure” (Bailey *et al.*, 1998).

Table 2.2 presents some of the formation damage causes, appraisal methods used, practical measures taken to prevent or overcome formation damage (Gatlin, 1962). With this basis guideline, we can implement the most suitable drilling method to minimize wellbore damage. Besides, it also provides the basis measures that can be used to overcome the formation damage caused by certain mechanisms such as clay swelling by using low filtrate loss drilling fluid.

2.10 Summary

This chapter describes an overview of formation damage, including damage mechanisms, the possible effect of rotating drill string eccentricity in detail, identification and quantification of formation damage, and formation damage prevention and minimization. First, a literature review was presented regarding formation damage occurring in the field either in vertical or horizontal wells, followed by the most significant damage mechanism encountered especially in horizontal wells. Next, identification of the potential physical parameters that will initiate the damage mechanisms caused by the drill string's eccentricity is given. Finally, a brief discussion on identification and quantification of formation damage in field application and laboratory studies was presented. At the end of this chapter, a brief formation damage prevention and minimization method was discussed.

Table 2.2: Basic appraisal method and practical prevention measures to overcome formation damage (Gatlin, 1960)

Damage Effects	Appraisal Methods	Practical Prevention Measures
Foreign fluid invasion		
a) Clay swelling	special contamination and flow test on core samples to determine compatibility of fluid involved.	Use of additives, which will reduce filtration losses.
b) Emulsification	3 stages filtration based on Carmen equation.	Reduce pressure differential against formation to lowest safe value.
c) Reduction in relative permeability due to introduction of third phase.	Conduct the above at the temperature and pressure involved.	Minimize exposure time as much as possible.
Foreign solid invasion		
a) Size reduction or plugging of internal pores by intruding solids.	Analysis of initial surge filtration data from filter press test.	Addition of properly sized colloidal solids, which rapidly form an efficient bridge.
b) Increase interstitial water content and consequent reduction in oil or gas permeability.	Actual surge data against core sample of rock in question.	

CHAPTER III

EXPERIMENTAL PROCEDURES AND MEASUREMENT TECHNIQUES

One of the major tasks of this research was to design and construct the formation damage rig, which allow the study to be conducted at near downhole condition. This equipment could be used to evaluate the influence of the eccentricity of drill string on formation damage when coupled with differential pressure, exposure time, drill string rotation speed etc. In this research study, focus will be given mainly on overbalance pressure (differential pressure), as it was believed to have significant effect on formation damage. Overbalanced pressure drilling is a common practice in order to prevent kick. Consequently, the overbalanced pressure tends to force the mud filtrate to invade and damage the near wellbore formation. Besides, the effects of exposure time and drill string rotation speed on formation damage were also analyzed in this research study. This chapter describes the Berea sandstones samples preparation, hydraulic calculation, and experimental set-up, the experimental procedure of the system

Section 3.1 describes the preparation of the Berea sandstones and Section 3.2 describes the drilling fluid formulation. Section 3.3 describes the hydraulic calculation involved in the experiment. Section 3.4 describes the formation damage rig set-up that includes the description of major components of the system. Section 3.5 describes the equipments set-up for determining the permeability of the cores, while Section 3.6 explains the experimental procedures in detail of the system. Finally in Section 3.7, a summary of this chapter was given.

3.1 Sample Preparation

Sample preparation involved test specimens preparation and drilling fluid formulation. Test specimens preparation covered the entire process of preparing test samples, whilst the drilling fluid formulation involved the preparation of drilling fluid as per field formulation. The Berea sandstones used in this study were obtained from Cleveland Quarries, USA. Berea sandstone has been widely used as test samples in formation damage studies. In addition, it is free of water sensitive clay (0.03%). Thus, it was chosen as the test specimen in this study. The permeability and porosity of the Berea rock are 100 md to 200 md and 20%, respectively. The details of these tests are shown in Appendix A.

3.1.1 Preparation of Standard Berea Sandstones

The Berea sandstones preparation involved cutting process, cleaning, heat treatment, and saturation process.

(I) Core Cutting, Cleaning, and Heat Treatment Process

The size of Berea sandstones purchased from the Cleveland Quarries, USA, was 12" long with diameter of 2". It was cut from a large block of Berea sandstones in order to get consistent rock properties. The core was then cut into 6" length with diameter of 2" due to the fact that the core holder in this study could only accommodate cores with 6" length or less. A core cutter purchased from the Norton, USA, was used to cut the core, as shown in Figure 3.1. In order to have a perfect core surface, the core cutting process was conducted slowly under running water from a cooling system. The next step was core-cleaning process, which involved submerging the cores in flowing water in order to remove debris from the core surface. The cleaning process was followed by heat treatment process.

The purpose of this process was to remove liquid or vapor trapped inside the cores. This was achieved by placing the cores in an oven (Heraeus Instrument) that was heated up to 240°F, for 24 hours. After the heating process, core-drying process is carried out for another 24 hours by placing the cores in the desiccating chamber filled with silica gel.

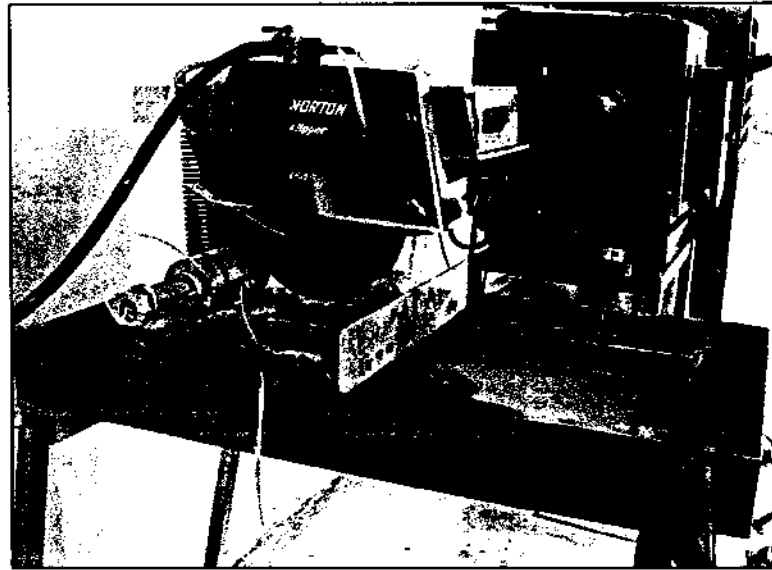


Figure 3.1: Berea sandstones cutting equipment

(II) Saturation Process

Saturating core samples is an important process that may determine the accuracy of the final results. Poorly saturated cores will influence the calculation of core permeability, thus it will affect the computation of damage ratio. A reliable saturation system is essential in order to minimize uncertainties in the values obtained during the rock permeability measurement.

A saturation unit consists of vacuum pump (Robin Air, USA), a specially fabricated chamber, a core holder, flask, and a hand pump. A complete saturation system is depicted in Figure 3.2. The Sarapar 147 (mineral oil) was used as

saturation fluid as it is inert to chemical reaction. Besides, the usage of Sarapar 147 as saturation fluid is to eliminate the emulsion problem due to filtrate invasion during experiment. If the saturating fluid is brine, the emulsion problem will exist when the filtrate from oil-based mud mixed with brine in the test samples. The core saturation process was executed in accordance to the API RP40 standard as follows:

- (1) A core sample was placed in the core chamber and the front cap of the chamber was tightened with the valve (1) closed.
- (2) The vacuum pump was switched on to induce high pressure for 12 hours to remove traces of vapor or liquid that was trapped inside the core after heat treatment. The purpose of inducing high vacuum pressure is to expedite the core saturation process.
- (3) At the end of the evacuation period, the valve (1) as shown in Figure 3.2, was connected to the outlet of a hand pump with its valve turned on. This was to allow the Sarapar 147 from the hand pump to be drained slowly into the core chamber until the Sarapar 147 oil was seen at the flask. When the Sarapar 147 was seen flowing out in the flask, it indicated that core chamber was completely occupied by Sarapar 147.
- (4) Switched off the vacuum pump and turned off the valves (1) and (2) immediately when the Sarapar 147 started to flow out from the chamber outlet to flask.
- (5) The saturating pressure was then increased gradually from 500 psi to 2000 psi using the hand pump. Pressure must be induced slowly to prevent core sample from getting damaged. After inducing the pressure to 2000 psi, the core sample was left for 24 hours in order to complete the saturation process.

(III) Core Preservation

Core preservation is an attempt to maintain the core saturation prior to analysis. This is to ensure that the cores that to be removed from the chamber are in good or fully saturated condition before being used for experiment. The preservation of fully saturated cores was implemented by keeping the cores in the Sarapar solution in a concealed container.

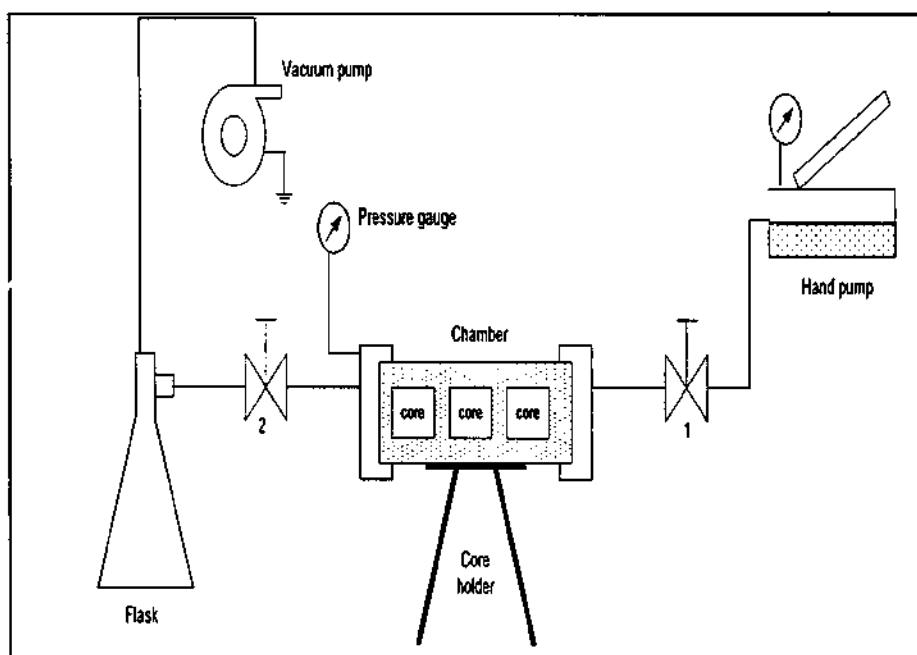


Figure 3.2: Schematic diagram of core saturation unit

3.2 Drilling Fluid Formulation

An invert emulsion oil-based mud system was used in this study. Invert emulsion consists of continuous oil phase and dispersed water droplets (Ananda, 1998). The oil-based mud (OBM) with 10.3 ppg which is used by EM-EMPI for their drilling activities was used as drilling fluid in this study. A brief description of Sarapar 147 in terms of composition and properties is presented in Table 3.1, while the drilling additives characteristics and functions is presented in Tables 3.2

and 3.3, respectively. Table 3.4 shows the detailed composition of the OBM and the mud rheological properties used for this research study. The drilling fluid for this study comprised based oil (Sarapar 147) and drilling fluid additives such as Versamul, Versacoat, Visplus, Versatrol, Lime, CaCl_2 (94%), and barite.

3.2.1 Based Oil: Sarapar 147

Sarapar 147, based oil is obtained from Shell MDS (Malaysia) Sdn. Bhd. It is a colorless mineral oil ranging from C_{14} to C_{17} and is derived from petroleum crude. The compositions and properties of Sarapar 147 are listed in Table 3.1.

Table 3.1: Chemical composition and properties of Sarapar 147

Hydrocarbon	Composition, %
N-paraffin	95 min
Iso-paraffin	5 max
Naphthenic	0.1 max
Parameters	Specification
Density at 15°C	773.0, kg/m^3
Boiling range	258.3, °C
Kinematics viscosity	12 (min), mm^2/s
Pour point	2.5, °C

3.2.2 Drilling Fluid Additives

These additives play an important role in formulating the oil-based mud. Table 3.2 describes the chemical characteristics of the drilling fluid additives used in this study.

Table 3.2: Chemical characteristics of drilling fluid additives obtained from Product Data Sheet of Kota Mineral and Chemicals Sdn Bhd (KMC)

Drilling Fluid Additives	Chemical Characteristic
Versamul	Versamul is a liquid blend of selected emulsifier, gelling agent, and fluid stabilizing additives in a non-toxic base. It produces fluid that is relatively non-toxic to marine life when blended to form the Versaclean mineral oil mud system. Versamul offers excellent emulsion stability as well as high temperature tolerance. The recommended concentration is 1-8 ppg.
Versacoat	Versacoat is a liquid blend of alkyl imidazoline, petroleum distillate, and methanol. Versacoat is easily mixed into the surface system and the recommended concentration is from 1/8 to 8 ppb.
Calcium chloride	Calcium chloride is a type of brine used in completion, workover, gravel packing, perforating, and packer fluids. It is an electrolyte using oil-based system to control the activity of mud. A special care should be given when choosing the appropriate grade of calcium chloride when preparing the oil-based mud system.
Lime	Lime is also known as calcium hydroxide ($\text{Ca}(\text{OH})_2$) with white crystalline powder in appearance. Lime is an important source of calcium ions, which will react with fatty acid based emulsifiers to provide the necessary emulsion system. The recommended concentration is between 2 to 8 ppb.
Versatrol	Versatrol is a selected blended powder of asphaltic-type material to be used as filtration control additive. It is effective over a wide range of temperature and contains an anti-caking agent. The recommended concentration

Drilling Fluid Additives	Chemical Characteristic
	between 4 to 10 ppb
Barite	Barite is a highly purified and low abrasion powder, with the chemical formula of BaSO_4 . In order to attain density above 9.5, yet maintaining low viscosity and minimum content of clay, thus barite is used in this study. Barite is insoluble in water, hence it does not react with clays or drilled solids.

Table 3.3: Function of mud additives

Mud Additives	Function
Versamul	Primary emulsifier with supplementary wetting agents, and gelling agents, improve emulsion stability, and enhance thermal stability, and increase contamination tolerance of oil mud
Versacoat	Secondary emulsifier as well as fluid loss reducer, improves emulsion stability, and it helps to maintain stability in the presence of contaminant.
Versatro	Fluid loss control agent, enhances emulsion stability, and imparts minimum viscosity increase.
CaCl_2	Control the activity (A_w) of the mud, osmotic control in oil based mud to stabilize reactive clay formation, and weighting agent in brine and workover fluids.
Lime	To control pH in water-based muds and is the preferred alkali in invert emulsion muds, and also as a flocculent in spud mud.
Barite	Used as weighting material.

Table 3.4: The detail of OBM drilling fluid formulation (oil water ratio=75/25)

Mud Composition	Chemical Quantity	Typical Mud Rheological Properties		
			Field Recommended Value	Laboratory Achieved Value
Sarapar 147	242.2, mL	600 rpm	-	54
VersaMul	5, g	300 rpm	-	34
VersaCoat	1, mL	PV,cP	As low as possible	20
Lime	5, g	Yp, lb/100ft ²	10-16	14
Water	60.5, mL	Gel strength (10s)	7-10	10
CaCl	18, g	Gel strength (10m)	10-15	14
Visplus	6, g	Electrical stability, V	1000-1100	1000
Versatrol, g	6	Mud weight, ppg	As required	10.3
Barite, g	175			

3.2.3 Drilling Fluid Mixing Procedure

Proper mixing procedure is the key to the success of drilling fluid formulation. Before using the formulated drilling fluid for experiment, a pre-study of its rheological properties is required to ensure the success of the experimental work. The components of the mud samples prepared with 10.3 ppg were listed in Table 3.4. The quantity of each component used was based on the required rheological properties of mud for a particular experiment. The mud system was formulated according to the guidelines provided in the "Recommended Practice on Standard Field Procedure for Testing Drilling Fluid, API RP 131, 1990". The laboratory mixing procedure was as follow:

- (1) The OBM was prepared by using 350 cc container with the assistance of Silverson Mixer.

- (2) While stirring, the pre-determined volume of versamul, versacoat, visplus, and versatrol were added via a syringe. Then Lime, CaCl_2 (94%), and barite were mixed into the systems sequentially at the interval of two minutes.
- (3) The drilling mud was stirred continuously for another 15 minutes until a homogenous mud system was achieved.
- (4) Finally, the mud rheological properties such as mud weight, plastic viscosity (PV), yield point (YP), gel strength at 10 seconds and 10 minutes, electrical stability, and High Pressure High Temperature filtrate loss (HTHP) are recorded at room temperature of 80°F.

Prior to measuring the mud rheological properties, all the equipments involved must be calibrated. This is to prevent any incorrect value being registered during the measurement process. The mud weight was measured by using the mud weight tester (Baroid), while Baroid rheometer (Model 1286) was used to measure PV, YP, and gel strength at 10 seconds and 10 minutes. A Baroid electrical stability tester (model 23 D) was used to check the emulsion stability of the mud.

3.3 Hydraulic Calculation

This Section describes the Reynold 's number calculation. It is used to determine the fluid flow behavior. Reynold's number is an important method to check whether the fluid flow behavior during experiment is conducted similar to the reservoir fluid flow condition or otherwise.

3.3.1 Reynold's Number

Reynolds number is an important equation to determine the characteristics of the fluid flow. It can be used to determine whether the fluid flow is in turbulent, laminar, or transition regimes.

For $Re < 2000$, flow is laminar, $Re > 4000$, the flow is turbulent, and $2000 < Re < 4000$ the flow is transition where it is neither laminar nor turbulent. Fluid flow behavior is of prime importance as the experiment was conducted near reservoir condition. The Reynold's number of the fluid flow in this study was 4800 as shown in Appendix B, which represented turbulent flow.

3.4 Formation Damage Rig

The major components involved in this equipment set-up were a mud tank, two mud pumps, piping system, testing unit, and measuring devices. The stainless steel material was used in the rig fabrication in order to prevent the components from becoming inefficient after certain period of running the experiment. Besides, stainless steel material was chosen due to the fact that the experiment was conducted at relatively high temperature and pressure conditions and the drilling fluid is corrosive in nature. The following Section describes clearly the construction, design, and functions of the various components used in the system set-up.

3.4.1 Tank Construction

The main purpose of the tank is for mixing the drilling fluid and also serves as a storage tank. The tank was made of stainless steel plate grade 304 s with a thickness of 3 mm. The diameter and length of the tank are 660 mm x 11500 mm respectively. It can accommodate 400 liters of drilling fluid at one time and consists of two important parts; tank cover and body.

The tank cover is mounted on the tank body via a set of special fabricated screw holders that are attached to the tank cover. The tank body consists of two layers. A heater is fitted to the internal layer of the tank, and the purpose of this heater is to preheat the drilling fluid before the experiment is conducted. The bottom part of the tank is semi-spherical in shape and has five baffle plates welded to the inner part of its body. The purpose of having the semi-spherical shape at the bottom and baffle plates is to minimize turbulent effect of the returning drilling fluid. A 3" opening at the bottom of the tank would allow the drilling fluid to flow into the pipelines.

Figure 3.3 shows the detail of the tank construction and related components. The tank is mounted on a supporting structure with height and width of 2550 mm and 2950 mm respectively, as shown in Figure 3.4. This is to allow sufficient working area on the platform and also to provide positive displacement of the drilling fluid to the main centrifugal pump.

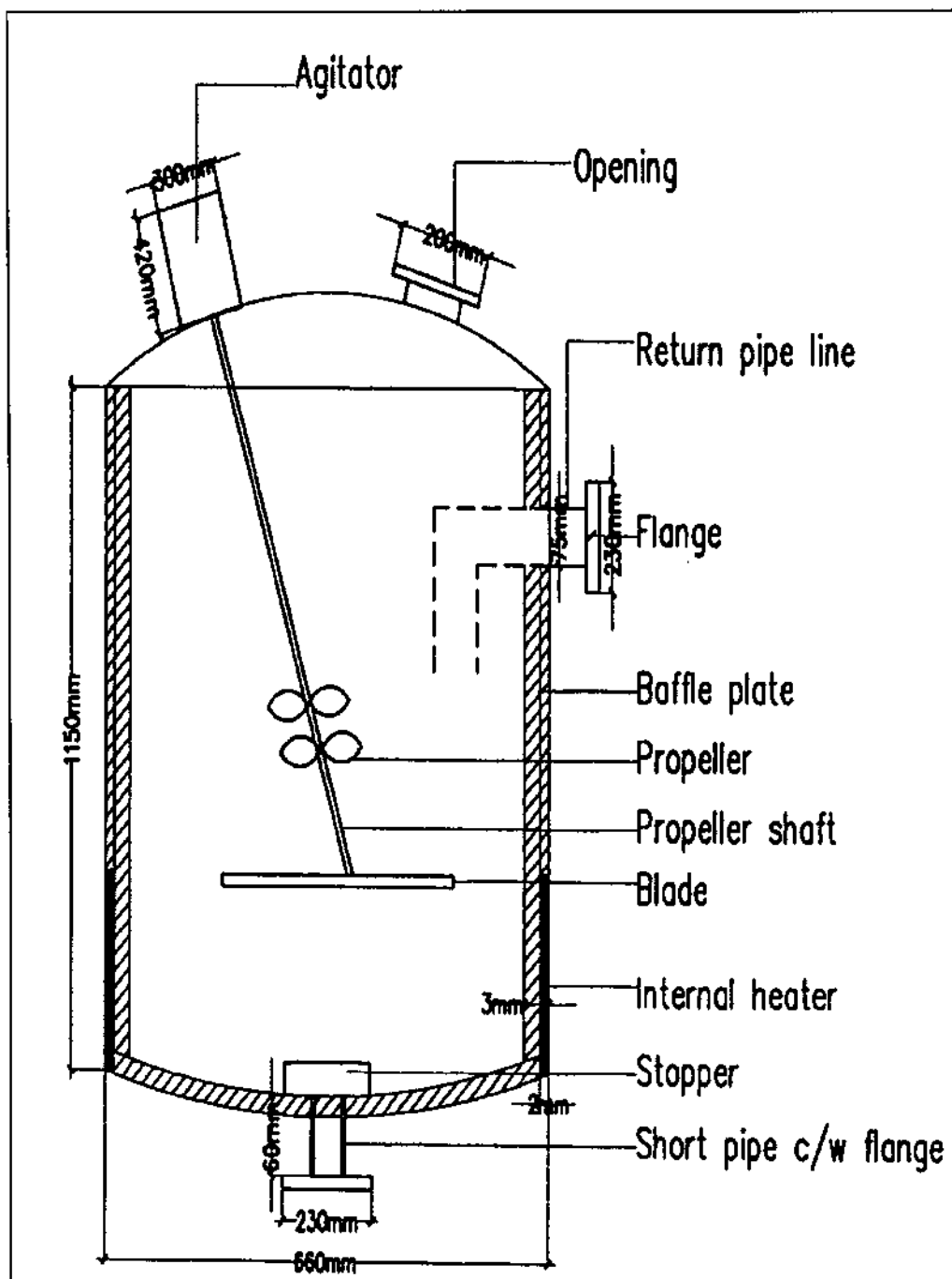


Figure 3.3: Tank construction sectional detailed diagram

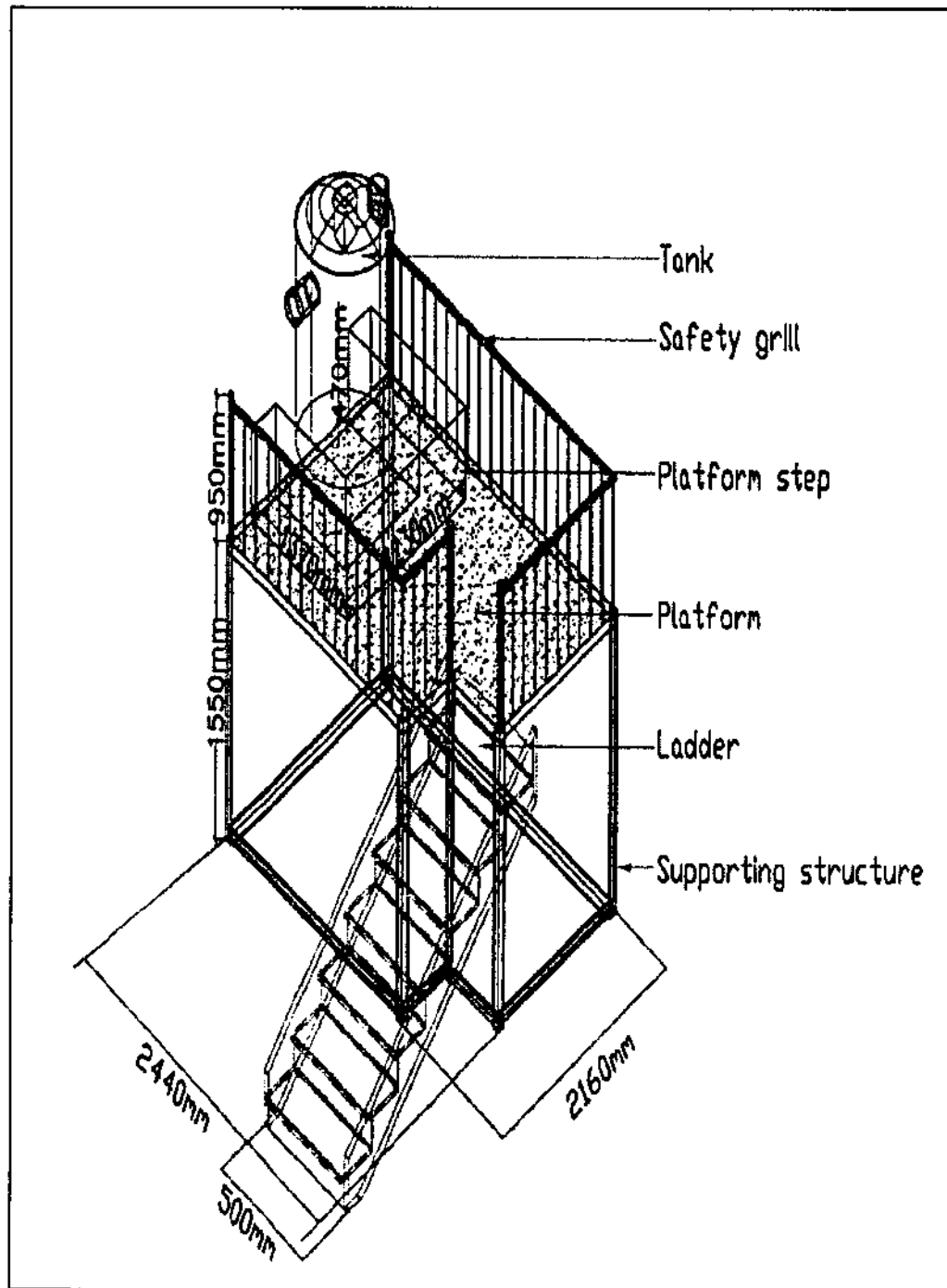


Figure 3.4: Platform to support the mixing tank

3.4.2 Flowline System

The flowline system was installed using the stainless steel grade 304 materials. It consists of main flowline and secondary flowline system. The diameter of the main flowline is 3 inches, while the secondary flowline is 1 inch. The thickness of piping used for both flowlines is stainless steel schedule 40 (5 mm thickness). The flowlines were equipped with many essential accessories such as flanges, valves, tee joints, elbows and unions in order to provide a proper flowline system. Some C-hook type brackets were fitted at the bottom of the main flowline system. This is to prevent vibration from occurring during the high flow rate in the flowline induced by the centrifugal pump. The main flowline and secondary flowline systems were welded with Tungsten Ignition Technique (TIG). This is to prevent leakage. Besides, the TIG welding is a proven method to join and seal all stainless steel connections and can withstand high flowing pressure and temperature.

3.4.3 Valve Types

S-patent and ball valves were installed in the flowline system. The S-patent valve or globe valve is used to regulate flow rate in the main flowline, while the ball valve allows for the opening or closing of the flow of the flowline system. The globe valve model GS-C25 was manufactured by Inter. Its body, cover, and seating were made of cast carbon steel. It is suitable for liquids, gases, vapor, and steam. Thus it could be used in this study. The S-patent valve was installed horizontally in the flowline that parallel with the flow direction. The advantages of globe valves are low in cost, maximum working temperature of 200°C, and maximum working pressure of 35 bars. It can also be used to control the flow rate at flowline compared to ball valve, which is mainly used for closing or opening of flow functions only. Butterfly or knife valve can also be used but it is relatively expensive. Thus, S-patent valve was chosen for this study.

Ball valve is another type of valve used in the flowline. The ball valve model R950 is a full port ball valve made by Giacomini Production. This type of ball valve is suitable to be used under extreme pressure, temperature or mechanical stress. The maximum working pressure is 42 bar, whereas the maximum working temperature is 185°C. It is suitable for fluids, water, gas, hydrocarbons, and dry steam. The body of this valve is brass nickel-plated. The ball has a diamond cut brass finish before being nickled and then chrome plated. The ball, which is made of hot forged brass, allows high fluid flow with low turbulence and limits incrustations or impurities that could reduce manoeuvrability and sealing.

Ball valve is used to control the flow of drilling fluid from the storage tank into the flowline. It is also used to close the entrance of fluid into the tank in order to allow circulation of fluid in the flowline system. Ball valve is suitable to be used at the outlet and inlet of the tank because it could function well in opening and closing the fluid flowlines.

3.4.4 Pump Types

Two centrifugal pumps were used in the flowline system. A 40 hp centrifugal pump was used in the main flowline and a 1 hp pump for the secondary flowline. The centrifugal pump was chosen due to its ability to produce constant flow rate, could work in dirty fluid condition, and if the discharge valve was plugged by particles, the centrifugal pump would not get damage.

(I) Main Pump

A centrifugal pump with 40 hp (model CR-32-13-2) made by Grundfos was used in the main flowline to allow the experiment to be conducted under dynamic conditions in order to simulate the downhole condition. The CR pump is a non

self-priming, vertical multistage centrifugal pump fitted with a Grundfos standard motor. A main control panel with 100 amperes 3-phase specification was used to control this main pump.

The pump consists of a base, motor stool, and pump head. The chamber stack and the outer sleeve were secured between the pump head and the base by means of stay bolts. This pump was equipped with a maintenance free mechanical shaft seal of the cartridge type. It can be used for non-explosive liquids; which do not contain large solid particles or fibers. The operating liquid temperature is from -30°C to 150°C , while the maximum pressure is 28 bar. Before operating, it is advisable to bleed off the pump in order to prevent air lock, as it is a non self-priming pump that may cause pump cavitation.

(II) Secondary Pump

A secondary centrifugal pump model CS100 made by Francola, Italy was used to prevent the occurrence of air lock in the main flowline. Hence, it protects the main pump from damage due to cavitation. It is fitted in the 1" stainless steel flowline. The secondary pump is operated by on-off knob located in the secondary control panel. The pump would be switched off once the drilling mud has occupied the entire volume of the flowline. The maximum working pressure is 10 bars, while the maximum temperature is 90°C . The secondary pump is connected to the main flowline by utilizing an elbow, tee, and union.

3.4.5 Flexible Hoses

Flexible hose used in this study is a stainless steel annular convoluted hose with double braided, made by Singaplex. It is a close pitch hose and working temperature ranging from -200°C to 700°C . Two flanges of ANSI 300 standard

were welded at both ends of the flexible hose. ANSI 300 flange was chosen due to its ability to withstand pressure up to 700 psi, thus it is suitable to be used in this project. The purpose of flexible hose is to allow the movement of the testing unit to the predetermine positions such as 45°, 90°, 125° etc. when it is mounted onto the special fabricated rotating testing rig holder. The two 5 feet long flexible hoses were connected to the inlet and outlet of the top bore assembly via the existing flanges at both ends and hooked-up by using screw and nut of size 30 mm.

3.4.6 Filtrate Collecting System

Filtrate is the fluid that coming out from the test sample due to pressure applied to drilling mud and contains fine particles. A measuring cylinder was used to collect the filtrate coming out from the filtrate port during the experiment. The filtrate loss data was then recorded.

3.4.7 Multi Angle Rotating Rig

In this research study, mild steel, C-channel, angle bar, and supporting plate were used to construct the rig holder. The purpose of the rig holder was to allow the rotation of the testing unit at preset levels during the experiment. The testing unit is mounted on the rotating rig holder and the rotation angle level could be temporary preset by adjusting it at the angle disk. The multi angle rotating rig holder was mounted on a supporting structure as depicted in Figure 3.5.

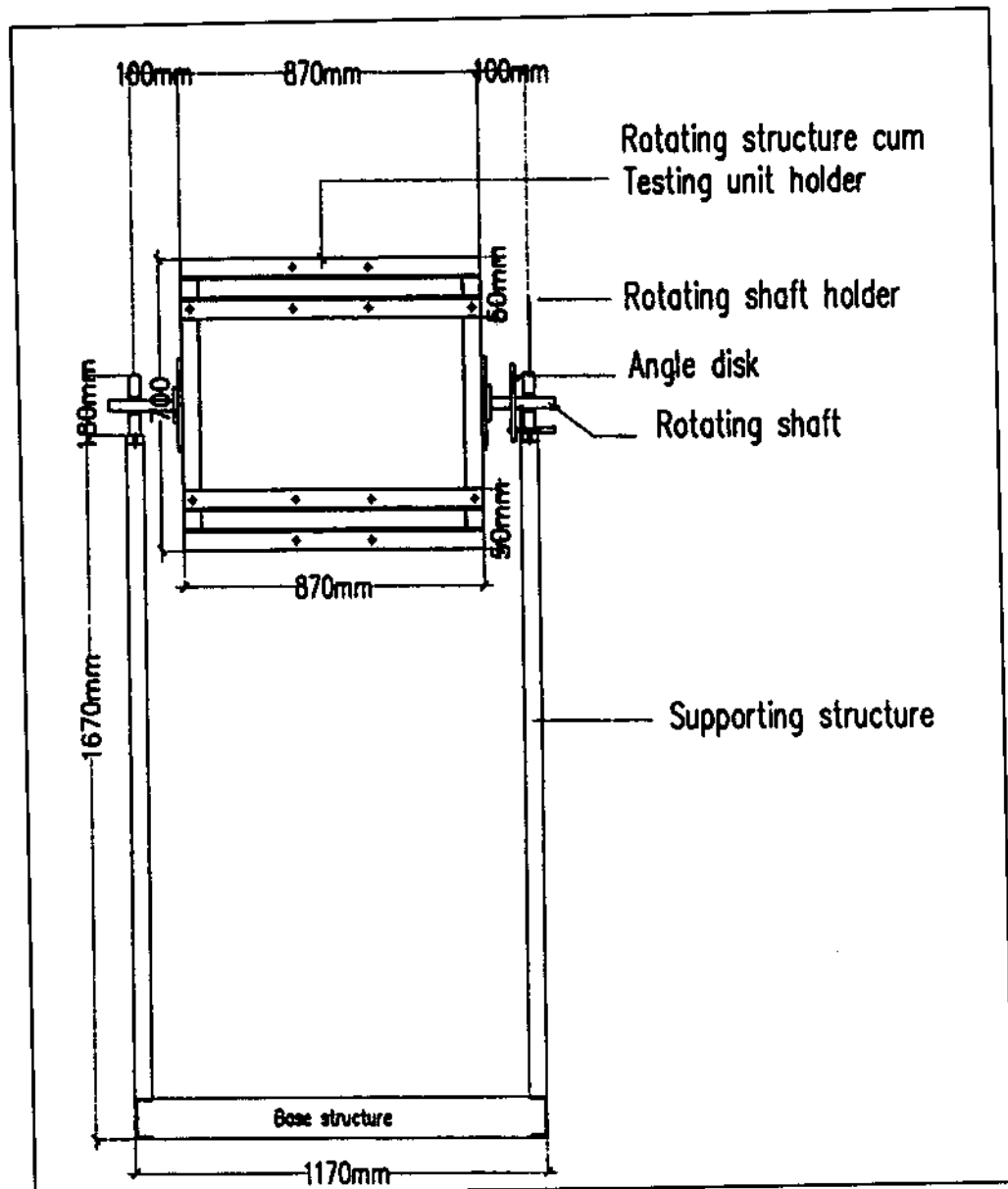


Figure 3.5: Rotating rig holder detailed diagram

3.4.8 Testing Unit

The testing unit is the most important component that consists of five main parts; top bore pipe assembly, center bore, core holders, bottom bore pipe assembly, and drill string.

The top bore assembly, bottom bore assembly, and drill string were made of stainless steel grade 304, whereas the stainless steel grade 316 was used to fabricate the center bore and mud. Figure 3.6 depicts the testing unit components.

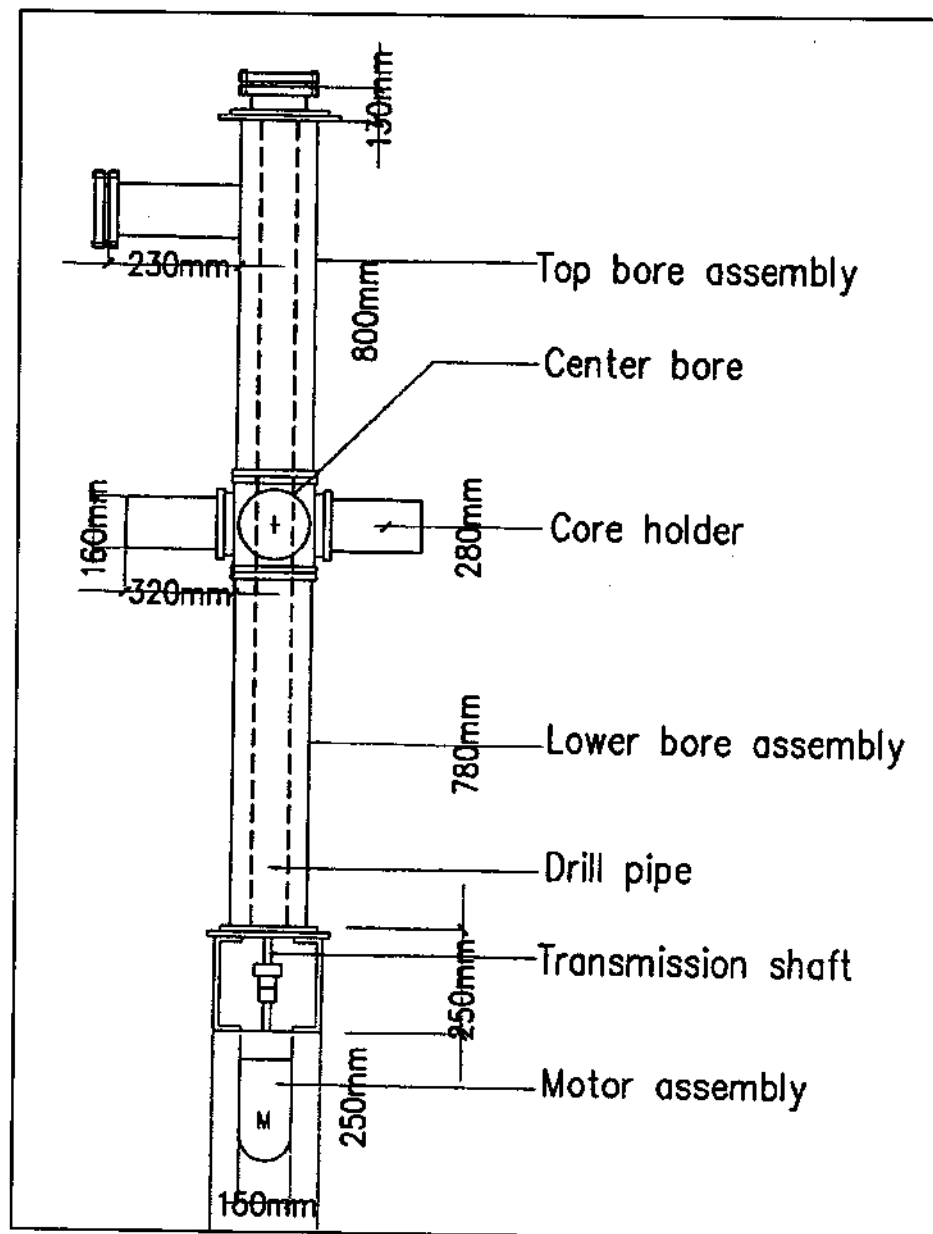


Figure 3.6: Related component attached to the testing unit

(I) Top Bore Assembly

The top bore assembly (TBA) consists of inlet and outlet flowlines, two flexible hoses, a slip plate housing, slip plate, bronze bushing, drill string housing, thrust bearing, thrust bearing retaining ring, bore pipe flange, and bore pipe.

Flanges were welded at the end of the inlet and outlet of the top TBA. This is to enable a flexible hose to be connected to the TBA assembly. The flexible hose was tightened to the drill string housing by stainless steel screws and nuts of size 30 mm.

The drill string was inserted into a drill string housing where a bronze bushing was attached. The bronze bush acts as a housing/holder to ensure smooth rotation of the drill string. A thrust bearing was installed at the outer perimeter of drill string. By installing the thrust bearing to the drill string indirectly reduces the torque force to drive the drill string, therefore the drill string stuck problem was eliminated. A thrust-bearing retainer ring was fitted at the top end of the pipe to prevent the thrust bearing from jumping out from its position.

A slip plate equipped with a flange was attached to the drill string housing to allow the eccentric movement of the drill string. The slip plate was connected to the bore pipe via the flange towards the center body/center assembly. Figure 3.7 shows the Sectional diagram of the TBA.

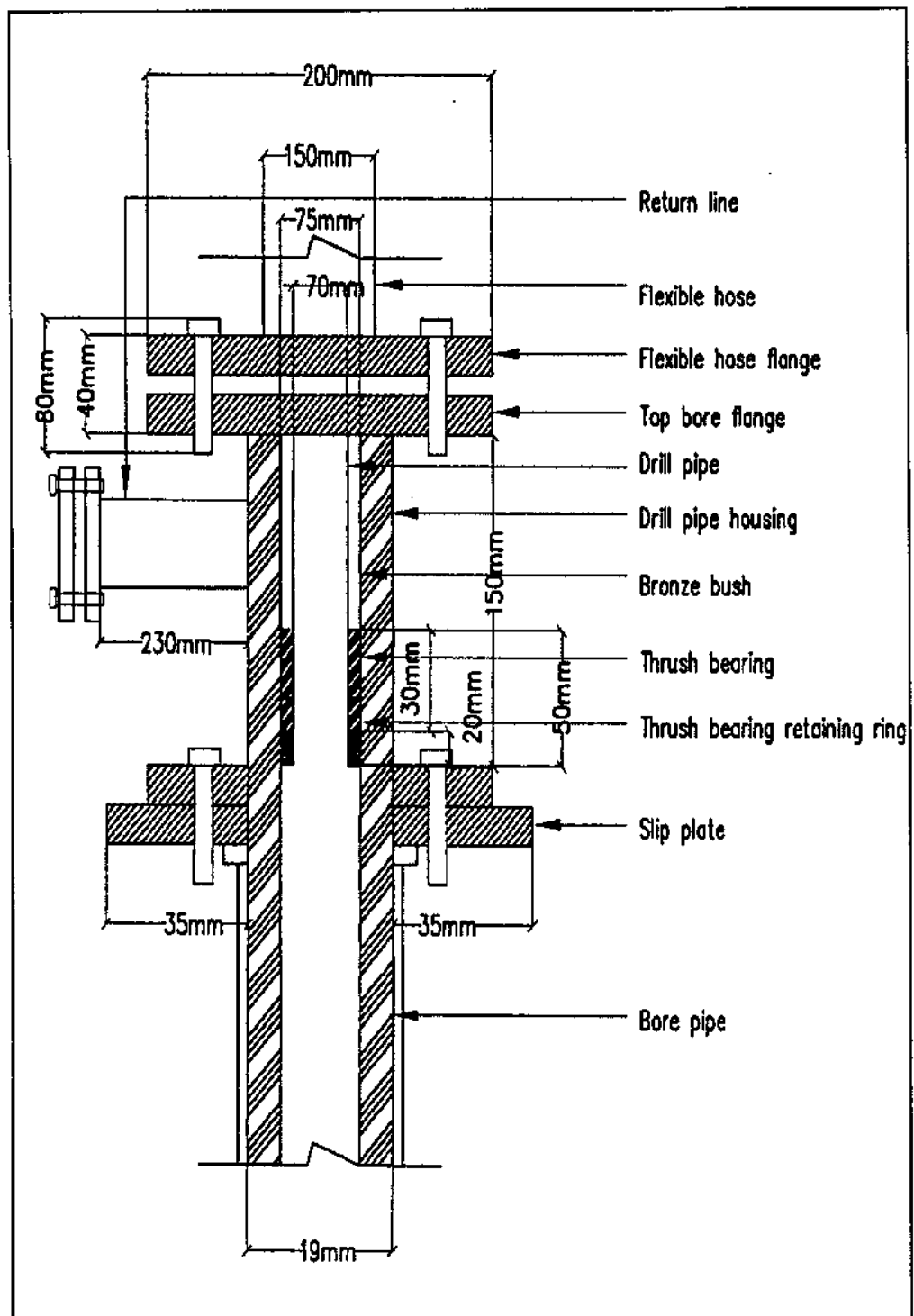


Figure 3.7: Sectional diagram of the top bore assembly

(II) Center Bore Assembly (CBA)

The top and bottom Sections of the center bore (could be seen from the diagram) were equipped with flanges. The center bore was connected to the TBA by a set of screws in the flanges. The center bore assembly (CBA) is the most important component where the core holder was attached to it. The major components attached to the CBA are bore pipe flange, fastening stud screw for core holders, and lower bore pipe. Center bore is made of stainless steel block grade 316. 4 stainless steel plates with 8 stud screws were welded at each opening of the center bore. This would allow the core holder to be connected to the center bore. Figure 3.8 shows a detailed Sectional diagram of the related components of CBA.

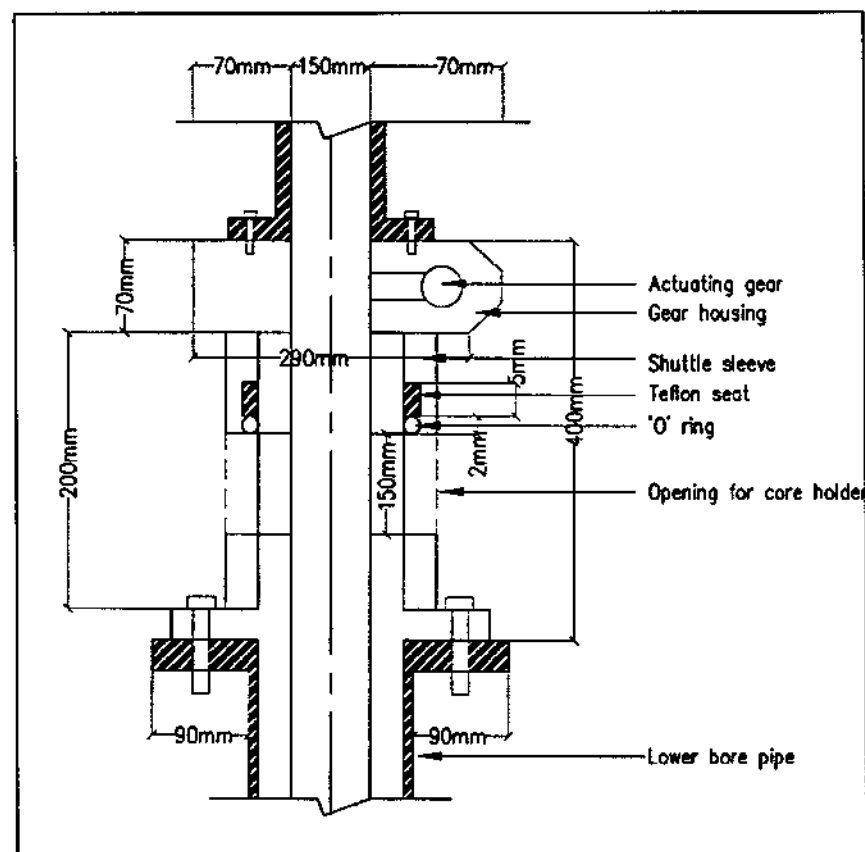


Figure 3.8: Sectional diagram of the center bore

(III) Core Holder

The core holder was used to house the test sample during the experiment. It was made of 10" diameter stainless steel block of grade 316. The newly designed and fabricated core holder is similar to the standard Hassler sleeve core holder that has some extended capabilities. The core holder was specially designed to allow drilling mud to be circulated across the face of the test sample (core). It could hold cores of 2" diameter with length of 6", and withstand a confining pressure of 1000 psi to prevent the test sample from slipping out of the core sleeve.

The core sleeve is a specially fabricated component as depicted in Figure 3.9. The material used to produce it was *nitrile* or known as *NBR* commercially. NBR was chosen due to its suitability for usage at high temperature and pressure conditions and relatively low in cost compared to viton material.

A push rod housing was attached to the end of the core holder and is used to adjust the test sample to a suitable conditions. An o-ring was placed between the push rod and push rod housing. This is to prevent fluid leakage to the outlet through the sidewall of the push rod. A filtrate collecting port is also available at the end of the push rod to allow the filtrate coming out from the test sample during experiment. Figure 3.10 shows the Sectional diagram of the core holder.

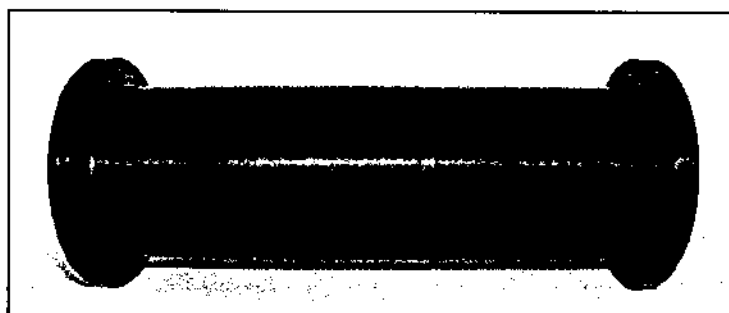


Figure 3.9: A core sleeve

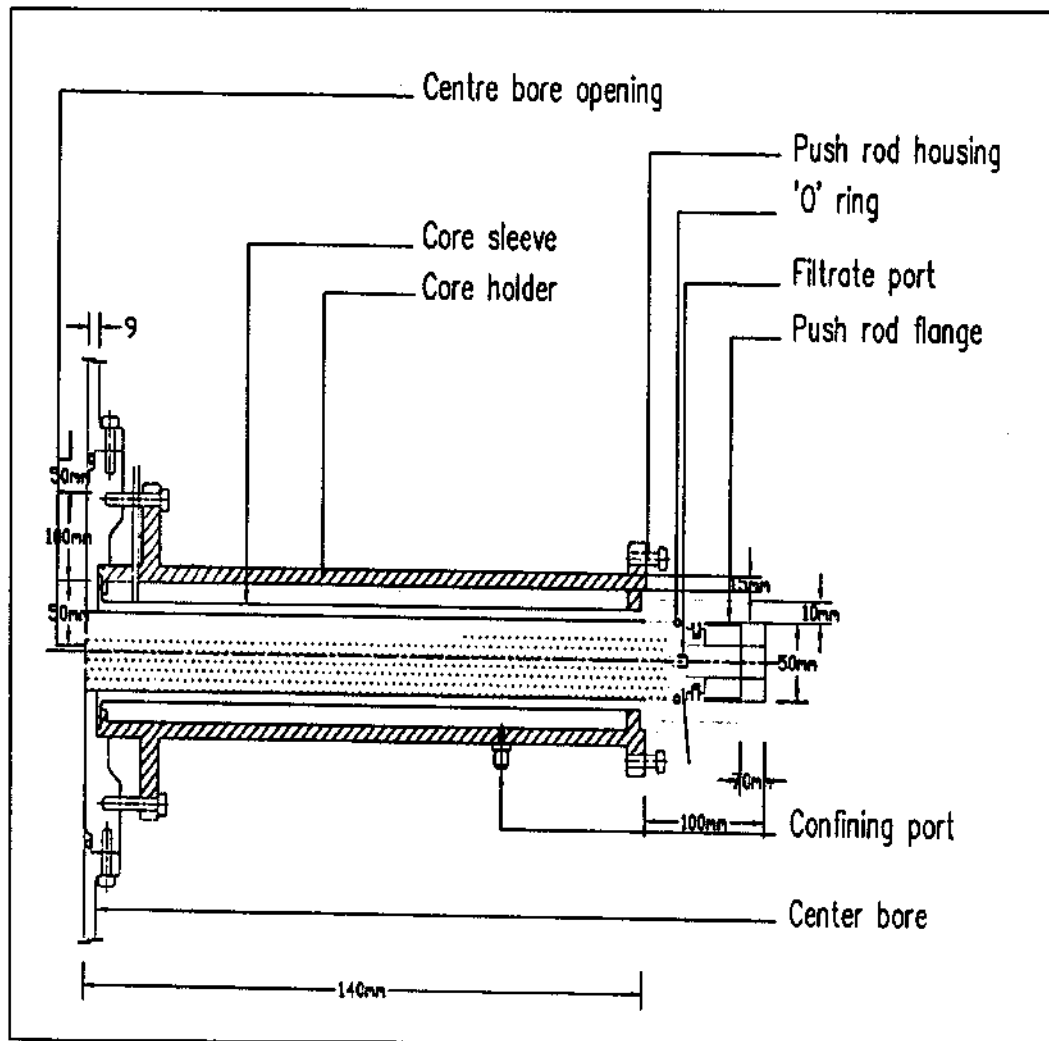


Figure 3.10: Sectional diagram of the core holder

(IV) Lower Bore Assembly

The lower bore assembly (LBA) consists of a bore pipe, drill string flanges, shaft seat, slip flange, transmission shaft, high pressure high temperature mechanical seal, bearing, motor support bracket, shaft coupling, and motor. The main functions of LBA are to transmit the torque to rotate the drill string and allow eccentric movement of the drill string. The center bore pipe was connected to LBA

using a flange welded at the bottom of the center bore and a flange welded at the top of LBA. They were connected to each other by a set of screws and nuts.

At the bottom of the bore pipe, a slip plate was attached to the bottom of a flange. This is to allow eccentric movement of the drill string in order to achieve the required drill string eccentricity condition for a particular study. The slip plate was attached to the slip flange and a rubber gasket was placed between them to prevent leakage during experiment. The slip flange has a 30 mm off center opening to allow off center movement. A transmission shaft was connected to the drill string at the slip flange holder in order to rotate the drill string when the drill string motor is switch on. A shaft seat with diameter of 75 mm and 20 mm preset hole was mounted at the bottom of the drill string to ensure the proper connection of transmission shaft and drill string.

A high pressure high temperature mechanical seal was placed in the transmission shaft housing. The purpose of the mechanical seal is to prevent fluid leakage from transmission shaft during pipe rotation at severe conditions. The mechanical seal consists of a preloaded spring, tungsten carbide seal, and ceramic seal. A shaft coupling was used to connect the transmission shaft and drill string motor. A shaft coupling was chosen due to its ability of self-aligning, thus it would ensure the smooth movement of the drill string.

A 3-phase motor equipped with a high performance adjustable speed frequency inverter manufactured by TECO was used to rotate and vary the drill string rotation speed. This type of motor was chosen due to its low electricity consumption and ability to run for long hours. The motor was mounted to the slip flange by a specially fabricated motor bracket, as shown in Figure 3.11.

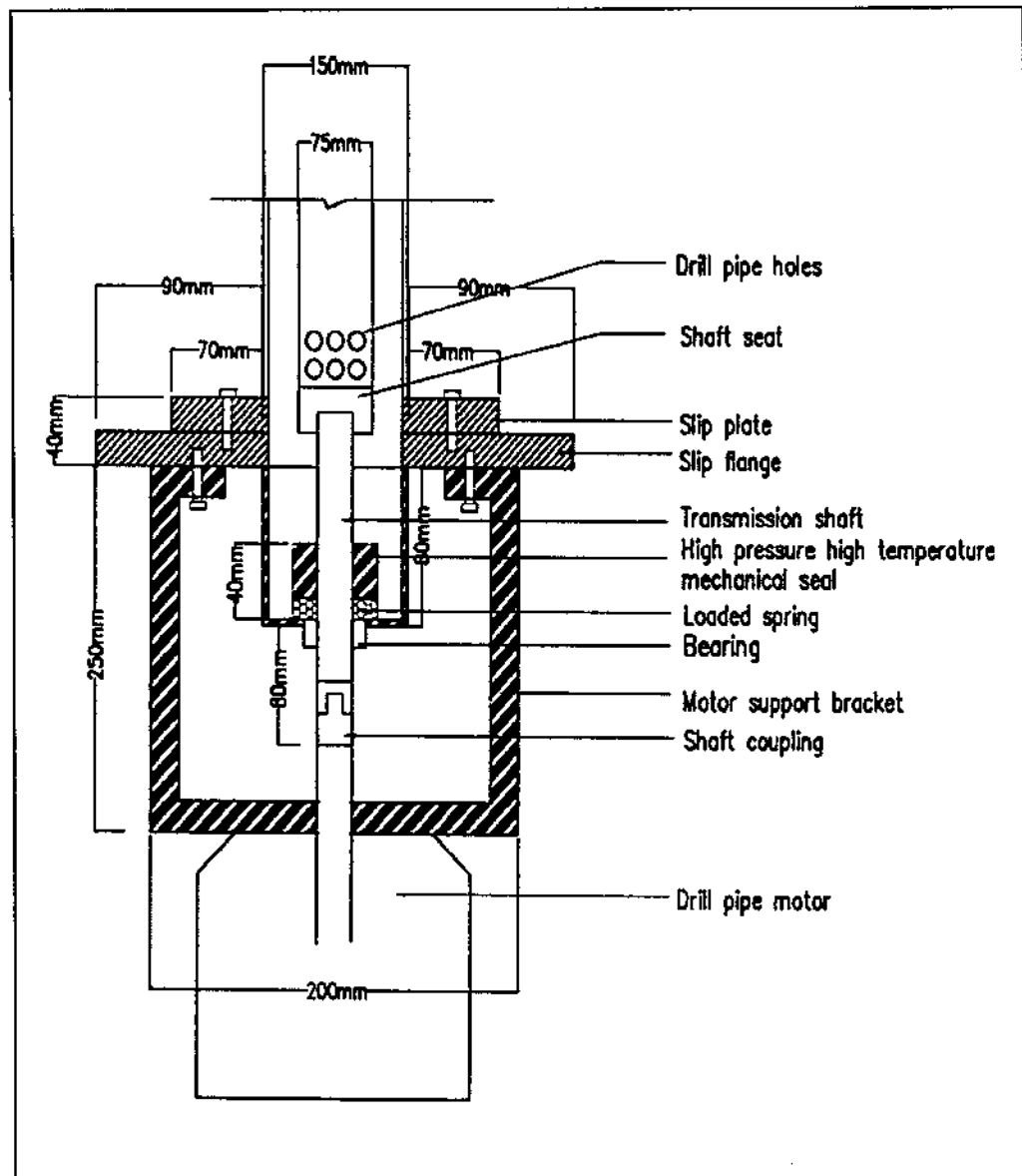


Figure 3.11: Sectional diagram of the lower bore assembly

(V) Drill String

The 3.5" drill string was made of stainless steel grade 304. This diameter was chosen to simulate the field condition for the slim-hole drilling technology, a term used when drilling a 6" hole with 3.5" drill string. At the bottom of the drill

string, 6 small holes of size 0.5" were drilled to enable the circulation of drilling mud. 0.5 hp motor was used to drive/rotate the drill string and the drill string rotation could be varied by adjusting the frequency inverter that was mounted on the secondary control panel. Figure 3.12 shows the Sectional diagram of the drill string.

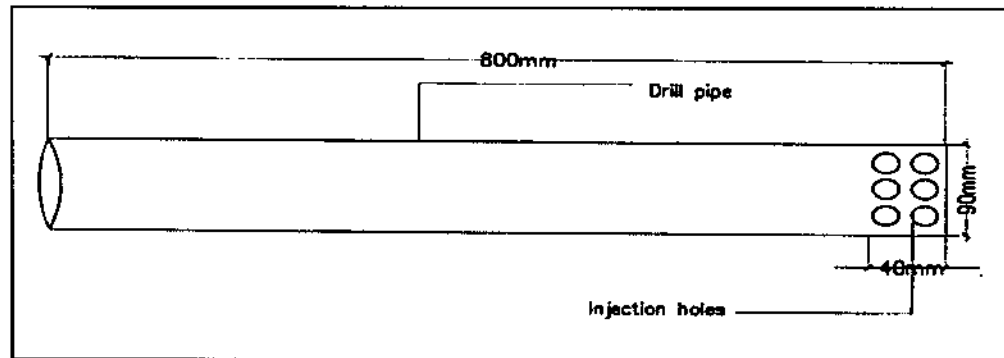


Figure 3.12: Sectional diagram of drill string

3.5 Permeability Measurement

The permeability measurement system was designed to determine the initial (K_i) and damaged (K_d) permeabilities of a test sample. The main components of this system are a core holder, measuring system, and injection fluid. Figure 3.13 shows the schematic diagram for the permeability measurement system. This Section also describes the measuring procedures to determine the test sample's permeability.

(I) Core Holder

The core holder was designed and constructed according to the principle of Hassler core holder. The core holder could accommodate a 2" diameter by 6" in length test sample. A separate core holder was used to measure the initial and damaged permeabilities. The description of the core holder is given in the Section 3.4.8 (III). The rubber sleeve that was used to prevent the test sample from slipping out of the core holder was subjected to a net pressure of 500 psi. This confining pressure was used to avoid the channeling of drilling mud during the experiment.

(II) Injection Fluid

Sarapar 147 was used as the reference fluid for measuring the initial and damaged permeabilities of the core. The reference fluid was pumped into the mud cell and then injected into the core holder via the 1/4" tubing. Others related components such as safety valve, control valve, and pressure gauge were also used to assist the permeability measurement.

(III) Measuring System

The measuring system comprised of reference fluid, a measuring cylinder, and stopwatch. Darcy's law was used to calculate the initial and damaged permeabilities of the test samples. The initial and damaged permeabilities of the cores were determined before and after exposing to drilling mud by using Darcy's law. From the initial (K_i) and damaged (K_d) permeabilities calculation, damage ratio can be determined. A calculation of initial (K_i) and damaged (K_d) permeabilities is shown in Appendix C.

Darcy's Law, $K = Q\mu L / \Delta P A$

where,

- K = permeability (Darcy)
- μ = liquid viscosity (cP)
- Q = flow rate (cc/sec)
- L = length of core (cm)
- ΔP = differential pressure across core holder (atm)
- A = cross-Sectional area of core (cm²)

3.5.1 Measurement of Initial Permeability (K_i) and Damaged Permeability (K_d) Procedures

The measurement of the K_i and K_d as follow:

- (1) Sarapar 147 was placed in the mud cell as a reference fluid. A saturated core was placed in the core holder and a confining pressure of 500 psi was induced to the core. Nitrogen gas was used to push out the Sarapar 147 from the mud cell towards the core sample.
- (2) A control valve was used to control the differential pressure of the fluid that was injected into the test sample. A pressure gauge mounted on the flow line is used to register the differential pressure across the core holder. When a steady flow rate of the flushed out reference fluid was achieved, the time needed to collect the predetermined volume of eluted Sarapar 147 was recorded.
- (3) Initial permeability was calculated based on the Darcy's law.
- (4) The measurement of the K_d of core was conducted once the test sample had been damaged by drilling mud. Repeat steps (1) to (3)

to determine the permeability of new test samples for a particular experiment.

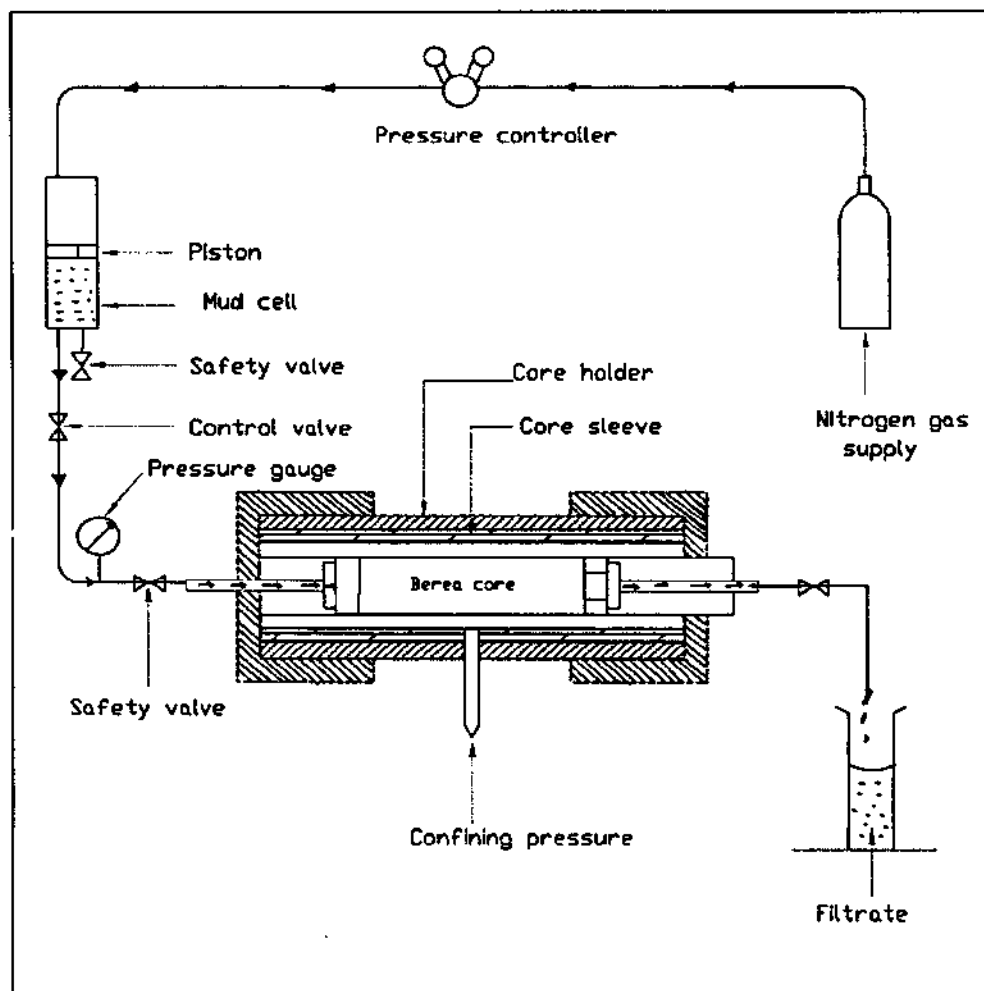


Figure 3.13: Schematic diagram of the equipment set-up for the measurement of K_i and K_d

3.6 The Operational Procedure of The System

This Section describes the experimental procedures that covered all related components and inter-connection between each component. Figures 3.14 (a) and (b) shows the schematic diagrams of all components involved in the measurement procedures. Figure 3.15 shows the complete system set-up.

(I) Experimental Procedures

The experimental procedure of this study was carried out as follow:

- Step 1:* A stopper was placed at the bottom of the tank to close the 3" opening flowline during drilling mud mixing process. The purpose of using stopper is to prevent the based oil and mud additives from flowing into the flowline before a proper mix achieved.
- Step 2:* 300 liters based oil (Sarapar 147) was poured into the mixing tank to fill the entire system in order to provide sufficient drilling fluid for the testing. Besides filling the entire system, the large volume of based oil is to prevent generation of bubbles in the flowline due to insufficient drilling fluid, which can cause air lock in the flowline that may damage the centrifugal pump.
- Step 3:* After pouring the based oil into the tank, switched on the agitator motor from the secondary control panel to stir it for 30 minutes. This was to expedite the process of achieving the homogenous phase of based oil and to enhance the mixing of based oil with additives.
- Step 4:* The pre-calculated mud additives were poured into the tank. Details calculation of drilling mud additives and its quantity is showed in Appendix D. The additives are added into the system sequentially at an interval of 10 minutes and the mixture was stirred continuously for another 30 minutes until a homogenous mud system was achieved. After the mud achieved the required rheological properties, removed the stopper with 3" ball valve (9) and S-patent valve (15) opened, to allow the drilling mud flowing into the flowlines.

- Step 5:* The testing unit was then preset to the horizontal position (90°) and maintained at a stationary condition for a given experiment by inserting the locking shaft into the angle disk before activating the secondary pump.
- Step 6:* The Berea sandstones of 6" in length and 2" in diameter with predetermined initial permeability was inserted into the core holder. The core holder was fitted to the testing unit while the testing unit was in horizontal position. After fitted the core holder to the testing unit, adjusted the position of Berea sandstone (test sample) parallel to the opening of the center bore to achieve direct exposure of the core sample to drilling mud by adjusting the push rod at the end of the core holder. A confining pressure of 500 psi was induced to the rubber sleeve to prevent fluid channeling and core slipping out from the core holder.
- Step 7:* Switch on the secondary pump from the secondary control panel with 1" ball valve, S-patent valve (15), and 3" ball valve (37) opens to fill the entire system before activating the main to prevent air lock occurs in the flowlines.
- Step 8:* Switched off the secondary pump, turned off the 1" ball valve, and S-patent valve (36) when the entire flowline system was filled up with the drilling mud. From the outlet of return flowline located at the mud tank, we can ensure that the entire flowline had been filled when the drilling mud emerges from the return line.
- Step 9:* Before switching on the main pump, activated the drill string rotation via the high performance frequency switch that was mounted at the secondary control panel. Then, preset the drill string rotation to the required speed by varying the reading at frequency inverter. After achieving the required drill string rotation speed, the main pump was switched on.

- Step 10:* When the main pump was switched on, the 3" ball valve (36) kept open with S-patent valve (36) closed, the drilling mud flowed into the flowline towards the testing unit via short pipe, 3" elbow, and S-patent valve (15). The flowing mud entered the testing unit via inlet flexible hose. The mud was then flowed into the rotating drill string and circulated out from the injection holes located at the bottom of the drill string. The circulating mud from the drill holes would then flow up towards BHA, CB, and TBA. It then flowed into the tank from the return flexible hose.
- Step 11:* The continuous circulation of drilling mud in the flowlines elevated heat in the flowlines. The S-patent valve was used to regulate the flow rate in the flowlines when the drilling mud was circulating with ball valve (9) closed. The experiment initiated once the predetermined differential pressure was achieved.
- Step 12:* The circulating mud in testing unit invaded into the test sample and damaged the core. Filtrate loss data was then taken from the filtrate collecting port.
- Step 13:* Switched off main pump at the end of the experiment. Drilling mud was drained out from testing unit and conducted the mud rheological properties checked to ensure the drilling fluid properties is in good condition before the next test. The damaged cores were taken out and placed in the permeability measurement equipment that is used for permeability measurement by referring to steps 1 to 3 as described in Section 3.5.1.
- Step 15:* A new test sample was inserted into the core holder. Differential pressures were varied from 100 psi to 400 psi at 0% drill string eccentricity by repeating steps 6 to 14. The eccentricity of the drill string was achieved by adjusting the slip plate located at the TBA and LBA.

Step 16: The study of the effect of drill string eccentricity when coupled with exposure time, drill string rotation speed at horizontal position was performed by repeating steps 6 to 15.

3.7 Summary

This chapter described the sample preparation, drilling fluid formulation, mixing procedure, hydraulic calculation, experimental rig set-up, permeability measurement set-up, and experiment procedures. The description of the Berea sandstones preparation was followed by the drilling fluid formulation, and rheological properties determination. Next, a detailed explanation of related components used in setting up the experimental rig was outlined. Finally, the experimental procedures were discussed.

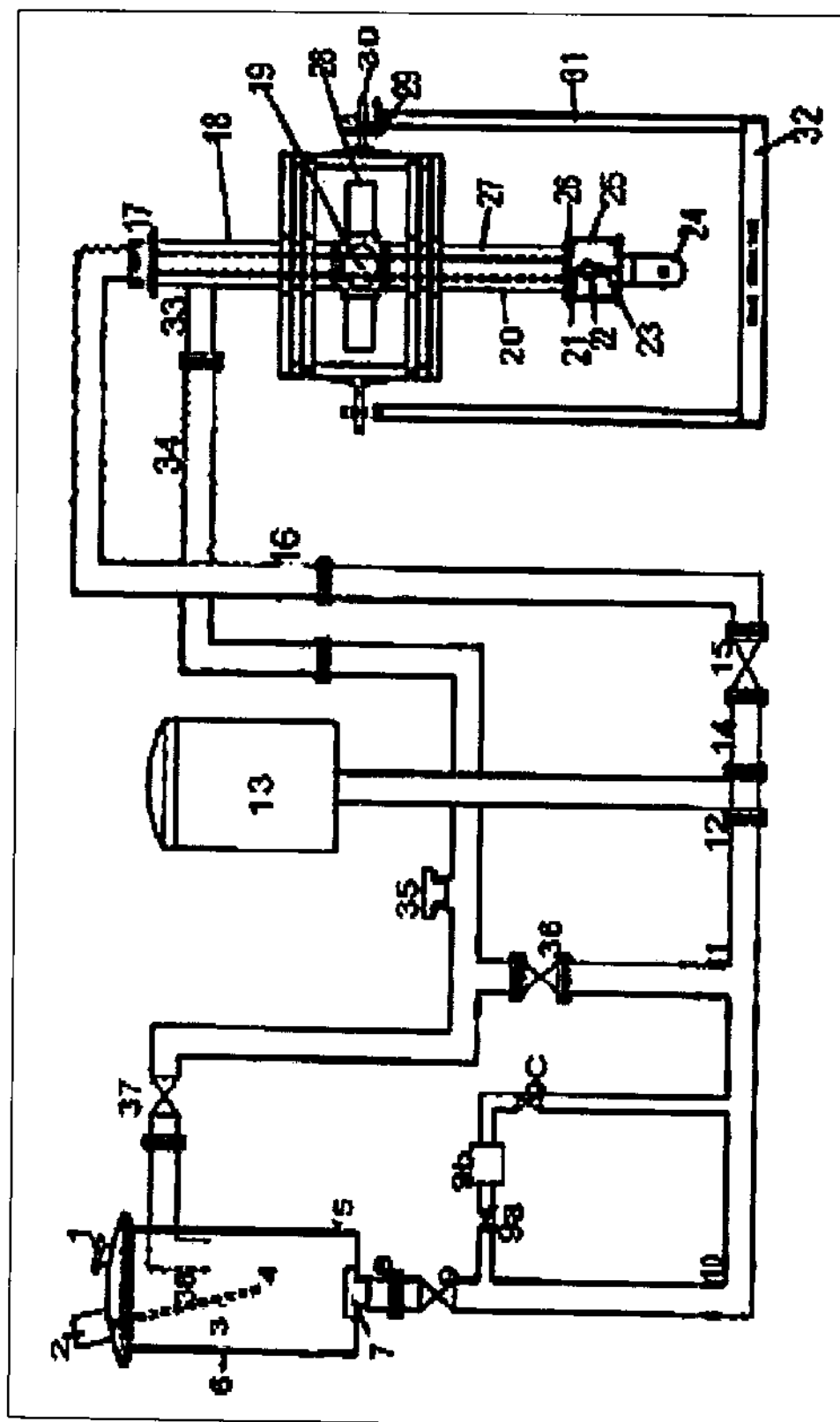


Figure 3.14 (a): Schematic diagram of the experiment set-up

1) Opening hole	10) 3" elbow
2) Agitator motor	11) 3" tee
3) Propeller shaft	12) Flange PN 25
4) Propeller blade	13) Main pump (centrifugal)
5) Baffle blade	14) Short pipe c/w flange
6) Mixing tank	15) S-potant valve
7) Stopper	16) Inlet flexible hose
8) Short pipe	17) Top slip plate c/w flange
9) 3" ball valve	18) Top bore assembly
9a) 1" ball valve	19) Center bore
9b) Secondary pump	20) Lower bore assembly
9c) 1" ball valve	21) Transmission shaft
22) Shaft coupling	30) Locking shaft
23) Mechanical seat (HPHT)	31) Rotating rig structure
24) Drill pipe motor	32) Base structure
25) Motor bracket	33) Short pipe
26) Bottom slip plate c/w flange	34) Return flexible hose
27) Drill pipe	35) Flow meter
28) Core holder	36) S-potant valve
29) Locking/angle disk	37) 3" ball valve
	38) Return line

3.14(h): Labeling of the schematic diagram

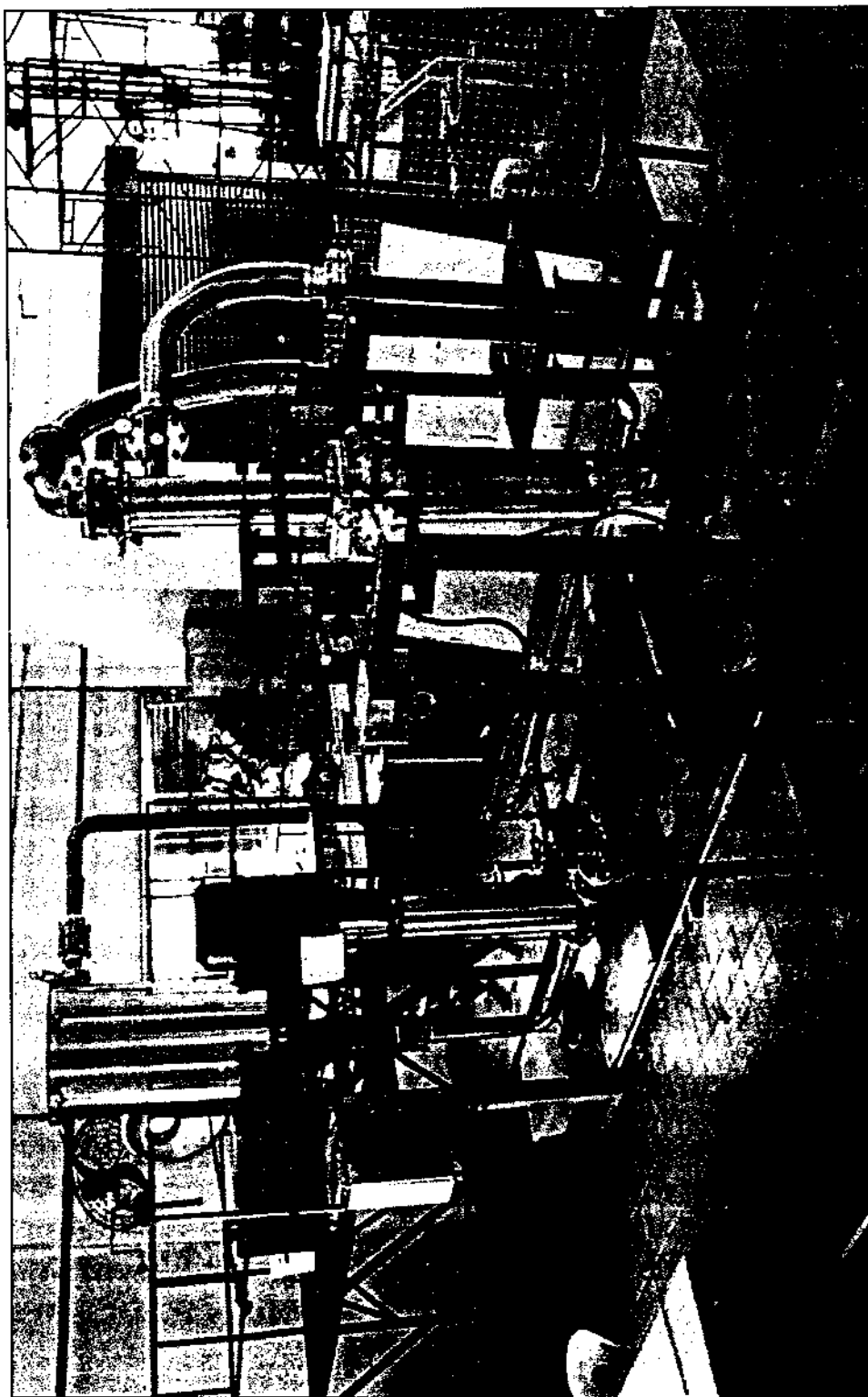


Figure 3.15: Complete system set-up

CHAPTER IV

RESULTS AND DISCUSSIONS

This chapter discusses the findings of formation damage caused by drill string eccentricity when it was coupled with others physical parameters. Section 4.1 discusses the rock properties analysis for Berea sandstones used in this study, whereas Section 4.2 discusses the drilling fluid preparation and its properties analysis. Section 4.3 discusses the method used to determine the required shifted values for drill string and explains the effects that contributed to the cores damage in detail, including the SEM photos. Section 4.4 discusses the comparison of formation damage in vertical and horizontal wells, and finally in Section 4.5, a summary of this chapter is given.

4.1 Rock Properties Measurement and Analysis

Rock properties measurement and analysis were required to provide the information about Berea sandstones such as permeability, composition of mineral etc. The X-Ray Diffraction (XRD) analysis had been carried out and it was found that the Berea sandstones comprised mainly silica and alumina, and no clay was detected, as shown in Appendix E. This result revealed that the Berea sandstones would not experience clay swelling effect, thus the damage to the test samples was mainly due to the particles or filtrate invasions.

The analysis report from the Cleveland Quarries showed that the rock permeability of the Berea sandstones were ranging from 100 to 200 md and the rock porosity was 22 to 24% as given in Appendix A. Even though the rock permeability was furnished in the report issued by Cleveland Quarries, but the rock permeability must be measured again in order to validate these values as they were used to determine the damage ratio of the core samples after being exposed to drilling mud.

The permeability measurement of the test samples was conducted using the system as shown in Figure 3.13 (Section 3.5.1). This system was used to determine the initial and damage permeability of the test samples. Generally, the values of the rock permeability recorded significantly influence the damage ratio calculation; therefore it is vital to conduct the rock permeability measurement for all test samples. Table 4.1 shows the information on test samples breakdown for different studied parameters, whereas Table 4.2 reveals cores permeability values of the test sample used in this study. The detail of the permeability calculation before and after exposing to drilling mud for all core samples used in experiment is shown in Appendix F. From Table 4.2, we could plot the permeability damage graph that could be used to conduct the analysis of the formation damage caused by the drill string eccentricity.

The rock permeability of the test samples were ranging from 130 to 240 md and the damage ratio were from -2.3% to 25.3%. Further explanations were given in the Section 4.3.2 to 4.3.8.

Table 4.1: The breakdown of studied parameters

Sample	Eccentricity, %	Studied Parameters
1-4	0	Horizontal with differential pressure from 100 to 250 psi
5-8	25	Horizontal with differential pressure from 100 to 250 psi
9-12	50	Horizontal with differential pressure from 100 to 250 psi
13-16	75	Horizontal with differential pressure from 100 to 250 psi
17-20	50	Vertical well with different eccentricity @ 200 psi
21-24	50	Horizontal with vary pipe rotation (0 rpm, 120 rpm, 140 rpm, and 150 rpm) @ 200 psi
25-29	50	Horizontal with vary exposure time from 30 minutes to 4 hours @ 200 psi

Table 4.2: Shows the rock permeability before and after damage

Core	Eccentricity, %	Differential Pressure, psi	Before Damage, K_i (md)	After Damage, K_d (md)	Permeability Variation Index, %	Remark
1	0	100	137.7	124.9	9.3	Horizontal well
2	0	150	162.9	130.3	20.0	
3	0	200	217.3	162.3	25.3	
4	0	250	251.6	195.6	22.3	
5	25	100	203.6	191.8	5.8	
6	25	150	238.7	211.7	11.3	
7	25	200	217.5	188.5	13.3	
8	25	250	224.5	233.0	-3.8	
9	50	100	149.2	138.7	7.0	
10	50	150	155.4	135.6	12.8	
11	50	200	164.1	138.5	15.6	
12	50	250	187.1	172.3	-7.9	
13	75	100	155.2	158.8	-2.3	
14	75	150	143.3	156.0	-8.8	
15	75	200	143.8	163.8	-13.9	
16	75	250	153.3	156.9	-14.9	

Core	Eccentricity, %	Differential Pressure, psi	Before Damage, K_i (md)	After Damage, K_d (md)	Permeability Variation Index, %	Remark
17	50	100	131.3	124.5	5.4	Vertical well at 200 psi
18	50	150	152.1	137.5	9.3	
19	50	200	148.4	132.7	10.6	
20	50	250	158.8	169.2	-6.2	
21	50	200	217.1	215.4	0.8	
22	50	200	164.1	138.5	15.6	Different Pipe rotation at horizontal position
23	50	200	207.5	180.3	16.2	
24	50	200	197.9	178.9	9.6	
25	50	200	164.1	138.5	15.6	
26	50	200	233.8	192.2	17.8	Different exposure time at horizontal position
27	50	200	223.2	180.9	18.9	
28	50	200	233.2	182.4	21.8	
29	50	200	232.5	177.9	23.5	

4.2 Drilling Fluid Preparations and Analysis

The drilling fluid preparation and analysis consist of:

- (i) explanation of the oil-based drilling mud,
- (ii) calculation of the required mud quantity, and
- (iii) analysis of mud rheological properties.

The mud system used in this study was the conventional VERSA system, which was tightly emulsified, temperature stable, oil-based drilling mud. This system can be formulated for any oil mud application such as Sarapar 147 and usually has a sufficiently low fluid loss and suitable to be engineered to meet a wide range of applications and requirements.

This study required low fluid loss in order to minimize the damage caused by the filtrate; therefore Versatrol was used as the preferred filtration control additive. In this study, Versamul was used as the primary emulsifier and it reacted with lime to form a calcium soap to act as an emulsifier. The Versacoat was used as primary wetting agent for conventional system and generated secondary emulsification. For viscosity generation, Visplus, an organophilic clay, was used to viscosify the fluid to support weighting material and provide gel strength. Calcium chloride brine was used as the internal phase of the inverted-emulsion.

A total of 300 liters of drilling mud was used in the experiment. The quantity of the respective mud additives required in this experiment was based on one lab barrel (350 ml) concept. For example, one lab barrel (350 ml) of inverted emulsion mud required 242.2 ml of Sarapar 147, therefore 300 liters of inverted emulsion mud system required 207.6 liters of Sarapar 147. The quantities of the others mud additives required were calculated as shown in Appendix D.

Table 4.3 shows the mud additives required for 300 liters mud. The mud preparation procedure for the experiment was similar to the mud preparation in the laboratory, except the quantity of based oil and mud additives required. The detail of the mud preparation procedure was given in Section 3.2.3.

Table 4.3: The required quantity of the based oil and mud additives

Mud Additives	Quantity (1 lab barrel)	Quantity (300 liters)
Sarapar 147	0.692 ppb (242.2 ml)	207.6 l liters
Versamul	5 ppb	4.29 kg
Versacoat	2 ppb	1.17 kg
Lime	5 ppb	4.29 kg
Distill Water	0.173 ppb (60.55ml)	51.9 l kg
CaCl ₂ (94%)	15 ppb	12.86 kg
Visplus	6 ppb	5.14 kg
Versatrol	5 ppb	4.29 kg
Barite	170 ppb	145.71 kg

The mud rheological properties must be checked in order to ensure that it was suitable to be used for the experiment. The rheological properties such as plastic viscosity (PV), yield point (YP), electrical stability voltage (ESV), and mud weight were checked throughout the experiment for all parameters involved in this study. From the rheological properties monitoring, it was found that the mud was stable throughout the experiment. This was to ensure that the cores damage was not due to the rheological properties changes at different mud temperatures.

Table 4.4 shows one of the rheological properties of the drilling mud at 100 psi and 0% drill string eccentricity. During the experiment, It was found that the plastic viscosity, yield point, gel strength at 10 seconds and 10 minutes were found to be within the acceptable limits. The electrical stability voltage of the mud was higher (1200 to 2000) than reference value (1000 to 1100) showing that the mud was well emulsified and had sufficient emulsifier in the mud system. Therefore, the cores damage due to the emulsion problem was eliminated. The detail of the rheological properties for the entire experiment was shown in Appendix G.

Table 4.4: The rheological properties of the mud for sample 1

Properties	Achieved Value	Testing Condition
RPM 600	54	0% eccentricity @ 120 rpm, 100 psi, 80°C, 30 minutes exposure time, and 60 ft/min annular velocity.
RPM 300	34	
Plastic viscosity, (600-300)	20	
Yield point, (300-PV)	14	
Gel (10s)	13	
Gel (10mins)	20	
ESV, volt	1603	
Mud weight, ppg	10.3	

4.3 The Study of Drill String Eccentricity on Formation Damage

Drill string eccentricity is believed to have some effects on formation damage. Prior to the discussion of the effect of drill string eccentricity on formation damage, it is vital to understand the drill string eccentricity calculation and mud flow behavior that might occur in the hole, especially when it is coupled with potential parameters such as differential pressure, drill string rotation, and exposure time that could contribute to core damage.

4.3.1 Eccentricity Calculation Diagram

The preset value of drill string eccentricity (0% to 75%) referred to the pipe stand off calculation published by Schlumberger (1996). Figure 4.2 used to define and assist the eccentric calculation model. From the calculation, the required shifted value of a particular drill string eccentricity study could be achieved by adjusting the top and bottom slip plates of the testing section. For example, for 25% drill string eccentricity; the pipe was shifted 7.9 mm away from the center of the hole. Table 4.5 shows the required shifted value of the drill string for a particular experiment. Appendix H shows the schematic diagram of the drill string eccentricity profile in horizontal hole.

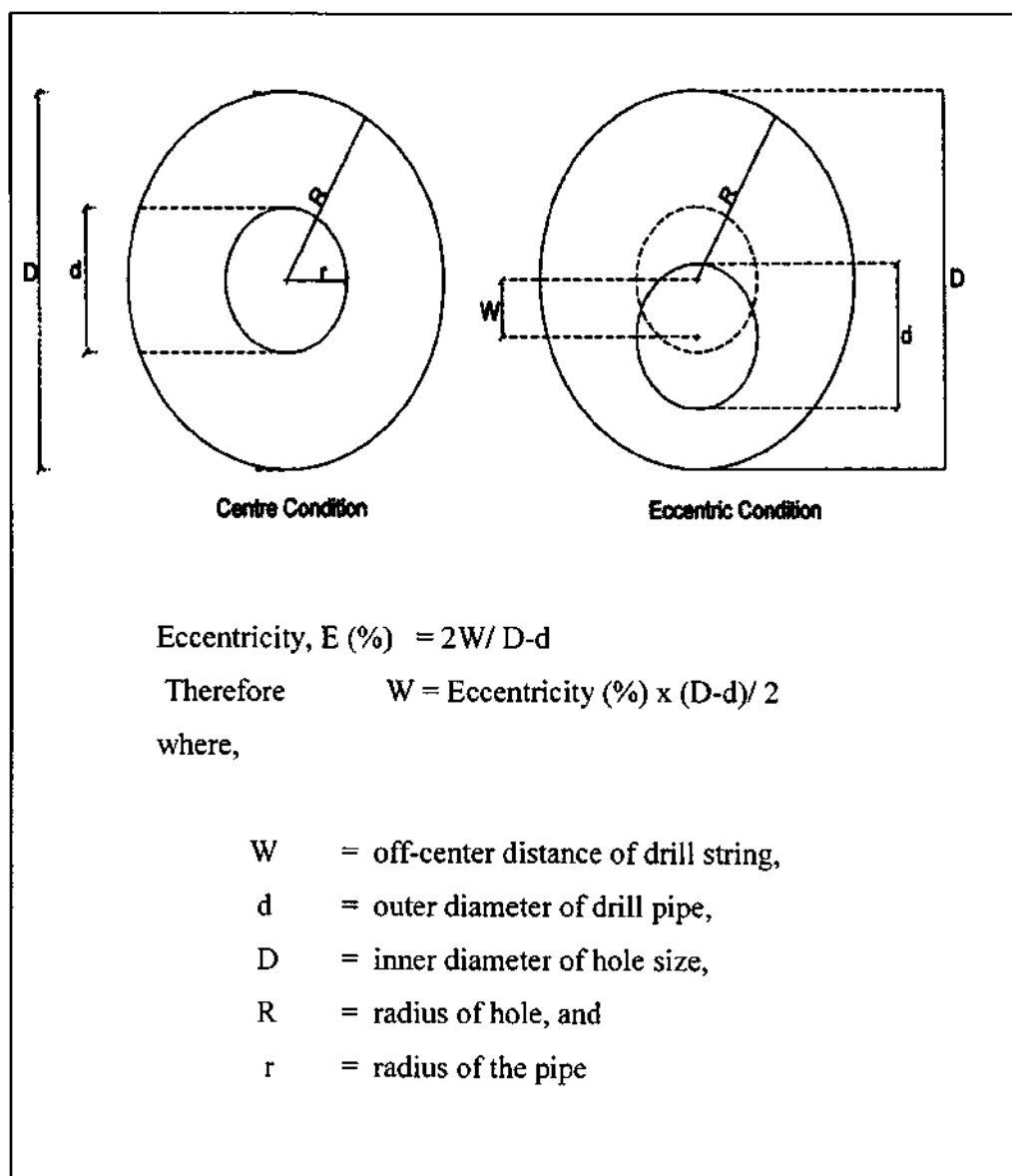


Figure 4.1: Calculation model of the drill string eccentricity

Table 4.5: Required shifted value for the drill string eccentricity studied

Drill string Eccentricity, (%)	Mathematic Calculation	Shifted Value from Centre of Hole
0	-	-
25	$(0.25 \times (152.4-88.9)/2) = 7.90 \text{ mm}$	7.90 mm
50	$(0.50 \times (152.4-88.9)/2) = 15.87 \text{ mm}$	15.90 mm
75	$(0.75 \times (152.4-88.9)/2) = 23.80 \text{ mm}$	23.80 mm

4.3.2 Mud Flow Pattern in Annulus

According to Linsay *et al.* (1996), fluids that are flowing in an annulus exhibiting yield stress and gel strength such as mud may form three flow regimes; no flow on the narrow side of annulus (drill string close to the formation, especially at bottom part of horizontal hole), turbulent on the wide side (upper part of the hole when drill string moves towards the bottom part of the hole), and laminar in between (drill string at the center of the hole) as depicted in Figure 4.2.

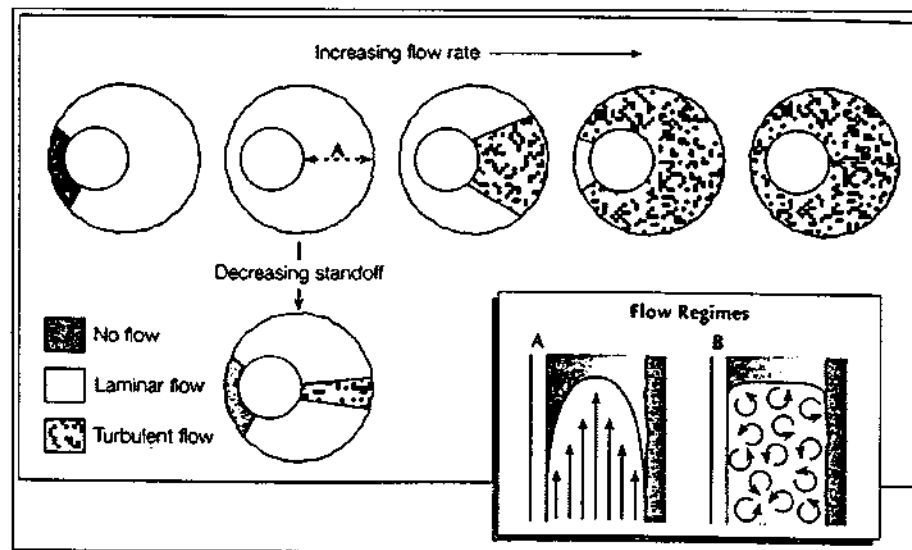


Figure 4.2: Flow pattern due to drill string eccentricity

Since there is no drill string rotation at static condition, thus forces required to flow the mud are created by the frictional pressure drop and mud density only. The mud yield strength must be less than the wall shear stress generated by frictional pressure drop to allow mud flow in the narrow gaps.

The wall shear stress can be increased by elevating the flow rate, drill string rotation speed, mud density, and reducing the drill string eccentricity. At higher flow rate, mud can be displaced effectively from the hole by the turbulent flow, but viable only if the hole size and drill string are relatively small. At low flow rate, drilling mud with high yield stress and gel strength could be static in narrow gap of an eccentric annulus because of distorted velocities and lower frictional pressure.

In this study, the mud annular velocity was 60 ft/min, and it furnished turbulent flow behavior throughout the experiment as the Reynold's number was 4800 that exceeded the turbulent flow boundary value of 4000 (Appendix B).

According to Rabia (1986), in turbulent flow, the fluid particles fluctuation near the wall dies out and the flow pattern is laminar. The flow region is also called as laminar sublayer. Since the core samples were placed in the core holders and the core holders were fitted along to the testing unit wall, therefore the flow pattern passed through the cores would be laminar flow or no flow due to drill string eccentricity. In laminar flow, the solid particles travel along with the carrying fluid, therefore the traveling part of the solid particles are in straight lines parallel to the wall axis.

4.3.3 Effect of Drill String Eccentricity on Formation Damage

The effect of drill string eccentricity towards the bottom part of the hole was conducted under constant mud weight of 10.3 ppg, temperature of 80°C and annular velocity of 60 ft/min. The definition of drill string eccentricity was given in Chapter II is believed to have some effects on formation damage especially in horizontal well. The Permeability Variation Index introduced by Faruk and Civan (2000) was used to calculate the severity of the cores damage after exposing to the drilling mud. The Permeability Variation Index (PVI) expresses the change or damage of formation permeability near the wellbore as a fraction, given by,

$$PVI = (K_i - K_d) / K_i \times 100\% \quad (i)$$

where,

- PVI = permeability variation Index, %
- K_i = initial permeability of core before exposed to mud (md), and
- K_d = damage permeability of core samples after exposed to mud (md)

The PVI was used to determine the damage of the core samples for the entire studied parameters caused by the drill string eccentricity. Higher PVI reflects higher damage to the core samples. Table 4.6 shows the PVI of cores samples after being exposed to the mud at different drill string eccentricity studied and differential pressures.

Table 4.6: PVI for the core sample at different drill string eccentricity

Differential Pressure	Eccentricity (%)	Permeability Variation Index, (%)
100	0	9.3
	25	5.8
	50	7.0
	75	-2.3
150	0	20.0
	25	11.3
	50	12.8
	75	-8.8
200	0	25.3
	25	13.3
	50	15.6
	75	-13.9
250	0	22.3
	25	-3.8
	50	-7.9
	75	-14.9

Figure 4.3 and Table 4.6 show that at 0% drill string eccentricity, higher differential pressure caused higher damage to the core sample. The induced differential pressure was ranging from 100 to 250 psi. At 100 psi, the core damage was 9.3%, whereas at 150 psi and 200 psi the damage were 20% and 25.3% respectively. At 0% eccentricity, the drill string was placed at the center of the hole, thus core damage was assumed solely due to the differential pressure exerted on the mud that pushed the particulates into the core samples. In the other words, the damage at 0% eccentricity was used as the reference value for other studied parameters.

Figure 4.3 and Table 4.6 also show that higher drill string eccentricity (25% to 50%) caused severe damage to the core samples and it was found to occur throughout the experiment at induced pressure ranging from 100 to 200 psi. The damage at 25% drill string eccentricity was 5.8%, whereas for 50% was 7.0% at the differential pressure of 100 psi. For differential pressure of 150 psi, the damage for 25% and 50% drill string eccentricity were 11.3% and 12.8%, respectively. At the induced differential pressure of 200 psi, the damage for 25% drill string eccentricity was 13.3%, whereas 50% was 15.6%.

Higher drill string eccentricity caused higher damage to the core samples for all the tests carried out up to 200 psi differential pressure. This was due to the formation of smaller annulus area at the bottom part of the hole than the top part of the hole, thus the mud particles at the bottom part were trapped easily as it moved slower in the smaller annulus area. When the induced differential pressure was acting on the mud, the drilling mud particles at smaller annulus area invaded deeper into the core samples and consequently caused severe damage to the core sample.

In contrast to the above finding, the experiment conducted at higher drill string eccentricity (75%) showed that the core sample did not experience any damage, but surprisingly caused improvement in permeability especially at higher differential pressure (250 psi). This was probably due to the presence of micro-fractures in the core samples, as shown in Figure 4.4. The micro-fractures caused the improvement of permeability as it created additional flow channels in the core samples. Figure 4.4 shows that the improvement of permeability for the core samples at 75% drill string eccentricity for differential pressure of from 100 psi, 150 psi, 200 psi, and 250 psi were -2.3%, -8.8%, -13.9, and -14.9%, respectively.

Drill string eccentricity would result the radial variation in annular flow velocity in horizontal well. Generally, higher drill string eccentricity results in larger radial variation in annular flow velocity around wellbore, where higher velocity in wide side or upper part of a hole (large annulus) and lower velocity or lower part of a hole on narrow side (smaller annulus). Viscous non-newtonian fluids like oil-based mud could be static or difficult to move in the narrow annulus.

Drilling mud flows freely in the larger flow area of annulus but tends to flow at a much slower rate in the smaller annulus area. As a result, in the small flow area annulus, the mud cake had formed significantly as compared to the larger flow area annulus, where most of the mud cake was swept away by the turbulent and swirling flow effect in the hole.

At 75% drill string eccentricity, the annulus area at the bottom part of a hole is relatively small which might cause no flow or slow flowing mud in this annulus area. When the induced differential pressure acting on drilling mud at this condition, it caused micro-fractures. This is due to the fact that the forces exerted at this point were higher and sufficient to cause the core to experience micro-fractures.

Table 4.7 shows the result for the test conducted at 75% drill string eccentricity at differential pressure of 250 psi. Two core samples were used simultaneously in this experiment; the first core was placed at the upper part of the horizontal hole, while the second core was placed at the lower part. Both samples were tested simultaneously under the constant mud weight of 10.3 ppg, differential pressure of 250 psi, temperature of 80°C and annular velocity of 60 ft/min. The core sample located at the upper part (annulus wide side) of the hole encountered damage, but the lower part (annulus smaller side) experienced *improved permeability* after being exposed to the drilling fluid. This might be due to the induced differential pressure and forces generated during the drill string rotation had exceeded the fracture limit of the core samples. Therefore, the core samples placed at the lower part experienced micro-fractures.

Table 4.7: Comparison of the PVI in horizontal well for top and bottom part of the hole

Sample	Section	Differential Pressure, psi	Permeability Variation Index, %
16	Top part	250	15.3
	Bottom part	250	-14.9

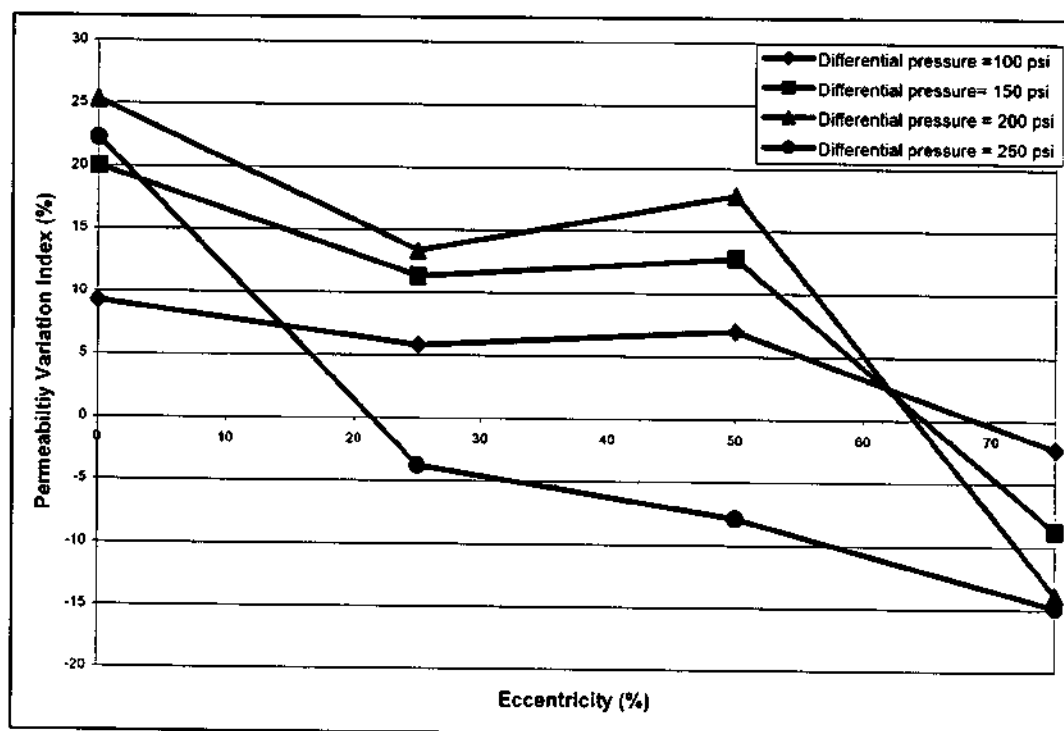


Figure 4.3: The effect of drill string eccentricity on permeability variation index

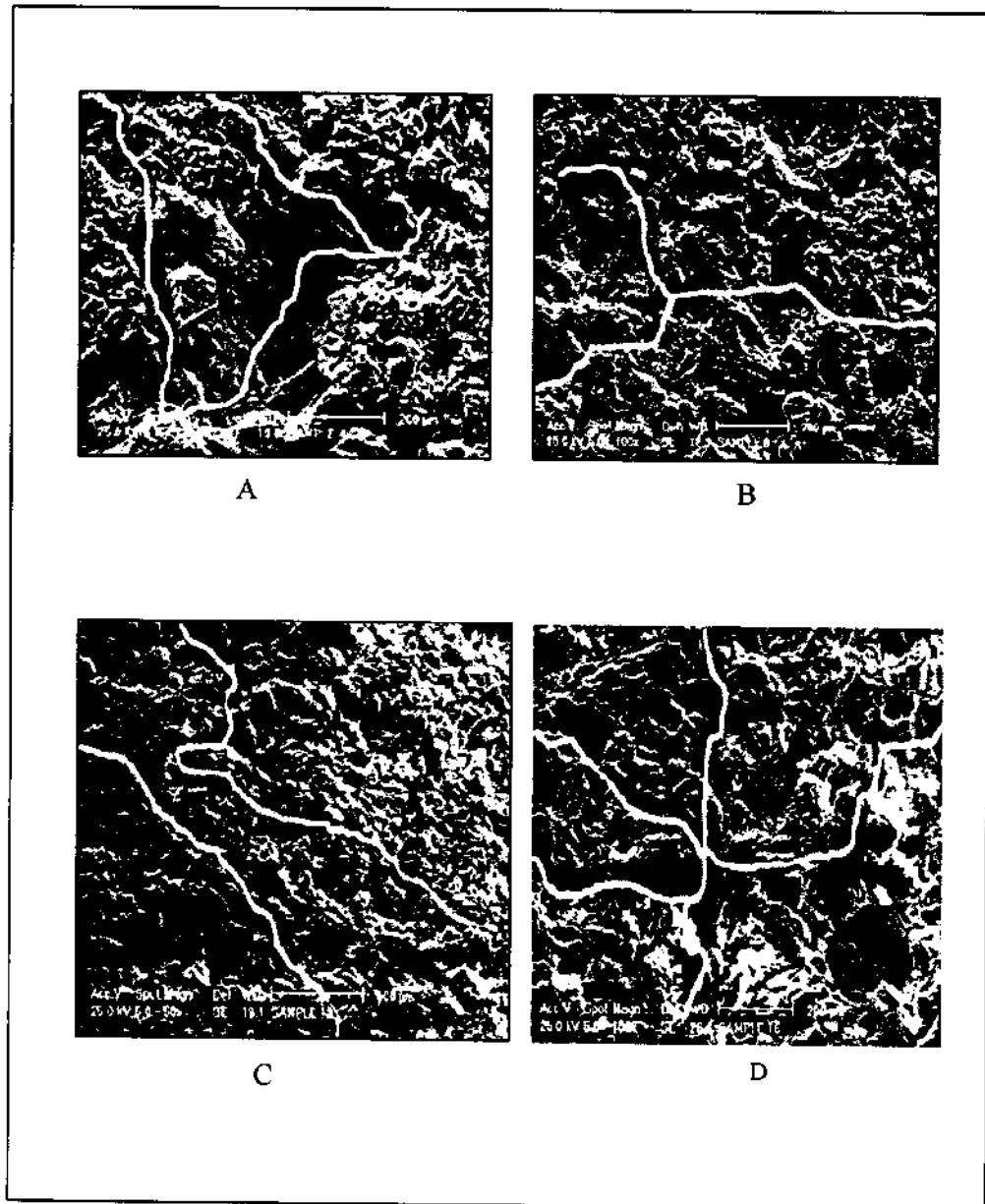


Figure 4.4: Fracture occurs in core sample at 75% drill string eccentricity; A (100 psi), B (150 psi), C (200 psi), and D (250 psi)

4.3.4 Filtrate Loss due to the Drill String Eccentricity

The drill string eccentricity has some effects on the cumulative filtrate loss volume, and generally higher drill string eccentricity causes higher filtrate loss. Figure 4.5 shows the filtrate loss volume collected at differential pressure of 100 psi and different drill string eccentricity conditions. The highest filtrate loss volume of 3.2 ml was recorded at 75%, whereas the lowest filtrate loss volume of 1.8 ml was recorded at 0% drill string eccentricity for the induced differential pressure of 100 psi. Figure 4.6 to 4.8 show the filtrate collected at different differential pressure and these entire figures gave similar filtrate loss volume profiles.

Table 4.8 shows the filtrate loss collected at four different drill string eccentricity conditions and it was found that higher drill string eccentricity contributed to higher filtrate loss. For example, the final filtrate loss volume after exposing core sample to drilling mud for 30 minutes at 25 %, 50%, and 75% drill string eccentricity with 200 psi differential pressure were 3.7 ml, 3.7 ml, and 3.8 ml respectively. The final filtrate volume (after 30 minutes) was comparable for 25% to 75% drill string eccentricity conditions at certain differential pressure studied, as shown in Table 4.8, except at 0% drill string eccentricity.

The final filtrate volume for 25% to 75% drill string eccentricity conditions was almost the same. The reason was drilling mud flowed with less resistant in the larger flow area annulus compared to annulus smaller area due to drill string eccentricity condition. The drilling mud in the annulus smaller area was flowing slowly and the differential pressure acting on the drilling mud enhanced the formation of mud cake at this condition compared to the mud flowing at annulus larger area, which experienced some swirling and turbulent effects. Once the impermeable and porous mud cake formed, it indirectly impeded the filtrate rate.

At 0% drill string eccentricity, the final filtrate loss volume of 2.9 ml (after 30 minutes) was recorded at differential pressure of 250 psi. This final volume was slightly lower than the experiment conducted at drill string eccentricity of 25% to

75% conditions. This is due to at higher drill string eccentricity condition, the drilling mud flowing slowly and might be trapped. The differential pressure exerted on it could drive filtrate easily into the core samples, thus it produced higher cumulative loss. Besides, at 0% drill string eccentricity, the mud flow at similar rate at the both sides (upper and lower parts) of hole, and the turbulent flow and swirling effects were significant and impeded the mud filtrate into core samples. Consequently, the cumulative filtrate loss volume was slightly lower.

Table 4.8: Final collected filtrate at varying drill string eccentricity

Differential Pressure, psi	Filtrate Volume at Vary Drill String Eccentricity, ml				Testing Condition
	0%	25%	50%	75%	
100	1.8	3.0	3.1	3.2	Filtrate collected at 30 minutes and the drill pipe rotation was 120 rpm.
150	2.1	3.2	3.3	3.4	
200	2.6	3.3	3.4	3.5	
250	2.9	3.7	3.7	3.8	

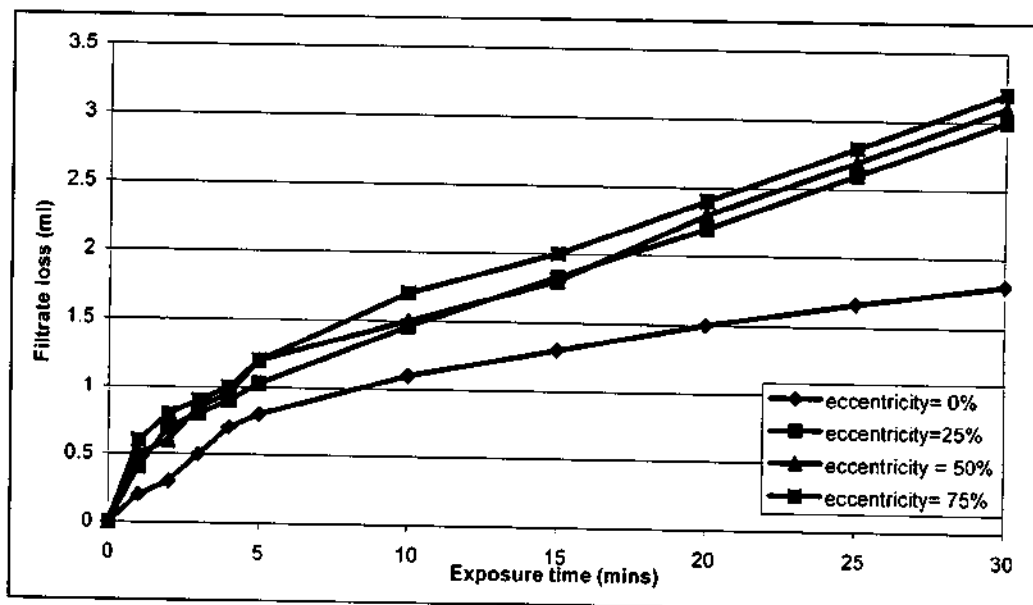


Figure 4.5: Filtrate collected for different drill string eccentricity conditions at differential pressure of 100 psi

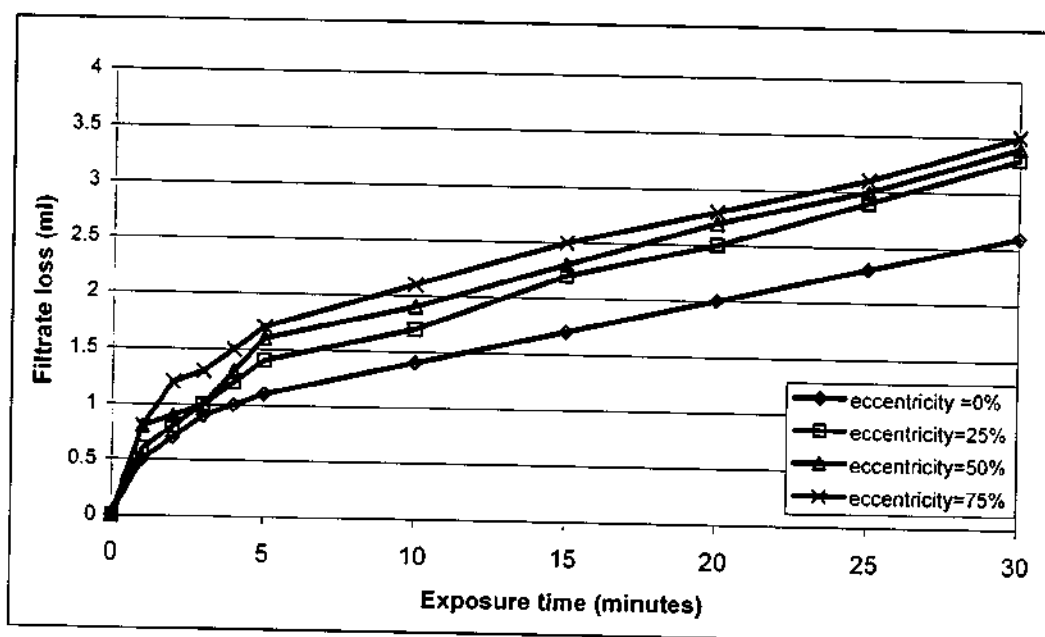


Figure 4.6: Filtrate collected for different drill string eccentricity conditions at differential pressure of 150 psi

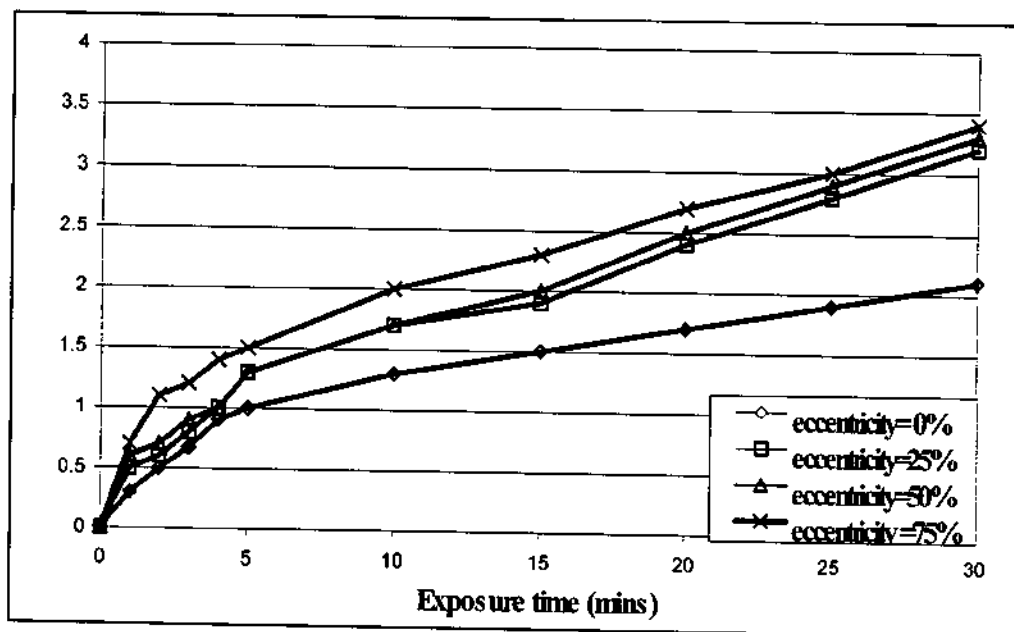


Figure 4.7: Filtrate collected for different drill string eccentricity conditions at differential pressure of 200 psi

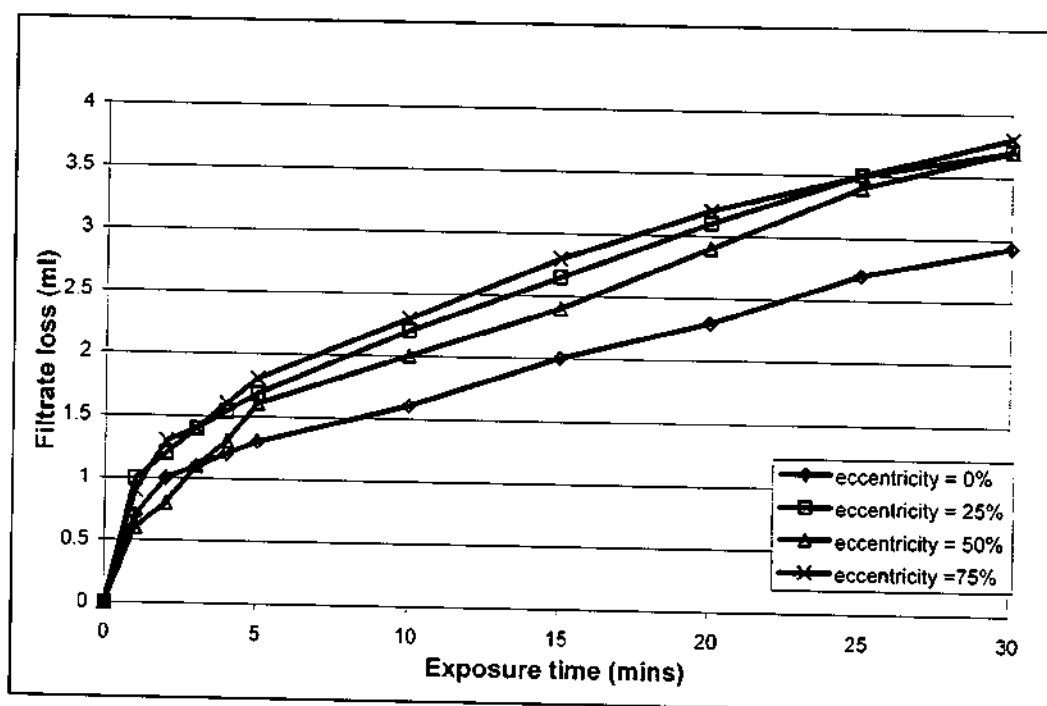


Figure 4.8: Filtrate collected for different drill string eccentricity conditions at differential pressure of 250 psi

4.3.5 Effect of Drill String Eccentricity Coupled with Differential Pressure on Formation Damage

According to Zukeffli *et al.* (2000), differential pressure has been well documented as one of the most importance physical parameters that have significant influence on formation damage studies. Generally, higher differential pressure could cause severe formation damage due to stronger forces that push the filtrate and solid particles into pores space and consequently cause formation damage.

The study was conducted at different differential pressures at certain drill string eccentricity condition (0% to 75%) with constant drill string rotation speed of 120 rpm, mud weight of 10.3 ppg, and annular velocity of 60 ft/min etc. It was found that PVI or damage increased with the increase of differential pressure from 100 psi to 200 psi for 25% to 75% drill string eccentricity. In reality, higher induced differential pressure of 250 psi should have given higher damage but the damage found was lower compared to the induced differential pressure from 100 to 200 psi, especially the test that conducted at 75% drill string eccentricity, as shown in Table 4.9.

Table 4.9: PVI for the core sample at different differential pressure

Eccentricity, %	Differential Pressure, Psi	Permeability Variation Index, %
0	100	9.3
	150	20.0
	200	25.3
	250	22.3
25	100	5.8
	150	11.3
	200	13.3
	250	-3.8
50	100	7.0
	150	12.8

Eccentricity, %	Differential Pressure, Psi	Permeability Variation Index, %
	200	15.6
	250	-7.9
	100	-2.3
75	150	-8.8
	200	-13.9
	250	-14.9

Figure 4.9 shows the results of Permeability Variation Index against the differential pressure. At 0% drill string eccentricity, higher differential pressure (from 100 psi to 200 psi) caused higher damage to the core samples. The damage occurred at 100 psi, 150 psi, 200 psi, and 250 psi were 9.3%, 20%, 25.3% and 22.3%, respectively. At higher induced pressure of 250 psi, the cores damage obtained in the experiment was slightly lower. This was due to the presence of micro fractures in the core sample at higher pressure under dynamic condition.

Figure 4.9 also reveals that at drill string eccentricity of 25% and 50%, the higher differential pressure induced (100 psi to 200 psi) to the core samples caused higher damage to the cores sample. For example, at 25% drill string eccentricity, the core damage induced to 100 psi, 150 psi, and 200 psi were 5.8%, 11.3%, and 13.3%, respectively. Whereas, for the test conducted at 50% drill string eccentricity for the induced pressure of 100 psi, 150 psi, and 200 psi, the damage induced were 7.0%, 12.8%, and 15.6%, respectively. From these two different drill string eccentricity studied, it was found that higher differential pressure would cause severe damage to the core samples due to the plugging of pore spaces by drilling mud particles as shown in Figure 4.11.

Figures 4.10 and 4.11 show the core samples before and after exposing to drilling mud. The pore spaces for the core sample before exposing to drilling mud could be seen clearly in Figure 4.10. Figure 4.11 shows the pore spaces that had been plugged by the mud particles after exposing to drilling mud at differential

pressure of 150 psi. Generally, higher induced differential pressure would plug the pore spaces more seriously.

Generally, higher induced differential pressure would cause severe damage to the core samples, as more particles were driven further into the pore spaces. At the induced differential pressure of 250 psi, the damage should be more severe than the induced differential pressures of 200 psi, 150 psi, and 100 psi, but conversely the permeability improved especially in 75% drill string eccentricity condition. After conducting the SEM, it was found that the core samples had fractured when tested under 250 psi differential pressure at 0% to 75% drill string eccentricity conditions.

The fracture problem at the 75% drill string eccentricity condition was the most severe and it was due to the higher trapped pressure in the small flow area annulus than other conditions. A slight increase in pressure induced at this condition would generate adequate forces to cause micro-fracture in the core samples. In addition, the drill string rotation also generated some extra forces that might contribute to fracture. Figure 4.12 clearly shows the fracture occurred in the core samples at the induced differential pressure of 250 psi at different drill string eccentricity conditions. Nevertheless, the fractures could only be visualized via SEM. Therefore, the fractures occurred was termed as *micro fractures*.

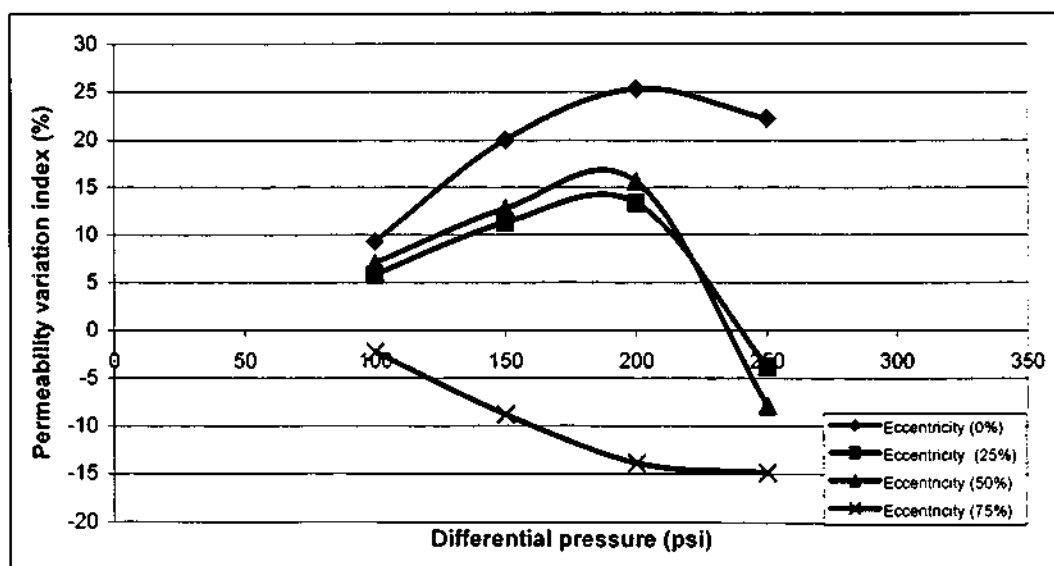


Figure 4.9: The effect of differential pressure on permeability variation index

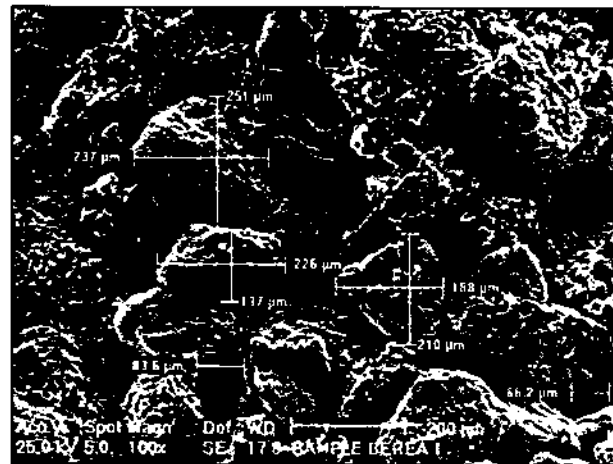


Figure 4.10: Pore spaces before exposing to drilling mud at 100x

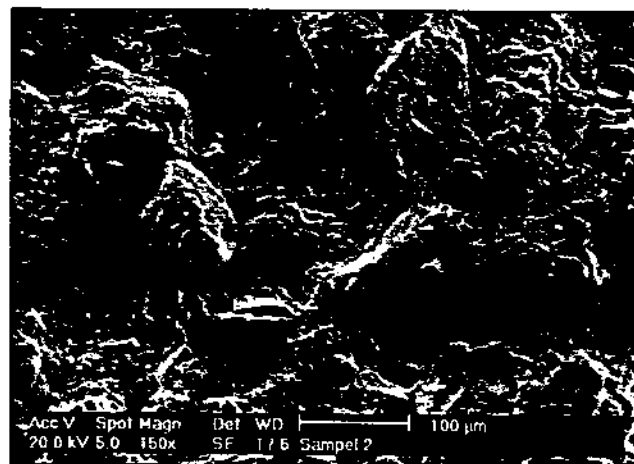


Figure 4.11: Pore space was severely plugged by mud particles after exposing to drilling mud at differential pressure of 150 psi

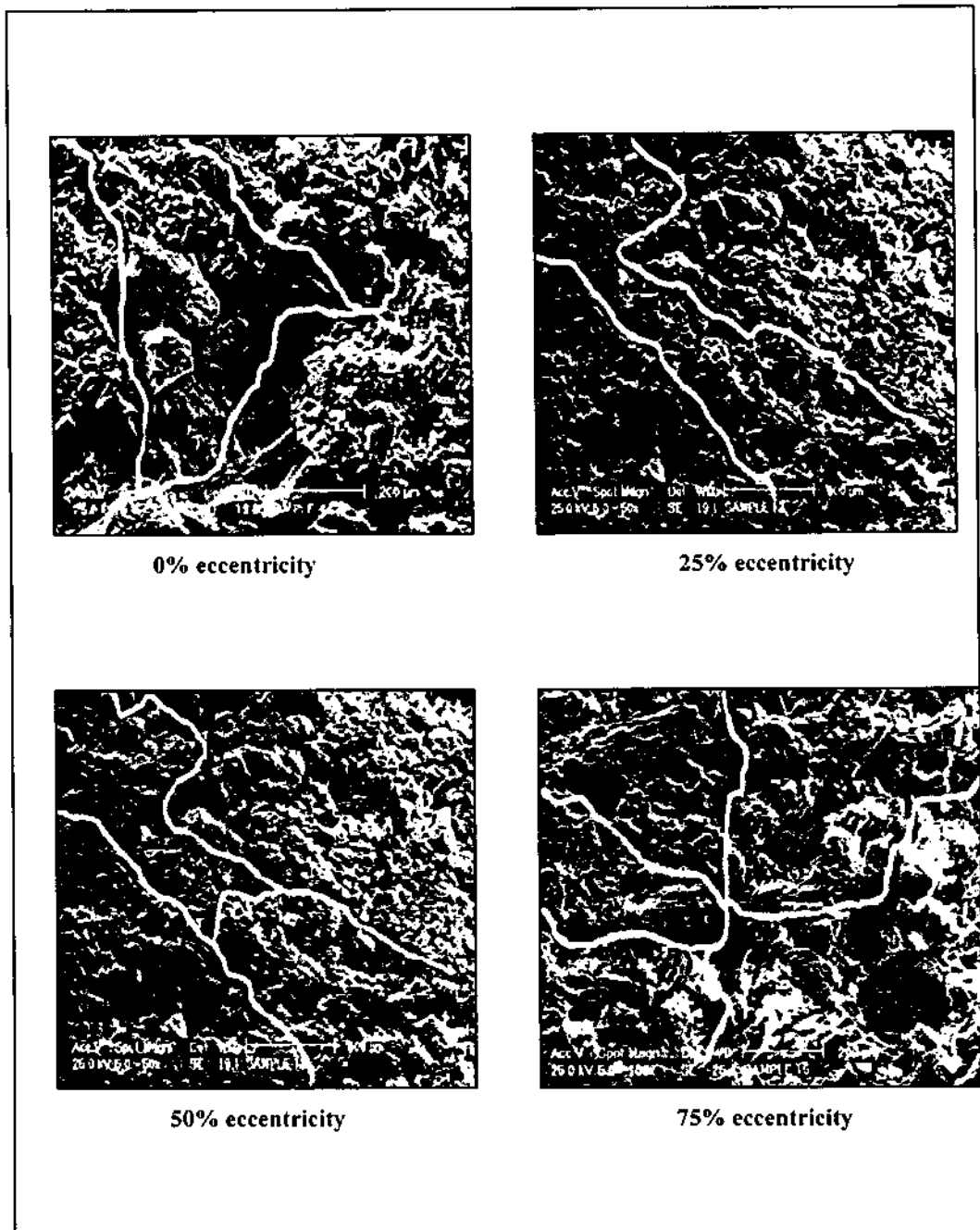


Figure 4.12: Micro fractures occurred at induced pressure of 250 psi for drill string eccentricity conditions

4.3.6 Effect on Differential Pressure on Filtrate Loss

Marx and Rahman (1987) and Teow (1999) in their laboratory studies found that higher differential pressure caused more filtrate and solid particles invaded deeper into the test samples. The cumulative filtrate loss volume was also higher at higher differential pressure.

The experiment was conducted at different differential pressure ranging from 100 psi to 250 psi at constant drill string rotation speed of 120 rpm and mud weight of 10.3 ppg and annular velocity of 60 ft/min. The final filtrate data was recorded at 30 minutes and as shown in Table 4.10. The table 4.10 shows that higher differential pressure caused higher cumulative filtrate loss. For example, the final filtrate loss volume at 30 minutes for 100 psi, 150 psi, 200 psi, and 250 psi at 0% drill string eccentricity condition were 1.8 ml, 2.1ml, 2.6 ml, and 2.9 ml, respectively. Whereas, the final filtrate volume for 25% drill string eccentricity condition at were 3.0 ml, 3.2 ml, 3.3 ml, and 3.7 ml, respectively, for the induced differential pressure of 100 psi, 150 psi, 200 psi, and 250 psi.

The studies at these different drill string eccentricity conditions showed that higher differential pressure induced to the core samples led to higher cumulative filtrate loss. This was due to stronger forces exerted by the differential pressure on the drilling mud that would drive or force more filtrates further into the core samples.

Figure 4.13 to Figure 16 show the filtrate loss due to the different differential pressures for different drill string eccentricity conditions. The entire figures gave the similar filtrate loss volume profiles with higher differential pressure caused higher filtrate loss.

Table 4.10: Final collected filtrate at vary differential pressures

Drill String Eccentricity, %	Filtrate Volume at Different Differential Pressure, ml				Testing Condition
	100	150	200	250	
0	1.8	2.1	2.6	2.9	Filtrate collected at 30 minutes and the drill pipe rotation was 120 rpm.
25	3.0	3.2	3.3	3.7	
50	3.1	3.3	3.4	3.7	
75	3.2	3.4	3.5	3.8	

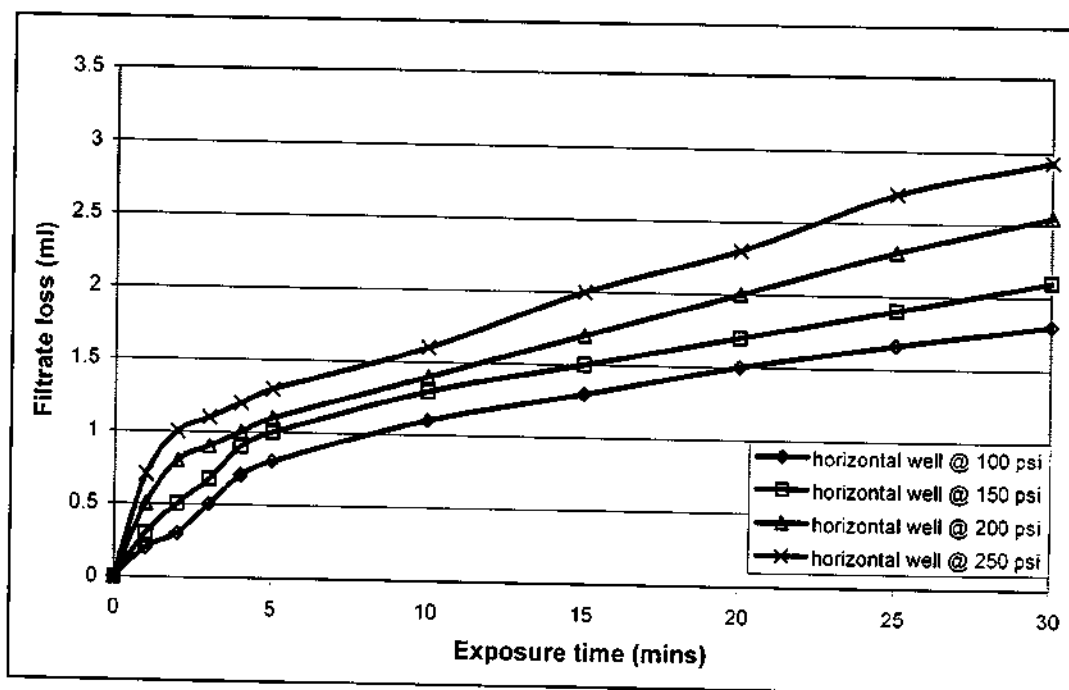


Figure 4.13: Filtrate collected for different differential pressures and 0% drill string eccentricity

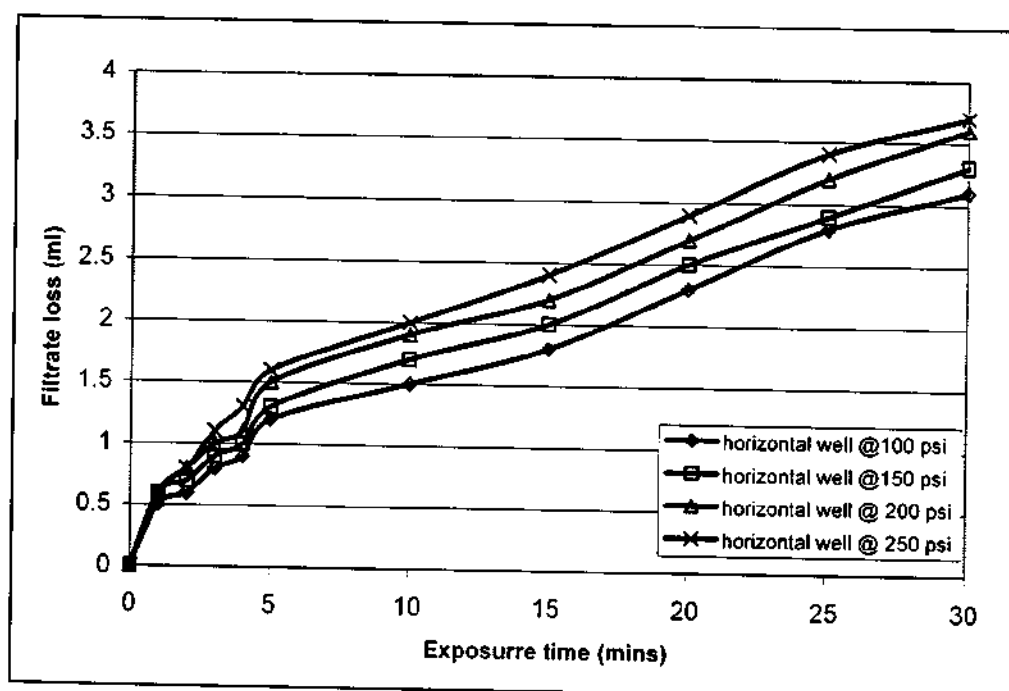


Figure 4.14: Filtrate collected for different differential pressures and 25% drill string eccentricity

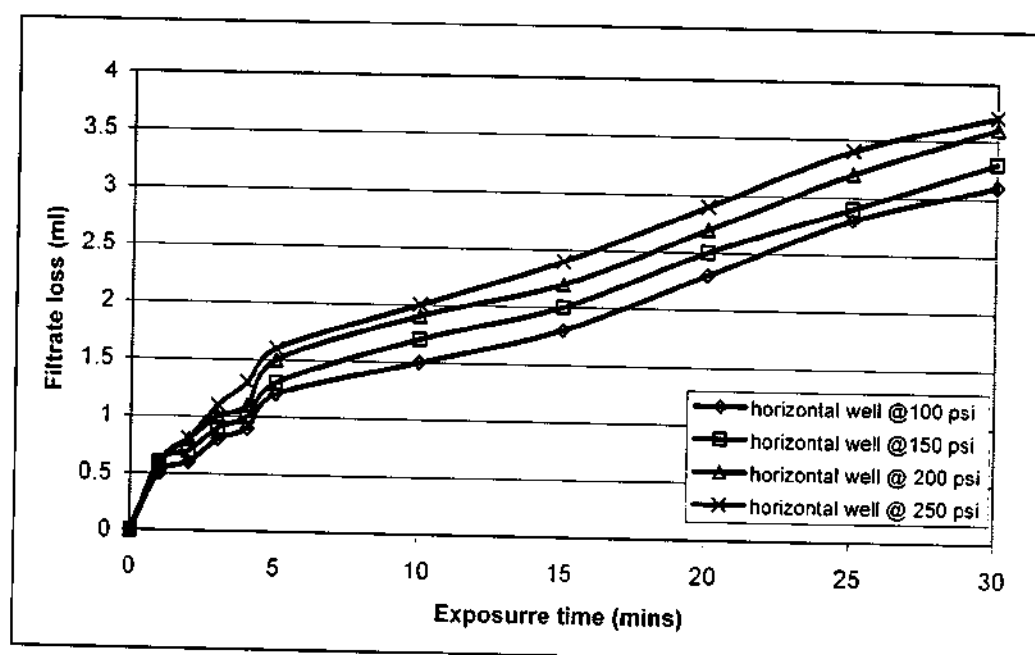


Figure 4.15: Filtrate collected for different differential pressures and 50% drill string eccentricity

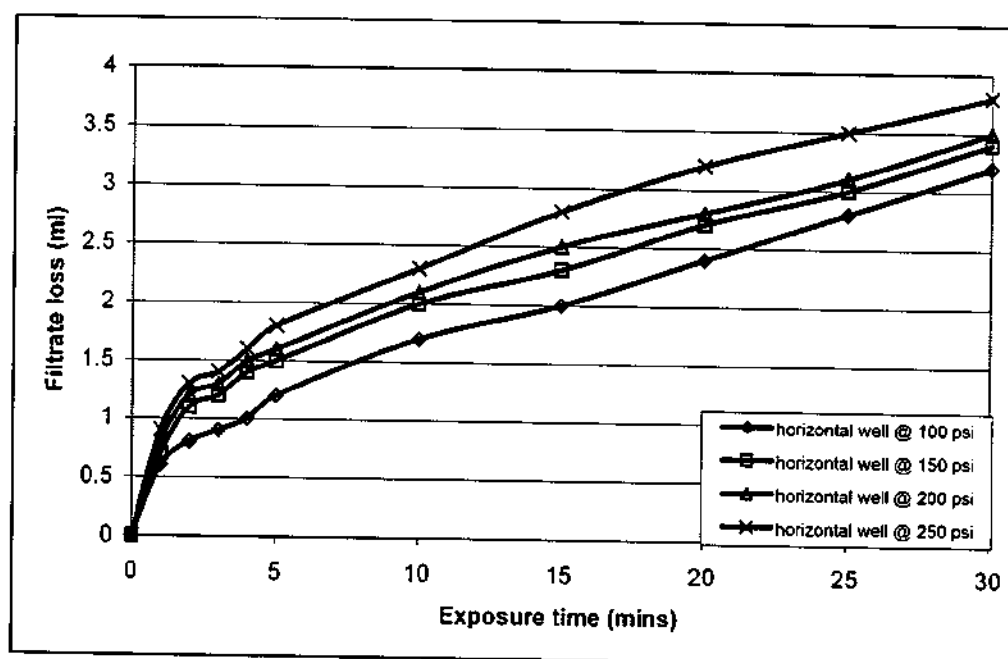


Figure 4.16: Filtrate collected for different differential pressures and 75% drill string eccentricity

4.3.7 Effect of Drill String Eccentricity Against Exposure Time on Formation Damage

Ray *et al.* (1998) in their laboratory study found that the formation damage increased with exposure time. In this study, whenever the severity of the core damage due to the exposure time was to be carried out, drill string eccentricity, induced differential pressure, drill string rotation speed, and mud weight, annular velocity were kept constant at 50%, 200 psi, 120 rpm, and 10.3 ppg, 60 ft/min, respectively.

In this study, exposure time was identified to be one of the parameters that contributed to cores damage, and core samples experienced higher damage at longer exposure time. Table 4.11 shows the PVI of the core samples after exposing to drilling mud at various exposure times. It was found that the PVI increased or damage increased with increase of exposure time.

Table 4.11: Classification of core samples for various exposure time studied

Sample	Exposure Time, mins	Permeability Variation Index, %	Testing Condition
25	30	15.6	Differential pressure of 200 psi with 50% drill string eccentricity and pipe rotation of 120 rpm
26	60	17.8	
27	120	18.9	
28	180	21.8	
29	240	23.5	

Figure 4.17 shows the results of Permeability Variation Index against the exposure time, and the experiment was conducted for the duration of 4 hours. Figure 4.17 obviously shows that longer exposure time caused higher damage to the core samples. For example, the core samples registered damage of 15.6% at 30 minutes, 17.8% at 1 hour, 18.9% at 2 hours, 21.8% at 3 hours and 23.5% at 4 hours.

Higher exposure time caused higher core damage. This was due to more filtrate would invade into the core samples and plug the pore spaces at longer exposure time compared to short exposure time, consequently it led to severe damage.

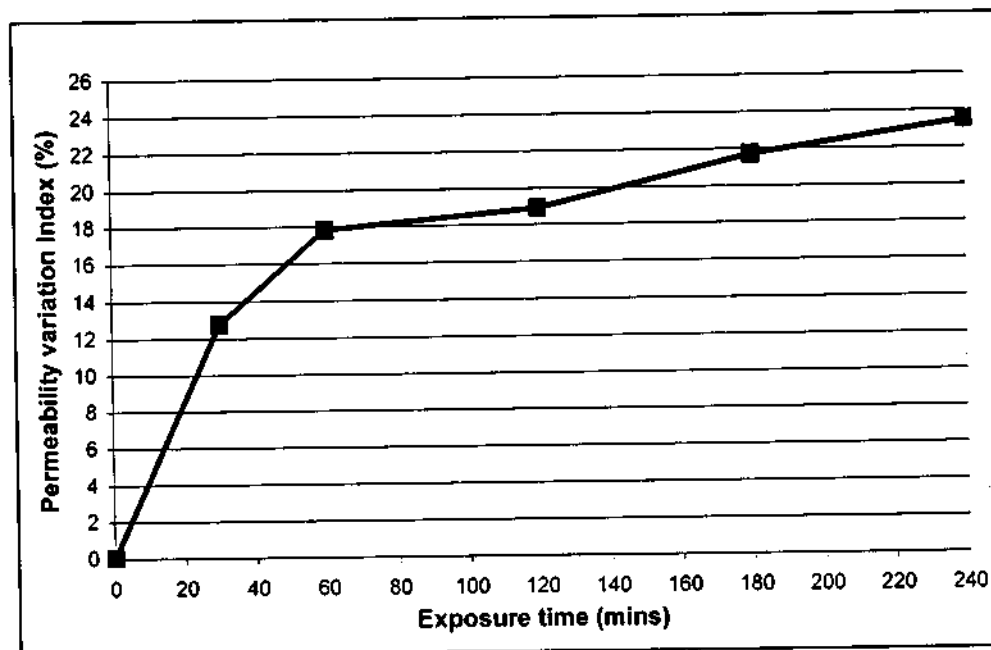


Figure 4.17: Permeability Variation Index against exposure time

4.3.8 The Influence of Exposure Time on Filtrate Loss

According to Di Jia and Sharma (1992), filtrates from drilling mud never stop from invading into formation and longer exposure time will result in higher cumulative filtrate loss. From the study, it was found that filtrate loss kept on occurring after 4 hours.

This experiment was conducted at different exposure times ranging from 30 minutes to 4 hours. The filtrate loss data were recorded and areas shown in Table 4.12. The experimental data showed that longer exposure time produced higher cumulative filtrate loss.

Figure 4.18 (A to E) represent the filtrate loss volume against exposure time for the duration of 30, 60, 120, 180, and 240 minutes. Higher exposure time gave higher cumulative filtrate loss. The highest final cumulative filtrate volume was

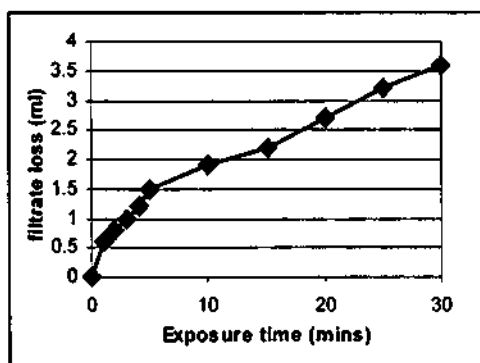
exposure time of 240 minutes, followed by 180, 120, 60, and 30 minutes, where the filtrate loss volume was 16 ml, 12.8 ml, 9.4 ml, 5.7 ml, and 3.6 ml respectively.

The filtrate loss volume collected at first minute (around 0.7 ml to 0.9 ml) was higher than the filtrate collected after 1 minutes and was called *surge period* by Xinghui and Civan (1993). After the first minute, the filtrate loss volume of 0.2 to 0.3 ml was constantly recorded until 20 minutes where the temperature was 75°C. The temperature increased from 75°C to 85°C when the experiment was conducted more than 20 minutes due to the friction of drilling mud with system component. The core samples were suspected to experience grains orientation expansion problem at this temperature; therefore the volume of filtrate loss collected after 20 minutes was slightly higher.

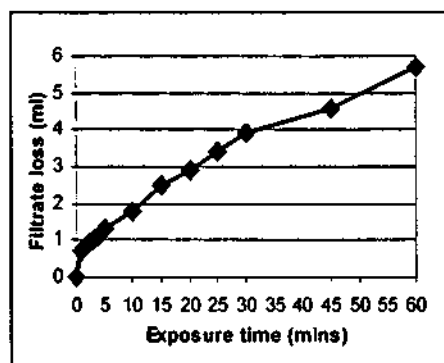
As shown in Table 4.12, the formation of impermeable mud cake had reduced the rate of filtrate loss after 30 minutes and filtrate loss volume was around 0.2 to 0.3 ml for every 5 minutes. It occurred at all exposure times studied and become dominant when mud cake started to formed.

Table 4.12: Filtrate loss against different exposure times

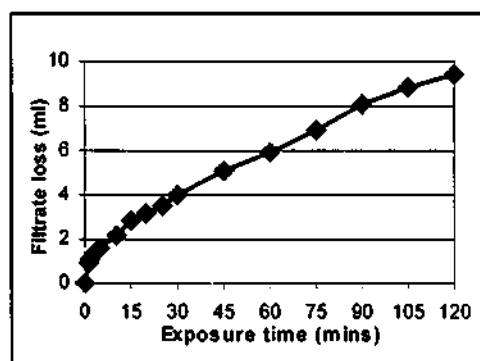
Exposure Time, mins	Filtrate loss, ml				
	Sample 29	Sample 28	Sample 27	Sample 26	Sample 25
0	0.0	0.0	0.0	0.0	0.0
1	0.7	0.8	0.9	0.7	0.6
2	0.9	1.1	1.1	0.9	0.8
3	1.1	1.2	1.3	1.0	1.0
4	1.3	1.4	1.5	1.1	1.2
5	1.5	1.5	1.6	1.3	1.5
10	1.7	1.7	1.8	1.8	1.9
15	2.0	1.9	2.1	2.0	2.1
20	2.4	2.3	2.4	2.3	2.4
25	3.0	2.9	3.0	2.9	3.0
30	3.7	3.7	3.8	3.7	3.6
45	4.8	4.7	5.1	4.6	-
60	5.8	5.5	5.9	5.7	-
75	6.7	6.4	6.9	-	-
90	8.0	7.4	8.1	-	-
105	9.0	8.1	8.8	-	-
120	10.3	8.9	9.4	-	-
135	11.0	9.8	-	-	-
150	11.7	10.7	-	-	-
165	12.4	11.7	-	-	-
180	13.2	12.8	-	-	-
195	14.0	-	-	-	-
210	15.0	-	-	-	-
225	15.7	-	-	-	-
240	16.0	-	-	-	-
	4 hours	3 hours	2 hours	1 hour	30 minutes



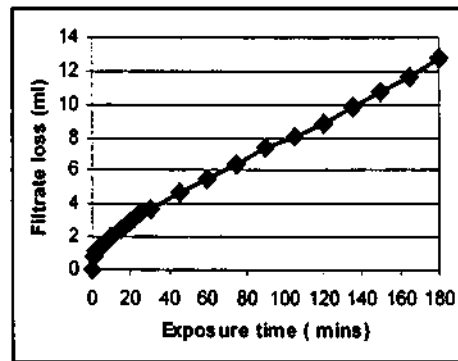
(A)



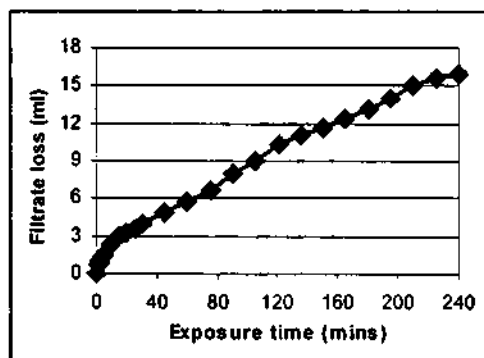
(B)



(C)



(D)



(E)

Figure 4.18: Filtrate loss against exposure time, A (30 mins), B (60 mins), C (120 mins), D (180 mins), and E (240 mins)

4.3.9 Effect of Drill String Eccentricity Coupled with Drill String Rotation Speed on Formation Damage

According to Sharma in 1997 from University of Texas, the effect of drill string rotation was found to be relatively insignificant from a formation damage point of view but is critical for cutting removal. In contrast, this research study found that the drill string rotation speed caused formation damage up to a certain degree.

The research study was conducted with various drill string rotation speed at drill string eccentricity of 50%, mud weight of 10.3 ppg, induced differential pressure of 200 psi, annular velocity of 60 ft/min, and the test sample was placed at the bottom of the hole. The test conducted with 50% drill string eccentricity and induced pressure of 200 psi due to the previous study that core samples were not experienced micro-fractures problem and most serious core damage occurred at this condition.

Table 4.13 shows the PVI of the core samples conducted at different drill string rotation speed coupled with 50% drill string eccentricity conditions. From the PVI calculation, higher PVI reflected higher damage of the core samples.

Table 4.13: Classification of core samples for drill string rotation speed

Sample	Drill String Rotation, rpm	Permeability Variation Index, %	Testing condition
21	0	0.8	Differential pressure of 200 psi with 50% drill string eccentricity for 30 minutes
22	120	12.8	
23	140	15.6	
24	150	-7.9	

Figure 4.19 shows that without drill string rotation speed (0 rpm), the core damage was 0.8 %. The cores damage detected at the drill string rotation speed of 120 rpm and 140 rpm were 12.8% and 15.6% respectively higher compared 0 rpm.

This was due to extra forces generated by the drill string rotation speed that acted on drilling mud would push more drilling mud particles into the formation, thus, it induced severe damage to the core samples. Generally, higher rotating speed will generate higher forces and consequently pushes more particles into the formation and causes severe damage.

In contrast, the test conducted under drill string rotation of 150 rpm showed improvement in permeability instead of damage to the core. This was believed that at drill string rotation of 150 rpm, the extra forces generated due to higher drill string rotation caused the micro-fractures occurred in the core sample especially at the lower part of the hole where the mud flowing slowly as shown in Figure 4.20. Slightly increased of pressure would permit fractures to occur more easy compared to the samples exposed to the drilling mud with lower or without drill string rotation.

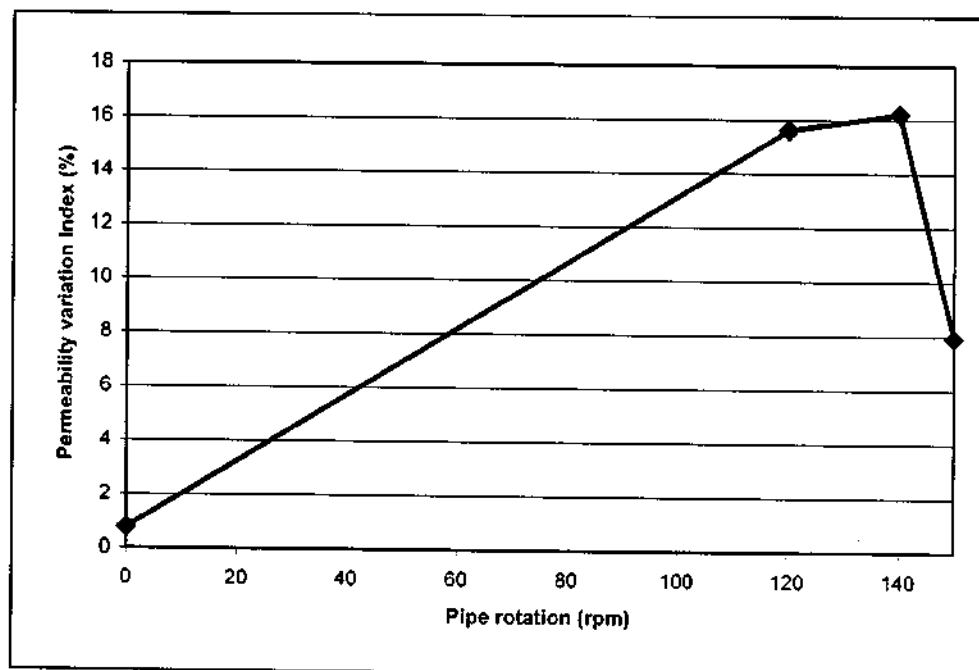


Figure 4.19: Permeability variation index for different drill string rotation speed at 200 psi

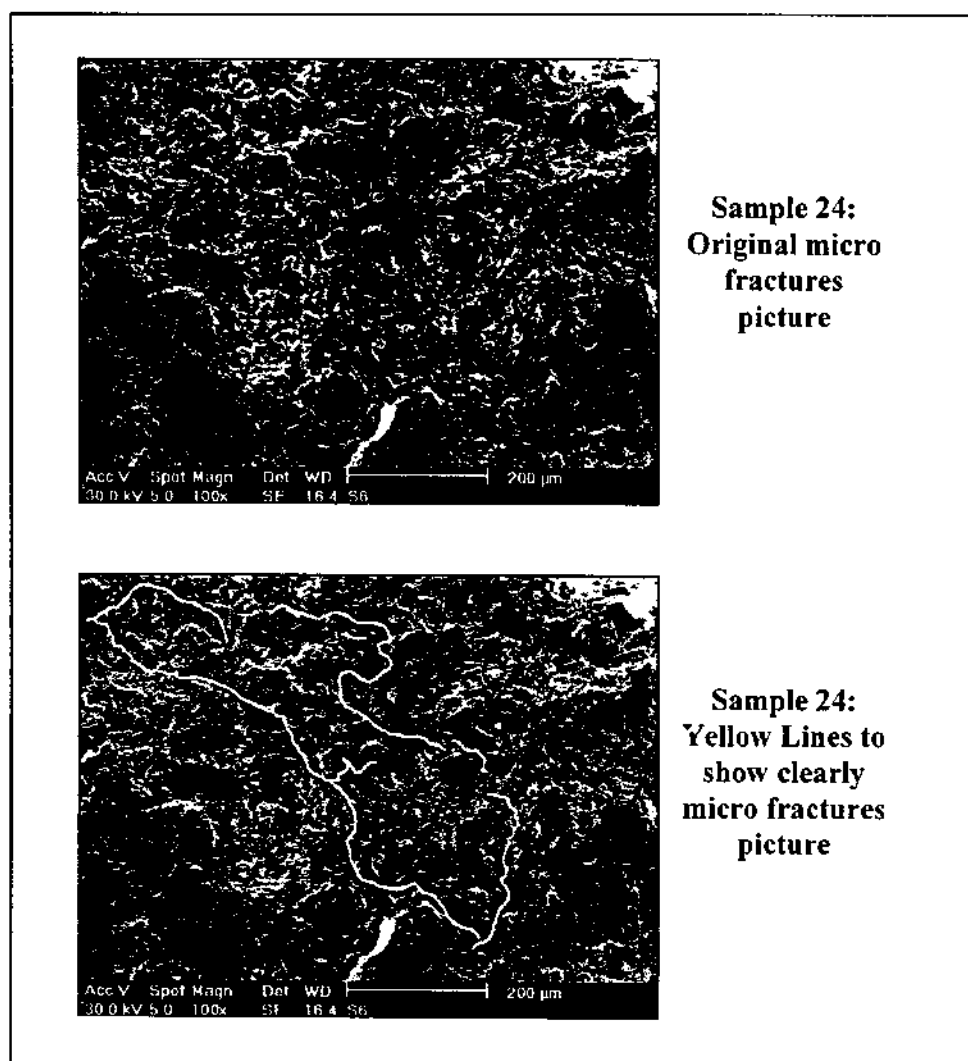


Figure 4.20: Micro fractures occurred at induced pressure of 200 psi @ 50% for drill string rotation of 150 rpm

4.3.10 Effect of Drill String Rotation Speed on Filtrate Loss

The experimental was conducted for the duration of 30 minutes. The filtrate loss volume was recorded at the interval of 1 minute for the first 5 minutes. After the first 5 minutes, filtrate loss data was taken at the interval of 5 minutes until 30 minutes. The filtrate loss data were shown in Table 4.14.

Table 4.14: Filtrate loss for different drill string rotations

Exposure Time, mins	Different Drill String Rotation Speed, rpm			
	0	120	140	150
0	0.0	0.0	0.0	0.0
1	0.5	0.7	0.8	0.9
2	0.8	0.9	1.1	1.2
3	0.9	1.1	1.3	1.4
4	1.0	1.3	1.5	1.6
5	1.1	1.4	1.6	1.8
10	1.5	1.7	1.9	2.1
15	2.0	2.2	2.3	2.5
20	2.4	2.7	2.8	2.9
25	2.9	3.2	3.3	3.4
30	3.3	3.5	3.6	3.9
	Filtrate Loss, ml			

Figure 4.21 shows that higher drill string rotation caused higher filtrate loss. The final filtrate volume for 0 rpm, 120 rpm, 140 rpm, and 150 rpm were 3.3 ml, 3.5 ml, 3.6 ml, and 3.9 ml, respectively. At higher drill string rotation, greater swirling forces were generated by the drill string, thus it drove more filtrate into the core samples. As a result, the filtrate collected was found to increase marginally.

The filtrate loss volume was higher at the end of the first minute and this was known as *surge period*. The filtrate loss volume of 0.2 ml to 2.3 ml was constantly recorded until the end of 20 minutes where the temperature of the system was 75°C. The temperature increased to 80°C when the experiment was conducted for more than 20 minutes. At this temperature, the core samples were suspected to experience the thermal expansion and caused the grains expanse. Therefore, the filtrate loss at the end of 20 minutes and thereafter, were higher and the filtrate loss for every 5 minutes after 20 minutes of conducting the experiment until the end of experiment was around 5 ml for all experiment conducted for drill string rotation speed from 0 rpm to 150 rpm.

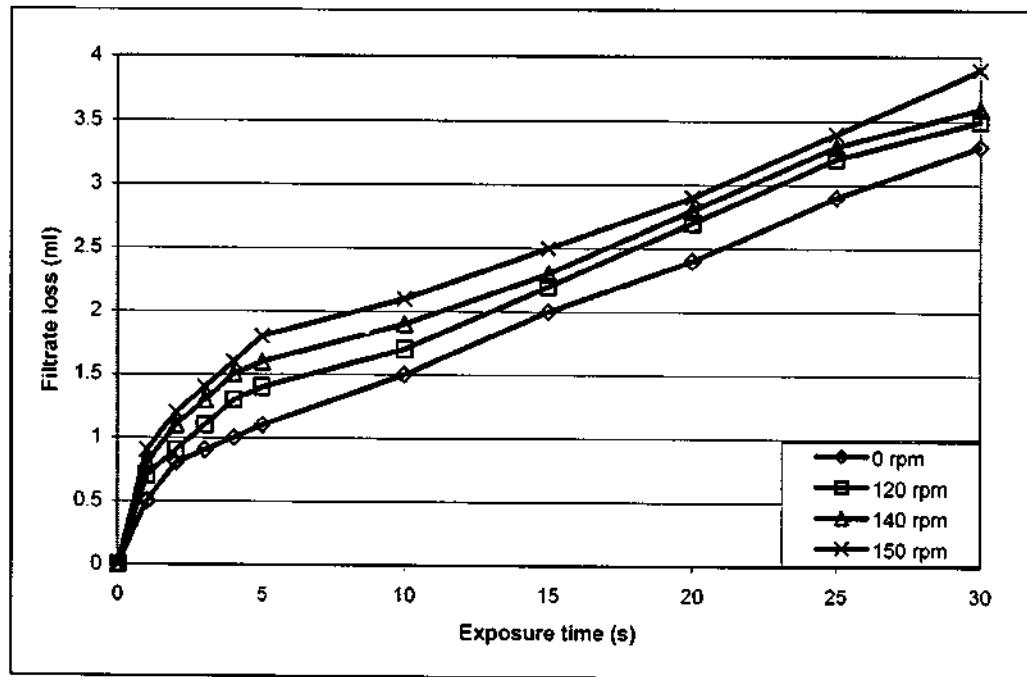


Figure 4.21: Filtrate loss for different drill string rotation speed at 200 psi

4.4 The Effect of Drill String Eccentricity in Horizontal and Vertical Wells

The testing unit was oriented to the required position to simulate the horizontal or vertical hole conditions. From the Permeability Variation Index (PVI) calculation, it was found that the severity of the damage in horizontal well was higher than the vertical well. The higher the PVI, the higher the damage experienced by the core samples and there were two main possible reasons that contributed to this phenomenon in horizontal well; anisotropy flow and the gravity effect.

Table 4.15 shows the result of the core samples that were tested horizontally and vertically at differential pressures ranging from 100 psi to 250 psi. The tests were conducted at 50% drill string eccentricity with 10.3 ppg mud weight and 60 ft/min annular velocity. The PVI was plotted against the differential pressure for

horizontal and vertical wells. Core samples from number 9 to 12 were exposed to differential pressures from 100 psi to 250 psi at horizontal condition, whereas core samples number 17 to 19 were conducted at vertical condition.

Table 4.15: Classification of core samples for horizontal and vertical wells

Sample	Differential Pressure, psi	Permeability Variation Index, %	Well Orientation
9	100	7.0	Horizontal
10	150	12.8	
11	200	15.6	
12	250	-7.9	
17	100	5.4	Vertical
18	150	9.3	
19	200	10.6	
20	250	-6.2	

Figure 4.24 shows the comparison of damage in horizontal and vertical wells that were conducted at 50% drill string eccentricity with constant mud weight of 10.3 ppg, drill string rotation of 120 rpm, and annular velocity of 60 ft/min with various differential pressure. It was found that higher differential pressure caused higher damage to the core samples in horizontal and vertical wells. This result was found to be consistent with the statement given by Zulkeffli (2000) and Marx and Rahman (1987) where higher differential pressure led to severe damage.

Differential pressure of 100 psi, 150 psi, and 200 psi, were induced to core samples 9 to 12 at horizontal position and samples 17 to 19 at vertical position. The cores damage was found to increase with increase in pressure and it occurred at both positions. From Figure 4.24, the damage recorded at 100 psi differential pressure in horizontal and vertical positions was 7% and 5.4%, respectively. The highest damage value recorded at 200 psi was 15.6% in horizontal well and 10.6 % for vertical well.

In this study, it was discovered that higher induced differential pressure will break the core samples. For example, Figure 4.24 shows that at 250 psi, both core samples in horizontal and vertical positions should register higher damage according to the theory, but conversely the damage was lower compared to 200 psi differential pressure. The damage value for the horizontal and vertical wells at 250 psi were -7.9% and - 6.2% respectively. After conducting the SEM studies, *micro fractures* were obviously seemed in the core samples and it was the main reason for the improvement of permeability in both horizontal and vertical wells.

Figure 4.22 shows that the micro fractures occurred in core samples placed at horizontal position, while Figure 4.23 for core samples at vertical position. The SEM photos at the 50x magnification clearly showed the micro fractures occurred in both samples. The micro fractures in vertical position was more severe compared to horizontal position, therefore the permeability improvement in the horizontal position (sample 20) was higher than the vertical position (sample 12), as shown in Figure 4.24.

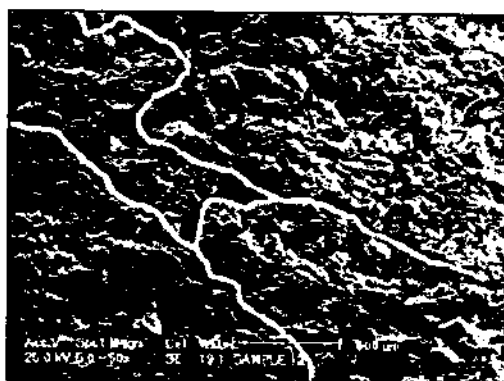
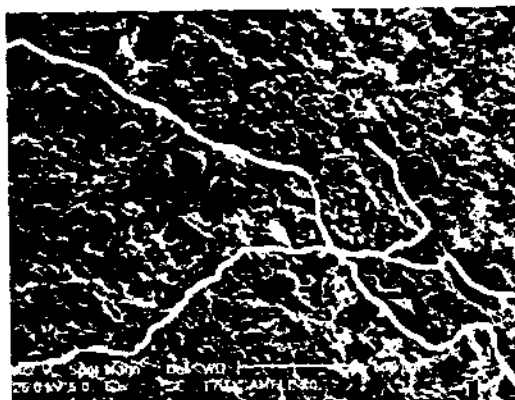


Figure 4.22: Micro-fractures in horizontal well at 50x magnification (Sample 12)



**Figure 4.23: Micro-fractures in vertical well
at 50x magnification (Sample 20)**

Figure 4.24 shows that damage was higher in horizontal (sample 9 to 11) well compared to vertical (sample 17 to 20). According to Bennion (1996), this phenomenon was due to the anisotropic flow effect where the flow patterns into a horizontal well was completely different to a vertical well, as illustrated in Figure 2.6. From Figure 2.6 it can be seen that sources of fluid flow in a vertical well is a uniform strata of crossed bedded planes which penetrates in an orthogonal fashion and will drain the reservoir in a uniform planar radial profile. Conversely, in a horizontal well, sources of fluid are from both the vertical and horizontal planar directions and hence it is much more radically affected by variation in the vertical permeability of the reservoir. Furthermore, the invasion damage of vertical well in a situation of uniform non-directional horizontal permeability will be in cylindrical pattern and the invasion damage is only dominated in one direction (x-direction), as shown in Figure 2.7.

Figure 2.7 also revealed that in a horizontal well, due to the frequent anisotropy of horizontal versus vertical permeability in most of the reservoir system, the invasion profile will be elliptical in nature where the invasion damage is dominated in x and y directions. This phenomenon provokes the situation where more mud particles will invade into the formation due to stronger forces and consequently causes severe damage in horizontal well.

Besides the anisotropy flow effects that caused higher damage to the core samples in horizontal position, the gravity effect was another factor that contributed to the severe damage in horizontal well compared to vertical well. In vertical well, the flow direction of drilling mud was influenced by gravity effect after being circulated out from the drill bit and this gravity effect acting on the drilling mud is lesser compared to the horizontal well. Therefore the mud invasion in vertical position (well) was only depending on the differential pressure that exerted on the drilling mud, as illustrated by Figure 4.25.

Figure 4.26 shows the mud flow occurred in the horizontal well. The gravity effect and differential pressure tend to push more mud particles to the bottom section of the well where core samples was placed. Therefore, it drove more particles into the core samples and caused severe damage at horizontal position.

Figure 4.27 shows the mud cake formed during the test conducted at horizontal position, whereas Figure 4.28 shows the mud cake formed during the test at vertical position. In comparison, it was obviously showed that the mud cake formation in horizontal position was more dominant compared to vertical position. Therefore, more particles could invade into core samples in horizontal position and caused serious damage compared to the core samples that placed vertically.

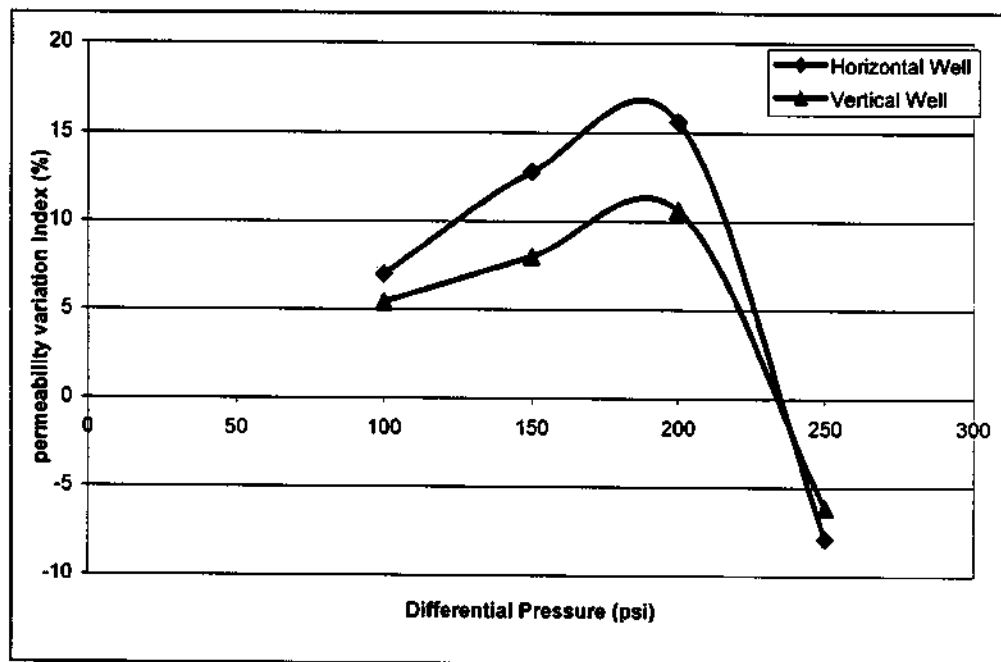


Figure 4.24: Comparison of formation damage in horizontal and vertical wells

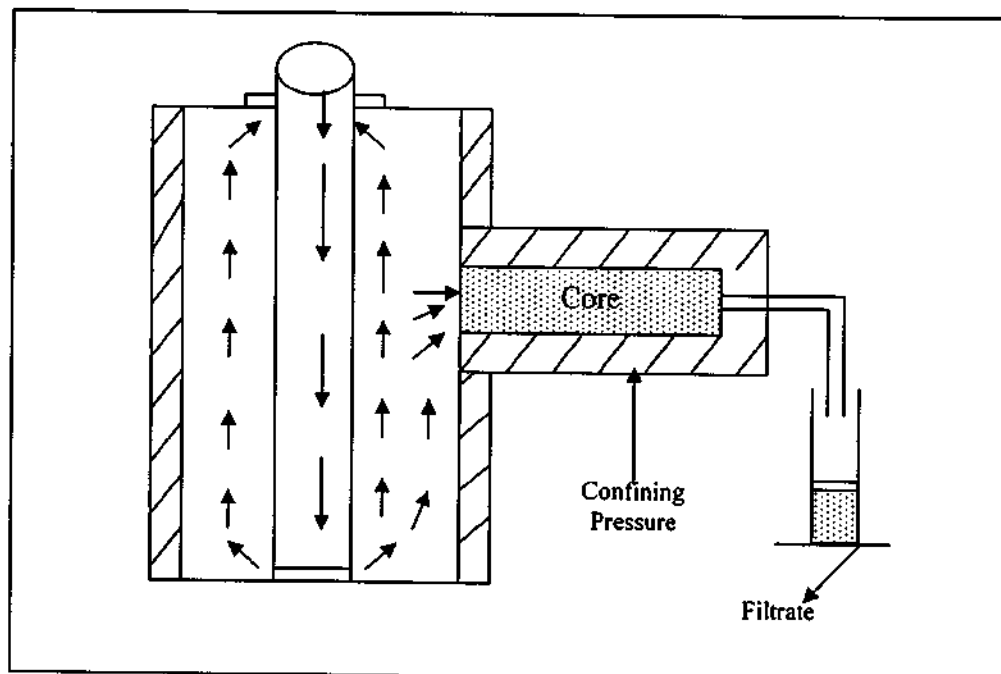


Figure 4.25: Drilling mud invasion schematically diagram in vertical well

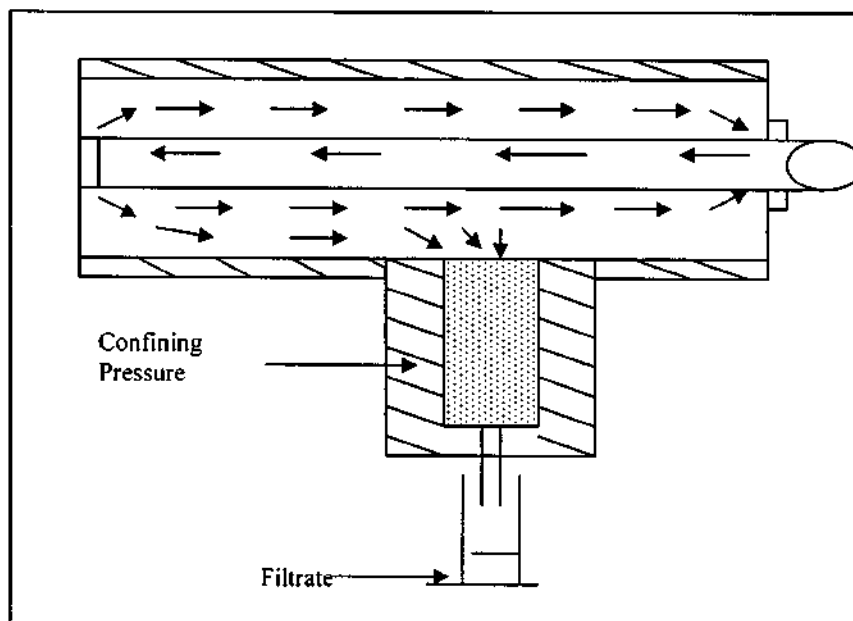


Figure 4.26: Drilling mud invasion schematically diagram in horizontal well

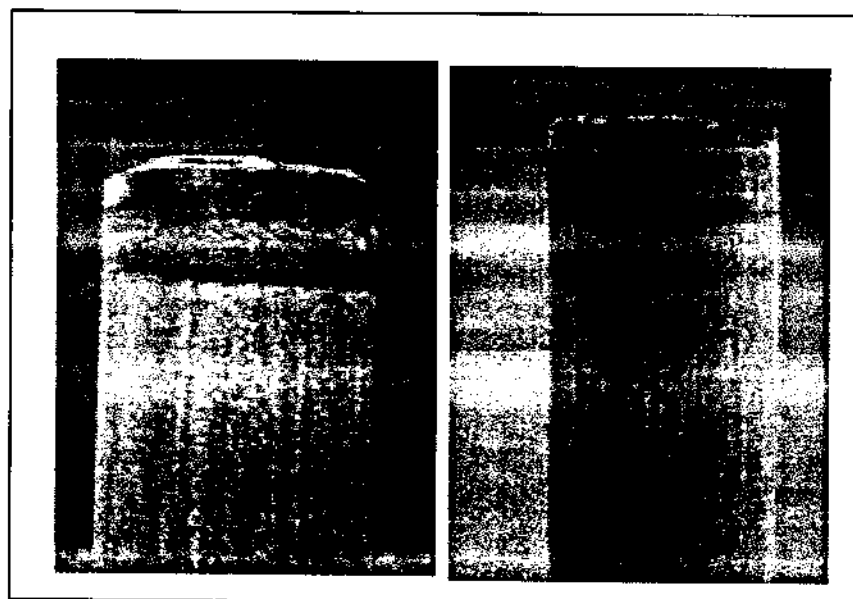


Figure 4.27: Mud cake formed in horizontal well

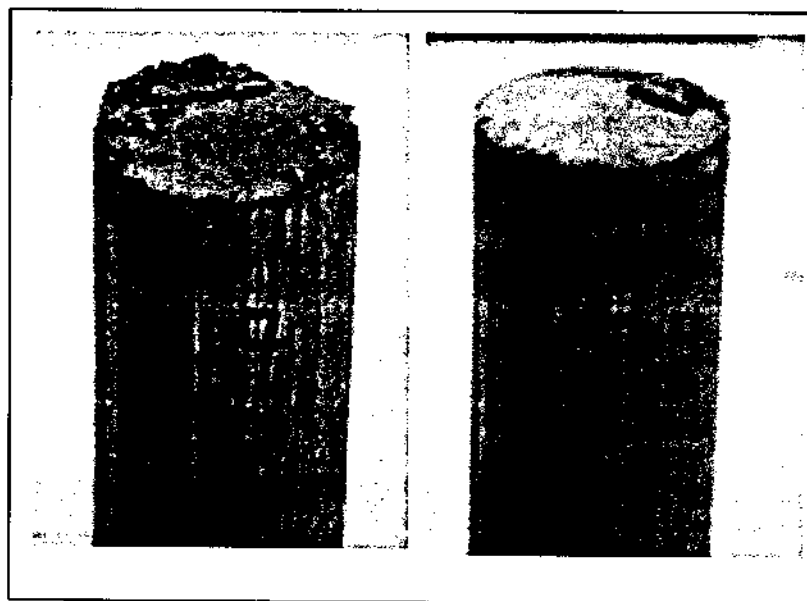


Figure 4.28: Mud cake formed in vertical well

4.4.1 Filtrate loss in Horizontal and Vertical Well

The filtrate loss volume for the horizontal well was lesser as compared to vertical wells, after the experiment was conducted for 30 minutes. Figure 4.29 and Table 4.16 show the filtrate loss volume for horizontal well, whereas Figure 4.30 and Table 4.17 are for vertical well. From Figure 4.29 and 4.30, the initial filtrate loss volumes were higher for both horizontal and vertical wells and this phenomenon was called *surge period* as mentioned by Xinghui and Civan (1993).

Figure 4.29 and Table 4.16 show the filtrate volume collected in horizontal well for the induced differential pressures from 100 psi to 250 psi throughout the experiment. At the first minute, the filtrate was 0.5 ml and it was constantly increase (0.1 to 0.3 ml per minute for first 5 minutes and 0.3ml to 0.4 ml per 5 minutes thereafter until 30 minutes) throughout the experiment. The highest filtrate volume of 3.7 ml was recorded at 250 psi and lowest filtrate loss volume of 3.1 ml at 100 psi. From this value obtained during the experiemtn, it shows that the filtrate volume increased with increasing differential pressure.

Figure 4.30 and Table 4.17 show filtrate volume collected in vertical well for the induced differential pressures from 100 psi to 250 psi. The filtrate collected at the first minute was 0.6 ml to 0.9 ml and increased to 0.2 ml to 0.3 ml per minute for the first 5 minutes. After 5 minutes, the filtrate was collected at an interval of 5 minutes until 30 minutes and the filtrate volume of 0.4 ml to 0.5 ml per 5 minutes were collected consistently. The highest filtrate loss volume was 4.5 ml at 250 psi and the lowest filtrate volume collected was 3.2 ml at 100 psi induced pressure.

In horizontal well, the formation of mud cake at the lower part of the hole was more dominant compared to vertical, as shown in Figures 4.27 and 4.28. The formation of impermeable mud cake in core samples located at the horizontal position was more rapidly compared to vertical position. Therefore the filtrate loss volume in horizontal well was lesser compared to vertical well.

Table 4.16: Filtrate loss for horizontal well @ various induced differential pressure

Exposure Time, mins	Eccentricity @ 50% @ Horizontal well			
	Sample 9, 100 psi	Sample 10, 150 psi	Sample 11, 200 psi	Sample 12, 250 psi
0	0	0	0	0
1	0.5	0.6	0.6	0.6
2	0.6	0.7	0.8	0.8
3	0.8	0.9	1	1.1
4	0.9	1	1.1	1.3
5	1.2	1.3	1.5	1.6
10	1.5	1.7	1.9	2
15	1.8	2	2.2	2.4
20	2.3	2.5	2.7	2.9
25	2.8	2.9	3.2	3.4
30	3.1	3.3	3.6	3.7
	Filtrate loss, ml			

Table 4.17: Filtrate loss for vertical well @ various induced differential pressure

Exposure Time, mins	Eccentricity @ 50%@ Vertical well			
	Sample 17 100 psi	Sample 18, 150 psi	Sample 19, 200 psi	Sample 20, 250 psi
0	0	0	0	0
1	0.6	0.7	0.8	0.9
2	0.8	0.9	1.1	1.1
3	0.9	1.2	1.3	1.4
4	1.1	1.4	1.5	1.6
5	1.2	1.5	1.8	1.9
10	1.6	2	2.4	2.6
15	2	2.5	2.9	3.1
20	2.5	2.9	3.3	3.6
25	2.9	3.2	3.7	4.1
30	3.2	3.5	4	4.5
Filtrate loss, ml				

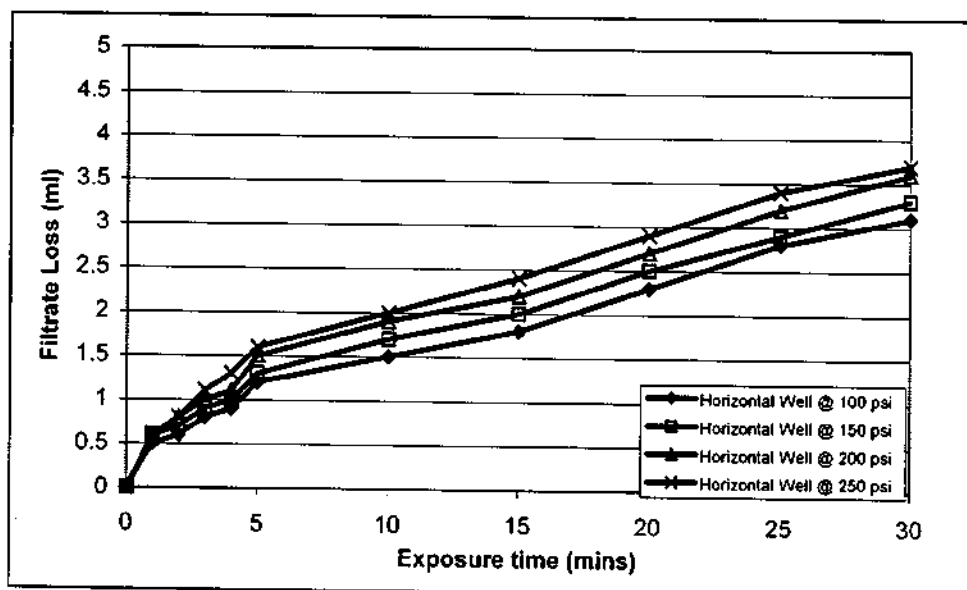


Figure 4.29: Filtrate collected in horizontal well

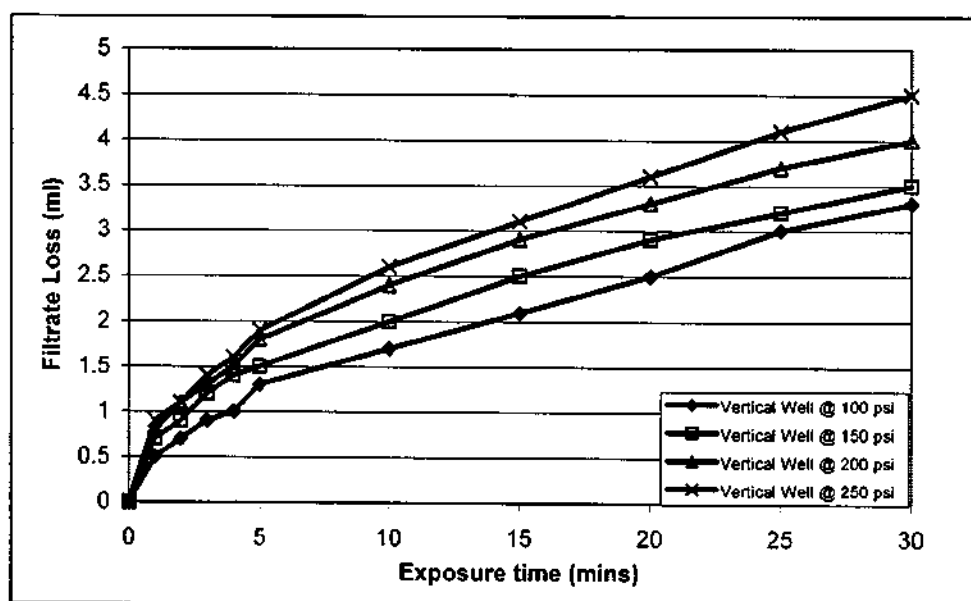


Figure 4.30: Filtrate collected in vertical well

4.5 Verification of Improved Permeability

Three extra runs had been carried in order to verify the *improved permeability* scenario in Berea sandstones. These tests were conducted under dynamic condition at constant mud weight, annular velocity, and temperature of 10.3 ppg, 60 ft/mins, and 80°C. Prior to the test, the test samples were prepared by following the preparation procedure as described in Section 3.1 to Section 3.11. After the cores preparation process, the cores samples were damaged by following the operational procedure of the system in Section 3.16. The cores damaged permeability checked was performed by following the procedure as describe in Section 3.5.1. after the Berea cores exposed to the drilling mud for 30 minutes.

Table 4.18 shows the information on test samples breakdown for different studied parameters, whereas Table 4.19 reveals cores permeability values of the test sample used in this study. The detail of the permeability calculation before and

after exposed the test sample to drilling mud is shown in Appendix F. The mud rheological properties before and after is shown in Appendix G

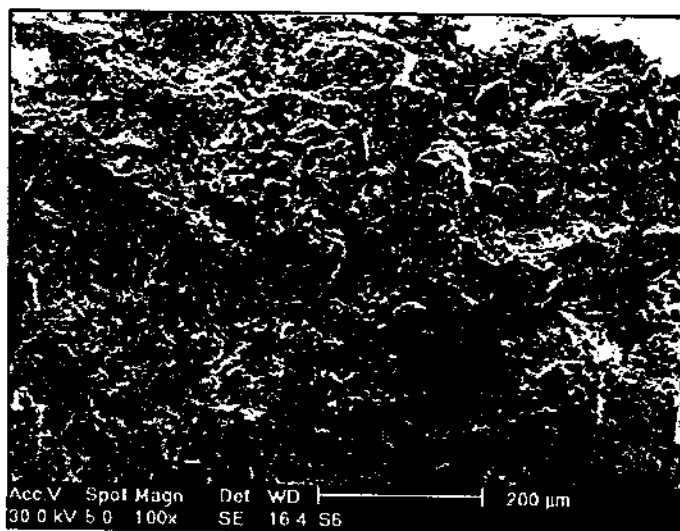
Table 4.18: The breakdown of studied parameters

Sample	Eccentricity, %	Studied Parameters
30	75	Horizontal with 0 rpm @ 250 psi
31	75	Horizontal with 120 rpm @ 250 psi
32	75	Horizontal with 150 rpm @ 250 psi

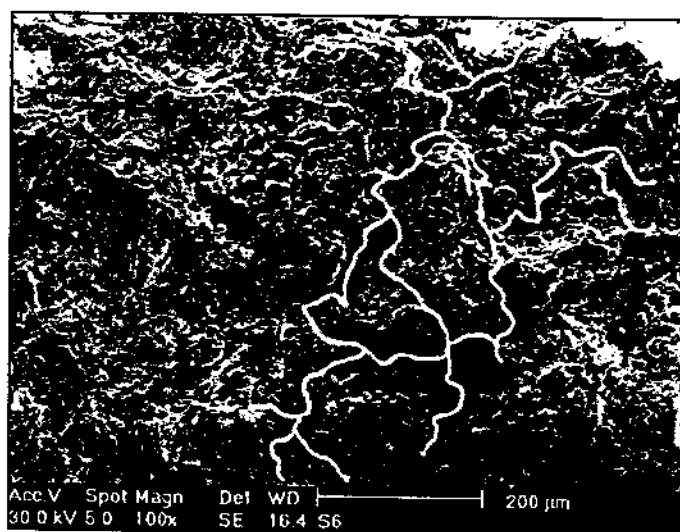
Table 4.19: Rock permeability before and after damage

Core	Eccentricity %	Differential Pressure psi	Before Damage K_i (md)	After Damage K_d (md)	Permeability Variation Index, %
20	75	250	162.28	176.63	-8.84
31	75	250	195.79	222.99	-13.89
32	75	250	220.82	258.31	-16.89

Table 4.19 showed that the studied at higher drill string eccentricity (75%) coupled with differential pressure of 250 psi contributed to the improved permeability scenario. SEM studies as shown in Figure 4.31 to Figure 4.33 revealed the presence of the micro fractures in the core samples was the root cause to the improved permeability experienced by the cores after exposed to the mud. The improved permeability may due to the induced differential pressure and forces generated by the drill string rotation that acting on the cores exceeded the fractures limit of the core samples. However, further studies on effect of eccentric drilling on formation damage in horizontal hole especially lower part of the hole needs to be carried out in order to have better understanding in this field.

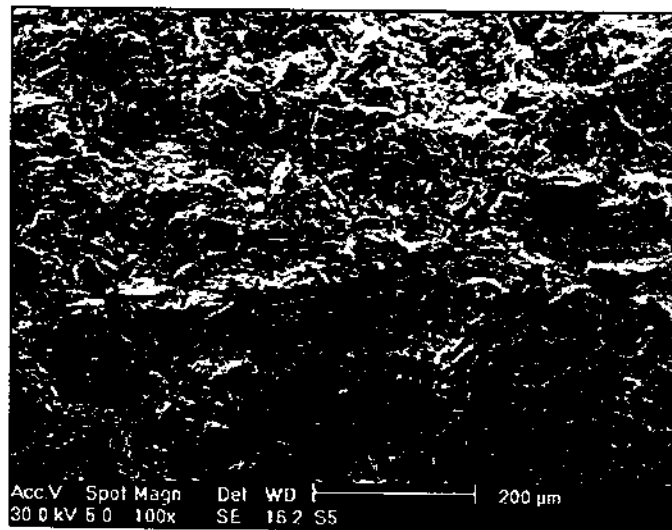


**Sample 29:
Original micro
fractures**

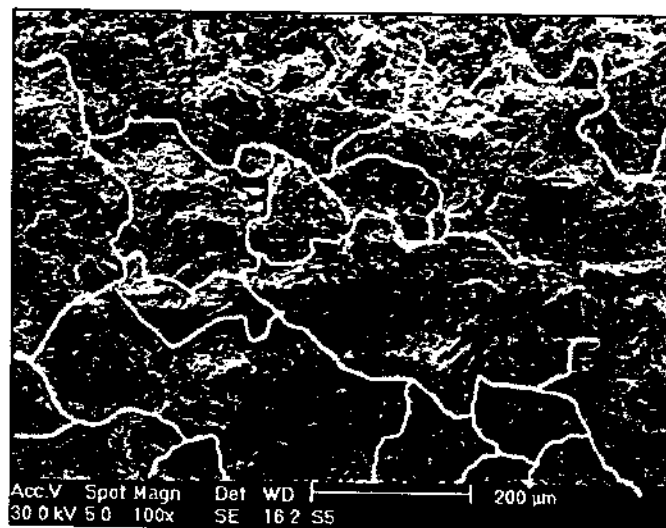


**Sample 29:
Assisted lines
to show micro
fractures**

**Figure 4.31: Micro fractures occurred at induced pressure of 250 psi @ 75%
for no drill string rotation**

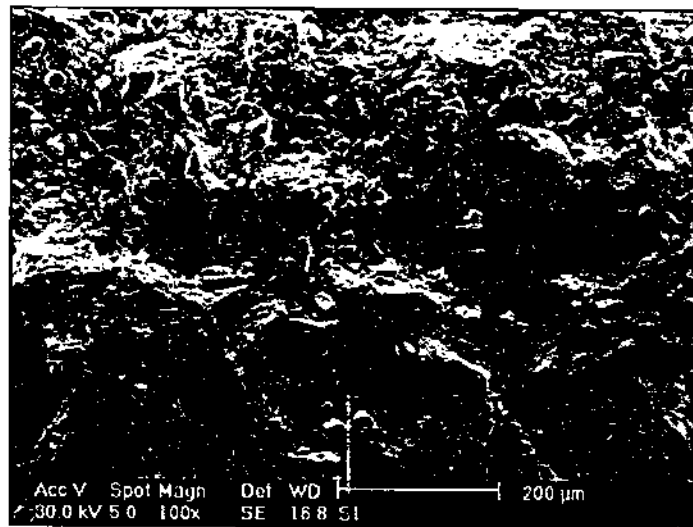


**Sample 30:
Original micro
fractures**

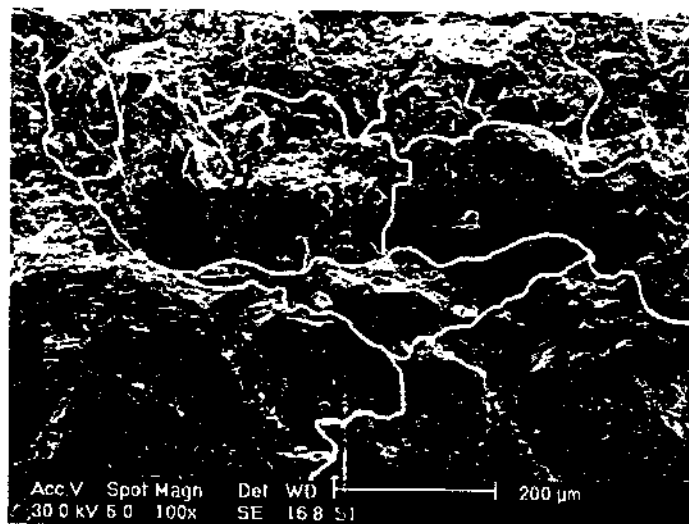


**Sample 30:
Assisted lines
to show micro
fractures**

**Figure 4.32: Micro fractures occurred at induced pressure of 250 psi @ 75%
for drill string rotation of 120 rpm**



**Sample 31:
Original micro
fractures**



**Sample 31:
Assisted lines
to show micro
fractures**

**Figure 4.33: Micro fractures occurred at induced pressure of 250 psi @ 75%
for drill string rotation of 150 rpm**

4.6 Summary

The experimental that had been carried out in showed that the drill string eccentricity did contribute to the formation damage. The effect of drill string eccentricity became severe when it was coupled with differential pressures, exposure times, and drill string rotation speed. Cores damage was found to be more severe in horizontal position compared to vertical position. At higher induced differential pressure, the core samples experienced improvement of permeability rather than severe damage. After conducting the SEM studies, the cores were found to have *micro-fractures*. A further study for this problem is needed in order to give better understanding of formation damage caused by the drill string eccentricity by using this rig.

After having the discussion with examiners and supervisor, three extra runs was carried out to verify the improved permeability scenario. From these three extra runs, it proved that the improved permeability scenario did exist due to the presence of micro fractures. Some further studies need to be carried out to investigate the micro fracture as proposed in Chapter 5.

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The works reported in this thesis were based on the studies carried out on the effect of drill string eccentricity on formation damage when coupled with various parameters such as differential pressure, drill string rotation speed, and exposure time under dynamic condition. Berea cores were used in this study due to negligible in clays contents. Therefore, the issue of formation damage caused by clay swelling could be eliminated. In other words, formation damage was mainly due to particles and filtrate invasions.

The experimental results showed that higher drill string eccentricity caused higher damage for test conducted up to 200 psi. This is due to the formation of small annulus space at the bottom section of the hole in horizontal well, thus the mud which moved slowly in this area get trapped easily. When the induced differential pressure was acting on the mud, the drilling mud particles invaded deeper into the core samples and caused severe damage. At induced differential pressure of 250 psi, the core experienced no damage. The SEM studies revealed the presence of *micro fractures* that caused *improved permeability* in the core samples. The cumulative filtrate loss volume increased with higher drill string eccentricity. This is due to the differential pressure exerted on the slow moving mud at small annulus side that could drive filtrate easily into the core samples. Therefore, the filtrate loss volume was higher.

Differential pressure is the most important physical parameter that contributes to core damage. Higher induced differential pressure caused higher damage to the core samples as more solid and filtrate particles invaded further into the cores, consequently caused severe reduction in permeability for the test conducted up to 200 psi. At higher induced differential pressure of 250 psi, the core damage obtained was slightly lower for 0% drill string eccentricity conditions and no damage (improved permeability) was recorded at 25%, 50%, and 75% drill string eccentricity studied for the induced differential pressure of 250 psi. This is due to the presence of micro fractures in core samples at higher induced differential pressure under dynamic condition. The experimental results showed that higher differential pressure caused higher final cumulative loss volume for the entire tests conducted at various drill string eccentricity conditions.

Exposure time is another factor that contributes to the formation damage. In this study, longer exposure time caused more damage to the core samples due to higher cumulative loss. Higher cumulative filtrate loss reflects more solid and filtrate particles invaded into the core samples, and consequently plugged the natural flow channels. Therefore, the damage was higher.

From this research study, the rotating drill string eccentricity caused certain degree of damage to the core samples. This is due to the swirling forces generated by the rotating drill string acting that acted on the drilling mud. The swirling forces have the tendency to push more drilling mud particles into the formation and thus, it induced damage to the core samples. Generally, higher drill string rotation speed (up to 140 rpm) generates higher swirling forces and consequently pushes more particles into the core samples that cause severe damage. In contrast, at higher rotating speed of 150 rpm, the core damage was lower and the SEM studies showed the presence of micro fractures in the test samples.

From this study, it was found that damage in horizontal well was higher than vertical due to the anisotropic flow effect where the flow patterns in horizontal well was completely different compared with a vertical well. The fluid flow in a vertical well is a uniform strata of crossed bedded planes which penetrates in an

orthogonal fashion and will drain the reservoir in a uniform planar radial profile. Conversely, in a horizontal well, sources of fluids are from both the vertical and horizontal planar directions. Furthermore, the invasion damage of vertical well will be in cylindrical pattern and the invasion damage is only dominated in one direction (x-direction), while in horizontal well, the invasion profile is elliptical in nature where the invasion damage is dominated in x and y directions. This phenomenon provokes the situation where more mud particles will invade into the formation due to stronger swirling forces and consequently causes severe damage in horizontal well.

This study also discovered that the core sample placed at the upper part of the horizontal hole experienced severe damage, while the core sample placed at the lower part of the hole experienced *improved permeability* due to the presence of micro fractures.

5.2 Recommendation for Further Studies

It is worth mentioning that this study covered the effect of drill string eccentricity on formation damage in horizontal well. Therefore, further studies of the effect are required to establish the important of drill string eccentricity on formation damage. The following suggestions are used as bases for further research:

- (I) A further study on the effect of drill string eccentricity of 75% needs to be carried out especially at differential pressure of 250 psi, where the cores experienced micro fractures. The study should involve the measurement of the core expansion rate by using the strain gauge and data logger. A camera shall be useful to be installed at the location near to the core sample to allow the real time monitoring of the particles invasion during the experiment.

- (II) A data acquisition system is needed to monitor and register the experimental variables such as flow rate, differential pressure, temperature etc. By introducing the data acquisition system to the existing system, the data interpretation will be more accurate, efficient, and reliable.
- (III) Cores sample shall touch the drill string while conducting the experiment to simulate the drilling process where drill string tends to lie down at the bottom section of the formation and erodes the formation. The erosion of the drill string and formation may contribute further to formation damage problem. To perform this study, the center bore of the testing unit needs to undergo some minor modification like enlarging the center bore hole to allow the Berea sandstones or test samples touch the drill string.
- (IV) A study of damage profile in a hole by attaching four core holders at evenly spaced around the center bore. This study can include the main physical parameters that will contribute to formation damage such as differential pressure, annular velocity etc.
- (V) Equipped the existing system with a frequency inverter to vary the flowrate. Thus, the effect of rotating drill string eccentricity can be studied when it is coupled with the change in annular velocity.
- (VI) Particulates from drilling mud have been well documented as primary source that contributes to formation damage. Generally, the further the particulates invade into formation, the severe the damage of the formation. Therefore, the depth of drilling mud particulates invasion is vital to carry out. By installing the pressure sensors along the core holder, this study can be carried out where the pressure drop profile

along the core can be seen. By monitoring the pressure drop profile along the core, the depth of particulates invasion can be determined.

- (VII) Install a shuttle sleeve at the center bore to prevent the drilling mud invasion prior to achieving the predetermined study parameters. Thus, the study of formation damage due to drill string eccentricity would be more reliable and efficient.
- (VIII) Different drilling mud systems cause different degree of wellbore damage. Therefore, the formation damage caused by different drilling muds shall be carried out to investigate this problem. Besides, adding the offshore cuttings into the mud system is also another important parameter that can be carried out to simulate the field condition. The effect of without rotating drill string can be carried out by removing the drill string from the testing unit. Therefore, the comparison of core damage with and without drill string can be performed.
- (IX) Formation damage study due to drill string eccentricity when coupled with parameters such as temperature, mud contaminants, annular velocity, formation damage induced microbial etc. shall be carried out in order to have better understanding of the occurrence of formation damage.
- (X) A comparison of formation damage in horizontal, highly deviated, and vertical wells can be carried out by preset the testing unit to the required angles. It is believed that the drill string eccentricity at different well angles has some effects on the formation damage. Therefore, further study on them is vital.

CHAPTER VI

BIBLIOGRAPHY

Abram, A. (1977). "Mud Design to Minimize Rock Impairment due to Particles Invasion." *Journal of Petroleum Technology*. 6. 586-592.

Abu Azam Md.Yassin, Abdul Razak Ismail, and Abdul Halim (1991). "Formation Damage due to Drilling Inclined Well." Presented at Regional Seminar on Coastal Offshore Engineering held in Kuala Terengganu, Malaysia. December, 9-11.

Adair, K. L. and Gruber, N. G. (1996). "New Laboratory Procedures for Evaluating of Drilling Induced Formation Damage and Horizontal Well Performance: An Update." Paper SPE 37139 presented at the 1996 International Conference on Horizontal Well Technology held in Calgary, Canada. November, 18-20.

Adinathan Venkitaraman, Robert, P. M. and Sharma, M. M. (1994). " Ultrasonic Removal of Near Wellbore Damage Caused by Fines and Mud Solids." Paper SPE 27388 presented at the 1994 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 7-10.

Allen, F. L., Riley, S. M. and Strassner, J. E. (1984). "Initial Study of Temperature and Pressure Effects on Formation Damage by Completion Fluid." Paper SPE 12488 presented at the 1984 Formation Damage Control Symposium held in Bakerfield, California. February, 13-14.

Al-Marhoon, N. O., Grattoni, C. A., Dawe, R. A., and Carter, J. N. (1998). "Formation Damage and Near Wellbore Flow in Reservoir-An Experimental Study." Paper SPE 49499 presented at the 1998, 8th Abu Dhabi International Petroleum Exhibition and Conference held in Abu Dhabi, U.A.E.. October, 11-14.

Amaefule, J. O., Kersey, D. G., Norman, D. L. and Shannon, P. M. (1988). "Advances in Formation Damage Assessment and Control Strategies." CIM paper No 88-39-65, Proceedings of the 39th Annual Technical Meeting of Petroleum Society of CIM and Canadian Gas Processors Association, Calgary, Alberta. June, 12-16.

American Petroleum Institute (1990). "Recommended Practice 13-I, Standard Procedure for Laboratory Testing Drilling Fluids." Washington, D.C.

Ananda Kumar Ray, Lehmbhar Singh., Dr. R. S. Dinesh and Daljit Singh. (1998). "Water Based Drilling Fluid Replaces Oil Base Mud to Control Formation Damage." Paper SPE 39443 presented at the 1998 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 18-19.

Argillier, J. F., Audibert, A. and Longeron, D. (1999). "Performance Evaluation and Formation Damage Potential of New Water Based Drilling Formulas." Paper SPE 38152 presented at the 1999 SPE International Symposium on Formation Damage Control held in The Hague, Netherlands. June, 2-3.

Baijal, S. K, Houchin, L. R. and Bridges, K. L. (1991). "A Practical Approach to Prevent Formation Damage by High Density Brines During Completion

Process.” Paper SPE 21674 presented at the Production Operation Symposium held in Oklahoma City, Oklahoma. April, 7-9.

Bailey, L., Meeten, G., and Way, P. (2000). “Filter Cake Integrity and Reservoir Damage.” Paper SPE 58737 presented at the 1998 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 18-19.

Bailey, L., Boek, E., Jacques, S., Boassen, T., Selle, O., Argillier, J. F., and Longeron, D. (1999). “Particulate Invasion from Drilling Fluids.” Paper SPE 54762 presented at the 1999 SPE International Symposium on Formation Damage Control held in The Hague, Netherlands. May 31-June 1.

Bennion, D. B., Thomas, F. B., and Bennion, D. W. (1991). “Effective Laboratory Coreflood Test to Evaluate and Minimize Formation Damage in Horizontal Wells.” Paper SPE presented at the 3rd International Conference on Horizontal Well Technology in Houston, Texas. November, 12-14.

Bennion, D. B., and Thomas, F. B. (1994). “Underbalanced Drilling of Horizontal Wells: Does It Really Eliminate Formation Damage?” Paper SPE 27352 presented at the 1994 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 7-10.

Bennion, D. B., Thomas, F. B., Bennion, D. W. and Bietz, R. F. (1995). “Mechanisms of Formation Damage and Permeability Impairment Associated with The Drilling, Completion and Production of Low API Gravity Oil Reservoir.” Paper SPE 30320 presented at the 1995 International Heavy Oil Symposium held in Calgary, Canada. June, 19-21.

Bennion, D. B., Thomas, F. B. and Bietz, R. (1996). “Formation Damage and Horizontal Wells: A productivity Killer?” Paper SPE 37138 presented at the

1996 International Conference on Horizontal Well Technology in Calgary, Canada. November, 18-20.

Bennion, D. B. (1999). "Formation Damage: The Impairment of the Invisible, by the Inevitable and Uncontrollable, Resulting in an Indeterminate Reduction of the Unquantifiable." *Journal of Canadian Petroleum Technology*. April. 38. 11-17.

Braun, G. and Boles, J. L. (1982). "Characterization and Removal of Amorphous Aluminosilicate Scales." SPE 24068 paper, Proceedings of 1982 SPE Western Regional Meeting, Bakerfield, California, March 30-April 1, 389-398.

Brown, K. E., and Lea, J. F. (1985) " Nodal System Analysis of Oil and Gas Wells." *Journal of Petroleum Engineer*. 1751-1763.

Browne, S. V. and Smith, P. (1994). " Mudcake Clean-up to Enhance Productivity of High Angle Wells." Paper SPE 27350 presented at the 1994 Formation Damage Control Symposium held in Lafayette, Louisiana. February.9-10.

Burnett, D. B. (1996). "Laboratory and Field Evaluation of the Role of Drill Solids in Formation Damage and Reduced Horizontal Well Productivity." Paper SPE 37125 presented at the 1996 International Conference on Horizontal Well Technology held in Calgary, Canada. November, 18-20.

Carrel, K. D. (1987). "The Occurrence, Prevention and Treatment of Sulphate Scale in Shell Expro." Paper SPE 16538 presented at the Offshore Europe held in Aberdeen Scotland. September, 8-11.

Chambers, M. R., Hebert, D. B. and Shuchart, C. E. (2000). "Successful Application of Oil-Based Drilling Fluids in Subsea Horizontal, Gravel Packed Wells In West Africa." Paper SPE 58743 presented at the 2000 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 23-24.

- Chauveteau, G., Nabzar, L. and Coste, J. P. (1998). "Physics and Modeling of Permeability Damage Induced by Particle Deposition." Paper SPE 39463 presented at the 1998 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 18-19.
- Chung, Ting Horng. (1992). "Thermodynamic Modeling for Organic Solid Precipitation." SPE 24851, Proceedings of 67th Annual Technical Conference and Exhibition of the SPE held in Washington, D.C. October, 4-7, 869-878.
- Civan, F. (2000). "Reservoir Formation Damage: Fundamentals, Modeling, Assessment, and Mitigation." Houston, Texas: Gulf Publishing Company.
- Civan, F. and Knapp, R. M. (1987). "Effect of Clay Swelling and Fines Migration on Formation Permeability." Paper SPE 16235, Proceeding of SPE Production Operation Symposium, OKC, 475-483.
- Donovan, J. P. and Jones, T. A. (1995). "Specific Selection Criteria and Testing Protocol Optimize Reservoir Drill-in Fluid Design." Paper SPE 30104 presented at the 1995 European Formation Damage Symposium held in The Hague, Netherlands. May, 15-16.
- Durand, C. and Rosenberg, E. (1998). "Fluid Distribution in Kaolinite or Illite Bearing Cores: Cryo-SEM Observation Versus Bulk Measurement." *Journal of Petroleum Science and Engineering*, 19. 65-72.
- Economides, M. J., Daniel, H. A. and Ehlig-Economides, C. (1994). "Petroleum Production System." Englewood Cliffs: Prentice Hall. 152-175.
- Elsevier (1996). "Oilfield Review." Schlumberger-Doll Research Old Quarry Road, USA.: Company Journal.
- Eng, J. E. (1993). "Velocity Profiles in Perforated Completions." *Journal of Completion Technology*, August. 586-590.

- Ezzat, A. M. (1993). "Horizontal Drilling and Completion Fluids Design Criteria." Paper SPE 25595 presented at the 1993 SPE Middle East Oil Technical Conference and Exhibition held in Bahrain, April, 3-6.
- Farina, J. (1984). "Geological Application of Reservoir Engineer Tool." 4th.ed. Texas: The AAPG Bookstore.12-13.
- Fordam, E. J., Roberts, T. P. L., Carpenter, L. D. and Hall, C. (1991). " Dynamic NMR Imaging of Rapid Depth Filtration of Clay in Porous Media." *Am. Inst. Chem. Engrs.* **37**. 1900-1903.
- Francis, P. (1997). "Dominating Effect Controlling the Extent of Drilling Induced Formation Damage." Paper SPE 38182 presented at the 1997 SPE European Formation Damage Symposium held in The Hague, Netherlands. June, 2-3.
- Francis, P. A., Eigner, M. R. P., Patey, I. T. M. and Spark, S. C. (1995). "Visualization of Drilling Induced Formation Damage Mechanisms Using Reservoir Condition Core Flooding Testing." Paper SPE 30088 presented at the 1995 SPE European Formation Damage Symposium held in The Hague, Netherlands. May, 15-16.
- Fraser, L. J. and Polnaszek, S. C. (1991). "A Study of Formation Damage Potential During Cementing Operations." Paper SPE 22775 presented at the 66th Annual Technical Conference and Exhibition of the SPE in Dallas, Texas. October, 6-9.
- Fraser, L. J., Reid, P., Williamson, D. and Enriquez Jr, F. (1995). "Mechanistic Investigation of the Formation Damage Characteristics of Mixed Metal Hydroxide Drill-in Fluid and Comparison with Polymer Base Fluids." Paper SPE 30501 presented at the 1995 SPE Annual Technical Conference and Exhibition, Dallas, Texas, October 22-25.
- Gatlin, C. (1960). " Petroleum Engineering: Drilling and Well Completion." Englewood Cliffs: Prentice Hall. 94-94.

- Gaurina-Medjimurec, N., Steiner, I., Simon, K. and Matanovic D. (2000).
 “ Avoidance of Formation Damage by Application of Proper Drill-In Fluid.” SPE 65185 presented at the 2000 SPE European Petroleum Conference held in Paris, France. October, 24-25.
- Gill, S. (1932). “ A Study of Rotary Drilling Fluid Sealing Effects of Rotary Mud on Productive Sand in the Southwest.” *The Oil Weekly*. 7.
- Golan, M. and Whitson, C. H. (1986). “ Well Performance.” IHRDC, Boston/Houston/London.
- Hansen, J. E., Stallmach, F., Basen, P. B., and Norsk Hydro, A. S. (1997). “New Methodology To Investigate Formation Damage Using Non-Destructive Analytical Tools.” Paper SPE 38161 presented at the 1997 SPE International Symposium on Formation Damage Control held in The Hague, Netherlands. June, 2-3.
- Hayatdavoudi, A. (1999). “Changing Chemophysical Properties of Formation and Drilling Fluid Enhances Penetration Rate and Bit Life.” Paper SPE 20729, Proceeding of 1999 SPE International Symposium on Oilfield Chemistry, Houston, Texas. February, 16-19, 273-285.
- Helio, S. and Quieroz, J. (2000). “How effective is Underbalanced drilling at Preventing Formation Damage.” Paper SPE 58739 presented at the 2000 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 23-24.
- Houchin, L. R., Baijal, S. K. and Foxenberg, W. E. (1991). “An Analysis of Formation Damage by Completion Fluid at High Temperature.” Paper SPE 23143 presented at the Offshore European Conference held in Aberdeen, September 3-6.

- Ishak, I. B., Steele, R. C., Maaulay, R. C., Stephenson, P. M. and Al Mantheri, S. M. (1995). "Review of Horizontal Drilling." Paper SPE 29812 presented at the 1995 SPE Middle East Oil Show held in Bahrain, March 11-14.
- Jiao, Di and Sharma, M. M. (1992). "Formation Damage due to Static and Dynamic Filtration of Water-Based Mud." Paper SPE 23823 presented at the 1992 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February 26-27.
- Johnson, M. D., Harless, M. L., Dickinson, A. L. and Burger, E. D. (1999). "Chemical Mitigation of Sulfide in Water-Injection system." *Journal of Petroleum Engineer.* March, 936-940.
- Jonathan, M. and Spark, S. C. (2000). "Microbial Induced Formation Damage in Oilfiled Reservoir." Paper SPE 39446 presented at the 2000 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 23-24.
- Jones, R. R. and Carpenter, R. B. (1991). "A Study of Formation Damage Potential during Cementing Process." Paper SPE 22777 presented at the 66th Annual Technical Conference and Exhibition of the SPE in Dallas, Texas. October, 6-9.
- Jordan, M. M., Graham, G. M., Sorbie, K. S., Matharu, A., Tomlins, R. and Bunney, J. (1998). "Scale Dissolver Application: Production Enhancement and Formation Damage Potential." Paper SPE 39499 presented at the 1998 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 18-19.
- Keelan, D. K. and Koepf, E. H. (1977). "The Role of Cores and Core Analysis in Evaluation of Formation Damage." *Journal of Petroleum Engineer.* May. 1751-1763.

- Khilar, K. H. and Fogler, H. S. (1983). "Water Sensitivity of Sandstones." *Journal of Petroleum Technology*. February. 55-64.
- Krilov, Z., Steiner, I., Goricnik, B., Wojtanowicz, A. J. and Cabrac, S. (1991). "Quantitative Determination of Solids Invasion and Formation Damage using CAT Scan and Barite Suspensions." Paper SPE 23102 presented at the 1991 Offshore European Conference held in Aberdeen, September, 3-6.
- Krueger, R. F. (1982). "An Overview of Formation Damage and Well Productivity In Oil Field Operations." *Journal of Petroleum Technology*. 131-152.
- Krueger, R. F. (1988). "An Overview of Formation Damage and Well Productivity in Oil Field Operations: An Update." *Journal of Petroleum Technology*. 535-558.
- Krueger (3), R. F. and Vogel, L. C. (1954). "Damage To Sandstone Cores by Particles From Drilling Fluids." *API Drilling and Production Practice*. 158.
- Kumar, T. and Todd, A. C. (1988). "A New Approach for Mathematical Modeling of Formation Damage due to Invasion of Solid Suspensions." Paper SPE 18203 presented at 63rd Annual Technical Conference and Exhibition of Society Petroleum Engineer held in Houston, Texas. October, 2-5.
- Kumar, T. (1991). "Formation Damage Resulting from Particle Invasion." *Journal of Petroleum Technology*. 146-158.
- Leontaritis, K. J., Amaefule, J. O. and Charles, R. E. (1994). "A Systematic Approach for the Prevention and Treatment of Formation Damage caused by Asphaltene Deposition." *SPE Production and Facilities*, August. 157.

- Leontaritis, K. J. (1998). "Asphaltene Near-Wellbore Formation Damage Modeling." Paper SPE 39446 presented at the 1998 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February.18-19.
- Liu, Xing Hui and Civan, F. (1994). "Formation Damage and Skin Factor due to Filter Cake Formation and Fines Migration in The Near-Wellbore Region." Paper SPE 27364 presented at the 1994 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 7-10.
- Liu, Xui. and Civan, F. (1993). " Characterization and Prediction of Formation Damage in Two-Phase Flow System." Paper SPE 25429, Proceeding of 1993 SPE Production Operation Symposium, Oklahoma City, Oklahoma. March, 21-23, 231-248.
- Longeron, D., Argillier, J. F., and Audibert, A. (1995). " An Integrated Approach for Evaluating Formation Damage due to Drilling Fluids." Paper SPE 30089 presented at the 1995 SPE European Formation Damage Symposium held in The Hague, Netherlands. May, 15-16.
- Mansoori, G. A. (1997). "Modeling of Asphaltene and Other Heavy Organic Deposition." *Journal of Petroleum Science and Engineering*. 17. 101-111.
- Mckinney, L. K. and Azar, J. J. (1988). "Formation Damage due to Synthetic Oil Mud Filtrates at Elevated Temperature and Pressure." Paper SPE presented at 8th Formation damage Control held in Bakefield, California. February, 8-9.
- Miranda, R. M. and Underdown, D. R. (1993). "Laboratory Measurement of Critical Rate: A Novel Approach for Quantifying Fines Migration Problems."

Paper SPE 25432 presented at the 1993 SPE Production Operation Symposium held in Oklahoma City, Oklahoma, USA. March, 21-23.

Mohan, K. K. and Fogler, H. S. (1997). "Colloidal Induced Smectitic Fines Migration: Extension of Microquakes." *ALChE.J.* March. 3. 565-576.

Mohd Zulkeffeli., Ajay, S. and Sharma, M. M. (2000). "Mechanisms of Mud Cake Removal during flowback." Paper SPE 58797 presented at the 2000 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February 23-24.

Mueke, T. W. (1979). "Formation Fines and Factors Controlling Their Movement in Porous Media." *Journal Of Petroleum Technology. AIME.* 114.

Nabzar, L., Chauveteau, G. and Roque, C. (1996). "A New Model for Formation Damage by Particle Retention." Paper SPE 31119 presented at the 1996 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February 14-15.

Newberry, M. E. and Barker, K. M. (2000). "Organic Formation Damage Control and Remediation." Paper SPE 58723 presented at the 2000 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February 23-24.

Nowak, T. J. and Krueger, R. F. (1951). "The Effect of Mud Filtrate and Mud Particles upon The Permeability of Cores." *API Drilling and Production Practice.* 164.

Oddo, J. E. and Thomson, M. B. (1994). "Why Scales Form and How to Predict It." *SPE Production Facilities.* February, 47-54.

- Ohen, H. A. and Civan, F. (1991). "Predicting Skin Damage due to Formation Damage by Fines Migration." Paper SPE 21675 presented at the Production Operation Symposium held in Oklahoma City, Oklahoma. April, 7-9.
- Oyno, L., Tjetland, B., Esbensen, K. H., Solberg, R., Scheie, A. and Larsen, T. (1998). "Prediction of Petrophysical Parameters Base on Digital Video Core Images." *SPE Reservoir Evaluation and Engineering*. February, 82-87.
- Pendleton, L. E. (1991). "Horizontal Drilling Review." Paper SPE 23535 presented at the 1991 Second Archie Conference: The Integration of Geology, Geophysics, and Petroleum Engineering Evaluation in Horizontal Wells held in Houston. November, 3-6.
- Reed, M. G. (1989). "Formation Damage Prevention During Drilling and Completion." Paper SPE 20149 presented at the 1989 Symposium Petroleum Technology in Centennial, Mexico. October, 16-19.
- Rink, M. and Schopper, J. R. (1998). "An Application of Image Analysis to Formation Evaluation." *The log Analysis*. January-February, 12-22.
- Saintpere, S. and Cenergy (2000). "Experimental Approach to Characterize Drilling Mud Invasion, Formation Damage and Cleanup Efficiency in Horizontal Wells with Openhole Completions." Paper SPE 58737 presented at the 2000 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 23-24.
- Sarkar, A. K. and Sharma, M. M. (1988). "An Experimental Investigation of Fines Migration Two-Phase Flow." Paper SPE 17437 presented at the 1988 California Regional Meeting, USA. April, 23-25.
- Schaible, D. F. (1986). "Identification, Evaluation, and Treatment of Formation Damage Offshore Louisiana." Paper SPE 14820 presented at the 7th

Symposium on Formation Damage Control held in Lafayette, Louisiana.
February, 26-27.

Sharma, M (1997). "Increase Well Performance." Statement adopted from Internet
Via University of Texas Websites.

Shaw, J. C. and Chee, T. (1996). "Laboratory Evaluation of Drilling Mud System
for Formation Damage Prevention in Horizontal Wells." Paper SPE 37121
presented at the 1996 International Conference on Horizontal Well Technology
held in Calgary, Canada. November, 18-20.

Shaw, J. C (1993). " State-Of-Art Review of Formation Damage in Horizontal
Wells." Paper SPE 36101 presented at the 1993 SPE Conference on Recent
Advances in Re-entry Horizontal Well and Formation Damage Mitigation held
in Calgary, Canada. November 18-20.

Simpson, J. P. (1974). " Drilling Fluid Filtration Under Simulated Downhole
Conditions." Paper SPE 4779 presented at the 1974 Symposium on Formation
Damage Control held in New Orleans, LA. February, 7-8.

Thomas, R. L., Saxxon, A. and Milne, A. W. (1998). "The Used of Coiled Tubing
During Matrix Acidizing of Carbonate Reservoirs Completed in Horizontal,
Deviated, and Vertical Wells." *SPE Production and Facilities*. August. 147-
162.

Todd, A. C., Kumar, T. and Mohanmmadi, S (1990). "The Value and Analysis of
Core-Based Water Quality Experiments as Related to Water Injection
Schemes." *Journal of Petroleum Engineer: Formation Evaluation*. 185-91.

Tovar, J., Azar, J. J., Lummus, J. L. and Sarma, D. S. (1994). " Formation Damage
Studies on Reservoir Rocks using Water-Base and Oil-Base Muds." Paper SPE

27349 presented at the 1994 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 7-10.

Unalmiser, S. and Funk, J. J. (1998). "Engineering Core Analysis." *Journal of Petroleum Engineering*. April. 106-114.

Van der Zwaag, C. H., Stallmach, F., Basan, P. B., Hansen, J. E., Soergaard, E. and Toennnesen. (1997). "New Methodology to Investigate Formation Damage using Non-Destructive Analytical Tools." Paper SPE 38161 presented at the 1997 SPE European Formation Damage Symposium held in The Hague, Netherlands. June, 2-3.

Vidick, B. and Reid, P. (1997). "Could Formation Damage Minimization Provide a Cost Effective Integrated Approach for The Design of Drilling and Cementing Fluid?" Paper SPE 38040 presented at the 1997 Asia Pacific Oil and Gas Conference held in Kuala Lumpur, Malaysia. April 14-16.

Western Atlas International (1992). " Advances in Formation Damage Assessment and Control Strategies." Short course conducted by Core Laboratories, a division of Western Atlas International, Houston, Texas.

Wojtanowicz, A. K., Krilov, Z. and Langlinais, J. P. (1987). " Study on The Effect of Pore Blocking Mechanisms on Formation Damage." Paper SPE 16233 presented at the 1987 SPE Production Operation held in Oklahoma City, Oklahoma, March 8-10.

Yan, Jie Nien., Jiang, Guan Cheng., Wang, Fu Hua., Fan, Wei Qing. and Su, Chang Ming. (1998). " Characterization and Prevention of Formation Damage during Horizontal Drilling." Paper SPE 37123 presented at 2nd International Conference and Exhibition on Horizontal Well Technology held in Calgary, Canada. November, 18-20.

- Yao, Chew Yan and Holditch, S. A. (1993). "Reservoir Permeability Estimation from Time-Lapse Log Data." Paper SPE 25513, Proceeding of the 1993 SPE Petroleum Production Operation Symposium, Oklahoma City, Oklahoma. March, 21-23, 963-975.
- Yeager, V. J. (1998). "Use of Downhole Diagnostics Enhances Determination of Formation Damage." Paper SPE 39466 presented at the 1998 SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana, February, 18-19.
- Yost, A. B. (1994). "Development of Advanced Drilling, Completion, and Stimulation Systems for Minimum Formation Damage and Improved Efficiency: A Program Review." Paper SPE 27353 presented at the 1994 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 7-10.
- Zaidi Yaacob and Azmeer Mohd. (2000). "Personal Communication via Telephone and E-mail." Johore Bharu, Malaysia.
- Zhang, Aik Seng., Somerville, J. M., Todd, A. C. (1993). "An Experimental Investigation of the Formation Damage caused by Produce Oil Water Injection." Paper SPE 26702 presented at the 1993 Offshore European Conference held in Aberdeen, September 7-10.
- Zhang, Yan., Chen, Zhu. and Yan, Jie Nian. (1998). "Investigation on Formation Damage Control of the Methylglucoside Fluids." Paper SPE 39442 presented at the 1998 International Symposium on Formation Damage Control held in Lafayette, Louisiana. February, 18-19.
- Zhou, Zie. (1995). "Construction and Application of Clay-Swelling Diagrams by Use of XRD Methods." *Journal of Petroleum Engineer.* April, 306.