STATUS OF THESIS

Title of thesis	Experimental Study of Phase Trapping Damage in Low Permeability and Tight Gas Reservoir by Using Malaysian Diesel Oil and Condensate

I ARSHAD AHMED

hereby allow my thesis to be placed at the Information Resource Center (IRC) of Universiti Teknologi PETRONAS (UTP) with the following conditions:

1. The thesis becomes the property of UTP
2. The IRC of UTP may make copies of the thesis for academic purposes only.
3. This thesis is classified as

[ ] Confidential

[√] Non-confidential

If this thesis is confidential, please state the reason:

The contents of the thesis will remain confidential for ________ years.

Remarks on disclosure:

Signature of Author

Permanent address: Q#72 Block B
Old Wahdat Colony Qasimabad
Hyderabad Sindh Pakistan

Date : 15-08-2013

Endorsed by

Dr. Muhannad Talib Shuker
Associate Professor
Geoscience & Petroleum Engineering Department
Universiti Teknologi PETRONAS
Bandar Seri Iskandar, 31750 Tronoh
Perak Darul Ridzuan, Malaysia

Signature of Supervisor

Name of Supervisor
Assoc. Prof. Dr Muhannad Talib Shuker

Date : 15-08-2013

UNIVERSITI TEKNOLOGI PETRONAS

EXPERIMENTAL STUDY OF PHASE TRAPPING DAMAGE IN LOW PERMEABILITY AND TIGHT GAS RESERVOIR BY USING MALAYSIAN DIESEL OIL AND CONDENSATE

by

ARSHAD AHMED

The undersigned certify that they have read, and recommend to the Postgraduate Studies Programme for acceptance this thesis for the fulfillment of the requirements for the degree stated.

Dr. Muhannad Talib Shuker
Associate Professor
Geoscience & Petroleum Engineering Department
Universiti Teknologi PETRONAS
Bandar Seri Iskandar, 31750 Tronoh
Perak Darul Ridzuan, Malaysia

Signature:

Main Supervisor: Assoc. Prof. Dr Muhannad Talib Shuker

Signature:

Co-Supervisor:

Assoc Prof Dr Ismail M Saaid
Head, Petroleum Engineering Department
Universiti Teknologi PETRONAS

Signature:

Head of Department: Assoc. Prof. Dr Ismail Bin Mohd Saaid

Date: 16-08-2013

EXPERIMENTAL STUDY OF PHASE TRAPPING DAMAGE IN LOW PERMEABILITY AND TIGHT GAS RESERVOIR BY USING MALAYSIAN DIESEL OIL AND CONDENSATE

by

ARSHAD AHMED

A Thesis

Submitted to the Postgraduate Studies Programme

as a Requirement for the Degree of

MASTER OF SCIENCE

PETROLEUM ENGINEERING DEPARTMENT

UNIVERSITI TEKNOLOGI PETRONAS

BANDAR SERI ISKANDAR,

PERAK

AUGUST 2013

DECLARATION OF THESIS

Title of thesis	Experimental Study of Phase Trapping Damage in Low Permeability and Tight Gas Reservoir by Using Malaysian Diesel Oil and Condensate

I ARSHAD AHMED

hereby declare that the thesis is based on my original work except for quotations and citations which have been duly acknowledged. I also declare that it has not been previously or concurrently submitted for any other degree at UTP or other institutions.

Witnessed by

Dr. Muhannad Talib Shuker
Associate Professor
Geoscience & Petroleum Engineering Department
Universiti Teknologi PETRONAS
Bandar Seri Iskandar, 31750 Tronoh
Perak Darul Ridzuan, Malaysia

Signature of Author

Signature of Supervisor

Permanent address: Q # 72 Old Wahdat Colony Qasimabad Hyderabad Pakistan

Name of Supervisor
Assoc. Prof. Dr Muhannad Talib Shuker

Date : 15-08-2013

Date : 15-08-2013

DEDICATION

First and foremost, I have to thank my parents for their love and support throughout my life. Thank you both for giving me strength to reach for the stars and chase my dreams.

I dedicate this thesis to my parents who have always been my nearest and have been so closed to me that I have found them with me whenever I needed. I also dedicate this thesis to my sisters, friends and teachers who are my nearest surrounders and have provided me with a strong love shield that always surrounds me and never lets any sadness enter inside.

ACKNOWLEDGEMENTS

First of all, I'm grateful to The Almighty Allah for establishing me to complete this study.

I wish to express my sincere thanks to my supervisor, Associate Professor, **Dr. Muhannad Talib Shuker** for continuous and generous supervision. I'm extremely grateful and indebted to him for his expert, sincere and valuable guidance and encouragement throughout study. Without his guidance and persistent help this dissertation would not have been possible.

I place on record, my sincere gratitude to **Dr Ismail Bin Mohd Saaid**Head of Department, Petroleum Engineering Department, for his constant encouragement.

I also thank Mr. Saleem Qadir Tunio Lecturer, Petroleum Engineering Department for his kind and moral support to fulfilment of study.

I take opportunity to record our sincere thanks to all the faculty members of Department for their help and encouragement. I also thank my parents for their unceasing encouragement and support.

I also place on record, my sense of gratitude to one and all who, directly or indirectly, have lent their helping hand in entire study.

ABSTRACT

Tight gas and low permeability reservoirs mostly have problems in terms of significant damages due to low matrix permeability during drilling, completion, stimulation and production. However, they required advanced improvement techniques to achieve flow of gas at optimum rates.Water blocking damage (Phase Trapping) is a form of mechanical formation damage mechanism, which is caused by the filtrate invasion in drilling and liquid leak-off into formation during stimulation operations mostly in fracturing. Water blocking have noticeable impact on total skin factor in the gas reservoirs which tends to reduces relative permeability around wellbore. Proper evaluation of damage and its factors to influenced its severity is essential for prevent from phase trapping damage and optimizing well productivity. It is required to have reliable data regarding interfacial tension between gas and water in order to minimize mechanical formation damage potential and optimize gas production.This study is based on the laboratory experiments of interfacial tension between the produced fluid and damaged fluid. Three systems were used in the methodology which are gas-diesel oil, gas-condensate and gas-brine system. The results show that gas condensate has the lowest interfacial tension as compared to gas-brine and gas- diesel systems. So it tends low severity ofphase trapping damage and reduction in gas productivity in low permeability tight gas reservoirs. The experiments of fluid displacement were carried out to validate the effect of interfacial tension and analysed the severity of permeability damage due to damaged fluid invasion. The outcomes showed that the condensate has less potential to phase trapping damage as compared to the diesel oil and brine. The simulation study is also carried out for better understanding of the effect of hysteresis on well productivity and flow efficiency.The result highlights the benefits of using Malaysian diesel-oil and condensate in drilling and fracturing the low permeability and tight gas reservoirs. The productivity was increased by 35% for Diesel-oil and 40% for Condensate increment in well productivity in comparison with water based fluid.

ABSTRAK

Gas ketat dan takungan ketelapan rendah kebanyakannya mempunyai masalah dari segi kerosakan penting kerana kebolehtelapan matriks rendah semasa penggerudian, siap, rangsangan dan pengeluaran. Walau bagaimanapun, mereka perlu teknik pembaikan maju untuk mencapai aliran gas pada kadar optimum. Kerosakan air menyekat (memerangkap Fasa) adalah satu bentuk pembentukan mekanisme mekanikal kerosakan yang disebabkan oleh serangan turasan dalam penggerudian dan cecair bocor keluar ke pembentukan semasa operasi rangsangan kebanyakannya dalam keretakan. Menyekat air mempunyai kesan ketara ke atas jumlah faktor kulit dalam takungan gas yang cenderung untuk mengurangkan kebolehtelapan relatif di sekitar lubang telaga. Penilaian yang betul kerosakan dan faktor-faktor yang mempengaruhi tahap untuk adalah penting untuk mengelakkan daripada fasa memerangkap kerosakan dan mengoptimumkan produktiviti juga. Ia diperlukan untuk mempunyai data yang boleh dipercayai mengenai ketegangan antara muka antara gas dan air untuk mengurangkan mekanikal pembentukan potensi kerosakan dan pengeluaran gas mengoptimumkan. Kajian ini adalah berdasarkan eksperimen makmal ketegangan antara muka antara cecair yang dihasilkan dan cecair yang rosak. Tiga sistem telah digunakan dalam kaedah yang minyak gas-diesel, gas kondensat dan sistem gas-air garam. Keputusan menunjukkan bahawa gas kondensat mempunyai ketegangan antara muka yang paling rendah berbanding dengan gas-air garam dan sistem gas-diesel. Jadi ia cenderung tahap rendah fasa kerosakan memerangkap dan pengurangan dalam produktiviti gas di ketelapan rendah takungan gas ketat. Eksperimen anjakan cecair telah dijalankan untuk mengesahkan kesan ketegangan antara muka dan dianalisis tahap kerosakan kebolehtelapan kerana serangan cecair rosak. Hasil menunjukkan bahawa kondensat mempunyai kurang potensi untuk menghentikan kerosakan memerangkap berbanding dengan minyak diesel dan air garam. Kajian simulasi juga dijalankan untuk lebih memahami kesan histerisis

produktiviti baik dan kecekapan aliran. Hasilnya menonjolkan manfaat menggunakan Malaysia diesel minyak dan kondensat dalam penggerudian dan kepatahan kebolehtelapan yang rendah dan takungan gas ketat dalam makna 30% dan kenaikan 40% masing-masing dalam produktiviti baik dalam perbandingan dengan cecair berasaskan air.

TABLE OF CONTENT

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1

INTRODUCTION

1.1 Introduction

The definition of a low permeability reservoir is somewhat arbitrary. But for the purpose if this particular water blocking phenomenon would be considered to be formation which have a surface routine average air permeability of less than 20md(millidarcy). It has been estimated that 10% of the world's proven reserves of hydrocarbons 200 x 10^9 BOF are in low permeability reservoirs.

Now days, the industry looking for increasingly exploit reserves of natural gas contained in low permeability intercrystalline sandstone and carbonate formations (<20md in permeability)[1, 2].The filtrate invasion of drilling fluid increased existing phase's saturation near wellbore. Therefore, porous media can cause deleterious relative permeability effects and substantially impact the relative permeability of oil and gas.

High resistivity and low initial water saturation can often exhibit in the low and tight permeability reservoirs. In these type of reservoirs may also be susceptible to problem consult with the retention of water or hydrocarbons based fluids. The phenomenon are said to as water blocking and hydrocarbon phase trapping which are main cause of reduced productivity in low permeability and tight gas reservoirs[3].
If a possibility to water based phase trapping is present, attention may be given to using different bases of fluids. It helps to reduce trapping and imbibition affinity. Oil base fluids may be used in conditions for low and tight permeability wet gas reservoirs. No spontaneous capillary imbibition effect will be found in the case of non wetting fluid[4, 5].

1.2 Problem Statement

Low permeability and tight gas reservoir are considered best candidate of phase trapping damage. It can be reduced by minimizing interfacial tension between wellbore fluid and produced fluid. So, it helps to increase the physical mobility of trapped fluid towards production. There are not reliable data regarding interfacial tension (IFT) between produced fluid (gas) and wellbore fluid (water/diesel/condensate). However, the relative permeability data is not much available due to lack of well testing problem in low permeability and tight gas reservoir. Quantitative evaluation is required to control phase trapping damage problem and improve productivity.

1.3 Proposed Solution

Fluid displacement experiments were taken place through the low permeability and tight core samples. The trapping of wellbore fluid was observed through flooded by produced fluid (gas). Permeability damage was measured after invasion of wellbore fluid within the core samples. It helps to observe trapping of wellbore fluid by flooding through tight and low permeability cores and followed by produced fluid. Prior to core flooding measurements, the interfacial tension between the produced fluid and wellbore fluid was investigated. So the effect of interfacial tension was observed on phase trapping of each wellbore fluid. Diagnosis and evaluation of phase trapping damage mechanism results determine impact on gas productivity in the low permeability and tight gas reservoirs.

It is essential to understand the diagnosis and prevention of water blocking damage mechanism with its impact on gas productivity in the low permeability and tight gas reservoirs.

1.4 Research Objectives

The research focused on the quantitative evaluation of phase trapping damage by measuring interfacial tension between wellbore fluid and produced fluid. Therefore, fluid displacements experiments were conducted to investigate the phase trap using hydrocarbon base fluid and water base fluid in order to achieve the objectives listed below:

1. Determine the interfacial tension of produced fluid and damaged fluid on the phase trapping
2. To measure the permeability damage through displacement of wellbore fluid (water base and hydrocarbon base fluids) by produced fluid (gas)
3. To evaluate the drawdown required to trapped fluid recovery

1.5 Research Design

The laboratory experiments are essential to design fluid displacement of wellbore fluid followed by produced fluid. Hence, various experiments were carried out to simulate the fluid trapping damage in low permeability and tight gas core samples. This work flow is typically classified into three phases.

1.5.1 Phase 1

Phase 1 is based on a detailed literature review to study the factors that may have significant effect on phase trapping around wellbore. Select the water base (synthetic brine) and hydrocarbon base fluids (diesel and condensate) as wellbore fluids. Low permeability and tight core samples (permeability ranges 0.1 – 18md) were chosen that have more susceptible for damage severity by phase trapping.

1.5.2 Phase 2

Phase 2 focuses the interfacial tension measurements between the wellbore fluid and produced fluid at different temperature and pressure conditions. Investigate the increment of displacement of trapped fluid towards the production by minimizing IFT. Using IFT measurements, calculation of capillary pressure was taken place to predict the irreducible saturation of trapped fluid within core samples.

1.5.3 Phase 3

Phase 3 is to present the core flooding experiments at steady state and reservoir conditions; the core sample was saturated with the wellbore fluid and displaced by the produced fluid (gas) at different flow rates. Estimate the end point permeability of produced fluid at the residual saturation of trapped fluid and also find the relationship of porosity permeability with irreducible saturation.

1.6 Scope of research

In this study, three different wellbore fluids were used to study the displacement of water base and hydrocarbon base drilling fluid after invasion near the wellbore. The core sample was fully saturated with wellbore fluid then displaced by gas flooding using different flow rates at different reservoir conditions. Prior to core flooding, the interfacial tension between the produced fluid (Nitrogen gas) and wellbore fluids was determined at different reservoir conditions. The synthetic brine was considered as water base while diesel oil and condensate imitates as hydrocarbon base fluids. Estimate the capillary pressure using measured interfacial tension values at different temperature and pressure. The core samples hold high capillary pressure and interfacial tension values between fluids; they may have more severity to damage permeability. For the investigation of residual trapped wellbore fluid, quantitative evaluation was carried out at 80 ^{0}C after observe the capillary pressure and IFT measurements to comprehend the results of core flooding

1.7 Significance of research

Recently, the development of low permeability and tight gas (Unconventional reservoirs) is growing rapidly to overcome the energy crisis. They require advance techniques to produce and evaluate the problems during the development of these reservoirs. Phase trapping is a major formation damage mechanism encountered during drilling, completion and stimulation. In this study, the hydrocarbon base fluid (Malaysian diesel oil and condensate) has used as wellbore fluid in completion and fracturing to minimize the trapped fluid. The outcome, in turn, has succeeded to reduce phase trapping by minimizing interfacial tension with comparison water base (wellbore fluid) and also generalized the study using different permeability and porosity ranges at reservoir conditions. In the future, this study helps in the reduction of phase trapping damage by selecting proper wellbore fluid for the low permeability and tight gas reservoirs and productivity losses control caused due to this blocking mechanism in future.

CHAPTER 2

THEORY AND LITERATURE REVIEW

2.1 Background to the Study

The background of study was based on the review of unconventional and tight gas reservoirs. The worldwide distribution of unconventional resources was also described in detail. The mechanism of the water blocking damage was discussed and factors that effects on phase trapping problem were also highlighted.

2.1.1 Unconventional Resources

Low permeability and porosity resources are considered as Unconventional resources.Those are hard to produce;they often need fracture stimulation or steam injections toenhancetheir recovery. The conventional resources areone third of worldwide oil and gas reserve, the remaining are unconventional resources as shown in Figure 2.1[6]. Note conventional resources make up less than a third of the total.The distribution of worldwide unconventional gas resources is shown in the Table 2.1[7].

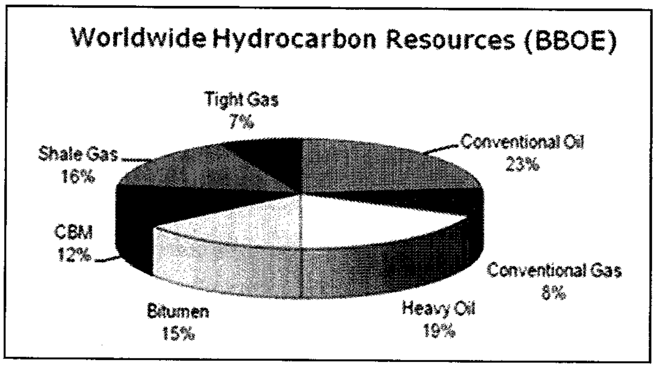


Figure 2.1: Worldwide hydrocarbon resources[6]

Table 2.1: Distribution of worldwide unconventional gas resources[7]

DISTRIBUTION OF WORLD WIDE UNCONVENTIONAL GAS RESOURCES				
Region	**CoalbedMethane (Tcf)**	**Shale Gas (Tcf)**	**Tight-Sand Gas (Tcf)**	**Total (Tcf)**
North America	3017	3840	1371	8228
Latin America	39	2116	1293	3448
Western Europe	157	509	353	1019
Central and Eastern Europe	118	39	78	235
Former Soviat Union	3957	627	901	5485
Middle East and North Africa	0	2547	823	3370
Sub-Saharan Africa	39	274	784	1097
Centrally planned Asia and China	1215	3526	353	5094
Pacific (Organization for Economic Cooperation and Development)	470	2312	705	3487
Other Asia Pacific	0	313	549	862
South Asia	39	0	196	235
World	9051	16103	7406	32560

2.1.2 Low Permeability Reservoirs

Master (1979) presented triangular distribution for the hydrocarbon resources types that can be assigned to various resources classes. Their positions in the triangle mentioned their abundance, their reservoir quality and technology needed for recovery (Figure 2.2)[8, 9]. As the triangle of gas-resource is going downwards, the reservoirs are more complicated because of its low permeability. The low permeability reservoirs are much potential than the high quality reservoirs[10, 11].

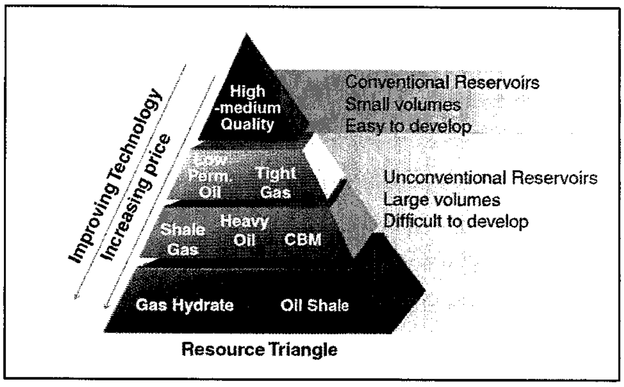


Figure 2.2: Volume of unconventional resources is larger than conventional resources[8]

2.1.3 Tight Gas Reservoirs

According to U.S Government, 1970, the definition of tight gas reservoir is said to be expected value of permeability to gas flow would be less than 0.1 md. The best definition was given "reservoirs that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores"[12-14].

2.2 Formation Damage during Drilling and Completion in Low Permeability Gas Reservoirs

Formation damage is a vast and expansion topic which has been discussed thoroughly in detail by many authors. In this study, we pay attention towards the mechanisms of formation damage which often most effective cause of reduced productivity in low permeability gas reservoirs.Figure 1 shows a schematic of these formation damage mechanisms predominantly fall in to the following three categories which are further sub divided.

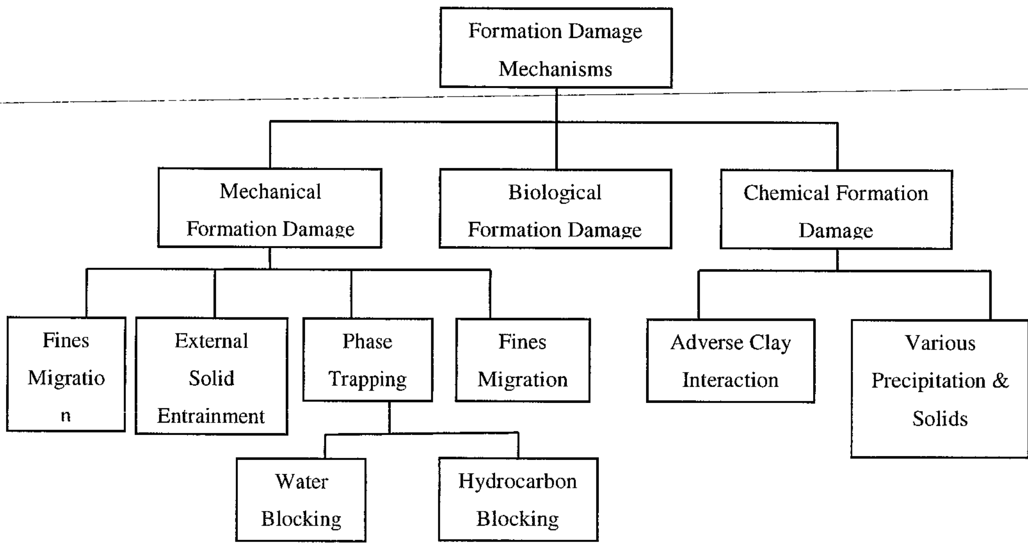


Figure 2.3: Chain of common formation damage mechanisms

2.2.1 Phase Trapping/Retention of Fluids

Water blocking damage is an important concern even in successfully fractured completions in low and tight formations.Water blocking (water phase trapping) is one of the major mechanisms which may cause reduction in productivity near the wellbore. Specific Laboratory equipment's are required to develop strategy for evaluation and diagnoses problems for given reservoir application. Formation of an average permeability 15md tends to practice completion skins through controllable drilling and completion operations. This skin is critical to improve flow efficiency. The formation damage in pores of low permeability is quite difficult to remove[15, 16].

Another term used for phase trapping is adverse relative permeability effects. This mechanism of formation damage is being increasingly recognized as a significant issue.It may exist in various different areas during drilling and completion operations and subsequent production operation with respect to low permeability gas reservoirs. Most notably areas are given below[17]:

1. Water-Based Phase Trapping/Water Blocking
2. Hydrocarbon-Based Phase Trapping
3. Retrograde Condensate Dropout Trapping and Removal

2.2.2 Water Blocking Damage/Water Phase Trapping

Water based fluids are used as drilling and completion media on a worldwide basis due to the relative preponderance (weighted). Water blocking damage may be associated with reservoir type either in both oil and gas reservoirs, when the reservoir consist a sub-irreducible initial water saturation. A considerable effort is require diagnosing and evaluating its effects [4, 18, 19].

2.2.3 Sub-Irreducible Water Saturation

These are worldwide basins which contain sub irreducible initial water saturation[4].Jean Marie, Montney, Rock Creek, Ostracod, Gething, Bluesky, Halfway, Doig, Cardium, and Viking are also included in the sub irreducible initial water saturation gas reservoirs. Further are documented in South America, Europe, Asia, Africa and Australia[20, 21].

Table 2.2: Worldwide basins[4]

United States of America (USA)	Canada Deep basin area
Powder River Basin	Paddy
Green River Basin	Cadomin
DJ Basin	Cadotte
Permian Basin	
United States of America (USA)	Canada Deep basin area
Powder River Basin	Paddy
Green River Basin	Cadomin
DJ Basin	Cadotte
Permian Basin	

2.2.4 Mechanism of Water Blocking Damage

Figure 2.4 shows a schematic of establishment water blocking within a low and tight permeability gas reservoir. For the better understanding, this mechanism is divided into three stages.

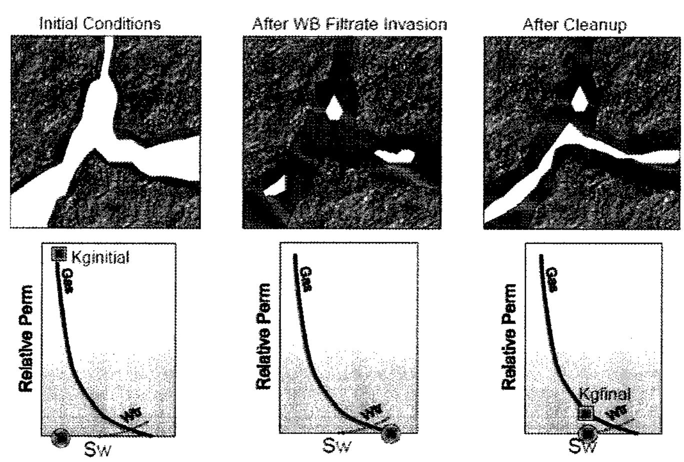


Figure 2.4: Mechanism of Water Blocking[4]

2.2.5 Stages of Water Blocking Mechanism

2.2.5.1 Stage 01(Initial Condition)

- It can be observed in the initial desiccated condition, the pre-existing Swi in porous media.
- Majority of the cross sectional area is available for gas flow which tends to high initial relative permeability.

2.2.5.2 Stage 02 (After Water Based Filtrate Invasion)

- When the zone is invaded with water based filtrate (i-e drilling mud filtrate, completion fluid, kill fluids etc)results in the establishment of a high water saturation

- It tends to be establishment of a high saturation of water in the zone immediately near wellbore or surrounding the wellbore or fracture face and generated establishment of critical gas saturation.

2.2.5.3 Stage 03 (After Clean up)

- Subsequently the drawdown of the reservoir results in the affected zone reverting to the irreducible water saturation
- Itis dictated by the capillary mechanics of the system rather than back to the potentially very low initial water saturation.

The irreducible water saturation is greater than initial water saturation(Sirr>Swi) , this results a notably restriction in the cross sectional area available for fluid flow observed in Figure 2.5. It causes reduction in relative permeability to gas. Figure 3 shows a schematic of these mechanisms.

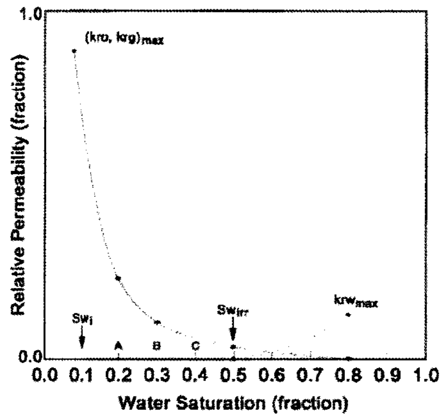


Figure 2.5: Water blocking-relative permeability relations[18]

2.2.6 Factors Which Affect the Severity of Water Blocking Damage

Water blocking damage occurs when a water based-fluid is introduced into the reservoir matrix in the region surrounding the wellbore (or in certain situations a natural or induced fracture face). A portion of the fluid is retained or hold in the rock matrix upon commencing production (or cases in which initiating injection). The following factors are highly affected by water blocking:

- Initial Fluid Saturation
- Rock Wettability
- Pore System Geometry
- Fluid type , composition and Interfacial tension
- Fluid Vapour Pressure and Partial Pressure
- Depth of invasion
- Available drawdown pressure and gradient for fluid recovery

2.3 Prediction of Permeability Damage Caused by Phase Trapping

Thomeer and Swanson developed empirical techniques for the prediction absolute permeability from capillary pressure data. They identified the insignificant contribution to smaller pores permeability as compared to the larger pores. Swanson's developed method for the characteristics capillary pressure curvesuses the inflection point on the lower portion of the capillary pressure curve to predict permeability. The inflection point shows maximum product of pore throat size times effective flow area. In Figure 2.6, the maximum value is inversely proportional to the distance of the inflection point from the lower left-hand corner of the axes, is proportional to permeability. Above this inflection point smaller pore throats, the shape of capillary pressure curves considered as fail in Swanson technique. Swanson involved in the measurement of air and brine permeability by correlated 300 sandstone and carbonates samples [22-24].

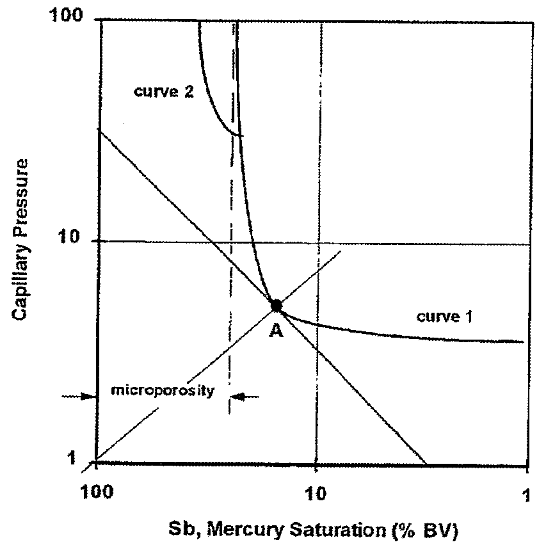


Figure 2.6: Swanson's Technique, Correlating Point of Tangency with Permeability[23]

As a measure of the interconnected pore volume, Thomeer's type curve technique uses vertical asymptote. Furthermore, bi-model behavior occurs, such as plateau (raised shape) on the capillary pressure curve 2 in Figure 2.6. Although for predict the absolute permeability[22, 25].

Swanson and Thomeer used capillary pressure curves, as consult their techniques which tend to ignore microporosity, represent close correlation with absolute permeability, and suggest that microporosity may not have any effect on relative permeability either. Furthermore, microporosity is saturated with water or not, there should be considered little if any change in effective permeability to hydrocarbon[23, 26, 27].

2.4 Buckle's Saturation

Buckle's saturation was introduced the concept of particular value of saturation (Buckle's water saturation) S_{wbu}. Blakeman found that the water block effects are the caused by the aqueous fluids blocking permeability contributing pores in the macropore size range. He presented that once water saturation is declined which is lower than buckle's saturation S_{wbu}. It exists at a pore throat diameter of 0.5 macrons (approximately 560 psi/mercury, or 85 psi air/brine capillary pressure) no additional increment in effective permeability to hydrocarbon occurs[28-30].

He recommended that the water saturation at relative permeability to water become zero S_{wim} is not equal to S_{wirr}. He stated that smaller macropores contain water which cannot move because of hydrocarbon completely occupy largest macropores, isolating the smaller macropores. If the higher capillary force is encountered, with the time these smaller pores can be desaturated resulting in an increase in effective permeability to gas. Blakeman validated his theory with experimental data from North Sea Jurrasic Sandstone[31].

Bennion et al., demonstrated an example of 75 percent reduction in relative permeability to hydrocarbons. It was observed to a 20 percent water saturation caused by the aqueous phase trapping in low water saturation.As Blakeman represented this point as S_{wim}, While Bennion el at shows this point as S_{wirr}. Furthermore, Bennion el at discussed on his paper about gas permeability measured on core samples from the "Paddy" and "Cadomin" Formations at floodout conditions.For the laboratory design program of paddy formation description includes depth of 1700m in the late 1970's. It was initially pressured at an original reservoir pressure of 1813 psi, thickness of 20m with an average porosity 15%, water saturation ranges 10-25% and in situ permeabilities have values upto 800md[4, 31, 32].

2.5 Laboratory Protocols for Evaluation of Phase Trapping

The laboratory protocols were mentioned that concern with displacement experiments.

2.5.1 Fluid displacement Experiments and Core Flooding

Core Flooding were successfully carried out, brine was flooded through the core samples at original reservoir pressure and temperature conditions. Then, reverse flooded of nitrogen gas was carried out to observe entrainment effects. Furthermore, brine was replaced by light condensate and the cycle was repeated. The effects of hydrocarbon invasion were measured. It was concluded that care sample with initial bench permeability to air was 104md. Single phase permeability of the core sample to brine at restored reservoir conditions measure 45.6md(which equal to the single phase permeability at reservoir condition). Reverse of gas flood to equilibrium, observed reduction in relative permeability of sample was 13.5 md with an 44.7% of residual water saturation [5, 33, 34].

The second consideration of Bennion el at., was Cadomin Formation in deep basin area of west central Alberta. In order to simulate the downhole processes, coreflood testing was undertaken at reservoir condition for investigate the behavior the water entrainment in the Candomin, shown in Figure 2.7. For the measurement of vertical permeability across the zone, leak-off tests were conducted on full diameter core measured, bench K_v to air was 3.9md (K_v measured was approximately 0.5 K_{hmax}). As the reservoir condition was restored, the in situ single phase permeability to air or formation brine declined to 0.17md[35].The outcome shown by reverse gasflood in presence of brine saturated in core, 50% water entrainment water saturated was noticed after stabilized flow periods. It tends reduction the core permeability by two third to 0.055md[36-38].

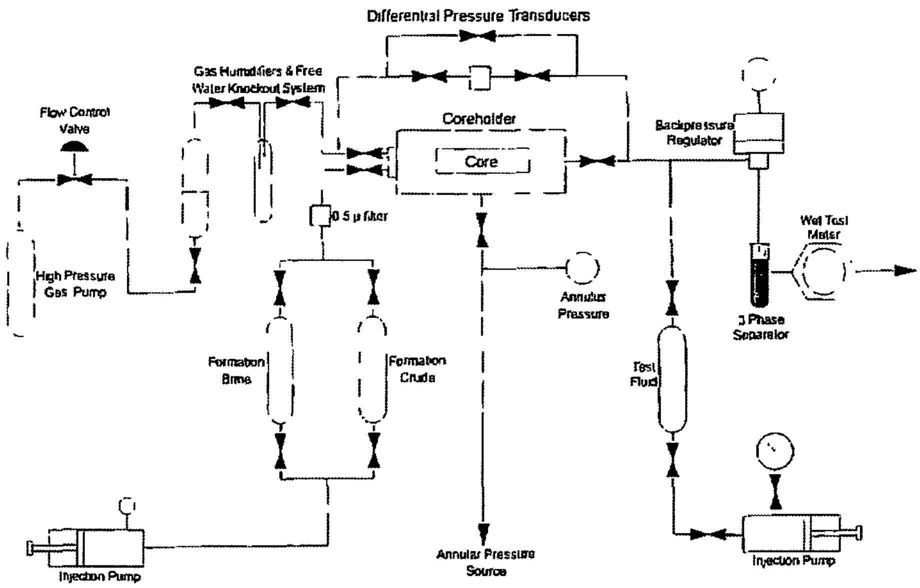


Figure 2.7: Experimental Apparatus for Evaluating Aqueous Phase Trapping[35]

Bennion et al presented that introduction of extraneous fluids into the near wellbore area, because to clean up the water saturation, S_{wirr} , by identify by the drawdown forces used to produce the well for overcome capillary pressure. (It is notice that the value of S_{wirr} is different the standard conventional). The result in higher the drawdown tends to up the capillary pressure curve one would move. In few cases this equivalent capillary pressure, originated during cleanup is less than the original capillary pressure generated in the reservoir. Hence, near wellbore the water saturation will remain high, resulting reduction in permeability. The cause of this permeability reduction is hysteresis effects, which results most significant for non-wetting phase like gas[7, 38, 39].

Amaefule and Kersey presented in their work experience on Gulf Coast sands, that the saturation range when change in relative permeability to non-wetting phase occurs is prior to reaching S_{wirr}, i-e observed to the right of the vertical asymptote. As the saturation is lower to the point, capillary curve must be vertical (approximately 12 psi), by this time 100% of absolute permeability has been recovered. Consequently, further reducing the water saturation has no more benefit[2, 21].

Gruber showed of the permeability datafor core plugs from the sandstone and carbonate reservoirs. Glauconitic formation samples were desaturated by the porous-plate technique at 1000 Kpa (air/brine) and Dunvegan formation sale were centrifuged under air at 1000 Kpa. The sample of Dolomite formation was centrifuged under air at 26000 Kpa capillary pressures. Finally the sample from limestone was dynamically flushed with a 17cp mineral oil at 6ml/min to connate water saturation. In Glauconitic core sample were sesaturated at 1000 Kpa, above the Buckle's saturation S_{wbu} and by considered average saturation of four core sample of 23.8 % resulted on an average affective air permeability of 91 % of the absolute air permeability. Result was found different for these core samples from Dunvegan formation[28, 40].

It was observed that the higher permeability plugs (34.2 and 14 md) only a slight reduction in air permeability with 21.7 and 26.5% water saturation while results 54% reduction in permeability in tighter, with the permeability of 4.7 md of tighter tends to permeability reduction to 54% of original its 47% water saturation[11][41].

2.5.2 Phase Trapping Test Apparatus/Equipment

Bennion el at., presented technique for evaluation of water phase trapping and hydrocarbon based fluids in low permeability gas reservoirs. A "phase trapping test" is usually conducted on samples, if available[11, 42].

By using this process, it is possible to representative average to better quality pay at down hole conditions.In order to evaluate the sensitivity of the matrix to both water and hydrocarbon based fluids and ascertain the best techniques. This procedure based on the region permeability measurements with same drawdown levels as the baseline pre-exposure permeability. Damage effect and threshold pressure (drawdown required are the first point of gas mobilization), shows permeability measurements for a low permeability gas reservoir using a water based 3% Kcl completion fluid[43, 44].
Imbibition issues discussed in well manner by Bennion el at in order to set of water-gas capillary pressure curves for a typical low permeability gas reservoir. The curves represented by high "threshold pressure" for initial gas intrusion into the water saturated matrix and a high irreducible water saturation. For these pore geometry

consist in a sub irreducible initial water saturation condition as mentioned, one can see that these is a large amount of capillary suction 'potential' that encountered between the natural equilibrium water saturation desired to be presented in the rock from a capillary mechanics point of view, compared with present water saturation level[4, 35].

Particularly, these situations create an extremely powerful hydrophilic section tendency for water (assumed wetting fluid) into the matrix. It might considerable invasion, because of capillary suction effects, can happen when water based fluids are introduced with the formations, even in the absence of overburden pressure. This phenomenon is known as countercurrent capillary imbibitions, illustrate that how significant increment in water saturation in the near wellbore or fracture face region even in underbalanced operations[7, 45, 46].

Zhao Feng evaluated the low permeability and tight sandstone gas reservoir by focusing characteristics such as small pore throat, strong water wetting and well developed fractures which are liable to be damaged during operation even in underbalanced condition. He observed two main damages in low permeability and tight sandstone gas reservoirs which are water blocking and stress sensitivity and evaluated by fracture visualization test system and capillary flow porometer. An example of water blocking damage on the Neopaleozoic tight sandstone reservoir in the Northe Ordos basin, this experimental result shows the drastically reduction in the gas phase permeability as water saturation increases. According to the simulation and modeling result performed in the study of tight sand reservoir concluded that the importance of water blocking(liquid phase trapping) is one of the major damage due to relative permeability and capillary pressure effects[47, 48].

As consult with relative permeability effects, Bennion el at presented a schematic of a typical reservoir condition relative permeability apparatus mentioned in Figure 2.8, with the exception of a use back pressure regulator to allow reservoir facilitate the use of live gas charged reservoir fluids. Information regarding phase blocking effects can be obtained by analysis of the relative permeability curves on a combined drainage-imbibitions test, which include[49-51]:

- Water trapping in a gas reservoir (Water flood sequence from Swi followed by a gas flood Swr)
- Water trapping in oil wet reservoir (Water flood sequence from Swi followed by an oil flood to Swr)[4].

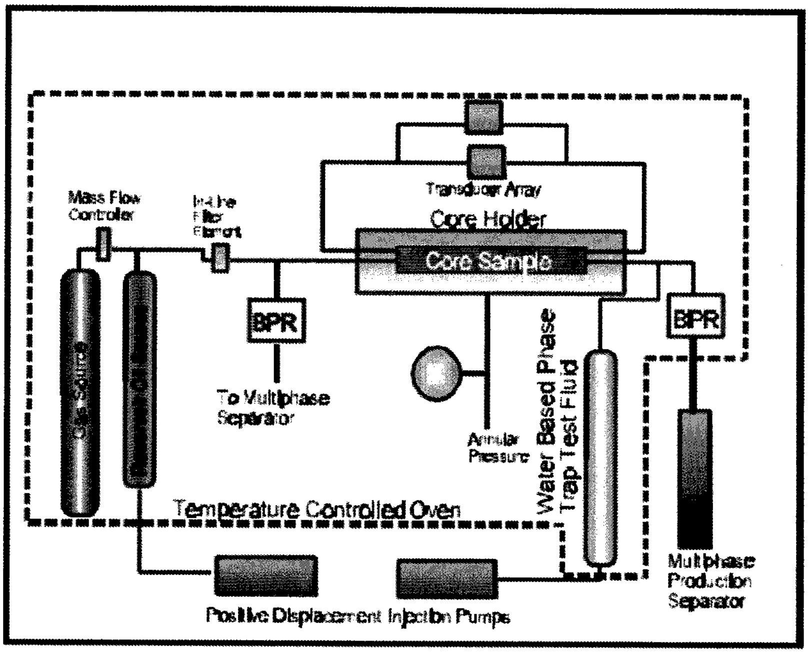


Figure 2.8: Basic Aqueous Phase Trapping Apparatus [5]

2.6 Reservoir Modelling and Simulation of Phase Trapping

The economic related to near-wellbore drilling-induced damage and clean up efficiency was tend to consider literature to made in the experimental and numerical studies to allow wellbore flow characteristics during the production. He presented a methodology for the modeling of possible formation damage during UBD. Spontaneous imbibitions leads cross flow phenomenon that are focused to model the filtrate invasion noted from well to porous media, as well in production.His study based on a numerical model accessing us to estimate well productivity reduction resulting to possible formation damage during UBD, such as temporary overbalanced drilling or spontaneous imbibitions[52, 53].

He also studied in his other articlethatnon-uniform skin around wellbore to study well productivity affected by formation damage. But, no exposure of laboratory experiments was involved to evaluate filtrate invasion. His objective was concern with well performance by considering laboratory experiments. For the modeling of invasion formation damage during UBD, two phase flow model was taken into account.. To simulate spontaneous imbibitions, counter-current flow has been modeled using capillary pressure. The two phase flow Equation 2.1 is given by:

$$\frac{\partial}{\partial t}(\emptyset \rho_f S_f) = div\left[\frac{\rho_f \bar{\bar{K}} k_{rf}}{\mu_f}(\nabla P_f - \rho_f g \nabla_z)\right] \tag{2.1}$$

Where,

S = saturation (subscript f for filtrate and h for hydrocarbon)

P = Pressure

k_r= Relative permeability of each fluid as a function of S_f

g = Gravity factor

$\emptyset$ = Porosity

ρ = Density

and μ is the viscosity

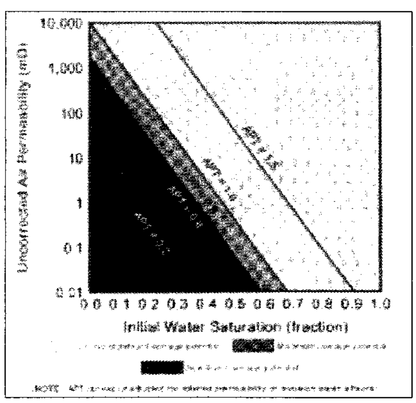


Figure 2.9: APTi Ranges[5]

Brian presented tool that can use for investigate reservoir parameters which may cause for aqueous phase trapping.The tight gas reservoir located in the Permain Basin was evaluated using two calculations for this purpose. These are APT_i and the value of BVW%. Further the potential of the phase trapping was screened by applying the criteria which was suggested by Bennion[35, 54, 55].

2.7 Diagnosis and Prediction Tools for Phase Trapping

2.7.1 Permeability Damage Ratio

A fully water saturated core was used to measure effective permeability of the produced fluid K_i. The saturation of core with water filtrate, the drainage process was initiated to establish irreducible saturation. After the drainage process, measure the effective permeability,K_d , and permeability damage ratio caused by aqueous phase trapping, D_{pt} which is estimated by Equation 2.2. The potential of D_{pt} is evaluated for APT is given in the Table 2.3.

$$K = 1 - \frac{K_d}{K_i} \tag{2.2}$$

where,

K= Permeability damage ratio

Kd= Permeability damage

Ki= Initial Permeability

Table 2.3: Potential for Damage[3]

D_{pt} Value	**Damage Potential**
$D_{pt}<0.05$	Less
$0.05 \leq D_{pt}<0.3$	Less to medium
$0.3 \leq D_{pt}<0.7$	Medium to high
$0.7 \leq D_{pt}<1.0$	High

2.7.2 Aqueous Phase Trapping Index (APTi) and Modified APT Index

APT can be evaluated by using another equation presented by Bennion et al(1996). The APT index was given in Equation 2.3[18]:

$$APT_i = 0.25\, log_{10}(K) + 2.2\, S_{wi} \tag{2.3}$$

Where,

APTi= Aqueous phase trapping index

Swi= Initial water saturation

Later on, Bennion proposed rigorous evaluation by considering more parameters such as relative permeability shape factor, invasion depth and reservoir pressure in form of Equation 2.4[18].

$$APT_i = 0.25\, log_{10}(K) + 2.2\, S_{wi} - 0.26\, log_{10}(x - 0.5) - 0.08\, log_{10}(I_d + 0.4) + 0.15 log_{10}(P_r) - 0.175 \tag{2.4}$$

Where,

x = relative permeability shape factor changing value from 0 to 8

I_d=invasion depth in cm

Pr = reservoir pressure

The Table 2.4 is used to figure out the prediction severity for APT.

Table 2.4: Criteria for prediction APT damage[18]

APT_i Value	**Prediction**
$APT_i \geq 1.0$	Reservoir unlikely to exhibit significant permanent sensitivity to APT
$0.8 \leq APT_i \leq 1.0$	Reservoir may exhibit sensitivity to APT
$APT_i < 0.8$	Reservoir will likely exhibit significant sensitivity to APT

The second diagnostic technique revolves around the calculation of the Percent Bulk Volume (BVW) (2004)[56]. Bulk volume water is present of the total volume (including rock) which is water. The calculation is developed by considering the logderived average porosity and initial water saturated values of the zone using Equation 2.5:

$$\%BVW = S_w(fraction) \times Porosity(fraction) \times 100 \quad (2.5)$$

Where the percent of the bulk volume water is denoted by (BVW), porosity is the average reservoir porosity (fraction) and S_w is the water saturation (fraction).
Further interpretation was carried out for reservoir characteristics shown in Table 2.5.

Table 2.5: Criteria for prediction APT damage[56]

% BVW Range	Reservoir Characteristics
%BVW ≥ 3.5	Formation unlikely to exhibit significant permanent sensitivity to aqueous phase trapping
3.5 ≤ %BVW ≤ 2.0	Formation may exhibit sensitivity to aqueous phase trapping
%BVW < 2	Formation will likely exhibit significant sensitivity to aqueous phase trapping

2.7.3 Phase Trapping Coefficient (PTC)

The concept of phase trapping coefficient (PTC) was introduced by the You and Kang (2009). It highlights the influences of interfacial tension and contact angle between the fluids, Equation 2.6 and damage potential was predicted with help of Table 2.6. Where, μ_m is the ratio of viscosity of produced fluid and damage fluid and σ is interfacial tension between produced fluid and damage fluid[1, 15, 56].

$$PTC = e^{\sqrt{\frac{k}{\emptyset}} \cdot \frac{\Delta p}{\sigma \cos\theta} \cdot \frac{S_{wi}}{\mu_m S_{wirr}}} \quad (2.6)$$

Where

Swirr = Irreducible water saturation

σ = Interfacial tension

μ = Viscosity

Ø = Porosity

μm = Viscosity ratios of fluids

Table 2.6: Phase Trapping Damage Prediction Criteria[56]

PTC	Prediction
PTC < 0.05	None
0.05≤PTC<0.3	Weakly
0.3≤PTC<0.5	Weakly to medium
0.5≤PTC<0.7	Medium to intensely
PTC≥0.7	Intensely

2.7.4 Coefficient of Aqueous Phase Trapping (CAPT)

Abouzar (2010) introduced the predictive formula namely coefficient of phase trapping (CAPT) for evaluating gas reservoir's potential for damage caused by APT. Prior to CAPT, the forecast model used for oil and gas reservoirs but this proposed particularly for gas reservoirs to diagnosis severity for damage through lumped all effective parameters in the one single parameter. Refer the Equation 2.7 for CAPT value and table 2 is mentioned here for prediction[57, 58].

$$CAPT = \frac{-\sqrt{\frac{K}{\emptyset}}\Delta P\, \mu_g}{e^{(S_{wirr}-S_{wi})\mu_w\, \sigma\, \cos\theta\, I_d^2}} \qquad (2.7)$$

Where

μg = viscosity of the gas

μw = viscosity of the water

2.8 Evaluation of phase trapping using relative permeability

Evaluation of phase trapping using relative permeability curves: For water based and oil based drilling fluids in the tight gas reservoirs[59, 60].

2.8.1 Corey's Formula

Corey presented details first in the Equation 1-3, S_w is water saturation, K_r is relative permeability to the wetting phase, S_{wirr} is irreducible saturation and K_{rnw} is relative permeability of non-wetting phase[61].

$$K_{rw} = [S_w^*]^{\frac{2+\pi}{\pi}} \tag{2.8}$$

Where,

$K_{rw} = Relative\ Permeability$

$S_w^* = Effective\ Saturation\ of\ Water$

$$K_{rnw} = [1 - S_w^*]^2 \left[1 - S_w^{*\frac{2+\pi}{\pi}}\right] \tag{2.9}$$

$$S_w^* = \left[s_w - s_{w,irr}\right]/\left[1 - s_{w,irr}\right] \tag{2.10}$$

2.8.2 Ibrahim, Bassiouni and Desbrandas Method

This methodis focused by combining Wyllie and Garden models with capillary pressure data. Capillary pressure data is used to estimate relative permeability as normalized method. Equation 2.11 expresses the relationship capillary pressure and water saturation[16, 62].

$$P_c = a/S_w^b \tag{2.11}$$

Where a is entry capillary pressure normalized method. Equation 2.11 expresses the relationship capillary pressure and water saturation.

$$K_{rw} = S_w^{*2}[S_w^c - S_{wirr}^c]/[1 - S_{wirr}^c] \tag{2.12}$$

$$K_{nrw} = [1 - S_w^*]^2[1 - S_w^c]/[1 - S_{wirr}^c] \tag{2.13}$$

$$S_w^* = [S_w - S_{wirr}]/[1 - S_{wirr}] \tag{2.14}$$

$$C = 2b + 1 \tag{2.15}$$

2.8.3 Naar and Hardescon Method

This method is focused by combining Naar and Hardescon models with capillary pressure data. It was expressed by the Equations 2.16 – 2.21[63, 64].

$$S_{w(imb)}^* = S_{w(drg)}^* - R\left[S_{w(drg)}^*\right]^2 \tag{2.16}$$

$$R = 0.617 - 1.28\Phi \tag{2.17}$$

$$K_{rwt} = \frac{1}{2K}\frac{S_b^w \sigma}{a}(\Phi^* S_w^*)^3 \tag{2.18}$$

$$\Phi^* = \Phi(1\text{-}S_{wi}) \tag{2.19}$$

$$X = \frac{log(2 - S_{gc} - S_{wi})}{log(S_{wi})} \tag{2.20}$$

$$S_{wi(normalized)} = \left[\frac{S_w}{S_{wi}}\right]^x - (1 - S_{wi}) \tag{2.21}$$

2.8.4 Ibrahim and Koedetitz Method

Capillary pressure data is used to estimate relative permeability as normalized method. Equation 2.22 and 2.23 are expressed Ibrahim and Koedetitz Method[62, 64].

$$K_{rgw} = 1.3046802 S_g{}^* - 8.159598\, S_g{}^{*2} + 25.50978\, S_g{}^{*3} - 31.53754\, S_g{}^{*4} + 13.883828\, S_g{}^{*4} \tag{2.22}$$

$$K_{rw} = 0.9455537\, S_1^{\ *} - 1.2967293\, S_1^{\ *2} + 1.69592785\, S_1^{\ *3} - 0.0424518 S_{gc}(lnk_a)^3 S_1^{\ *5} - 145.83025\, S_{wc}^{\ 1.5}(\emptyset S_1^{\ *})^2 + 0.02764389\left(K_a S_{gc}\right)^4 S_1^{\ *4} \qquad (2.23)$$

Where

$S_g^{\ *}$ *and* S_1 *are given as,*

$$S_g^{\ *} = \frac{S_g - S_{gc}}{1 - \left(S_{gc} + S_{lc}\right)}$$

$$S_1^{\ *} = 1 - \left(\frac{S_g}{1 - S_{lc}}\right)$$

$$K_{rw} = 0.9455537 S_1^{\ *} - 1.2967293 S_1^{\ *2} + 25.50978 S_g^{\ *3} - 31.53754 S_g^{\ *4} + 13.883828 S_g^{\ *4}$$

K_{rgw} =1.3046802

CHAPTER 3

METHODOLOGY

The material collection, material description and experiments are the main concern of this chapter. The material collection is related to the core samples selected and fluid collected from different sources for experimental use and described in this chapter. Three core samples were selected having different porosity and permeability for fluid displacement experiment. The experiments start with determination of petrophysical properties of core sample and measure the fluid properties. Prior to displacement experiment, the interfacial tension between produced fluid and wellbore fluid has measured at different temperature and pressure conditions to observe relation between phase trapping damage and interfacial tension.

Furthermore, the experiments were performed to measure effective gas permeability pre- and post-invasion of water base and hydrocarbon base fluid. In order to generalize the study, different properties of core sample was used to find out relationship of irreducible water saturation with porosity and permeability. The equations of Interfacial tension and two phase relative permeability are corrected to see its impact on the permeability damage.

3.1 Material

This section gives detailed information about the core samples, source of collection, description and fluid samples. The work flow and laboratory facilities are also stated used throughout the experiments.

3.2 Collection of samples

3.2.1 Core Samples

The core sample of sandstone was purchased from Cleveland Berea Sandstone, USA, the composition of which is provided in Appendix A. There are three core samples used in the study having permeability of 18md, 15md and 0.1 md. The composition of core samples is mentioned in the Appendix Table A1.

3.2.2 Fluid Sample

The fluid samples were collected from the Melaka refinery PETRONAS Penapis Sdn Bhd Sungai Udangan Melak. Bintulu. Three samples was undergoes for the experimental study of interfacial tension and its effect on phase trapping in tight gas reservoirs. These fluid samples are mentioned as below.

3.2.2.1 Diesel Oil

The Diesel oil properties are listed in the Table 3.1.

Table 3.1: Properties of Diesel Oil

Parameters	**Values**
Density (gram / cm^3) at 15 ^0C	0.8558
Density (gram / cm^3) at 80 ^0C	0.8198
IBP (^0C)	109.5
FBP (^0C)	410.0
Sulfur Wt%	1.2374

Table 3.1 shows the density in gram/cm3, Initial boiling point 0C, Final boiling point 0C and Sulfur content in Wt%.

3.2.2.2 Condensate

The properties of the condensate are mentioned in the Table 3.2.

Table 3.2: Properties of Bintulu Condensate

Parameters	**Values**
Density (gram / cm^3) at 15 ^0C	0.7257
Density (gram / cm^3) at 80 ^0C	0.7012
API gravity D4052 D	63.484
Sulfur Wt%	0.0388
Salt content ptb	0.02
Water content ppm(Wt)	103.60

Table 3.2 shows the density in gram/cm3 , API gravity, salt content ptb, water content ppm(Wt) and Sulfur content in Wt%.

3.2.2.3 Synthetic Brine

The composition of brine was maintained same as sea water and used to behave water based fluid or water base wellbore fluid. The properties are listed in Table 3.3.

Table 3.3: Properties of Synthetic Brine

Parameters	**Values**
Density (gram / cm^3) at 70 ^0C	0.79
Viscosity (cP) at 70 ^0C	2.19
Nacl (Weight %)	3.5

3.2.2.4 Gas Sample

The nitrogen was used to imitate the produced gas after fluid invaded near wellbore in the tight gas reservoirs. The nitrogen cylinder was taken from the Universiti Teknologi PETRONAS UTP lab.

3.3 Preparation of Material

This section presents the preparation of synthetic brine, fluid samples and core samples.

3.3.1 Dry the Core Sample

Four 3-inch Berea core samples were dried in a 100 ^{0}C oven for 24 hours. Ensure the core sample is completely dried, the core properties were measured. The details of the properties are mentioned in the experimental section.

3.3.2 Synthetic Brine

The bulk volume of brine was prepared and measure for core flooding. In addition, the brine was filtered to avoid the undesired solids during core flooding.

3.4 Experiments

This section consists of experiments, test objectives, briefly procedure and tools used for each of experiments. It also includes all the mathematical relations used in data analysis.

3.4.1 Interfacial Tension Measurement

The Vinci Interfacial Tension Meter (IFT-700) was used for the IFT measurement by using rising drop method in different temperature and pressure. It is designed to determine interfacial tension and contact angle, and also to observe heat and mass transfer phenomena. The equipment is shown in (Appendix A). The IFT system consists of a high pressure cell which is visible. It has also capillary injector to develop drop at reservoir conditions. With the help of sapphire windows, it is viewed from both ends. It assists several drop configurations for IFT and contact angle measurement at interface of fluids. The video camera with telecentric optical system was used to catch the view of drop shape.

Furthermore, the Drop Analysis System (DAS) made this process faster (up to 15 calculation per second) and more effective. The images were generated and IFT calculation becomes easier by using DAS software. The complete shape of the drop was analysed with advanced Drop Shape Analysis software. Thisequipment can be operated at high pressure (up to 69 MPa, 10,000 psi) and high temperature (up to 200°C).

The three Gas-liquid systems were used in the interfacial tension measurement at high temperature and pressure conditions.

1. Brine-Nitrogen
2. Condensate-Nitrogen
3. Diesel-Nitrogen

Prior to measure interfacial tension values, the density of fluids was required as input in IFT-700 Software at high temperature. Anton Par Density meter model DMA4500 was used to measure the density of these fluids at desired temperature of experiment, figure is shown in (Appendix B2). The results of fluid density at desired temperature of experiment are listed in the Table 3.4.

Table 3.4: **Density of fluids at 80 ºC**

Fluid	Density
Brine	0.9862
Diesel Oil	0.8198
Condensate	0.7012

3.4.1.1 Interfacial Tension Meter Procedure

1. Clean the flow lines of the equipment with the toluene. Fill the chamber with fluid sample and the volume of injected fluid was measured with help of gauges.
2. Then, open the valve of chamber that allows filling the cell with brine.
3. Input the needle size, density of fluids and calibrate the video camera into the software.
4. Set the temperature and pressure inside the cell and generate the drop of gas. Video camera helps to see shape of drop either it is proper or improper.
5. Measure the IFT values by the software.
6. Getting all reading at desired temperature and pressure, drain the fluid from cell.
7. Clean with toluene then repeat above process from step 1 to 6 for the condensate-nitrogen and diesel nitrogen systems.

3.4.2 Capillary Pressure Estimation

An interfacial tension isa dominant factor of capillary pressure and they are also directly proportional to each other.The relationship of capillary pressure and interfacial tension are given in the form of following Equation 3.1[65],

$$P_c = \frac{2\sigma \cos\theta}{r^2} A \tag{3.1}$$

Where,

Pc = Capillary pressure, psi

σ= interfacial tension, dynes/cm

θ = contact angle, degree

r = pore throat radius, microns

A= 145 x 10-3 (constant, to convert in psi)

~~The capillary pressure is calculated by Equation with help of measured IFT values.~~

3.4.3 Core Flooding Experiment

The core flooding was designed for measuring the damage permeability of gas after wellbore fluid invasion. The procedure was revised and adopted in which preparation; injection and data analysis have been classified in the following contents. Figure 3.2 provides the flow chart which shows the interfacial tension and displacement experiments.

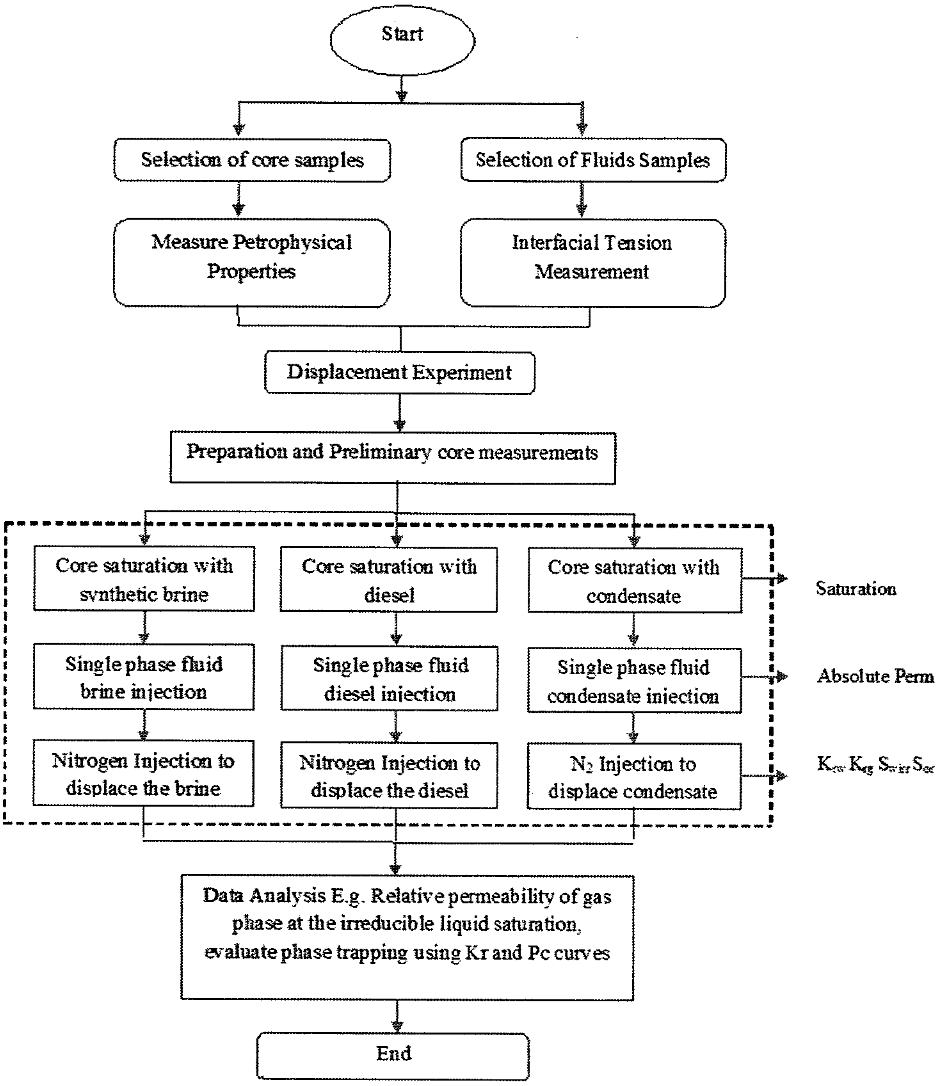


Figure 3.1: Flow chart of core flooding experiment

3.4.3.1 Core Flooding System

The core flooding was performed using Relative Permeability System Model RPS-8300-10000, manufactured by Core Laboratory, USA. It has two syringe types of displacement pumps to deliver a continuous constant pressure and flow. This system consists of three separate accumulators for brine, diesel and gas. All the accumulators are located inside in closed system of controlled oven to simulate reservoir conditions. The data acquisition system and syringe pump control are operated through computerized system. Pressure transducers, thermocouples, pressure valves, back pressure valve, manifolds and flow regulators are accessories of the system which involves in flooding schemes and properties. A measuring cylinder is used to collect the discharge fluids of flooding from an outlet. Figure 3.1 present the schematic of core flooding system.

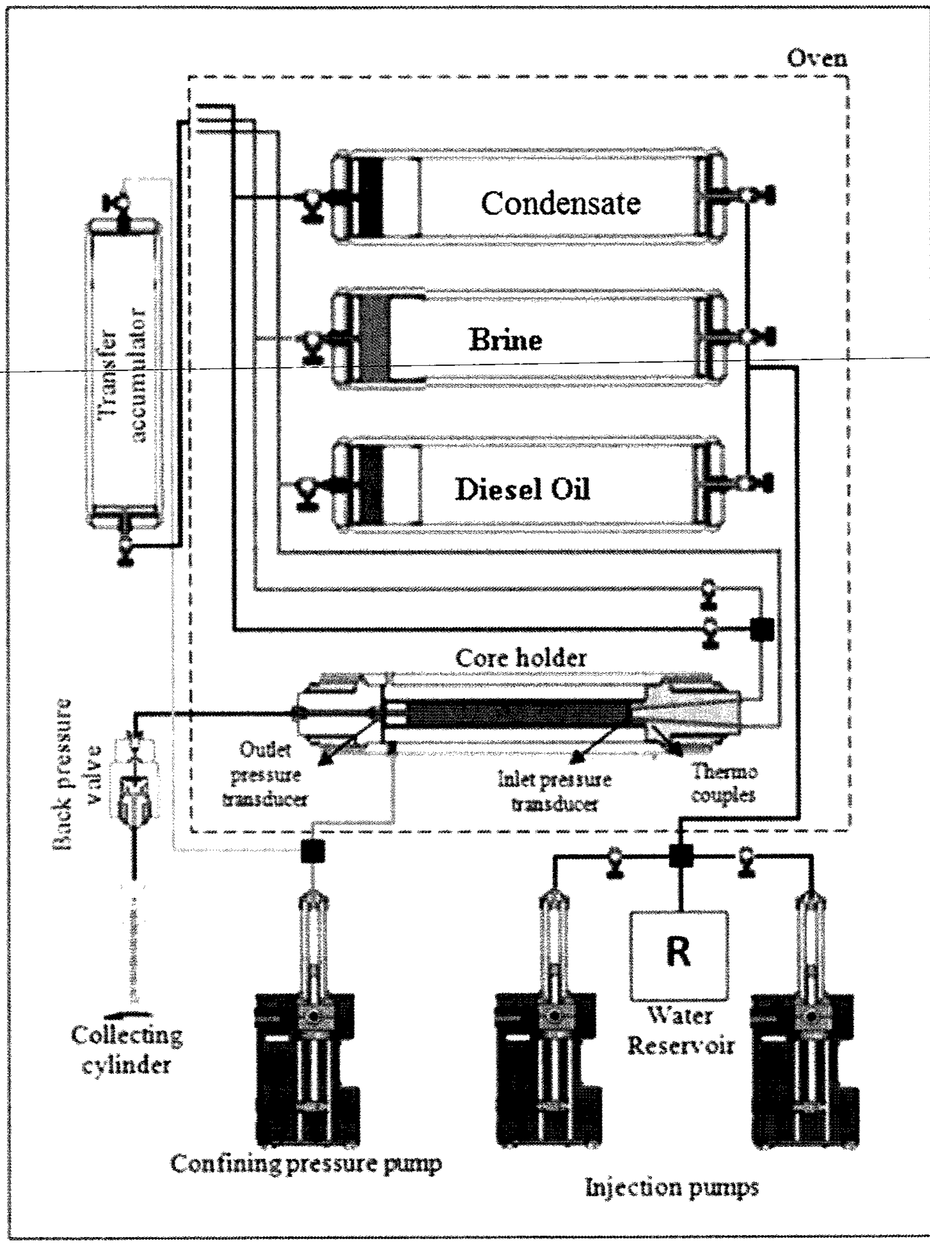


Figure 3.2: Schematic of core flooding system

3.4.3.2 Procedure

The procedure of core flooding is divided into following steps:

1. Core sample measurement

A water saturation method was used to measure the porosity of core samples in which brine was used as saturated fluid of the core. The bulk volume of core sample was calculated from its geometrical dimensions using Equation 3.2.

$$V_b = \pi \frac{D^2}{4} L \tag{3.2}$$

where V_b= bulk volume of core, cm^3

D = diameter of core, cm

L = length of core, cm

The pore volume (PV) was estimated with help of Equation 3.3. Weight of dry core sample and saturated core sample was measured by GF-1000 digital weight balance, shown in Appendix A6.

$$PV = \frac{M_{sat} - M_{dry}}{\rho_{brine}} \tag{3.3}$$

where PV = pore volume, cm^3

M_{sat} = mass of saturated with brine, gram

M_{dry} = mass of vacuumed core, gram

ρ_{brine}= brine density, gram /cm^3

Then porosity of core sample was determined using Equation 3.4.

$$\phi = \frac{PV}{V_b} \tag{3.4}$$

Where ϕ = porosity, %

2. Porosity and Permeability Measurement

The POROPERM instrument which is a permeameter and porosimeter was used to save time and energy by measuring simultaneously porosity and permeability of core sample in single run. Windows operating system made this tool more user-friendly. For visualization, refer Appendix B1.

3. Preparation of core sample for flooding experiment

Preliminary, Vacuum Saturator was used to remove vacuum inside the core sample, shown in Appendix Figure B7. Prior to water or oil based fluid injection, it is essential to 100% saturation should be achieved and remove the vacuum within the core sample. The vacuum Saturator was used to completely saturate core with water base or oil base fluid. The saturated core sample, brine, diesel and condensate solution were placed in a core flooding system. The temperature of oven was raised up to 80 ^{0}C to maintain an equal temperature inside the core sample.

1. Flooding parameters

The flow rate of initial gas injection was kept at 0.5 cm^3/min. The flow rate was calculated based on the average frontal displacement velocity in reservoir [66]. Accordingly, the flow rate of 0.5 cm^3/min was obtained. The pressure meanwhile was maintained 1900 psi at temperature of 80^0C. These parameters were maintained constant throughout the injections to accomplish the core flooding. These same parameters were considered for all three core samples.

2. Gas injection

The core sample was placed inside the core holder assembly at desired temperature and pressure conditions adjusted. The gas injection starts with rate of 0.5 cm^3/min was measured the pressure drop at inlet and outlet of core sample. The computer program helps to calculate gas permeability and display digital real time reading with the help of following equation. Manually, the Equation can be used by substituting parameters estimated from digital reading of Relative Permeability System RPS equipment during flooding.

$$K_g = \frac{2\mu Q_b P_b L T_{act}}{A(P_1^2 - P_2^2) T_{ref}} . 1000 \qquad (3.5)$$

Where,

μ = Viscosity, cp

Q_b = Flow rate, cc/min

P_b = Pressure, psia

L = Length of core sample, cm

T_{act} =Actual Temperature, R

T_{ref} = Reference Temperature, R

3. Brine-Gas injection

The brine is used for injection in order to evaluate water base fluid damage. The brine saturated core sample was kept into core holder were adjusted temperature and pressure at desired testing conditions. The prepared brine was continuously flushed through the core sample. It helps to ensure the complete of the core saturation with brine. The gas injection started with rate 0.5 cm^3/min to displace the saturated brine within the core sample. The gas injection was continued until the brine saturation was reduced to residual saturation, and then the end point of permeability of gas was measured. The gas injection was stopped when the pressure drop reached to the condition of steady state. The pressure data was recorded using the automatic logging system of machine, which in turn was used to calculate the absolute permeability of core sample. The produced brine was collected with help of measuring cylinder outside the oven. The mentioned procedure was adopted for all core samples.

4. Diesel oil-Gas injection

For the evaluation of damage caused by oil based fluids, the diesel was used same way as brine in previous step. The diesel oil was placed on top section of core holder as mentioned in the Flooding system schematic. Prior to diesel oil injection, the core was fully saturated with diesel oil using vacuum using Vacuum Saturator. The core was placed into core holder at desired testing conditions then gas was flooded at same rate 0.5 cm^3/min into core sample until diesel oil saturation reduced at residual oil saturated and achieved steady state conditions. The gas permeability was measures at that residual saturation. The effluent produced from core was stored in measuring cylinder. This entire procedure was applied for other core samples as well.

5. Condensate-Gas Injection

In this step, completely saturated core with condensate was kept into core holder. The gas injection was initiated with rate 0.5 cm^3/min same as previous steps. The gas flooding was continuously performed until the effluents were collected with negligible condensate. Gas injection was stopped when the desired steady state condition was achieved and measures the gas permeability at residual condensate saturation.

The whole procedure was repeated with other core samples having different properties. Three core samples were tested and investigated throughout the study.

3.4.4 Sendra Windows Version 2011.3

Sendra is a two-phase 1D black=oil simulator model used for analyzing single SCAL experiments as well as several SCAL experiments simultaneously. It is tailor made for revealing relative permeability and capillary pressure from two-phase and multi-phase flow experiments performed in the SCAL laboratory. Sendra covers oil-water, oil-gas and water-gas experiments and both imbibitions and drainage is handled. A third stagnant phase can easily be included.

Sendra was used to concise the relative permeability curves using experimental data and correlation. It helps to visualised the effect of different experimental results on relative permeability curves. The produced fluid volume from core flooding system versus time was input into the Sendra. It helps to generate relative permeability curves and showed best fit correlation with experimental results.

CHAPTER 4

RESULT AND DISCUSSION

4.1 Interfacial Tension

4.1.1 Gas-Brine System

The measurement of interfacial tension between the damage fluid and produced fluid at different pressure and temperature was examined. The result has shown high value of interfacial tension between brine and gas phase at different temperature and pressure. Figure 4.1 shows the highest values of IFT was found in the brine-gas system stated from 44 to 59 dynes/cm. The lowest value of interfacial tension was observed at higher temperature and highest pressure.

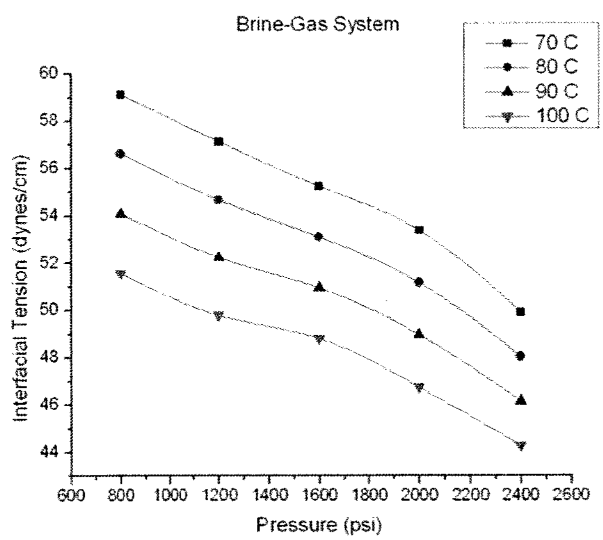


Figure 4.1: Interfacial tension of brine-gas system at different temperature and pressure

4.1.2 Diesel-Gas System

The diesel-gas system had moderate values of IFT that was noted as 14 – 19 dynes/cm varies with temperature and pressure, refer Figure 4.2. While the value of interfacial tension was fluctuated on the high temperature as the vaporizing was taken place. The boiling point of diesel oil was also near about the higher value of temperature in the experiment. The maximum value of interfacial tension was found at the low temperature and low pressure.

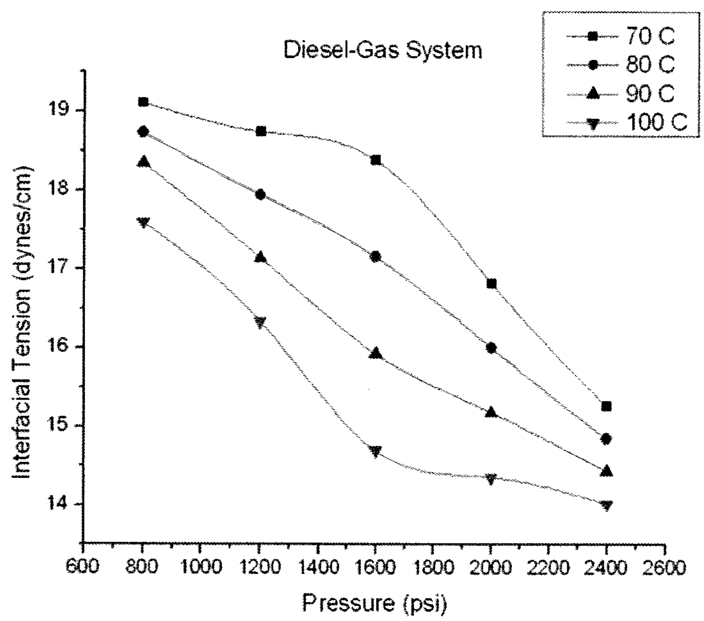


Figure 4.2: Interfacial tension of diesel-gas system at different temperature and pressure

4.1.3 Condensate-Gas System

The condensate has low density as compared to the diesel oil and brine so it has low value of interfacial tension. The minimum value was investigated at 100 C temperature was 6.1 dynes/cm and highest one was 11.5 dynes/cm. Figure 4.3 gives observation about fluctuation in interfacial values at different temperature and pressure due to its low density.The condensate-gas system has low Interfacial tension tends low capillary pressure as well. It may results in low tendency of phase trapping within the core sample during flooding system.

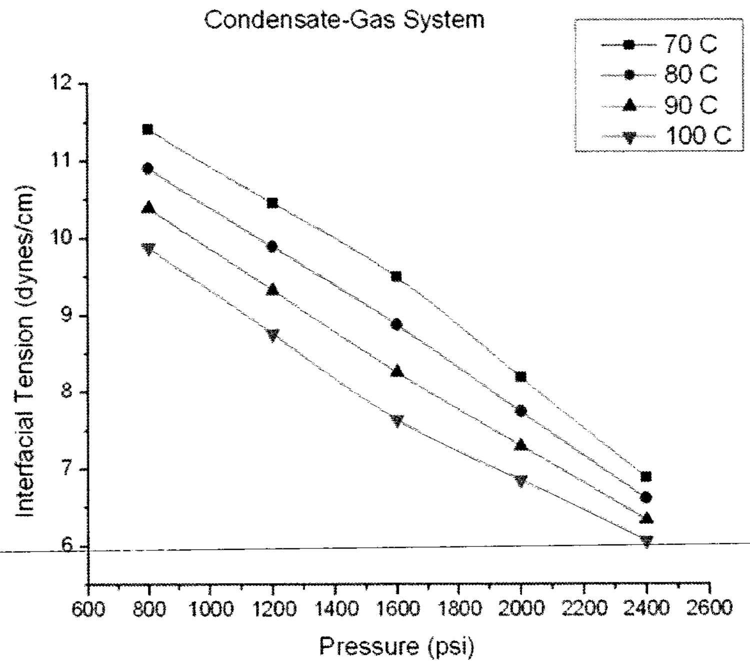


Figure 4.3: Interfacial tension of condensate-gas system at different temperature and pressure

4.2 Capillary Pressure

The three systems were under estimation of capillary pressure.

4.2.1 Gas-Brine System

The capillary pressure was estimated with the help of Equation 3.1 by substituting the value of measured interfacial tension of each fluid. As the capillary pressure is directly proportional to the interfacial tension so the high value of Pc exist in the case of brine-gas system which is visualized by the Figure 4.4. However the moderate and low values of capillary pressure are presented in the Figure 4.5 and 4.6 respectively. The effect of temperature was noticed to be insignificant almost negligible on the capillary pressure values. The brine-gas system exist more capillary forces due to fluid densities and their properties.

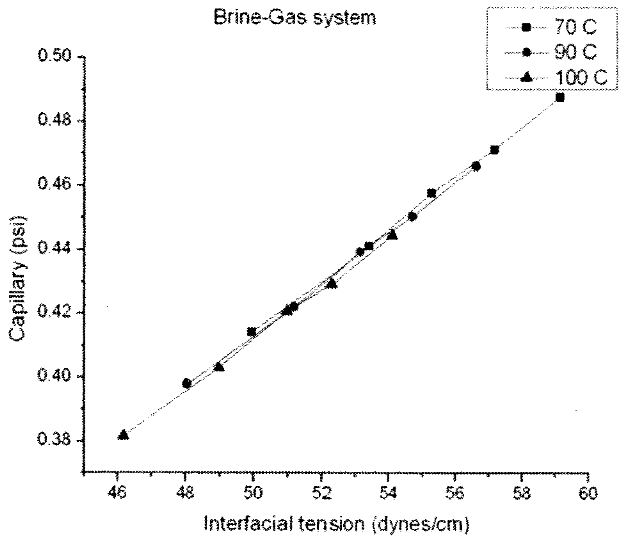


Figure 4.4: Capillary pressure vs Interfacial tension of brine-gas system at different temperature conditions

4.2.2 Diesel-Gas System

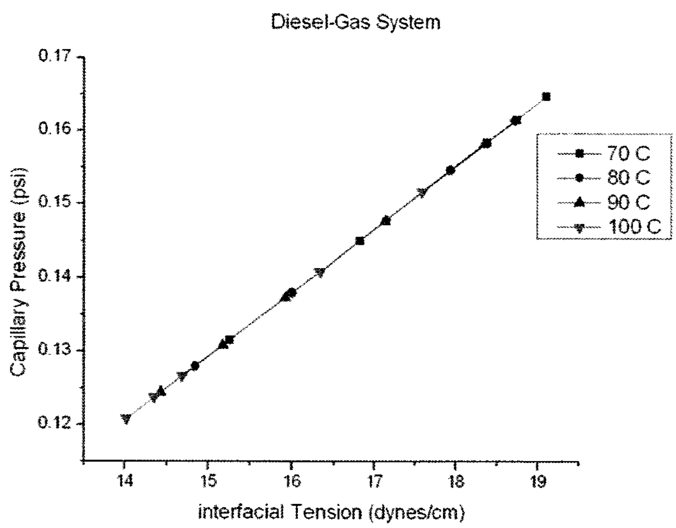


Figure 4.5: Capillary pressure vs Interfacial tension of diesel-gas system at different temperature conditions

4.2.3 Condensate-Gas System

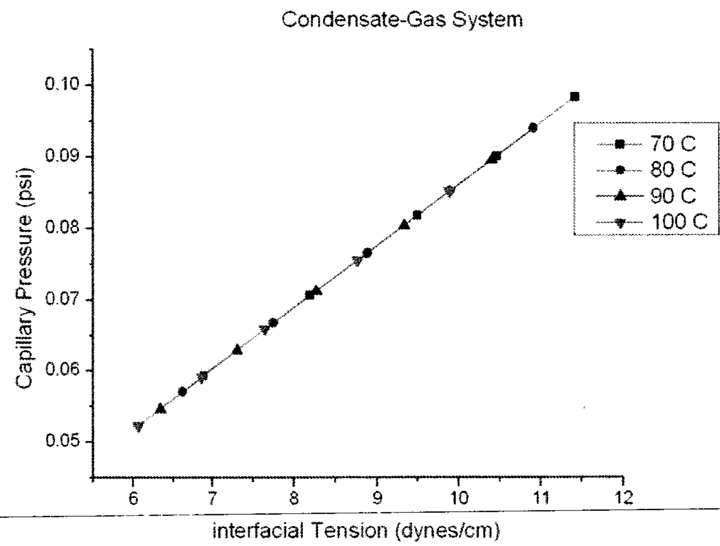


Figure 4.6: Capillary pressure vs Interfacial tension of condensate-gas system at different temperature conditions

It is concluded that condensate-gas system has low potential to phase trapping damage and displaced efficiently by gas produced which results improve in well productivity. All hypotheses have needed to validate by experimental setup of core flooding system. These fluid systems have to be run individually through different properties of core samples. It tends impact of interfacial tension on particular fluid trapping within core sample.

4.3 Effect of Temperature on Interfacial Tension

The relationship of interfacial tension with temperature was found inversely proportional to each other. In this research work three systems were carried out in the experimental result, brine-gas system, diesel oil-gas system and condensate-gas system, shown in Figures 4.1, 4.2 and 4.3 respectively. The interfacial value of brine-gas was measured at 100 C temperatures about 41.5 to 51.5dynes/cm while 70 C temperature values contain 51 to 59 dynes/cm shown in Figure 4. The moderate rate of interfacial tension was remaining about 47 to 54 dynes/cm and 49 to 57 dynes/cm at the temperature of 80 C and 90 C respectively.

4.4 Effect of Interfacial Tension on Capillary Pressure

The effect of pressure on the interfacial tension was observed exponential increments in the values shown in the brine-gas system, diesel oil-gas system and condensate-gas system, shown in Figure 4.4, 4.5 and 4.6. As the interfacial tension is a dominant factor of capillary pressure so the capillary pressure increases with help of it. The capillary pressure was estimated 0.38 psi at value of interfacial tension 46 dynes/cm therefore; the maximum value of capillary pressure in brine-gas system was noticed 0.49 psi at 59.5 dynes/cm interfacial tension, shown in Figure 6. The less values was recorded of capillary pressure for diesel-oil system and condensate-gas system there were 0.12 to 0.165 and 0.05 to 0.095 at the interfacial tension of 14 to 19 and 6 to 11.5 respectively.

4.5 Gas Permeability Using Brine Saturation for Tight Core

Three Core Samples was under investigation for permeability measurement after brine invasion.

- The brine has damaged almost 80% of gas permeability due to phase trapping within all three core samples.
- In Figure 4.7, the green line shows the regain of permeability after invasion of brine/water base fluid within the core sample.
- But it is not completely maintained as initial condition.
- The gas permeability damage was investigated 85% damage as compared initial gas relative permeability.

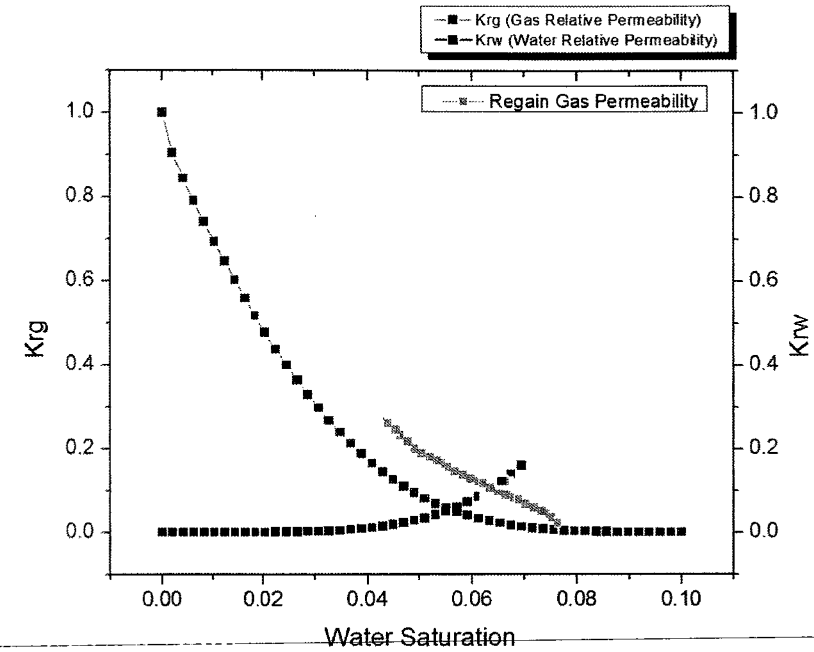


Figure 4.7: Relative Permeability Curves of Water/Brine Base Fluid for Sample TI

4.6 Gas Permeability Using Diesel Oil Saturation for Tight Core

- The diesel oil has less damage than brine or water base fluid.
- Similarly, the saturated core with diesel oil displaced with gas flooding and measures the regain permeability.
- The diesel oil has damaged almost 50% of gas permeability and improves 30% increment in gas permeability, refer Figure 4.8.
- The orange line shows improvement in the regain permeability after invasion of diesel oil fluid and region shows less damage than brine/water base fluid.

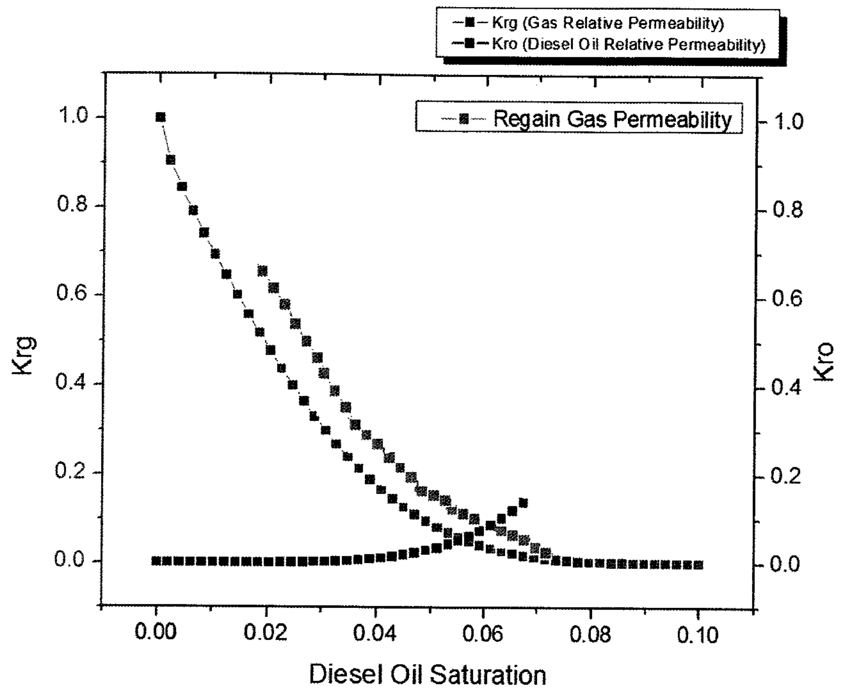


Figure 4.8: Relative Permeability Curves of Diesel Oil Based for Sample TI

4.7 Gas Permeability Using Condensate Saturation for Tight Core

The condensate has less interfacial tension with the reservoir fluid, so it was observed in the Figure 4.9 that condensate has improved regain permeability than brine and diesel.

- The pink line showed the reduction in relative permeability of gas after condensate invasion.

- It helps to reduced almost 60% of relative permeability as compared with initial conditions.

- The sky blue line stated regain of permeability after clean up in the mentioned figure.

- The essential concern was taken place to use it as temperature rating which is not near its boiling point.

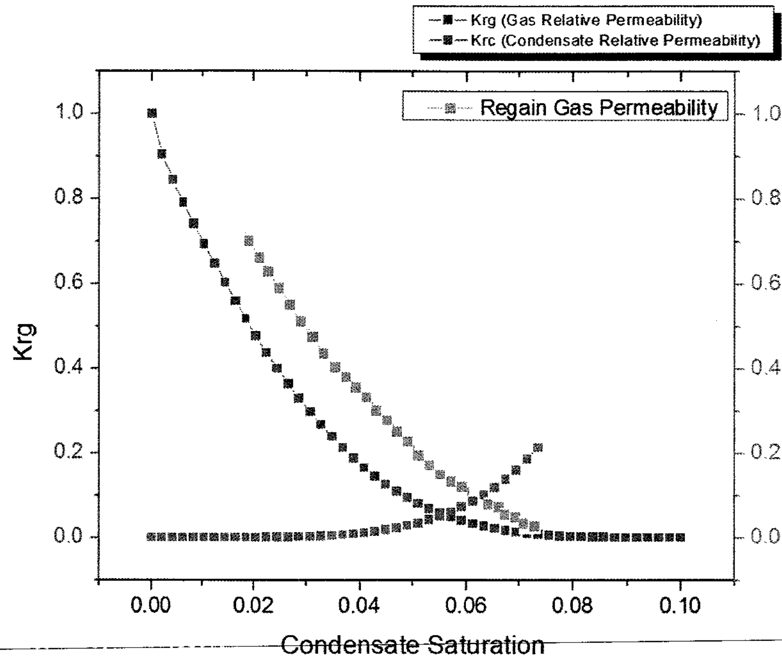


Figure 4.9: Relative Permeability Curves of Condensate Fluid for Sample TI

4.8 Gas Permeability Using Brine Saturation for Low Permeability Core

The low permeability core sample was under investigation for permeability measurement using brine.

- As low permeability core samples are less sensitive in relative permeability damage. The brine has damaged almost 76% of gas permeability due to phase trapping within all three core samples.

- In Figure 4.10, the green line shows the regain of permeability after invasion of brine/water base fluid within the core sample.

- It has been recovered more than tight core sample in previous investigation.

- The gas permeability damage was investigated 83% damage as compared initial gas relative permeability. But it was also maintained by drawdown pressure due to less capillary forces.

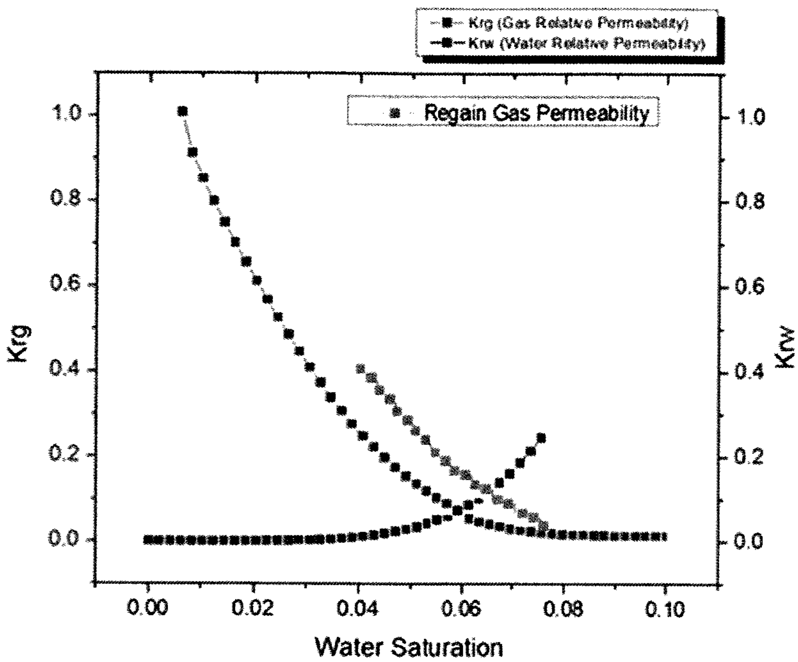


Figure 4.10: Relative Permeability Curves of Water/Brine Base Fluid for Core Sample L2

4.9 Gas Permeability Using Diesel Oil Saturation for Low Permeability Core

The diesel oil has less dense than brine. So it was less reduction in relative permeability in the low permeable core sample.

- Figure 4.11 shows that the diesel oil has damaged almost 52% of gas permeability and improves 32% increment in gas permeability.
- The regain in permeability was shown with help of orange line which was most close to initial relative permeability of gas.
- The low permeability has less efficiency to trap wellbore fluid compared with tight core.

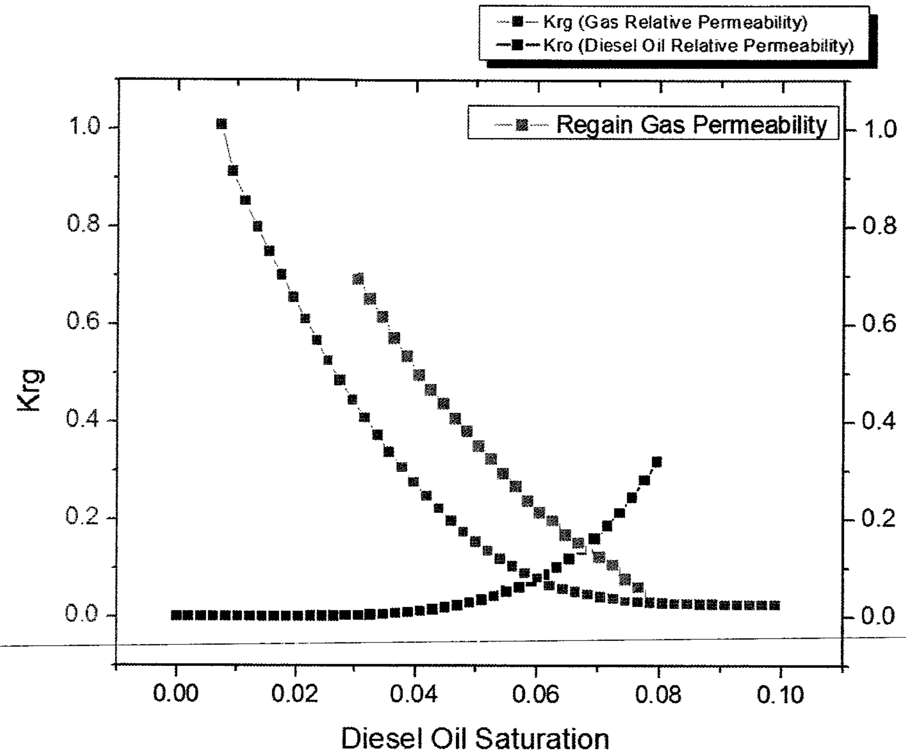


Figure 4.11: Relative Permeability Curves of Diesel Oil Based for Core Sample L2

4.10 Gas Permeability Using Condensate Saturation for Low Permeability Core

The condensate has less density as compared with diesel oil and brine. It was also exhibit low interfacial tension with reservoir gas.

- It was stated in Figure 4.12 that condensate has improved regain permeability than brine and diesel which was shown by sky blue line.

- It helps to reduced almost 60% of relative permeability as compared with initial conditions while it was 75-90% permeability damage in brine case.

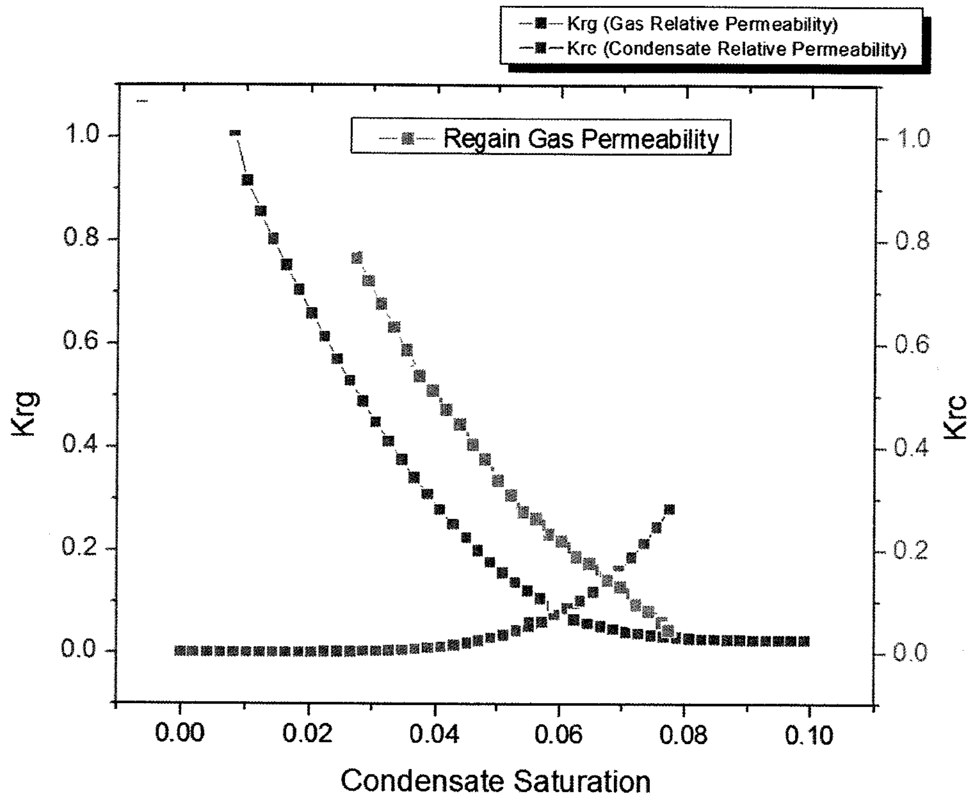


Figure 4.12: Relative Permeability Curves of Condensate Fluid for Core Sample L2

4.11 Gas Permeability Using Brine Saturation for Low Permeability Core

The L1 core sample has high value of permeability and porosity, so it consists less tendency to trap invaded fluids. The low permeability core sample was under investigation for permeability measurement using brine.

- As low permeability core samples are less sensitive in relative permeability damage. The brine has damaged almost 50% of gas permeability due to phase trapping within all three core samples.

- In Figure 4.13, the green line shows the regain of permeability after invasion of brine/water base fluid within the core sample.

- It has been recovered more than tight core sample in previous investigation.

- The gas permeability damage was investigated 55% damage as compared initial gas relative permeability. But it was also maintained by drawdown pressure due to less capillary forces.

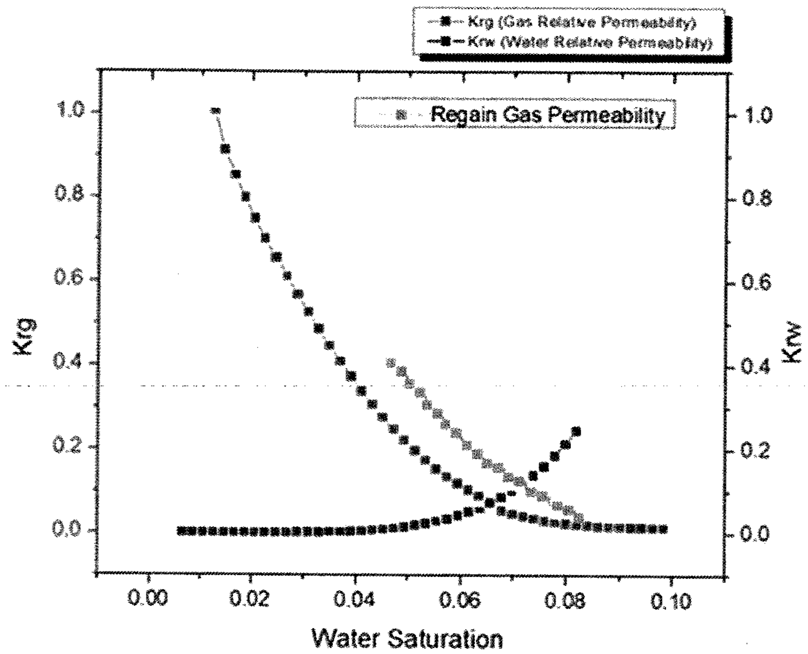


Figure 4.13: Relative Permeability Curves of Water/Brine Base Fluid for Core Sample L1

4.12 Gas Permeability Using Diesel Oil Saturation for Low Permeability Core

The diesel oil was recovered maximum amount of produced fluid with dealing of L1 core sample. The diesel oil has less dense than brine. So it was less reduction in relative permeability in the low permeable core sample.

- Figure 4.14 shows that the diesel oil has damaged almost 45% of gas permeability and improves 33% increment in gas permeability.

- The regain in permeability was shown with help of orange line which was most close to initial relative permeability of gas.

- The low permeability has less efficiency to trap wellbore fluid compared with tight core.

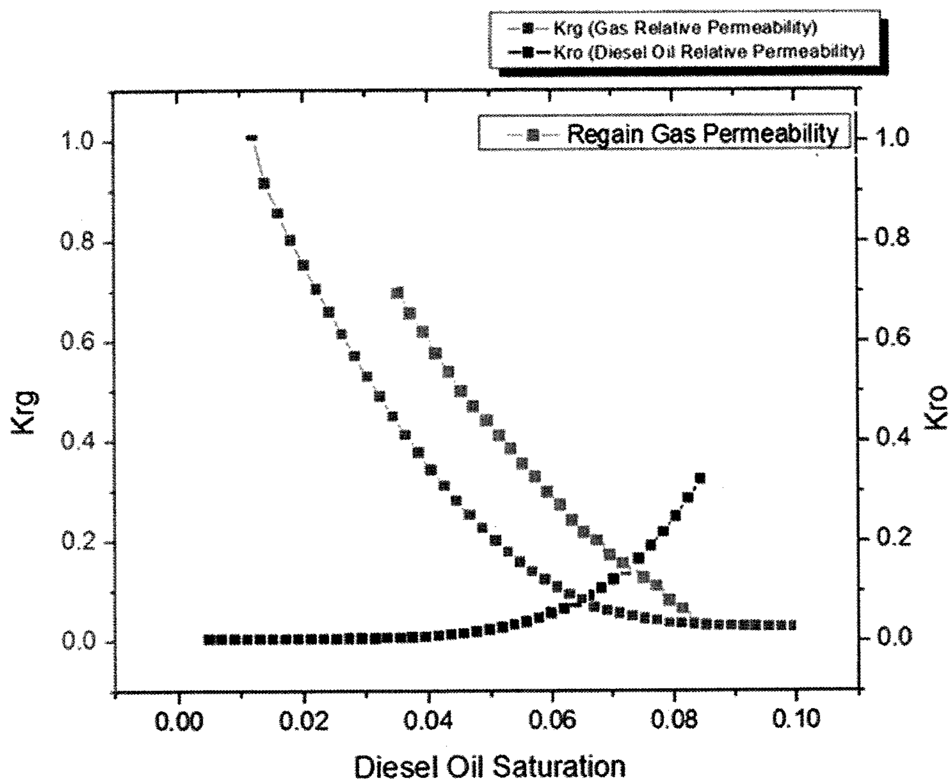


Figure 4.14: Relative Permeability Curves of Diesel Oil Based for Core Sample L1

4.13 Gas Permeability Using Condensate Saturation for Low Permeability Core

The L1 core sample was under investigated by invading condensate. The maximum effluent fluid was found from outlet of core flooding assembly. The condensate has less density as compared with diesel oil and brine. It was also exhibit low interfacial tension with reservoir gas.

- It was stated in Figure 4.15 that condensate has improved regain permeability than brine and diesel which was shown by sky blue line.

- It helps to reduced almost 35% of relative permeability as compared with initial conditions while it was 82-90% permeability damage in brine case.

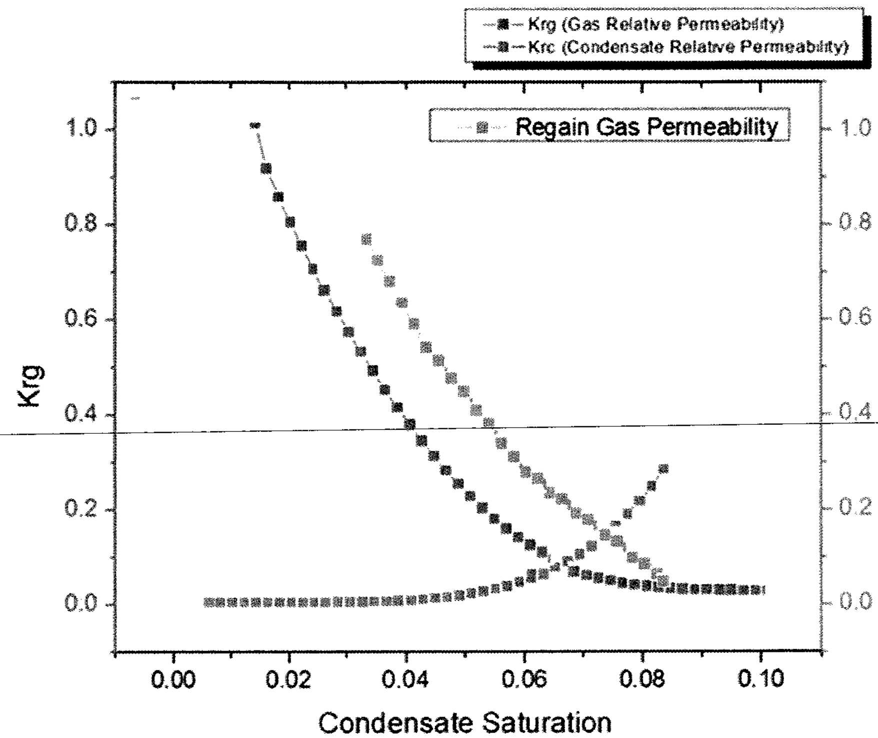


Figure 4.15: Relative Permeability Curves of Condensate Fluid for Core Sample L1

4.14 Relation of Irreducible Saturation with Porosity and Permeability

The low permeability and tight core was investigated in core flooding experiment. The residual saturation of invaded fluid was observed with help of effluent fluid from the outlet of core flooding.

- The low matrix nature of tight core sample tends more irreducible saturation of damage fluid.

- Tight core has more residual saturation due to high capillary while low permeability and porosity core recovered by sufficient drawdown pressure of reservoir.

- The porosity and permeability has inversely proportional relationship with irreducible saturation of the invaded fluid.

- This invaded fluid was caused of dramatically reduction in well productivity.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusions

1. On the basis of IFT results, condensate has less severity to phase trapping in the low permeability and tight core samples as compared to diesel and brine. The essential concern is taken place to ensure properties of condensate are feasible to use as wellbore fluid. Hydrocarbon base fluids have smaller value of damage than water base as well less tendency to trap near the wellbore during drilling and completions.

2. As the interfacial tension is the dominant factor of capillary pressure, the capillary pressure is directly proportional the interfacial tension. The exponentially increase in the value of interfacial tension was observed with capillary pressure rate.

3. The effect of temperature on interfacial tension values has obtained. The interfacial tension is inversely proportional to the temperature. The smaller value was found at the highest temperature.

4. Core flooding setup is required to evaluate the damage potential by injecting these fluids, estimate irreducible saturation which caused trapping of gas production and reduced well productivity.

5. The gas permeability damaged by diesel oil and condensate is less than water base fluid. The water base fluid damage permeability almost 80% of initial value. The diesel oil reduced permeability damage by 50% and the condensate helps 60%. But the condensate has temperature limitation and properties to use as wellbore fluid.

6. The core sample which has low porosity and low permeability may cause serious phase trapping damage due to the existence high capillary forces. Tight core has more tendencies to trap fluids as compared low permeability cores.

7. The relation between irreducible saturation with porosity and permeability is also essential to predict the formation nature either it exist severity of phase trapping.

8. Proper evaluation and diagnosis of water blocking damage by laboratory experiments tends to be an effective prevention for the reduction of formation damage and optimized productivity of gas in low permeability reservoirs.

9. The core sample L2 and L1 were less severity of phase trapping damage as compared with T1 core sample in all three cases. T1 core sample was high capillary due to its low matrix permeability and exist high interfacial tension of invaded fluid with produced fluid.

10. The necessary procedure should be adopted during dealing with tight cores. The compatibility of invaded fluids with produced fluid was also main concern during experiments to avoid problems like emulsion.

5.2 Recommendations

1. Mixing alcohols with wellbore fluid are the promised method to reduce interfacial tension between wellbore fluid and reservoir fluid.

2. For large scale projects, the gas should be flooded with different flow rate and injection pressure to see effect of flow rate on trapping mechanism and drawdown required to remove phase trapping.

Publication

1. “"Minimizing Phase Trapping Damage Using Malaysian Diesel Oil” in SPE/IADC Middle East Drilling Technology Conference and Exhibition, 2013 Madinat Jumeirah, Dubai, UAE, SPE-166805-MS.
2. “Reducing Phase Trapping Damage by Minimizing Interfacial Tension and Capillary Pressure in Tight Gas Resservoirs” Material Science and Engineering Journal, 2013.
3. Evaluation of Phase Trapping Damage Using Malaysian Hydrocarbon Based Fluids, Annual Post Graduate Conference APC 2013, UTP Malaysia.
4. “Prediction of Phase Trapping Damage by considering Interfacial tension in Tight Gas Reservoirs” in International Oil & Gas Symposium & Exhibition IOGSE 2013 UMS Malaysia
5. “Reducing Phase Trapping Damage by Minimizing Interfacial Tension and Capillary Pressure in Tight Gas Resservoirs” International Conference, ICMER, UMP, Pahang, 2013

REFERENCES

[1] H. Johnson, "Low permeability reservoirs: introduction " *Petroleum Geoscience, March 2001, v. 7, p. 2, ,* vol. v. 7, p. 2, , 2001.

[2] J. Amaerule, D. Kersey, D. Norman, and P. Shannon, "Advances in formation damage assessment and control strategies," in *Annual Technical Meeting*, 1988.

[3] D. Bennion, F. Thomas, and R. Bietz, "Low permeability gas reservoirs: problems, opportunities and solutions for drilling, completion, stimulation and production," in *SPE Gas Technology Symposium*, 1996.

[4] D. B. Bennion and F. B. Thomas, "Formation damage issues impacting the productivity of low permeability, low initial water saturation gas producing formations," *Journal of energy resources technology,* vol. 127, pp. 240-247, 2005.

[5] D. Bennion, F. Thomas, and T. Ma, "Recent advances in laboratory test protocols to evaluate optimum drilling, completion and stimulation practices for low permeability gas reservoirs," in *SPE Rocky Mountain Regional/Low-Permeability Reservoirs Symposium and Exhibition*, 2000.

[6] CGG, "Passion for Geoscience," p. Unconventional Resources.

[7] S. Holditch, "SS: Unlocking the Unconventional Oil and Gas Reservoirs: Stimulation of Tight Gas Sands," in *Offshore Technology Conference*, 2009.

[8] H.-H. Rogner, "An assessment of world hydrocarbon resources," *Annual review of energy and the environment,* vol. 22, pp. 217-262, 1997.

[9] Z. Dong, S. Holditch, D. McVay, and W. Ayers, "Global Unconventional Gas Resource Assessment," *SPE Economics & Management,* vol. 4, pp. 222-234, 2012.

[10] Z. Daqian and L. Shuzhen, "TYPES AND CHARACTERISTICS OF LOW PERMEABILITY SANDSTONE PESERVOIRS IN CHINA [J]," *Acta Petrolei Sinica,* vol. 1, 1994.

[11] C. W. Spencer, "Review of characteristics of low-permeability gas reservoirs in western United States," *AAPG Bulletin,* vol. 73, pp. 613-629, 1989.

[12] R. Kennedy, W. Knecht, and D. Georgi, "Comparisons and Contrasts of Shale Gas and Tight Gas Developments, North American Experience and Trends," in *SPE Saudi Arabia Section Technical Symposium and Exhibition*, 2012.

[13] S. Holditch, "Tight gas sands," *Journal of Petroleum Technology,* vol. 58, pp. 86-93, 2006.

[14] J. Shaw and M. Reynolds, "Reservoir Quality Evaluation for Stimulation Design in Low Permeability Gas Development," in *Canadian International Petroleum Conference*, 2004.

[15] M. Erwin, C. Pierson, and D. Bennion, "Brine imbibition damage in the Colville River field, Alaska," *Old Production & Facilities,* vol. 20, pp. 26-34, 2005.

[16] D. Bennion, F. Thomas, D. Imer, and T. Ma, "Low permeability gas reservoirs and formation damage-tricks and traps," in *SPE/CERI Gas Technology Symposium*, 2000.

[17] Y. Wang, Z. Chen, V. Morah, R. Knabe, and M. Appel, "Gas-Phase Relative Permeability Characterization on Tight-Gas Samples'," *Petrophysics,* vol. 53, pp. 393-400, 2012.

[18] D. Bennion, F. Thomas, R. Bietz, and D. Bennion, "Water and hydrocarbon phase trapping in porous media-diagnosis, prevention and treatment," *Journal of Canadian Petroleum Technology,* vol. 35, 1996.

[19] M. Tsar, H. Bahrami, R. Rezaee, G. Murickan, S. Mehmood, M. Ghasemi, *et al.*, "Effect of Drilling Fluid (Water-based vs Oil-based) on Phase Trap

Damage in Tight Sand Gas Reservoirs (SPE 154652)," in *74th EAGE Conference & Exhibition*, 2012.

[20] J. Walls, A. Nur, and T. Bourbie, "Effects of pressure and partial water saturation on gas permeability in tight sands: experimental results," *Journal of Petroleum Technology,* vol. 34, pp. 930-936, 1982.

[21] D. Bennion, F. Thomas, D. Bennion, and R. Bietz, "Mechanisms of formation damage and permeability impairment associated with the drilling, completion and production of low API gravity oil reservoirs," in *SPE International Heavy Oil Symposium*, 1995.

[22] J. Thomeer, "Introduction of a pore geometrical factor defined by the capillary pressure curve," *Journal of Petroleum Technology,* vol. 12, pp. 73-77, 1960.

[23] B. Swanson, "A simple correlation between permeabilities and mercury capillary pressures," *Journal of Petroleum Technology,* vol. 33, pp. 2498-2504, 1981.

[24] J. Pickell, B. Swanson, and W. Hickman, "Application of air-mercury and oil-air capillary pressure data in the study of pore structure and fluid distribution," *Old SPE Journal,* vol. 6, pp. 55-61, 1966.

[25] B. Davis and W. Wood, "Maximizing economic return by minimizing or preventing aqueous phase trapping during completion and stimulation operations," in *SPE Annual Technical Conference and Exhibition*, 2004.

[26] K. Sampath and C. Keighin, "Factors affecting gas slippage in tight sandstones of cretaceous age in the Uinta basin," *Journal of Petroleum Technology,* vol. 34, pp. 2715-2720, 1982.

[27] N. Hands, K. Kowbel, S. Maikranz, and R. Nouris, "Drill-in fluid reduces formation damage, increases production rates," *Oil and Gas Journal,* vol. 96, 1998.

[28] N. Gruber, "Water Block Effects in Low Permeability Gas Reservoirs," in *Annual Technical Meeting*, 1996.

[29] D. K. D. Haussler and M. G. R. F. H. Eeckman, "A generalized hidden Markov model for the recognition of human genes in DNA," in *Proc. Int. Conf. on Intelligent Systems for Molecular Biology, St. Louis*, 1996, pp. 134-142.

[30] S. Jones, "A technique for faster pulse-decay permeability measurements in tight rocks," *SPE formation evaluation,* vol. 12, pp. 19-26, 1997.

[31] D. Bennion and T. Ma, "Formation damage processes reducing productivity of low permeability gas reservoirs," in *SPE Rocky Mountain Regional/Low-Permeability Reservoirs Symposium and Exhibition*, 2000.

[32] P. Chowdlah, "Influence of water-desaturation technique and stress on laboratory measurement of hydraulic properties of tight sandstones," *SPE formation evaluation,* vol. 3, pp. 679-685, 1988.

[33] D. B. Bennion, F. Thomas, and D. Bennion, "Effective Laboratory Coreflood Tests to Evaluate and Minimize Formation Damage in Horizontal Wells," in *3rd International Conference on Horizontal Well Technology, Houston, Texas, Nov 12*, 1991.

[34] P. Chowdiah, "Laboratory measurements relevant to two-phase flow in a tight gas sand matrix," in *SPE Annual Technical Conference and Exhibition*, 1987.

[35] D. Bennion, R. Bietz, F. Thomas, and M. Cimolai, "Reductions in the productivity of oil and low permeability gas reservoirs due to aqueous phase trapping," *Journal of Canadian Petroleum Technology,* vol. 33, 1994.

[36] D. Bennion, F. Thomas, D. Bennion, and R. Bietz, "Fluid design to minimize invasive damage in horizontal wells," *Journal of Canadian Petroleum Technology,* vol. 35, 1996.

[37] D. BENNION, F. THOMAS, R. BIETZ, and A. JAMALUDDIN, "Recent Investigations Into Formation Damage and Remediation Technology for Horizontal Well Applications," in *9th International Conference on Horizontal Well technology and Applications, Houston, TX*, 1997.

[38] R. Doane, D. Bennion, F. Thomas, R. Bietz, and D. Bennion, "Special core analysis designed to minimize formation damage associated with vertical/horizontal drilling applications," *Journal of Canadian Petroleum Technology,* vol. 38, 1999.

[39] D. Bennion and S. Bachu, "The impact of interfacial tension and pore size distribution/capillary pressure character on CO2 relative permeability at reservoir conditions in CO2-brine systems," in *SPE/DOE Symposium on Improved Oil Recovery*, 2006.

[40] D. B. Bennion and F. B. Thomas, "Recent investigations into formation damage in horizontal wells during overbalanced and underbalanced drilling and completion procedures," in *2nd Annual Conference on Emerging Technology–Coiled Tubing–Horizontal Wells–Extended Reach and Multilaterals, June, Aberdeen, Scotland*, 1994.

[41] D. B. Bennion, F. B. Thomas, A. Jamaluddin, and T. Ma, "The effect of trapped critical fluid saturations on reservoir permeability and conformance," in *Annual Technical Meeting of the Petroleum Society of CIM, Calgary, Alberta, Canada*, 1996, pp. 8-10.

[42] D. Bennion, "Advances in Laboratory Coreflow Evaluation to Minimize Formation Damage Concerns With Verticallllorizontal Drilling Applications," *Paper,* vol. 95, p. I05.

[43] C. Laroche, J. Kamath, F. Nakagawa, and Y. Yortsos, "Gas Relative Permeability reduction due to Waterblocking–A Laboratory Based Analysis," in *paper to be presented at the 2000 SCA conference, Abu Dhabi, October*, 2000, pp. 18-22.

[44] D. Longeron, J. Alfenore, N. Salehi, and S. Saintp? re, "Experimental approach to characterize drilling mud invasion, formation damage and cleanup efficiency in horizontal wells with openhole completions," in *SPE International Symposium on Formation Damage Control*, 2000.

[45] D. Marshall, G. Russell, and M. Byrne, "Return permeability: A detailed comparative study," in *SPE European Formation Damage Conference*, 1999.

[46] H. Lu, J. Guo, Y. Wang, M. Yang, and W. Nan, "Trapping Damage Analysis of Water Locking/Aqueous Phase of Tight Sandstone Gas Reservoir in Ke Keya Structure," in *IADC/SPE Asia Pacific Drilling Technology Conference and Exhibition*, 2012.

[47] Z. Feng, T. Hongming, M. Yingfeng, L. Gao, and X. Xijin, "Damage evaluation for water-based underbalanced drilling in low-permeability and tight sandstone gas reservoirs," *Petroleum Exploration and Development,* vol. 36, pp. 113-119, 2009.

[48] Y.-l. Kang and P.-y. Luo, "Current status and prospect of key techniques for exploration and production of tight sandstone gas reservoirs in China," *Petroleum Exploration and Development,* vol. 34, p. 239, 2007.

[49] K. Jairam and L. Catherine, "Laboratory based evaluation of gas well deliverability loss due to waterblocking," in *SPE Annual Technical Conference and Exhibition*, 2000.

[50] J. Ward and N. Morrow, "Capillary pressures and gas relative permeabilities of low-permeability sandstone," *SPE Formation Evaluation,* vol. 2, pp. 345-356, 1987.

[51] K. Newsham, J. Rushing, A. Chaouche, and D. Bennion, "Laboratory and Field Observations of an Apparent Sub Capillary-Equilibrium Water Saturation Distribution in a Tight Gas Sand Reservoir," *paper SPE,* vol. 75710, pp. 5-8, 2002.

[52] Y. Ding, B. Herzhaft, and G. Renard, "Near-Wellbore Formation Damage Effects On Well Performance-A Comparison Between Underbalanced And Overbalanced Drilling," in *SPE International Symposium and Exhibition on Formation Damage Control*, 2004.

[53] Y. Ding, D. Longeron, G. Renard, and A. Audibert, "Modeling of both near-wellbore damage and natural cleanup of horizontal wells drilled with water-based drilling fluids," *SPE Journal,* vol. 9, pp. 252-264, 2004.

[54] O. d. Río and A. Neumann, "Axisymmetric drop shape analysis: computational methods for the measurement of interfacial properties from the shape and dimensions of pendant and sessile drops," *Journal of colloid and interface science,* vol. 196, pp. 136-147, 1997.

[55] E. Blakeman, "Application of Bimodal Porosity Concepts to the Development of Log Interpretation Models," in *SPE Annual Technical Conference and Exhibition*, 1989.

[56] L. YOU and Y. Kang, "Integrated evaluation of water phase trapping damage potential in tight gas reservoirs," in *8th European Formation Damage Conference*, 2009.

[57] A. Mirzaei Paiaman, J. Moghadasi, and M. Masihi, "Formation damage through aqueous phase trapping in gas reservoirs," in *SPE Deep Gas Conference and Exhibition*, 2010.

[58] S. Holditch, J. Jennings, S. Neuse, and R. Wyman, "The optimization of well spacing and fracture length in low permeability gas reservoirs," in *SPE Annual Fall Technical Conference and Exhibition*, 1978.

[59] D. Bennion and F. Thomas, "Underbalanced drilling of horizontal wells: Does it really eliminate formation damage?," in *SPE Formation Damage Control Symposium*, 1994.

[60] H. Bahrami, R. Rezaee, A. Saeedi, and G. Murikhan, "Phase trapping damage in use of water-based and oil-based drilling fluids in tight gas reservoirs," in *SPE Asia Pacific Oil and Gas Conference and Exhibition*, 2012.

[61] S. Holditch, "Factors affecting water blocking and gas flow from hydraulically fractured gas wells," *Journal of Petroleum Technology,* vol. 31, pp. 1515-1524, 1979.

[62] A. Ibrahim, Z. Bassiouni, and R. Desbrandes, "Determination of relative permeability curves in tight gas sands using log data," 1992.

[63] D. Bennion, F. Thomas, B. Schulmeister, and U. Romanova, "Water and Oil Base Fluid Retention in Low Permeability Porous Media-an Update," in *Canadian International Petroleum Conference*, 2006.

[64] M. Ibrahim and L. Koederitz, "Two-phase steady-state and unsteady-state relative permeability prediction models," *SPE Middle East Oil Show,* 2001.

[65] V. Joekar-Niasar, S. Hassanizadeh, and A. Leijnse, "Insights into the relationships among capillary pressure, saturation, interfacial area and relative permeability using pore-network modeling," *Transport in Porous Media,* vol. 74, pp. 201-219, 2008.

[66] A. K. Flaaten, "Experimental study of microemulsion characterization and optimization in enhanced oil recovery: a design approach for reservoirs with high salinity and hardness," University of Texas at Austin, 2007.

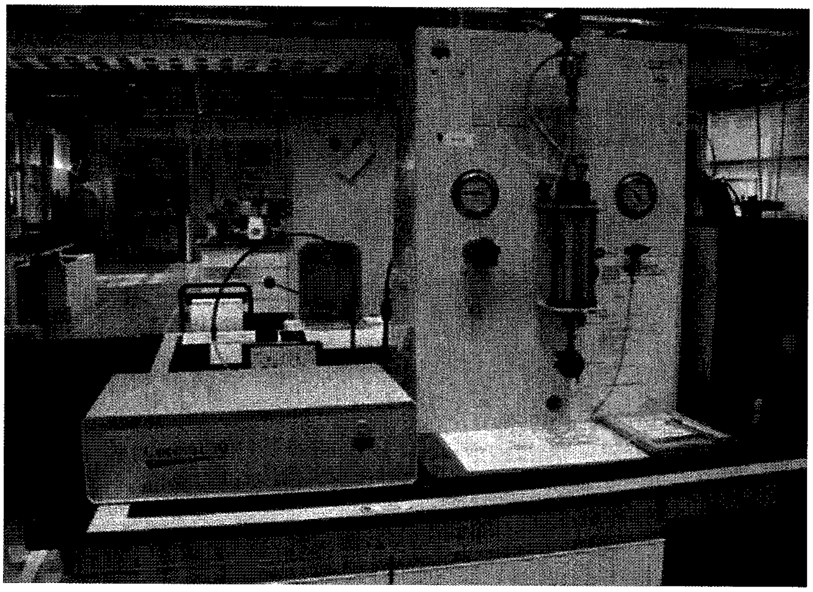
APPENDIX A

Table A1: Composition of Berea sandstone core sample

Ingredients	**Formula**	**Percentage (%)**
Silica	SiO_2	93.13
Alumina	Al_2O_3	3.86
Ferric Oxide	Fe_2O_3	0.11
Ferrous Oxide	FeO	0.54
Magnesium Oxide	MgO	0.25
Calcium Oxide	CaO	0.10

APPENDIX B

EQUIPMENTS



FigureB1: POROPERM

Figure B2: Density Meter

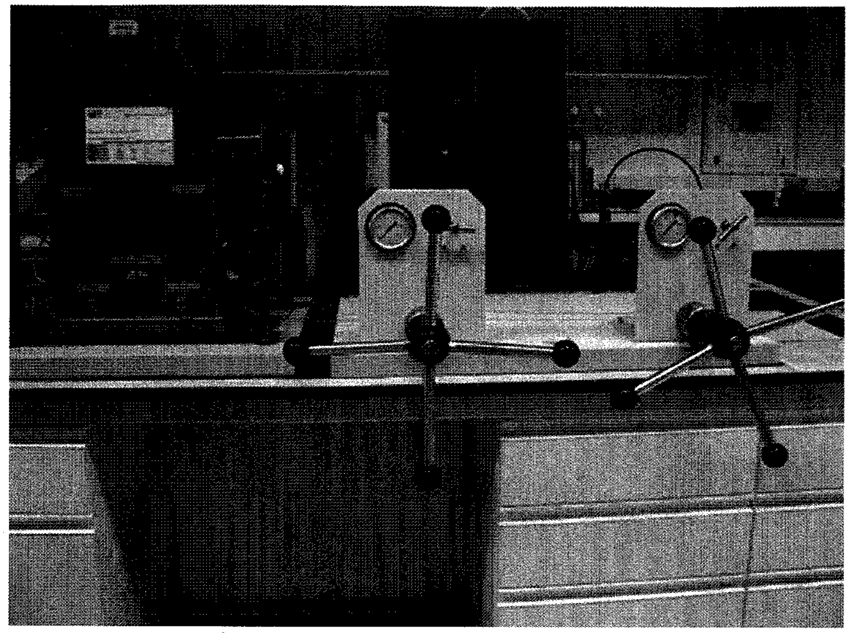


Figure B3: Interfacial Tension Meter

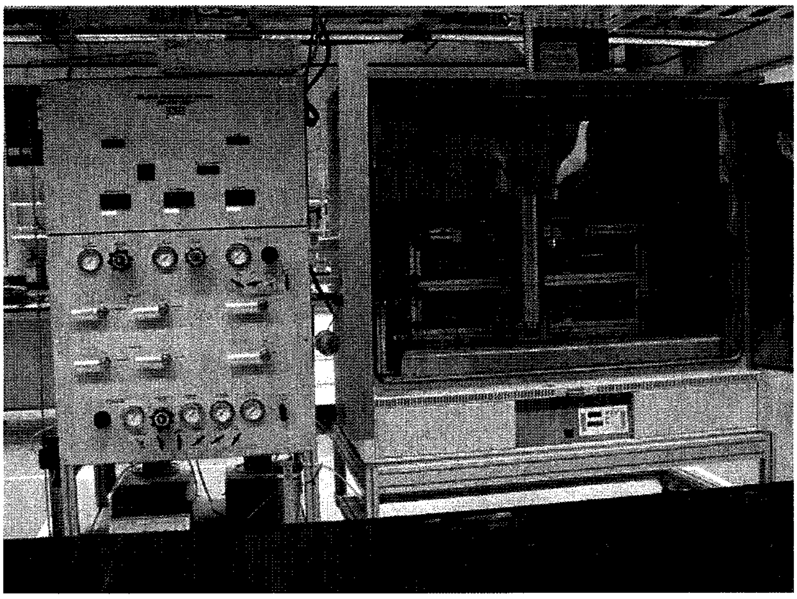


Figure B4: Relative Permeability System RPS

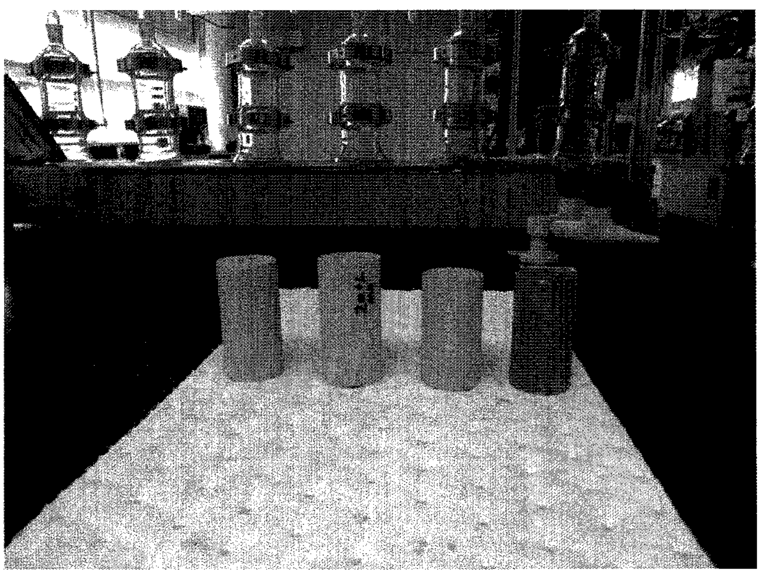


Figure B5: Core Samples

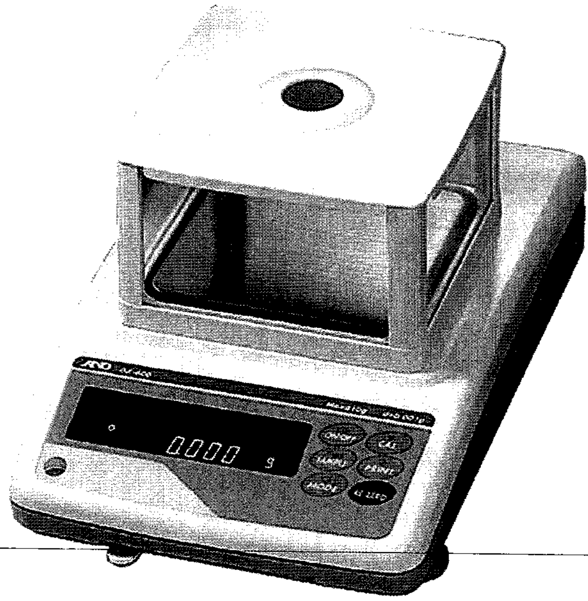


Figure B6: GF-1000 Digital Weight Balance

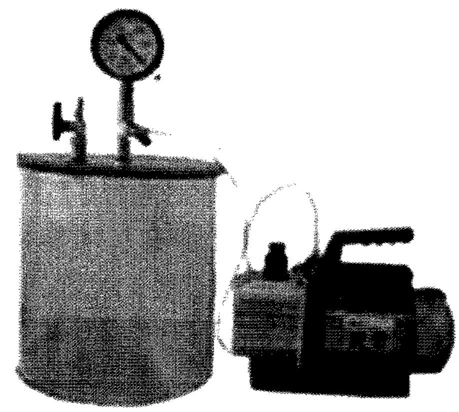


Figure B7: Vacuum Saturator

APPENDIX C

RESULTS

Table B1: Densities

Density of synthetic brine (g /cm^3)	0.9862
Density of Diesel oil (g/cm^3)	0.8198
Density of Bintulu Condensate	0.7257

Table B2: Phase saturations

Irreducible water saturation	S_{rw}	0.41
ResidualDiesel oil saturation	S_{or}	0.293
Residual condensate saturation	S_{cr}	0.263

Table B3: Detail of Core Sample's Characteristics

Sample	Porosity, %	Permeability, md
Sample L1	13.6	18
Sample L2	12.4	15
Sample T1	11.4	0.1

Table B4: Effective Gas Permeability

Sample	L1	L2	T1
End Point Gas K_r at S_{wr}	0.213	0.281	0.368
End Point Gas K_r at S_{or}	0.512	0.423	0.401
End Point Gas K_r at S_{cr}	0.515	0.431	0.421