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Optimization of CO₂ WAG Processes in a Selected Carbonate Reservoir: Laboratory Study

Mohamed Elwy Abdalla Amin

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جامعة الإمارات العربية المتحدة
United Arab Emirates University

UAEU

**Optimization of CO₂ WAG Processes in a Selected Carbonate
Reservoir: Laboratory Study**

By

Mohamed Elwy Abdalla Amin

Department of Chemical and Petroleum Engineering
Faculty of Engineering
United Arab Emirates University

A thesis submitted in partial fulfillment
of the requirements for the degree of
Master of Science in Petroleum Engineering

Master Program of Petroleum Engineering
Department of Chemical and Petroleum Engineering
Faculty of Engineering
United Arab Emirates University

June 2012



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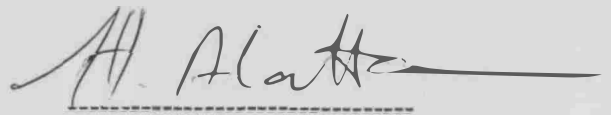
Thesis of **Mohamed Elwy Amin**
Submitted in Partial Fulfillment for the Degree of
Master of Petroleum Science and Engineering

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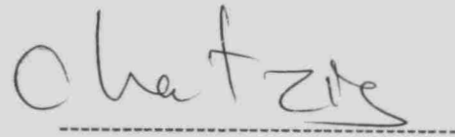
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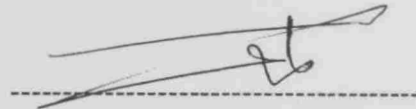
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United Arab Emirates University
2011/2012

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NOMENCLATURE

A = Cross Sectional Area (cm)

E_d = Displacement Efficiency (fraction)

k = Permeability (effective) (md)

L = Length (cm)

M = Mobility Ratio

N_{ca} = Capillary Number.

P_{test} = Test pressure (psi)

ΔP = Pressure Drop (psi)

PV = Pore Volume (cc)

Q = Flow Rate (cc/sec)

S_G = Gas Saturation (%)

S_{GC} = Connate Gas Saturation (%)

S_L = Liquid Saturation (%)

S_{OI} = Initial Oil Saturation (%)

S_{OR} = Residual Oil Saturation (%)

S_{WC} = Connate Water Saturation (%)

T = Temperature ($^{\circ}F$ or $^{\circ}R$)

V = Velocity (ft/D or cm/min)

Abbreviations:

CGI = Continuous Gas Injection

$CCGI$ = Continuous CO_2 Gas Injection

$OOIP$ = Original Oil in Place (bbl)

$ROIP$ = Residual Oil in Place (bbl)

MMP = Minimum Miscibility Pressure (psi)

WAG = Water Alternating Gas

Greek Letters:

σ = Interfacial tension (dynes/cm)

μ = Kinematic Viscosity (cp)

θ = Contact angle (degrees)

Φ = Porosity, (fraction).

ABSTRACT

Miscible gas flooding using carbon dioxide is currently investigated as a possible EOR process for a number of United Arab Emirates (UAE) reservoirs. The major factors affecting the implementation of CO₂ floods are the availability of CO₂ at economic prices and the net utilization ratio of CO₂ per barrel of additional oil recovered. Minimizing net utilization requires controlling the high mobility ratio which causes lower sweep. To control the mobility ratio, the Water-Alternating CO₂-Gas (WAG) technique is proposed.

The objective of this work is to experimentally assess the recovery of oil with CO₂ injection in a selected UAE carbonate reservoir. Two types of CO₂-flooding experiments were conducted, continuous miscible CO₂ injection and CO₂-WAG injection using a specialized experimental rig. The effect of changing the CO₂-Water ratio, water salinity, and initial water saturation on the overall performance of the flood were investigated. All laboratory tests were conducted under controlled conditions of pressure and temperature corresponding to field conditions. Results of this laboratory investigation reveal a general trend of improved oil recovery with increased volume of CO₂ inside core samples during the flooding process. The observed ultimate oil recoveries range from 52 percent with continuous water injection to 72 percent of the original oil in place with continuous CO₂ injection with ultimate oil recoveries of the CO₂-WAG floods falling in between. The optimum CO₂-WAG ratio was found to occur at 1:1.

The outcomes of this work should contribute to our understanding of CO₂-WAG floods for the selected UAE reservoirs and supports the ongoing R&D efforts made by the operating oil companies in the UAE towards application of CO₂-WAG floods

Chapter 1

INTRODUCTION

1.1. Background:

About 377 billion barrels of oil remains trapped in discovered reservoirs after primary and secondary recovery processes. This oil can be our source of energy for years to come. However, as of date, this oil is deemed *unproducible* by current technology. Large research expenditure and efforts are being directed toward enhancing the recovery of this oil but with limited success. Although complete recovery of all the trapped oil is difficult, the target resource base is very large. Of the major contending processes for this trapped resource, gas injection appears to be an ideal choice.

The National Petroleum Council (NPC) defines Improved Oil Recovery (IOR) as "...incremental oil that can be economically produced...over that which can be economically recovered by conventional primary and secondary methods". The main goal of any EOR method is to increase the capillary number thus providing "favorable" mobility ratios ($M < 1.0$).

The capillary number is defined as the ratio of viscous to capillary forces^{1,2}.

$$N_c = \frac{\text{Viscous Forces}}{\text{Capillary Forces}} = \frac{v\mu}{\sigma \cos \theta} \dots\dots\dots (1.1)$$

where v is the superficial velocity, μ is the fluid viscosity, σ is the water-oil-water interfacial tension and θ is the contact angle between the oil-water interface and the rock surface measured between the rock surface and the denser phase (water in this case).

The mobility ratio, M , is defined as the ratio of mobility of the displacing fluid to that of the displaced fluid.

$$M = \frac{(k/\mu)_{Displacing}}{(k/\mu)_{Displaced}} \dots\dots\dots (1.2)$$

where k is the relative or effective permeability.

The overall efficiency of any Enhanced Oil Recovery (EOR) process depends on both the microscopic and macroscopic sweep efficiencies. While the fluids density difference and rock heterogeneity affect the macroscopic efficiency, the microscopic displacement efficiency is influenced by the interfacial interactions involving interfacial tension and dynamic contact angles.

Gas injection is the second largest process in enhanced oil recovery processes today³. The residual oil saturations in gas swept zones have been found to be quite low. However, the volumetric sweep of the flood has always been a cause of concern³. The mobility ratio, which controls the volumetric sweep, between the injected gas and displaced oil bank in gas processes, is typically highly unfavorable due to the relatively low viscosity of the injected phase. This difference makes mobility and consequently flood profile control the biggest concern for the successful application of this process.

The above concern has led to the development of the Water-Alternating-Gas (WAG) process for flood profile control. The higher microscopic displacement efficiency of gas combined with the better macroscopic sweep efficiency of water have been found to significantly increase the incremental oil production over the plain waterflood. The WAG process was first proposed by Caudle and Dyes in 1958 and has remained the industry default mobility control method for gas injection, mainly due to the lack of proven flood profile control alternatives. Reservoir key parameters such as wettability, interfacial tension, connate water saturation and gravity segregation could add complexity to the design of a successful WAG flood.

The current work involves a laboratory investigation to evaluate the performance of CO₂-WAG process, WAG ratio, WAG timing, brine composition and the relative merits and demerits of the miscible CO₂ WAG flooding over continuous CO₂ or conventional water flooding under specific reservoir conditions.

Chapter 2

LITERATURE REVIEW

A comprehensive review of the literature on the WAG process is presented in the following section.

2.1. Mobility control Process:

The overall efficiency of the EOR process depends on both, the microscopic displacement efficiency and the macroscopic volumetric efficiency. The aerial sweep efficiency is controlled mainly by the mobility ratio, together with reservoir heterogeneity, between the fluids in question while the density difference between the fluids determines the vertical sweep efficiency. The low residual oil saturation in the swept zones and the poor volumetric sweep efficiency are the main concerns in the gas floods. Thus, the flood front control has become of prime importance.

Huge research efforts have been made to improve the flood profile control in gas floods^{4,5}. These include development of direct thickeners with gas-soluble chemicals like Telechelic Disulfate, Polyflouroacrylate and Flouroacrylate-Styrene copolymers, which can increase the viscosity of gases several folds (e.g. For CO₂ viscosity increase from 2 – 100 folds). Other methods such as, modifications in the injected slug such as the use of Natural Gas Liquids (NGL) instead of water for highly viscous oils in low pressure, poorly producing and unconsolidated formations were also proposed. Although they seem promising on the laboratory/simulator scale, important issues like feasibility, cost, applicability, safety and environmental impact still need to be addressed⁶.

2.2. WAG Process:

Almost all the commercial miscible gas floods today employ the WAG method¹. The WAG process is shown schematically as Figure 2.1. Gas injection projects contribute about 40% of the total US-EOR production: most of which are WAG floods. Almost 80% of the WAG flood projects in the US were reported an economic success⁷.

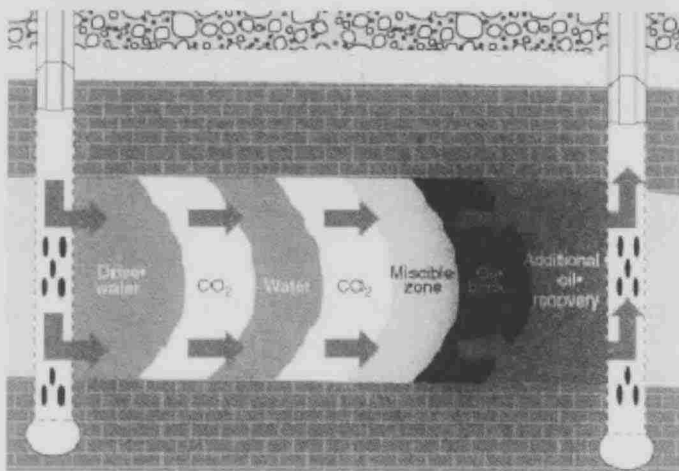


Figure 2.1: Schematic of the Water-Alternating-Gas Process⁸.

The WAG survey conducted by Hadlow⁷ reported an ultimate recovery of about 8–14% OOIP, based on simulation and pilot tests. However, the more recent survey of 2001 and based on 59 projects by Christensen et al.⁹ shows that the average increase in oil recovery was only 5 – 10%. The popularity of the WAG process is evident from the increasing number of projects and many successful field wide applications⁵.

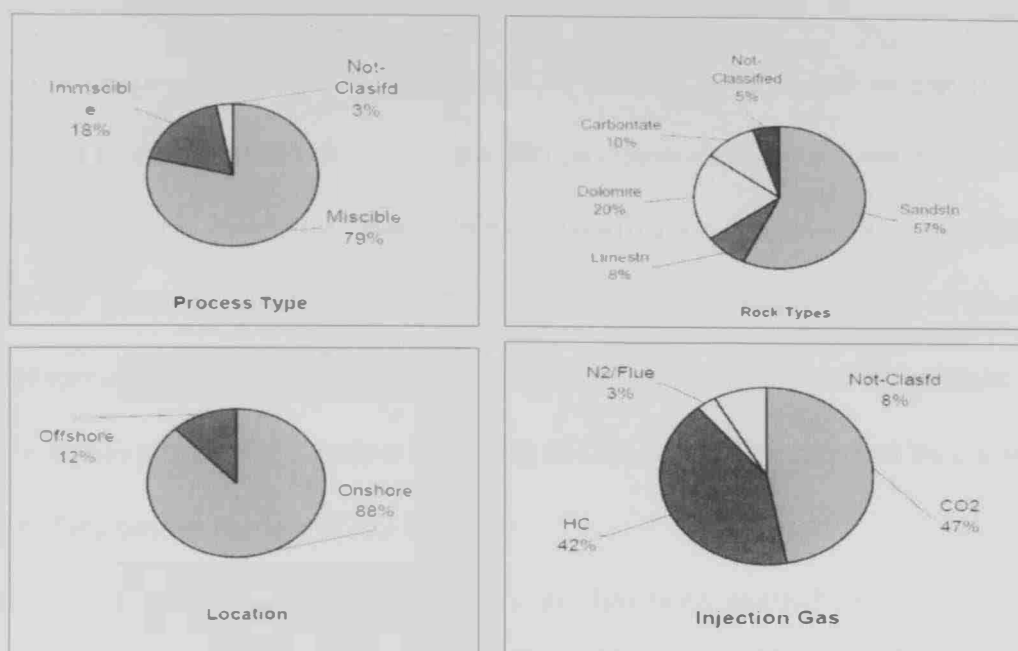


Figure 2.2: WAG survey – Distribution / Application of WAG⁹.

Christensen et. al.⁹ also sheds light on the application scenario and distribution of the WAG process. US had the largest share of WAG applications of 62.7%, followed by Canada at 15.3%. The process was seen mostly applied to onshore reservoirs (88%), Fig. 1.2, but applicable to a wide range of reservoir types, from chalk to fine sandstone. The popularity of the miscible flood was evident from the fact that 79% of the WAG projects employed miscible. The CO₂ floods lead the WAG applications with a share of 47% of total projects, closely followed by hydrocarbon gas at 42%.

2.3. WAG Process Classification

The large-scale reservoir applications need a good classification system for better understanding and design of WAG process. Although Caudle and Dyes¹⁰ suggested simultaneous injection of water and gas to improve mobility control, the field reviews show that they are injected separately⁹. The main reason for this injection pattern is the better injectivity when only one fluid is injected.

Christensen et al.⁹ attempted to systematically classify the WAG process. They grouped the process into four types: miscible, immiscible, hybrid and others based on injection pressures and method of injection. Many reservoir specific processes developed have been patented and are generally grouped under the 'other' WAG classification. Some of the examples are the 'Hybrid-WAG' process patented by UNOCAL¹¹, and the 'DUWAG' process of Shell¹². These patented processes namely; Hybrid-WAG and DUWAG were developed to optimize recoveries from gas injection processes wherein a large slug of CO₂ is injected followed by 1:1 WAG.

2.4. Design Parameters for the WAG Process:

The WAG review showed that this process has been applied to rocks from very low permeability chalk up to high permeability sandstone. Most of the applied processes were miscible. The miscibility issue is generally based on gas availability, but is mainly reported as an economic consideration and the extent of reservoir repressurization required for process application. The major design issues for WAG are reservoir characteristics and heterogeneity, rock and fluid characteristics, composition of injection gas, injection pattern, WAG ratio, three-phase relative permeability effects and flow dispersion. It is important to note that plain gas injection is considered as a part of WAG process with a WAG ratio of 0:1, hence the design issues pertinent to WAG are applicable to plain gas injection as well.

2.4.1. Reservoir Heterogeneity and Stratification:

Stratification and heterogeneities strongly influence the oil recovery process. Reservoirs with higher vertical permeability are influenced by cross flow perpendicular to the bulk flow direction. Viscous, capillary, gravity and dispersive forces generally influence this phenomenon¹³. Cross-flow may influence to increase the vertical sweep, but generally the effects are detrimental to oil recovery – mainly due to the gravity segregation and decreased

flow velocity in the reservoir. This leads to reduced frontal advancement in lower permeability layer. WAG recoveries and continuous gas injections are more strongly affected by these phenomena. Reservoir heterogeneity controls the injection and sweep patterns in the flood. The reservoir simulation studies¹³ for various k_v/k_h (vertical to horizontal permeability) ratios suggest that higher ratios adversely affect oil recovery in WAG process.

2.4.2. Rock and Fluid Characteristics:

Fluid characteristics are generally black-oil or compositional PVT properties obtained in the laboratory by standardized procedures¹³. Very accurate determination of fluid properties can be obtained with current techniques. However, rock-fluid interactions such as adhesion, spreading and wettability affect the displacement in the reservoir. In reservoir simulators, rock-fluid interactions are generally lumped into one parameter – relative permeability. The relative permeability is the connecting link between the phase behavior and transport properties of the system. Relative permeability is an important petrophysical parameter, as well as a critical input parameter in predictive simulation of miscible floods. Relative permeability data are generally measured in the laboratory by standardized procedures with actual reservoir fluids and cores and at reservoir conditions¹³.

2.4.3. Injection Gas Characteristics:

This issue is more related to the location than the applicability of the reservoir. The question of availability is most important as far as the design criteria are concerned. The CO₂ design criteria suggest a minimum depth limitation as well as dictate the specific gravity and viscosity criteria of the oil to be produced from the concerned reservoir. In offshore fields, the availability of hydrocarbon gas directly from production makes hydrocarbon gas injection feasible. Good example of this issue is the Ekofisk field where miscible hydrocarbon WAG was

suggested to be more suitable for Ekofisk, even though CO₂ WAG yielded higher incremental production under laboratory conditions¹⁴. Christensen et al.⁹ suggest that all the offshore fields use hydrocarbon WAG, however the option to use CO₂ is being tested for environmental concerns.

2.4.4. Injection Pattern:

The WAG process review⁹ clearly shows the popularity of the 5-spot injection pattern with close well spacing on shore. In spite of higher costs, the 5-spot injection pattern with closed well spacing is still popular since it gives better control over the process. Inverted 9-spot patterns are also reported in DUWAG and the Hybrid WAG projects of Shell and Unocal respectively.

2.4.5. Tapering:

Tapering is the decrease in gas-to-water ratio as the flood progresses. This is generally done to control the gas mobility and channeling as well as to prevent early breakthrough of the gas. This step is important especially when the injected gas is expensive and needs recycling. Tapering is generally done in most of the CO₂ and hydrocarbon floods and prevailed even in the earliest WAG flood trials^{7,9}.

2.4.6. WAG Ratio:

The optimum WAG ratio is influenced by the wetting state of the rock¹⁵. WAG ratio of 1:1 is the most popular for field applications⁹. However, gravity forces dominate water-wet tertiary floods while viscous fingering controls oil-wet tertiary floods. High WAG ratios have a large effect on oil recovery in water-wet rocks resulting in lower oil recoveries. Tertiary CO₂ floods controlled by viscous fingering had a maximum recovery at WAG ratio of about 1:1. Floods dominated by gravity tonguing showed maximum recovery with the continuous CO₂

slug process. The optimum WAG ratio in secondary floods was a function of the total CO₂ slug size.

For water-wet rocks, 0:1 WAG ratio (continuous gas injection) is suggested for secondary as well as tertiary floods¹⁵. For a partially oil-wet rock, tertiary gas injection with 1:1 WAG ratio is suggested. The recovery depends on the slug size with larger slug size yielding better results cause this gives a better chance to form the miscibility bank. A 0.6 PV slug size gives maximum recovery, but 0.2 – 0.4 PV slug size is dictated by economics¹⁵. Tertiary and secondary CO₂ floods (in both oil-wet and water-wet reservoirs) are viscous (or finger) dominated. In these cases, miscible CO₂ floods would greatly enhance oil recovery since miscibility reduces fingering considerably¹⁵.

2.4.7. Flow Dispersion Effects:

The WAG injection results in a complex saturation pattern as both gas and water saturations increase and decrease alternatively. This results in special demands for the relative permeability description for the three phases (oil, gas and water). There are several correlations for calculating three-phase relative permeability in the literature¹⁶, but these are in many cases not accurate for the WAG injection since the cycle (water / gas) dependant relative permeability modification and application in most models are not considered. Stone II model is the most common three-phase relative permeability model used in commercial reservoir simulators today; however, it is necessary to obtain experimental data for the process planned.

2.4.8. Gravity Considerations in WAG:

Green and Willhite¹⁷ suggest that the same density difference, between injected gas and displaced oil that causes problems of poor sweep efficiencies and gravity override in these types of processes can be used as an advantage in dipping reservoirs. Gravity determines the “gravity

segregation” of the reservoir fluids and hence controls the vertical sweep efficiency of the displacement process. Gravity-stable displacements of oil by plain gas injection or WAG in dipping reservoirs as secondary or tertiary process results in very high oil recovery. This has been confirmed by laboratory tests, pilot tests as well as field applications^{3, 18-25}. Although the purpose of WAG injection is to mitigate the gravity segregation effects and provide a stable injection profile, WAG in downdip reservoirs have shown better profile control and higher recoveries. Hence the gravity considerations in WAG design are indispensable.

2.4.9. Laboratory Studies and Simulation:

Detailed laboratory studies coupled with reservoir simulation are of paramount importance for successful WAG design²⁶. The quality of data input to the simulator is the key to provide quality predictions²⁷. For compositional simulations phase behavior and slim-tube experiments should be performed and used to tune the EOS model. This tuned model helps in accurate characterization of reservoir fluid. Also relative permeability and capillary pressure hysteresis modeling for three-phase flow is a requirement when simulating miscible WAG floods. Although these compositional effects do not affect immiscible floods to the same extent as in miscible floods, a tuned EOS coupled with an accurate three-phase relative permeability model is required for reliable predictions from the simulation. Significant improvements are being made in three-phase relative permeability models²⁸⁻³³. As a result, accuracy of the simulation studies is improving.

2.5. The Need for Miscibility Development:

Most of the gas injection processes could be segregated as miscible or immiscible. Gas injection processes are most effective when the injected gas is nearly or completely miscible with the oil in the reservoir³⁴. The immiscible gas flood increases oil recovery by raising the

capillary number due to the relatively low interfacial tension values between the oil and injected gas. In miscible flooding, the incremental oil recovery is obtained by one of the three mechanisms: oil displacement by solvent through the generation of miscibility (i.e. zero interfacial tension between oil and solvent – hence infinite capillary number), oil swelling and reduction in oil viscosity³⁵.

Miscible flooding has been used with or without WAG for the control of viscous fingering and reduction in gas-oil interfacial tension of the system. Miscibility is achieved by repressurization in order to bring the reservoir pressure above the minimum miscibility pressure (MMP) of the fluids. Christensen et al.⁹ observed that it is difficult to distinguish between miscible and immiscible processes since in many cases, a multicontact gas-oil miscibility may have been obtained. This leads to uncertainty about the actual displacement process. Loss of injectivity and/or failure of pressure maintenance in the actual reservoir, attributable to many factors, cause the process to fluctuate between miscible and immiscible during the life of the process. The authors⁹ also point out that the earlier miscible processes used expensive solvents like propane, which are uneconomical in the present price context. The injectivity problems and pressure loss dictate closer well spacing – hence increased costs – although no severe impairments in the project economics have been reported because of these problems only⁹.

There seems to be no consensus in the literature for the need for development of miscibility in gas floods³⁴⁻³⁶. Rogers and Grigg¹³ suggest that interfacial tension is the most sensitive and the most easily modified parameter in the capillary number, and suggest that considerable decrease in interfacial tension at relatively low cost is the benefit of miscible flooding. However, overlapping values of interfacial tension for immiscible, near-miscible and miscible floods have been reported^{9,37,38}. Although Rogers and Grigg¹³ suggest a way to

improve the capillary number, the issue of viscous forces still needs to be addressed. Viscous forces strongly depend on the reservoir heterogeneities, petrophysical properties and cross-flow in the reservoir, hence are strongly reservoir dependant. Rao³⁷ suggests the use of chemicals to alter wettability in non-water wet reservoirs where miscibility achievement (for reduction in interfacial tension) may not be as important as the water-wet reservoirs where miscibility is useful to maximize pore-level displacement efficiency.

2.6. Effect of Low Salinity Brine on Oil Recovery:

2.6.1. Early Stages of Research:

Tang and Morrow³⁹ observed an increase in water flood and spontaneous imbibition recovery with a decrease in salinity in numerous cases. The authors used Berea cores, CS crude and refined oil and 7 different brines ranging from 35,960 ppm TDS to 151.5 ppm TDS.

Recovery improved significantly in the CS reservoir and Berea cores when low salinity brine was injected instead of high salinity brine, but recovery improved only marginally in the more clay free cores. Berea cores that were fired and acidized, to stabilize fines, were insensitive to brine salinity. Cores that were repeatedly water flooded produced fines and were sensitive to brine salinity in early water floods, but stopped producing fines and were insensitive to brine salinity in late water floods. Cores initially 100% saturated with crude oil - with fines completely immersed in the oil phase -were insensitive to brine salinity. At last, cores saturated with refined mineral oil, rather than crude oil, were insensitive to salinity. Tang and Morrow concluded that heavy polar components in the crude oil adsorb onto fine particles along the pore walls and that these mixed-wet fines are stripped by low salinity brine, altering wettability and increase oil recovery.

Zhang and Morrow⁴⁰ conducted water flooding and spontaneous imbibition experiments using 4 different samples of Berea sandstone and three different crude oils. The authors observed improved recovery by injecting low salinity brine in secondary and tertiary modes. The impact of low salinity brine varied significantly between the different samples of Berea, suggesting that mineralogy was the most important variable affecting oil recovery. The lowest permeability block of Berea ($k_{\text{nitrogen}} \sim 60$ to 140 md) showed no sensitivity to salinity. The lack of response was attributed to the presence of chlorite. In several cases, cores responded to low salinity brine in the secondary but not the tertiary mode. Low salinity effects become more dramatic as the initial water saturation increased. In all cases, injection of low salinity brine was accompanied by an increase of pressure followed by a gradual decrease, effluent pH also increased.

Some publications indicated that there is no benefit of low salinity water flooding, also present in the literature. Sharma and Filoco⁴¹ investigated the impact of connate and injection brine salinity and crude oil on oil recovery, residual saturations and wettability using Berea cores, 3 different oils and NaCl brine in various concentrations. In imbibition experiments decreasing connate brine salinity increased recovery and significantly affected relative permeability. The salinity of the displacing brine had no significant impact. Drainage experiments recovery and relative permeability were insensitive to salinity. During waterflooding of crude oil, oil recovery increased with decreasing connate brine salinity. However, during waterflooding of mineral oil, recovery was insensitive to connate brine salinity. In all cases, waterflood recovery was insensitive to the salinity of the injected brine. Sharma and Filoco suggested that low salinity connate brine changes the wetting properties of the rock surface from water-wet to mixed-wet and thereby increase the recovery.

Webb et al.⁴² observed a reduction in residual oil saturation in the near well bore region by injecting low salinity brine. Three different brines were injected into a clastic formation from a producing well. Saturation was measured after each injection using a pulsed neutron capture log. A base line S_{or} was established with a synthetic native brine (250,000 ppm). Synthetic sea water (120,000 ppm), injected second, did not reduce oil saturation further. A low salinity brine (3,000 ppm), injected last, reduced S_{or} significantly in two sand intervals and slightly in another.

Zhang et al.⁴³ reported increased recovery in the tertiary mode by reducing reservoir brine salinity by 20 times. Two consolidated reservoir sandstone cores samples were used. X-ray diffraction indicated that each of the cores were rich in chert and kaolinite. Two different crude oils and a mineral oil were used. Almost 70% incremental oil recovery was achieved in the secondary mode. Both the high and low salinity secondary floods were conducted through the same core. Tertiary recovery was also quite large; 25% incremental recovery in the best case. The recovery was achieved slowly, taking more than 10 injected pore volumes. In several cases the pH fell upon injection of low salinity brine; contrary to other researchers' observations. Pressure drop was closely tied to incremental recovery. In all cases where significant incremental recovery was achieved pressure drop increased significantly then fell gradually.

Pu et al.⁴⁴ observed low salinity tertiary recovery from an almost clay-free core for the first time. Researchers injected coalbed methane (CBM) water into 3 sandstone reservoir cores composed of quartz, feldspar, dolomite and anhydrite cements but which had very little clay. The CBM water salinity was about 1,316 ppm TDS. Cores were first waterflooded with high salinity formation brine (38,651 ppm). When oil production to high salinity brine ceased CBM water was injected. In all cases CBM water liberated additional oil. In each core the benefit of

tertiary low salinity flooding became less dramatic after each flood and restoration. One core was acidized to remove dolomite crystals and subsequently its recovery became insensitive to low salinity flooding. Pu et al.⁴⁴ proposed that dolomite crystals play an important role in the low salinity recovery mechanism. Some of the dolomite crystals become mixed-wet as they contacted the oil phase during aging. During the low salinity flood the dolomite crystals may detach from the pore walls releasing oil from the rock surface. The detached dolomite crystals will then reside at the crude oil/brine interface increasing resistance to flow of brine at the interface, delay snap-off at pore-throats and preventing the collapse of oil lamella.

2.6.2. Focused Research on Carbonate Rocks:

Bagci et al.⁴⁵ studied the effect of brine composition on oil recovery by water flooding using limestone cores. Ten different brine compositions were examined for injection through the study. The brines were NaCl, CaCl₂, KCl, and binary mixtures of them at two different concentrations (2 and 5 wt%). The highest oil recovery was 35.5% of OOIP for 2 wt% KCl. The authors concluded that any adjustment to the injected brine composition of a mature waterflood can offer a possible and economically feasible approach to increase oil production. Wettability alteration was mentioned as a reason for recovering more oil but without any further explanation. That work mainly showed coreflood experiments using long core samples (20 inches) and at a reservoir temperature of 122 °F. Low salinity effluent brine samples showed higher pH and that was caused by ions exchange reaction.

Høgnesen et al.⁴⁶ concluded that any modification to the injection water ions can impact rock wettability and that can result in additional oil to be recovered. They presented an imbibition study at high temperature condition using reservoir limestone, outcrop chalk cores, seawater and formation water. The results showed that increasing the sulfate ion concentration

at high temperature can act as a wettability modifying agent in carbonates, and increased the oil recovery. Scale and souring problems will be enhanced as increasing the sulfate concentration in the injected water. Moreover, this strategy has limitations with regard to initial brine salinity and temperature. At low temperature condition, cationic surfactant was mixed with the aqueous solution and that increased the spontaneous imbibition through the cores.

Webb et al.⁴⁷ presented a study that compared oil recovery from a North Sea carbonate core samples using sulphate free formation simulated brine, with seawater, which contains sulphate. The imbibition capillary pressure experiments were performed at reservoir conditions using live crude oil and brine. The final results showed that the simulated seawater was able to modify the wettability of the carbonate system, changing the wettability of the rock to a more water-wet state. This conclusion was made based on the saturation change noted in the spontaneous imbibition tests between simulated formation and seawater.

Most of the low salinity water flood studies were conducted on limestone; seawater, also, was recommended as an injection fluid in chalk formations. Strand et al.⁴⁸ explained in preliminary experimental studies the chemical mechanism for the wettability alteration in fractured limestone after injecting seawater, sodium chloride brine, and formation water. Synthetic seawater with and without sulfate ions was used to determine the sulfate ions effect on wettability. Spontaneous imbibitions results at 248°F showed 15% increase in the oil recovery when limestone core was imbibed with seawater compared to seawater free of sulfate ions. Seawater has the lowest TDS compared to the other examined brines, but it did not include any brine test that has lower salinity than seawater. More details on reaction mechanism will be explained in the wettability section.

Fjelde⁴⁹ presented results on low salinity water that increased oil recovery in limestone formation. Spontaneous imbibition experiments were conducted using formation water and low salinity water. Low salinity water showed similar oil recovery results to seawater experiments.

2.7. Problems Associated with the WAG Process:

Although laboratory models show very high sweep efficiencies, the complexity in operations and gravity override make WAG a difficult process in the field to minimize the mobility driven instabilities associated with the gas flood processes. Decrease in sweep efficiency farther from the injection well and gravity segregation of injected gas and water are illustrated in Figure 2.3.

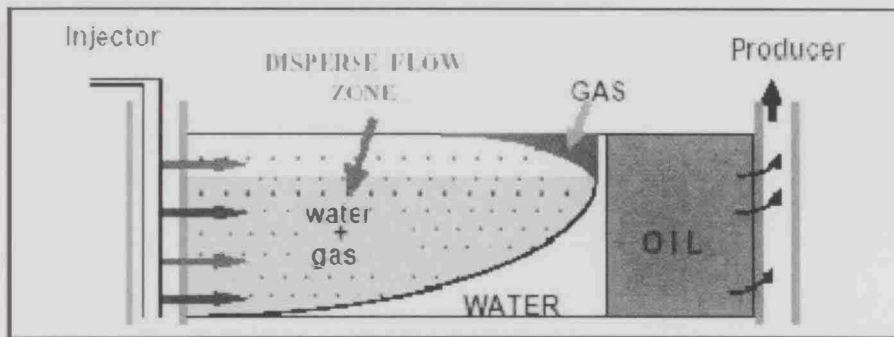


Figure 2.3: Schematic of the Gas-Water Gravity Segregation in Far-Wellbore Region²⁶.

Literature review shows that gas injection is generally applied as a tertiary flood, after a secondary waterflood. High water saturations shield residual oil from injected solvent giving rise to severe water-shielding effect in tertiary gas floods. This effect is more prominent in water-wet reservoirs. Wettability affects the water-shielding effect, which is further discussed in the literature^{15,37}.

Apart from these reservoir problems, there are many reported operational problems for WAG implementation like corrosion, asphaltene and hydrate formation, and early breakthrough. A complete and exhaustive list of operational problems have been described by Christensen et

al.⁹. Good management and operational procedures are required to mitigate these operational problems, and “Negative effects with WAG injection are rarely seen, and most operational problems have been handled successfully⁹”. Nevertheless, these procedures require close monitoring and constant update. The WAG recoveries rarely exceed 5 – 10% and major operational problems are a part of the daily routine for the operators.

The objective of this work is to investigate CO₂-WAG process and to optimize factors that affect its performance such as WAG ratio, WAG timing and brine salinity using carbonate core samples collected from a selected field in UAE.

CHAPTER 3

EXPERIMENTAL APPARATUS AND PROCEDURE

3.1. Tasks Identification:

Coreflood experiments to identify the multiphase flow characteristics of the fluids are central to this work. The corefloods of the project are of the dynamic displacement type. Identification and separation of parameters to effectively study their effects on the process are required. Pure CO₂ gas and two types of Injecting water were used as injectants in the floods. Dead oil sample from the field of interest was used as the 'Oleic' phase and actual brine sample from the same field was used as the aqueous phase.

Initially, base case flooding experiments were conducted using actual carbonate cores, actual formation brine and dead oil. The base case experiments were conducted with continuous water injection and continuous CO₂ gas injection (CCGI) corefloods in miscible flow mode using a vertical core system set up. Similar experiments were conducted using CO₂ WAG flow mode using different WAG ratios and various injection water salinities so as to examine the effects of injection water composition, WAG ratio and WAG timing on the ultimate oil recovery.

3.2. Experimental Fluids:

Analytic grade reagents were used in all the experiments. The salts that were used for synthetic formation brine preparation were with a purity of 99.99%. Actual injection water, Umm Erraduma Brine, was filtered and used in the experiments. To prepare the formation brine and the diluted UER brine, deionized water from the United Arab Emirates laboratories was used. The compositions of the various brines used in the tests are shown in Table 3.1. The

Carbonate core samples used in the experiments were taken from Bu Hassa Field, Abu Dhabi, UAE.

Table 3.1: Compositional Analysis of Different Brines

Brine	mg/L								TDS salinity (ppm)
	Ca ⁺⁺	K	Mg ⁺⁺	Na ⁺	CO ₃	HCO ₃ ⁻	Cl ⁻	SO ₄ ⁻	
Formation Brine	15992	---	1282	51820	---	391	111852	272	163,071
UER	14033	---	3024	57613	---	244	122023	420	197,584
UER 5000 ppm	355	---	77	1458	---	6	3088	11	5000

Table 3.2: Crude Oil Compositional Analysis

Component	Mole%	Component	Mole%
H ₂	0	C ₅	0.01
H ₂ S	0	iC ₅	1.99
CO ₂	2.59	nC ₅	2.66
N ₂	0.12	C ₆	4.78
C ₁	34.16	C ₇	3.82
C ₂	6.72	C ₈	6.11
C ₃	6.36	C ₉	2.58
iC ₄	1.54	C ₁₀₊	22.51
nC ₄	4.05	Total	100

3.3. Experimental Design:

The plan of experiments which was implemented to accomplish the objectives of this study is presented in a block diagram as shown in Fig. 3.1.

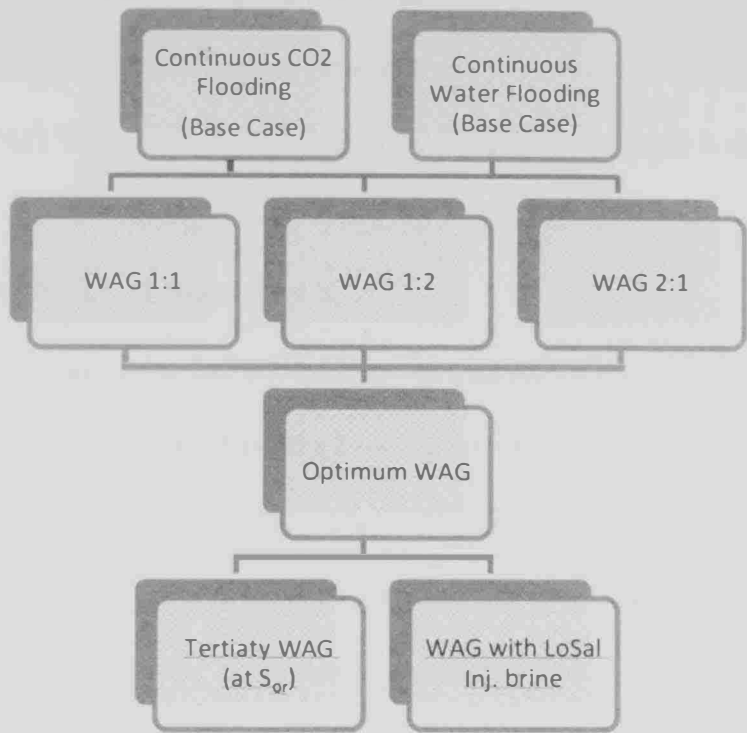


Figure 3.1: Block Diagram Showing the Sequence of Core Flood Experiments

All gas flooding experiments were carried out in a miscible mode flooding, i.e. injection pressure is above the CO₂-oil minimum miscibility pressure (MMP). The MMP was found to be around 2700 psia using widely-used correlations⁵⁰⁻⁵³. Consequently, the injection pressure for all experiments was set at 3000 psia.

Four sets of experiments were conducted in this work and as follows:

Set A: Base Case Flooding: (Carbonate Core sample + dead oil + Formation Brine)

- Vertical mode continuous UER water flooding.
- Vertical mode continuous miscible CO₂ flooding.

Set B: Optimum WAG ratio determination: (Carbonate Core sample + dead oil + Formation Brine)

- Vertical mode secondary WAG 1:1 flooding.
- Vertical mode secondary WAG 1:2 flooding.
- Vertical mode secondary WAG 2:1 flooding.

Set C: Optimum WAG Timing determination: (Carbonate Core sample + dead oil + Formation Brine.

- Vertical mode WAG 1:1 flooding at S_{or} .

Set D: Effect of LoSal water injection on WAG performance.

- Vertical mode secondary WAG using LoSal water injection.

3.4. Experimental Setup:

The high-pressure coreflood apparatus was setup to conduct unsteady-state coreflood experiments. The schematic of the apparatus is shown in Figure 3.2. It consists of a two high-pressure syringe pumps. One for injecting fresh (tap) water at desired flow rate to the bottom part of the floating piston transfer vessel, and the other for injecting supercritical CO_2 into the core. The transfer vessel was filled with the fluid (injection brine) to be injected into the core. High-pressure steel piping (1/8" ID) carries the fluid to be injected into the core with the assistance of a liquid re-distributor plate. The produced fluids were allowed to pass through the backpressure regulator (with a pre-set pressure of 3000 psia) into a measuring cylinder / electronic balance to determine cumulative fluids production as a function of run time / pore volumes injected. The inlet, outlet, differential, back and annulus pressures were measured using pressure regulators (previously calibrated against a standard dead-weight tester) mounted on the coreflood apparatus.

In this work, selected fresh short carbonate core samples were used as the porous medium. The cores have a single coating of Teflon on them to prevent damage during handling and processing of the core such as end facing, polishing and cutting.

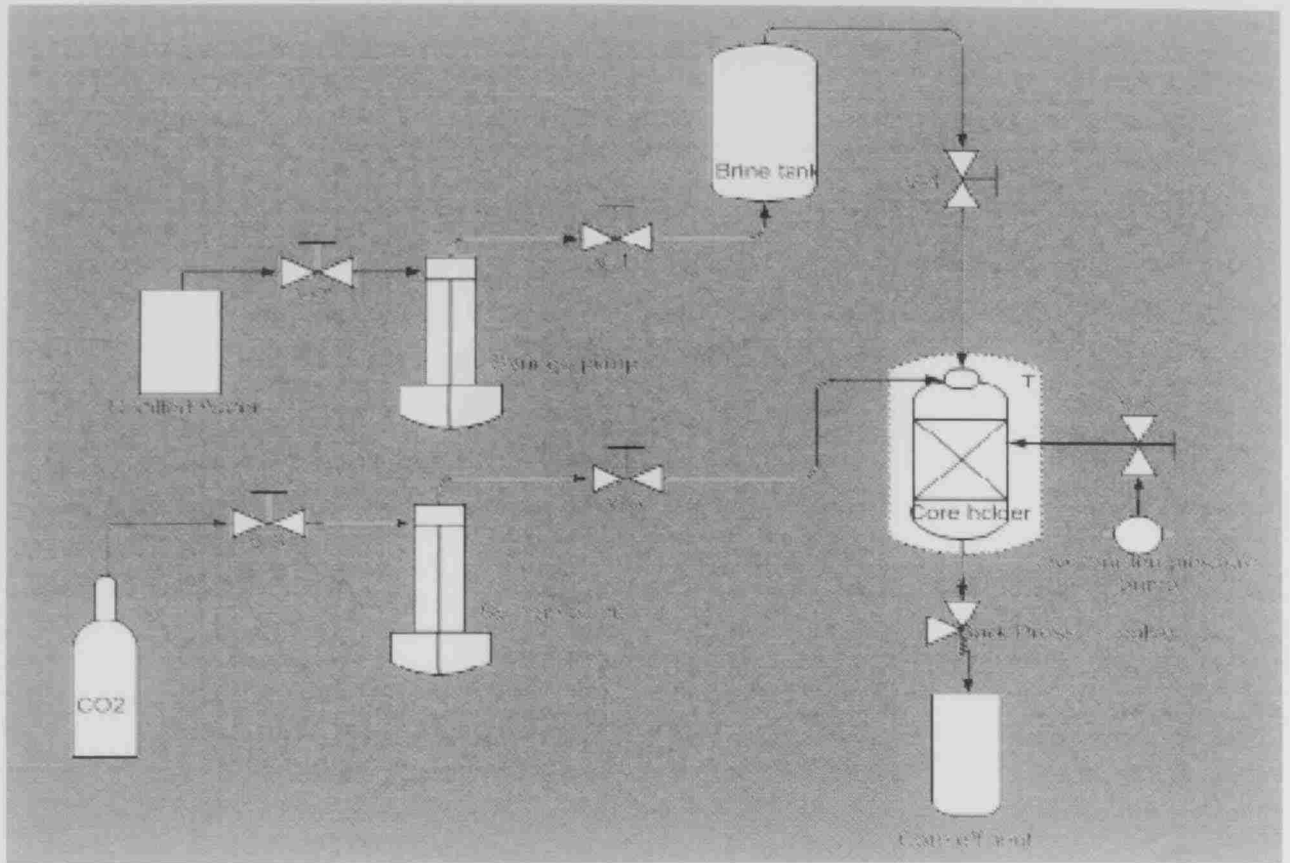


Figure 3.2: Schematic of Core Flooding System

The basic elements of the core-flooding apparatus are labeled in Fig. 3.2. Individual pictures of materials and equipments used are shown in Figures 3.3 through 3.8.



Figure 3.3: Sample of reservoir rock used

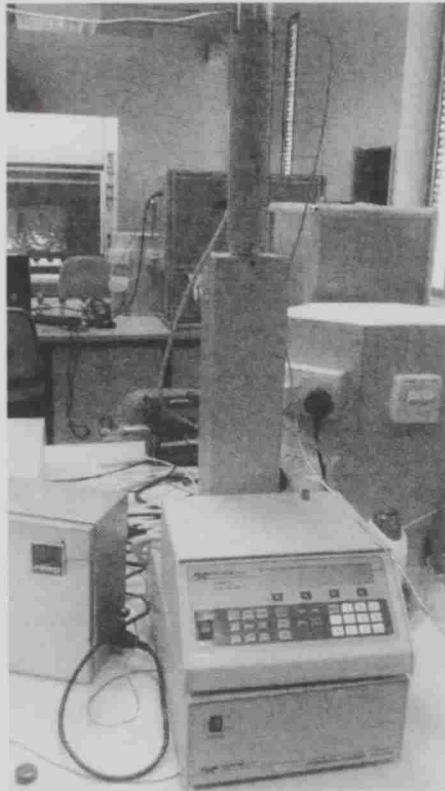


Figure 3.4: Syringe Pump

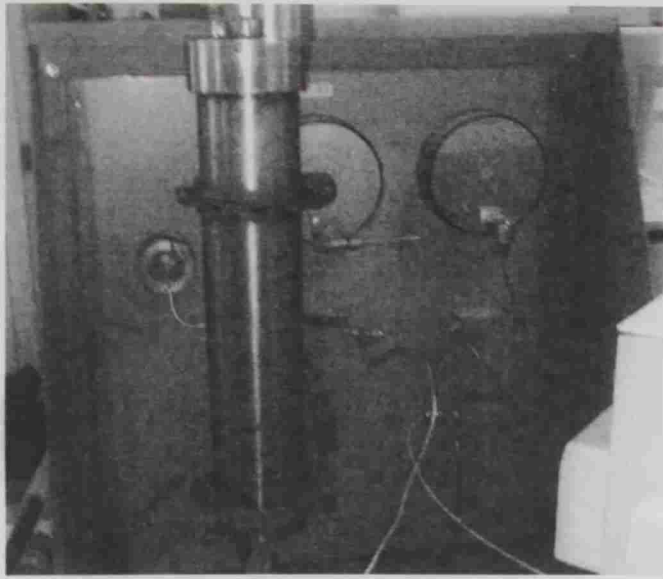


Figure 3.5: Oil/Brine Accumulator

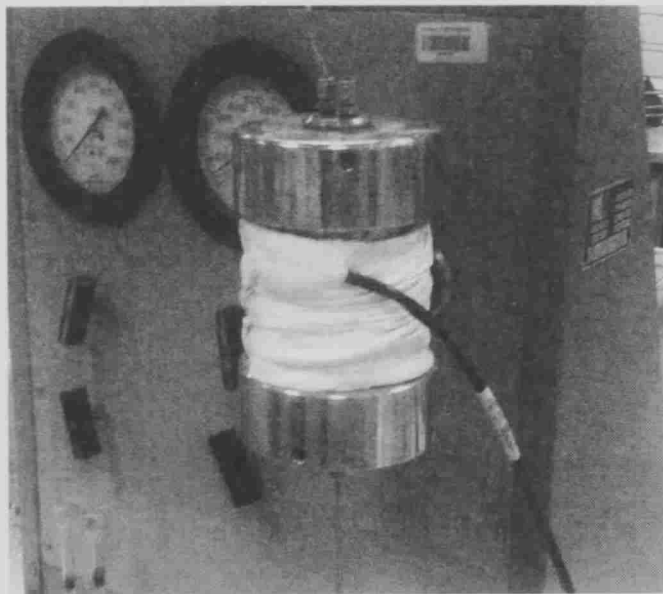


Figure 3.6: Core Holder

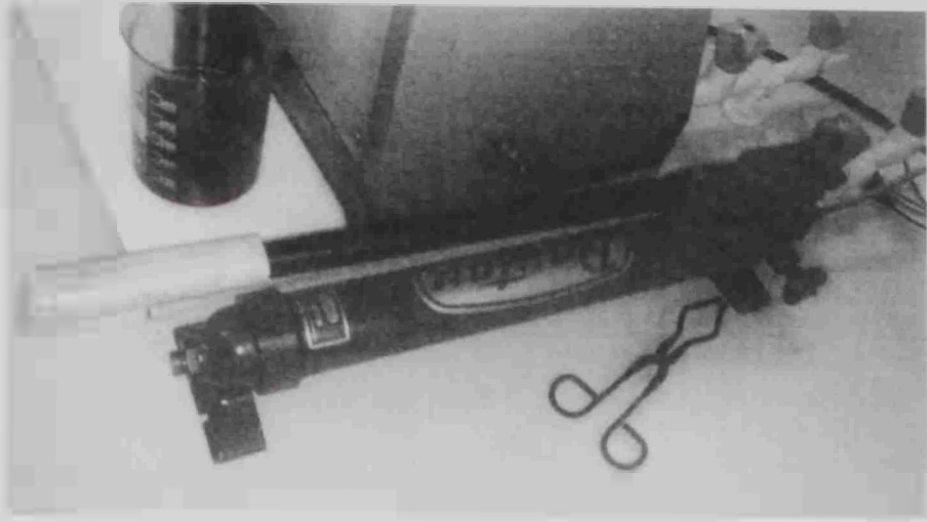


Figure 3.7: Overburden Pressure Pump

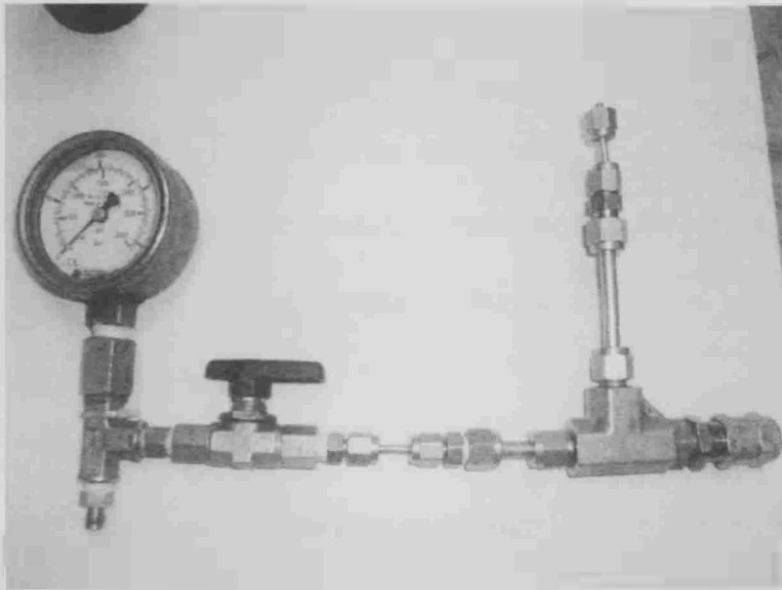


Figure 3.8: Relief Valve

3.5. Experimental Procedure:

Two types of experiments were performed in the present study. These include continuous CO₂ gas injection and WAG. All the experiments consisted of the following steps: Saturation with brine, determination of pore volume and absolute permeability, oil flood to connate water saturation, end point oil-permeability, waterflood to waterflood residual oil saturation, end point water-permeability and tertiary gas flood. The core was filled with brine solution after core cleaning to determine pore volume and absolute permeability. It was brought to connate water saturation by flooding with crude oil at high flow rates (160 cc/hr). The core was then water flooded (60 cc/hr) using the brine of similar composition as the connate water to bring the core to water-flood residual oil saturation, which represents the secondary recovery process. At the of the brine flooding process, significant residual oil remained in the core. WAG injection and continuous CO₂ injection tests were then conducted after the secondary recovery process.

As stated earlier, every flood has its own unique procedure. However, common operations like cleaning and absolute permeability measurement are applicable to all floods. The final tertiary EOR process is experiment dependent. The procedure is as follows.

3.5.1. Core Cleaning Procedure:

Soxhlet Extraction Apparatus, Fig. 3.9, was used to extract oil and salts and clean the core samples. This unit can handle 6 samples at a time. Usually toluene is recommended to extract hydrocarbons, and methanol is recommended to dissolve salts, the standard procedure for cleaning the samples is described below:

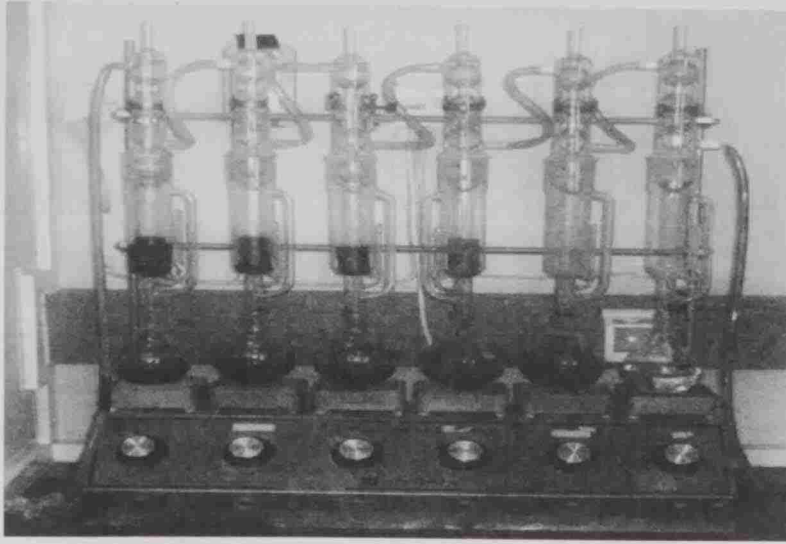


Figure 3.9: Soxhlet Extraction Apparatus.

1. The samples were placed as shown in Fig. 3.9 in the upper part of the Soxhlet.
2. Toluene was added to the lower flasks.
3. Started the water flow through the water condenser.
4. Started the heaters under the flasks.
5. The cores were left in the Soxhlet for three days under observation.
6. After the three days, cores were removed from the Soxhlet and placed in open air for two hour at least to dry up.
7. The cores were then exposed to ultraviolet light source. If it fluorescent light were observed that would indicate residual organic materials to be present then step 1 to 6 had to be repeated. If not, the cores were proved to be free from organic matter.
8. Methanol was used instead of toluene and steps 1-6 were repeated.
9. After three days, cores were removed from the Soxhlet and placed in open air for at least two hour to dry.

10. A drop of AgNO_3 was placed on the core. If a white precipitate was formed, then there were salts in the core and step 8 and 9 were repeated. If not, cleaning was successfully carried out.
11. Samples were placed in open air for two hour at least to dry up. Then placed in oven for eight hours.

3.5.2. Absolute Permeability Measurement:

The core was fully saturated with brine at the start of this step. The absolute permeability of the core was then measured, which also serves as a means to check the efficiency of the cleaning procedure. The standard procedure involves the following steps.

- Flood the core using field/synthetic brine (about 1 – 2 hrs for each flow rate) after the cleaning process is over. This step is required despite the fact the core was just flushed at the end of cleaning process with brine. This flood is performed at lower flow rates to establish pressure equilibrium and removal of any entrapped air.
- Brine flooding is continued until a stable pressure drop is obtained.
- The brine production and pressure drop are measured and tabulated.
- The procedure is repeated for three different flow rates till consistent pressure drops and permeability are obtained.
- The measured stable pressure drops and the corresponding flow rates are used to calculate absolute permeability of the core using Darcy's law,

$$k = \frac{14600 * Q * \mu * L}{A * \Delta P} \dots\dots\dots (3.1)$$

where. Q is flow rate in cc/sec; μ is the viscosity of injected fluid in cp; L is the length in cm; A is the cross-sectional area in cm^2 . and ΔP is pressure drop in psi.

3.5.3. Oil Flood To Determine Connate Water Saturation:

The oleic phase (Bu-Hassa Crude Oil) was first transferred to the oil transfer vessel and pumped into the core using the Syringe pump. The oil must always be filtered before pumping it into the core.

- The core was flooded using crude oil for 2 PV.
- The cumulative volumes of brine and oil produced and pressure drop were measured and recorded as a function of time.
- The oil flood was conducted at low flow rates to prevent oil fingering.
- After 2.0 PV of oil injection or till no more water was produced, whichever comes later, the flow rate was lowered and the system was allowed to stabilize before measuring the stabilized pressure drops.
- The connate water saturation (S_{WC}) was then determined through material balance.

3.5.4. Secondary Brine Flood To Determine Residual Oil Saturation:

Now the cores are at connate water and initial oil saturation. And before flooding with brine water, they were aged for two weeks to restore their original wettability and for refinement of the oil – water distributions at the pore level. The flooding procedures are as follows:

- The core was flooded using field Um-Erraduma brine (about 2 PV) after the oil flood.
- The volumes of brine and oil produced were recorded as a function of time and pressure drop was maintained constant.
- The flood was conducted at low flood rate to assure no fingering to occur.
- After about 2.0 PV injection, the flow rate was lowered and the system was allowed to stabilize before measuring the stable pressure drops.

- The measured stable pressure drop(s) and the corresponding flow rate(s) were used to calculate end-point water permeability of the core using Darcy's law.
- The material balance was used to calculate the S_{or} .

3.5.5. Secondary Carbon Dioxide Flood:

Now the cores are at connate water and initial oil saturation and before flooding with CO_2 , they were aged for two weeks to restore their original wettability and for refinement of the oil – water distributions at the pore level. The flooding procedures are as follows:

The secondary gas injection was carried out in two modes: continuous CO_2 injection and Water-Alternating-Gas (WAG) injection using the following procedure.

3.5.5.1. Continuous CO_2 Injection

- The core was flooded with CO_2 gas after the brine flood.
- The flooding was usually carried out at very low flow rates (0.5 cc/min.) to ensure stability of the floods and to satisfy the Leas and Rappaport criterion⁵⁴. This represents the slowest step in the overall experimental procedure and it needs careful planning and monitoring.
- The brine and oil volumes produced were measured using the separator readout and tabulated as a function of time (PV injected).
- Material balance was then applied to calculate the S_{or} .

3.5.5.2. CO_2 Water-Alternating-Gas Injection:

- The core was flooded with CO_2 and water alternately after the brine flood.
- The flood was usually carried out at relatively low flow rates (0.5 cc/min) to ensure stable floods and to satisfy the Leas and Rappaport criterion⁵⁴. Again, This represents the

slowest step in the overall experimental procedure and it needs careful planning and monitoring.

- The slug size used was 20% of the pore volume (PV). Gas and water were injected alternately in 20% PV slugs.
- It was important to have similar pressures in both the brine and gas cylinders to prevent instabilities and early breakthrough during the flood. For this brine and CO₂ transfer vessels were connected to the pump and allowed to equilibrate for at least 24 hours.
- After equilibration of pressure in both brine and gas cylinders, 20% PV slug of gas was injected into the core. An equal volume slug of brine was then injected.
- This procedure was repeated for 2 cycles.
- The produced brine and oil volumes were measured using the separator readout and tabulated as a function of time (PV Injected)
- Material balance was then applied to calculate the S_{or} .

3.5.6. Tertiary Carbon Dioxide Flood:

The tertiary gas injection was carried out in one mode, Water-Alternating-Gas (WAG) injection, using the following procedure.

3.5.6.1. Water-Alternating-Gas Injection:

- The core was flooded with CO₂ and water alternately after the brine flood.
- The flood was usually carried out at relatively low flow rates (0.5 cc/min) to ensure stable floods and to satisfy the Leas and Rappaport criterion⁵⁴. Again, This represents the slowest step in the overall experimental procedure and it needs careful planning and monitoring.

- The slug size used was 20% of the pore volume (PV). Gas and water were injected alternately in 20% PV slugs.
- It was important to have similar pressures in both the brine and gas cylinders to prevent instabilities and early breakthrough during the flood. For this brine and CO₂ transfer vessels were connected to the pump and allowed to equilibrate for at least 24 hours.
- After equilibration of pressure in both brine and gas cylinders, 20% PV slug of gas was injected into the core. An equal volume slug of brine was then injected.
- This procedure was repeated for 2 cycles.
- The brine and oil volumes produced were measured using the separator readout and tabulated as a function of time (PV Injected)
- Material balance was then applied to calculate the S_{or} .

CHAPTER 4

RESULTS AND DISCUSSION

The core flooding tests were conducted in three steps. The preliminary oil flood was used to measure the connate water saturation of the core. Brine was injected into the core to determine the secondary recovery and residual oil saturation after waterflooding. Secondary (or tertiary) miscible gas injection (Continuous CO₂ Gas Injection, CCGI, or WAG injection) was used to evaluate the efficiency of this process. The results of the core tests conducted in this work are discussed below.

The objective of the tests was to determine the effects of mode of gas injection (CCGI or WAG), WAG ratio, WAG Timing and brine composition on dynamic displacement tests in selected carbonate cores from UAE.

These tests were conducted at 3000 psi (miscibility pressure). Two types of the ongoing field injection brines (Umm-Erraduma and Umm-Erraduma diluted to 5000 ppm) were used for flooding and CO₂ floods were conducted in two modes (Continuous CO₂ Gas Injection (CCGI) and WAG). WAG experiments were carried out at different ratios and timings (see Fig. 3.1).

The carbonate cores used for the test were aged for 14 days, to restore their original wettability. In order to eliminate the effects of rock heterogeneity, all tests were conducted on cores from the same reservoir unit, having similar properties in terms of porosity, permeability and pore size distribution. Also, actual oil sample from the field of interest as the oleic phase was used as in all experiments and standard cleaning procedure was implemented between various displacements.

4.1. Results of Oil Flooding Tests:

This group of tests involves injection of crude oil into core samples that were initially saturated with brine to achieve connate water saturation. This process was an important step to determine the original oil in place (OOIP). A summary of the results of these experiments are summarized in Table 4.1:

Table 4.1: Summary of Results of Oil Flooding Tests

Expt. No.	Experiment Title	Brine Salinity, ppm	P_{Test} , psia	K_{abs} , md	Φ	PV, cc	S_{WC} , fraction	S_{OI} , fraction
1	Continuous Brine	197,584	3000	13.7	0.24	17.7	0.4	0.6
2	Continuous Miscible CO ₂	197,584	3000	15.5	0.21	17.94	0.5	0.5
3	Miscible WAG 1:1	197,584	3000	13.1	0.24	19.66	0.33	0.67
4	Miscible WAG 1:2	197,584	3000	16.6	0.24	18.86	0.33	0.67
5	Miscible WAG 2:1	197,584	3000	14.6	0.26	19.93	0.38	0.62
6	Tertiary Miscible WAG 1:1	197,584	3000	13.7	0.24	17.7	0.4	0.6
7	Miscible WAG1:1	5000	3000	14.7	0.23	18.51	0.39	0.61

4.2. Results of Brine Flooding Tests:

This group of experiments involves brine injection into the core samples, which were at connate water saturation to achieve after waterflooding residual oil saturations. Brine was injected at stable flow rates into the core after the oil flooding. This step could assess the feasibility of secondary oil recovery scheme. The results of the brine flooding phase of experiments are summarized in Table 4.2 and Fig. 4.1:

Table 4.2: Summary of Results of Brine Flooding Tests:

Expt. No.	Experiment Title	Brine Salinity, ppm	P_{Test} , psia	K_{abs} , md	Φ	S_{OR} , fraction	Recovery % OOIP	E_d , fraction
1	Continuous Brine	197,584	3000	13.7	0.24	0.29	51.9	0.52

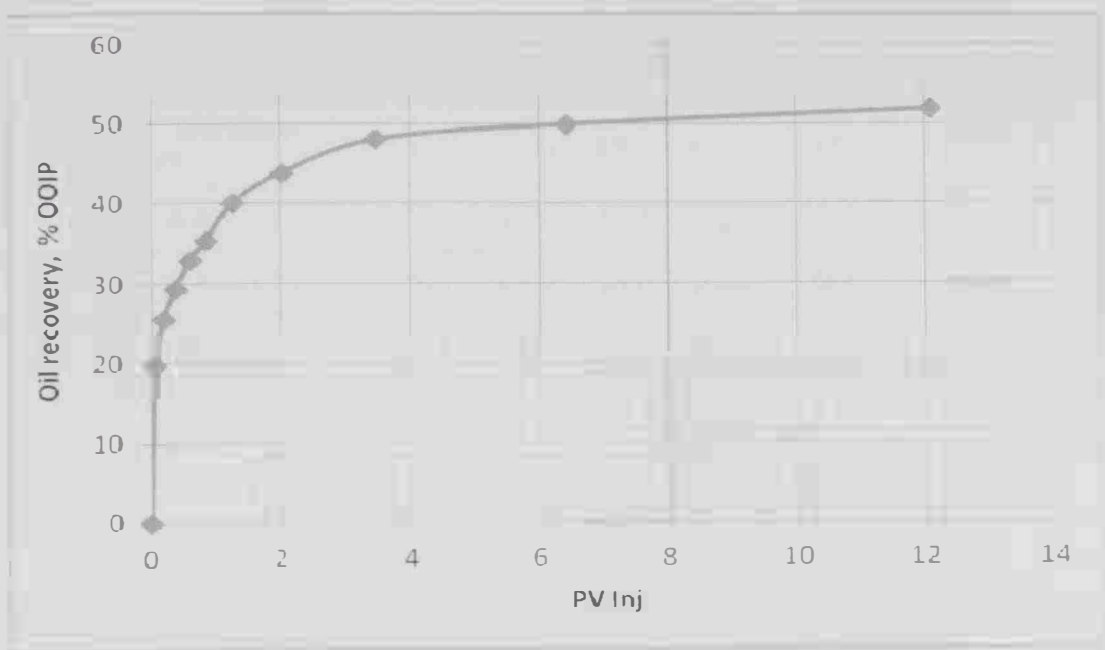


Figure 4.1: Experimental Results of Continuous Water Flooding

Figure 4.1 shows that oil recovery was about 52 % of OOIP after flooding the core sample with about 12 PV of UER brine.

4.3. Results of Gas Injection Floods:

This set consists of two types of experiments: Continuous CO₂ Gas Injection (CCGI) and Water-Alternating-Gas (WAG). Gas injection is a popular EOR process in light oil reservoirs. As the literature review suggests, almost 80% of the gas injection processes employ the WAG method. The continuous CO₂ injection process and 1:1 WAG (with 0.2 PV slug size) are

considered as the most popular gas injection EOR processes employed in the field today. Hence, investigation of the displacement characteristics for these processes was conducted. The results of the gas flooding phase of experiments are summarized in Table 4.3 and Figures 4.2 through 4.7:

Table 4.3: Summary of Results of Gas Injection Tests

Expt. No.	Experiment Title	Brine Salinity, ppm	P_{Test} , psia	K_{abs} , md	Φ	S_{OR} , fraction	Recovery % OOIP	E_d , fraction
2	Miscible Continuous CO ₂	197,584	3000	15.5	0.21	0.13	73.44	0.73
3	Miscible WAG 1:1	197,584	3000	13.1	0.24	0.2	69.85	0.7
4	Miscible WAG 1:2	197,584	3000	16.6	0.24	0.2	69.84	0.7
5	Miscible WAG 2:1	197,584	3000	14.6	0.26	0.27	56.1	0.56
6	Tertiary Miscible WAG 1:1	197,584	3000	13.7	0.24	0.25	58.87	0.59
7	Miscible WAG1:1	5000	3000	14.7	0.23	0.16	72.77	0.73

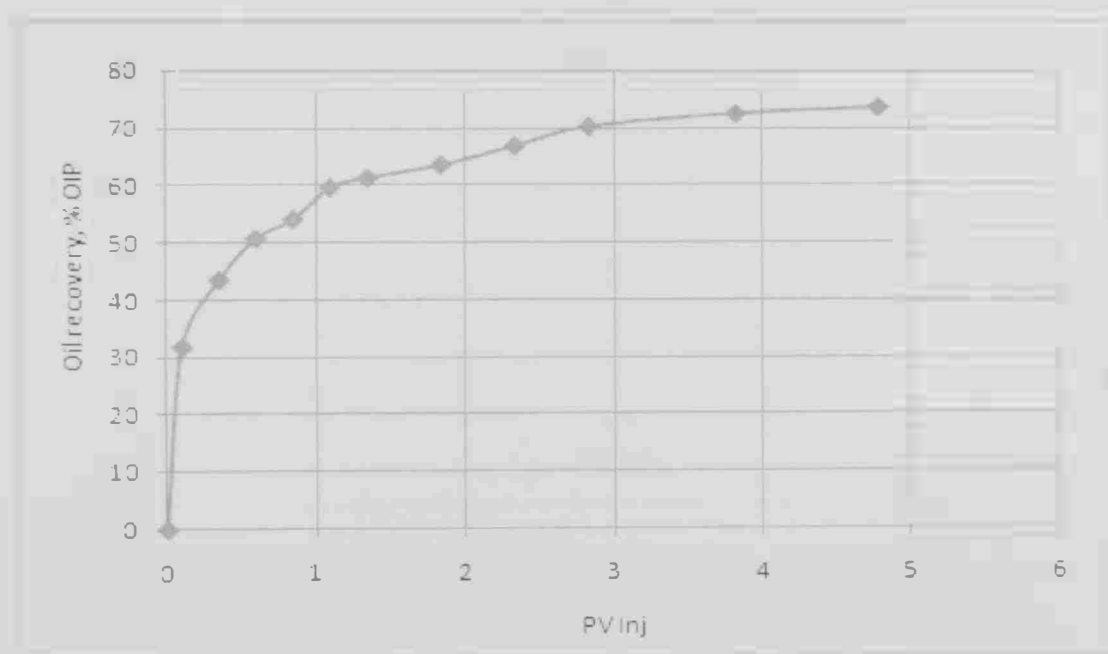


Figure 4.2: Experimental Results of Continuous CO₂ Injection

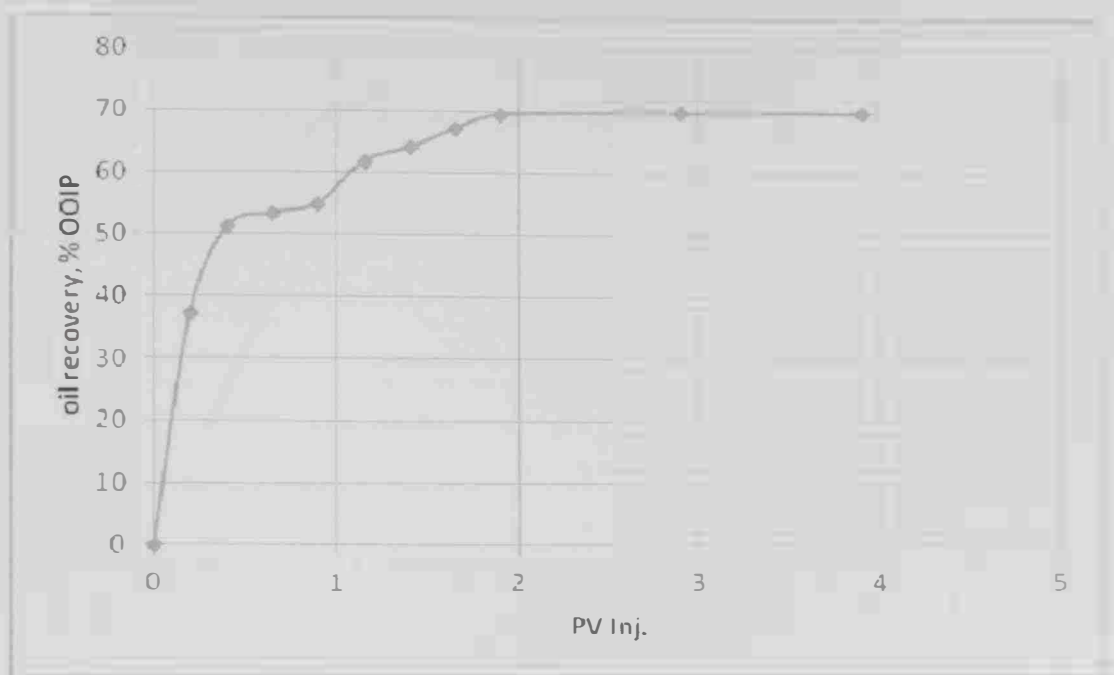


Figure 4.3: Experimental Results of WAG Ratio 1:1 in Secondary Recovery Scheme

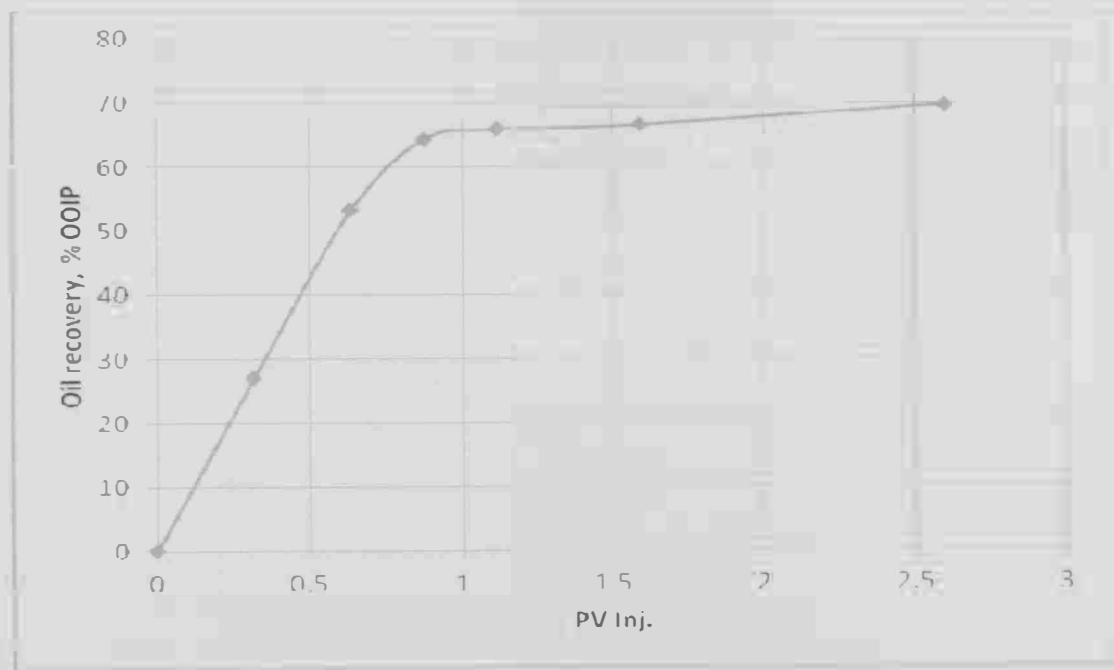


Figure 4.4: Experimental Results of WAG Ratio 1:2 in Secondary Recovery Scheme

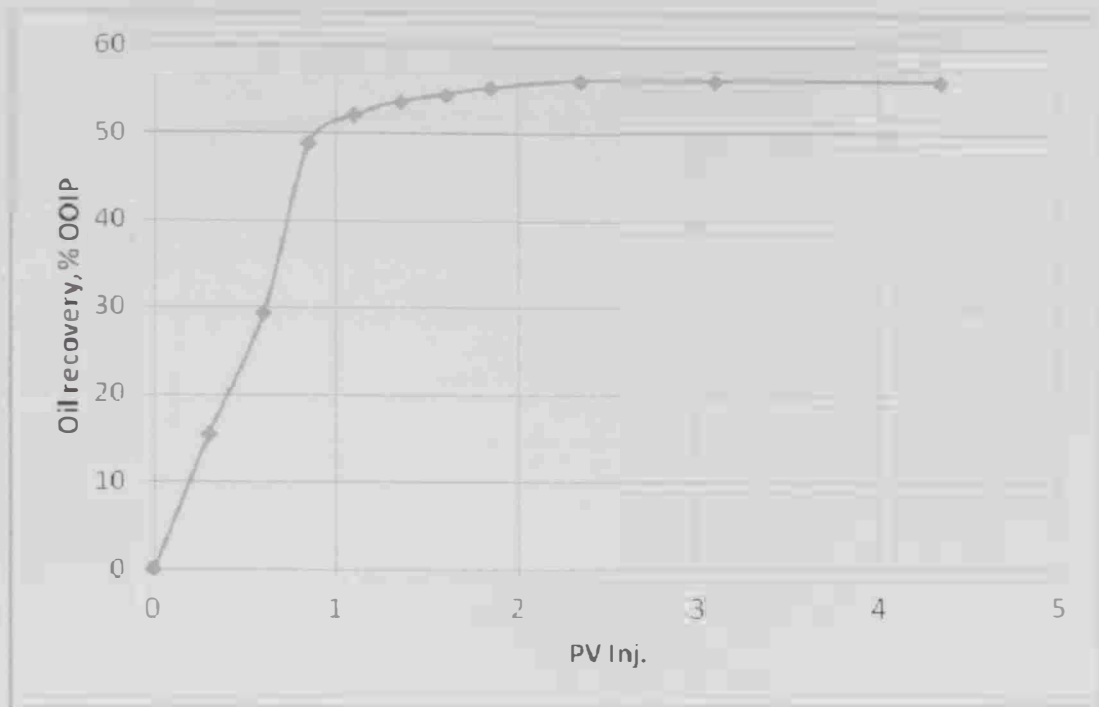


Figure 4.5: Experimental Results of WAG Ratio 2:1 in Secondary Recovery Scheme

CCGI showed high oil recovery 73.5 % OOIP with CO₂-WAG ratios 1:1 and 1:2 showed close results in terms of ultimate oil recovery 70% for both CO₂-WAG ratios.

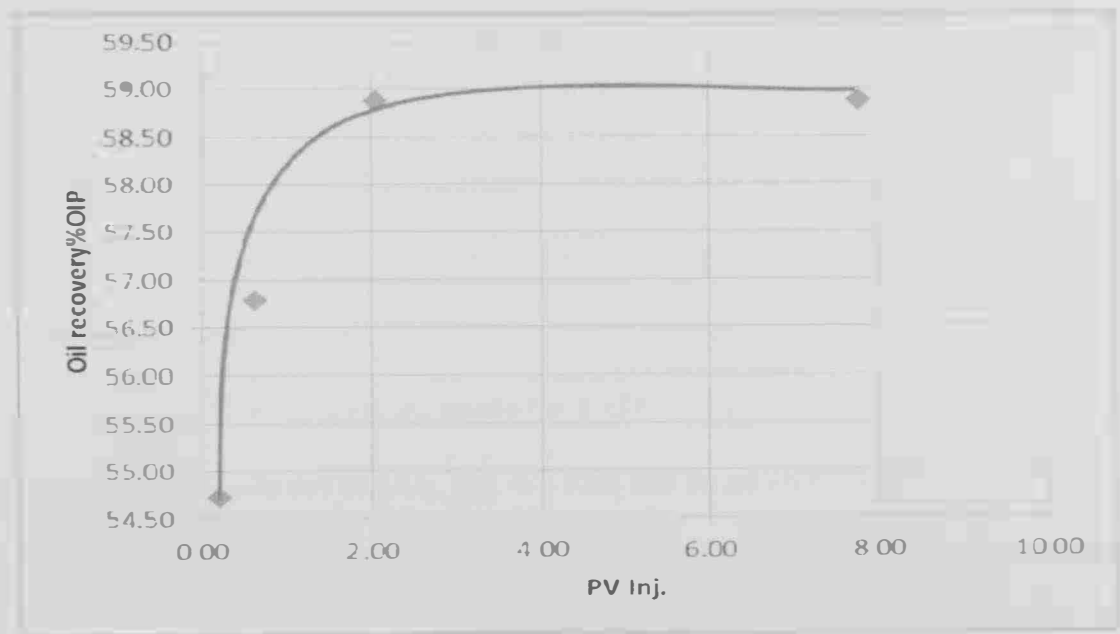


Figure 4.6: Experimental Results of WAG Ratio 1:1 in Tertiary Recovery Scheme

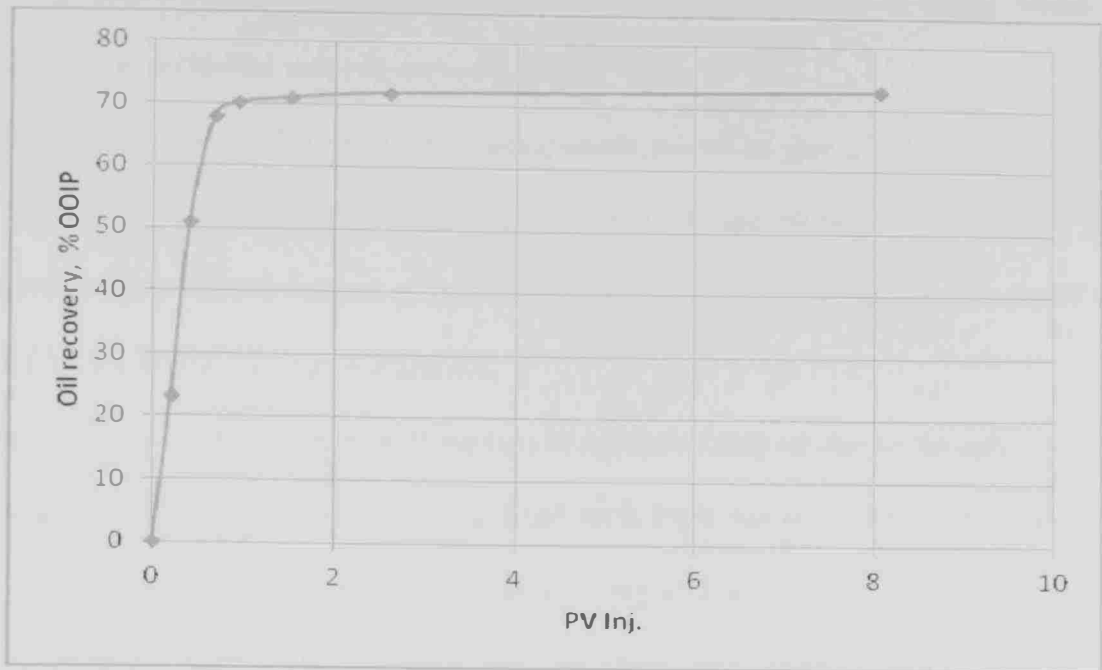


Figure 4.7: Experimental Results of WAG 1:1 in Secondary Recovery Scheme Using Diluted UER Brine (5000 ppm)

While Tertiary stage recovery yielded around 59 % OOIP, Using UER 5000 ppm in secondary mode CO₂ WAG produced about 72.5 % OOIP.

4.4. Discussion of Results:

4.4.1. Effect of WAG Ratio on Oil Recovery:

For comparison purposes, the results of the various sets of experiments are combined in Fig. 4.8. It can be noticed that:

Continuous miscible CO₂ flooding shows the highest oil recovery of 73.44 % OOIP after injection of about 5 pore volumes of CO₂, Fig. 4.2 This can be attributed to miscibility between oil and CO₂ which would eliminate the interfacial tension between oil and CO₂ significantly and, hence, increasing the capillary number which affects the oil recovery positively. This observation agrees with published work on sandstone, chalk, and limestone⁵⁵⁻⁵⁷. Continuous

brine flooding shows about 52% OOIP after injecting 12 pore volumes of water which is comparable to some published work on carbonate cores⁵⁸.

WAG ratios 1:1 and 1:2 seem to give comparable results to that of CCGI (Continuous CO₂ Gas Injection) in terms of ultimate oil recovery, 69.85 % and 69.84 %, respectively. The latter, however, requires lower volume of injected fluid than the former, around 4 PVs for WAG 1:1 and 2.5 PVs for WAG 1:2, Figs 4.3 and 4.4.

These lower volumes of fluid needed in these two WAG ratios may be due to the enhancement of mobilization efficiency by introducing a fluid with high viscosity (brine) which could reduce the mobility ratio and improve the volumetric sweep efficiency.

WAG ratio 2:1 shows better results than the continuous water flooding, 56.1 % oil recovery after 4.5 PVs of brine injected. This improvement in oil recovery may be attributed partially to miscibility between oil and CO₂ and partially to improved mobility ratio. Yet, This WAG ratio doesn't seem to be as effective as WAG 1:1 and WAG 1:2.

Looking at it from economic point of view and based on the aforementioned discussions, the WAG ratio 1:1 seems to be the best option compared to all of the other methods as it requires the least amount of compressed CO₂.

Recovery efficiency for any EOR process is function of displacement efficiency, mobilization efficiency and capture efficiency. In terms of displacement efficiency, $[(S_{oi}-S_{or}) / S_{oi}]$, Fig. 4.9, shows that CGI yields the highest value, 0.73, followed by WAG ratios 1:1 and 1:2 at 0.7, which is indicative that WAG 1:1 may be considered as an acceptable alternative for CCGI and the optimum CO₂ flooding system for the selected field. On the other hand, WAG 2:1 and Continuous brine injection came in last in this comparison.

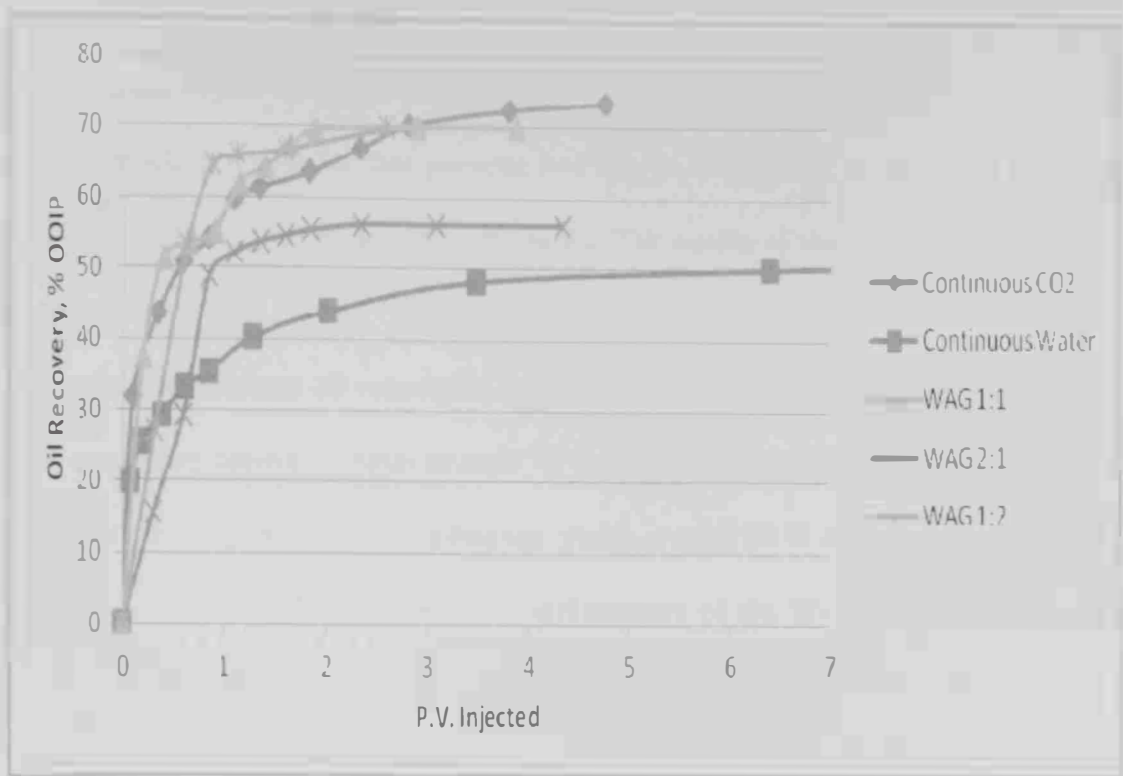


Figure 4.8: Comparison of Experimental Results: Selection of Optimum WAG Ratio

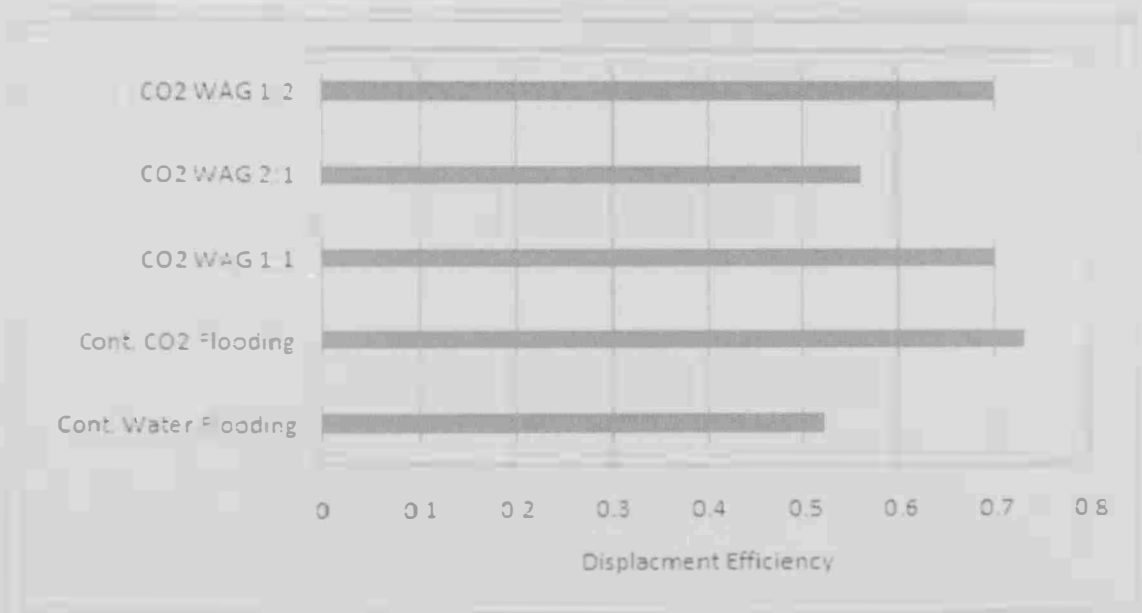


Figure 4.9: Displacement Efficiencies by Various Flooding Methods

4.4.2. Effect of WAG Timing on Oil Recovery:

The optimum WAG ratio 1:1 for this selected oil field was used to optimize the time to commence the WAG process. For this purpose two stages of recovery were examined, namely, secondary recovery at S_{oi} and tertiary recovery at S_{or} . The results of these runs are shown in Fig. 4.3, Fig. 4.6 and Fig. 4.10.

Comparing the ultimate oil recoveries by secondary and tertiary stages of production, it is noticed that secondary recovery yields around 70 % oil recovery with 4 pore volumes of fluids injected. The tertiary stage of recovery, however, yields around 59 % oil recovery after injection of about 8 pore volumes of fluids. The better performance of the WAG in secondary mode of production may be attributed to presence of a larger volume of oil in the pores of the sample and thus a better chance of forming a more stable Oil-CO₂ miscibility bank and thus a better mobilization efficiency.

The Effect of project timing is clearly shown in Fig. 4.11 in terms of displacement efficiency which shows that secondary mode has a value of $E_d = 0.7$ while the $E_d = 0.59$ in the case of tertiary stage of production.

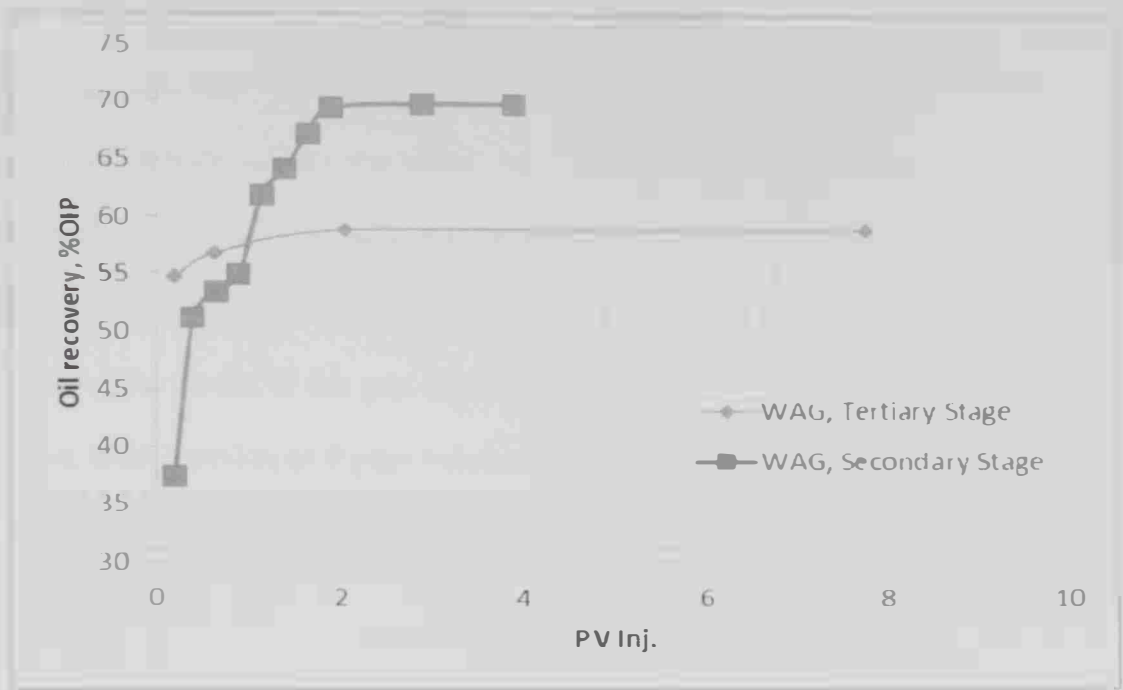


Figure 4.10: Comparison between Performances of Secondary and Tertiary Schemes



Figure 4.11: Displacement Efficiencies of Secondary and Tertiary Schemes

4.4.3. Effect of Injection Water Salinity on Oil Recovery:

Having found that WAG 1:1 ratio in secondary mode of production yields most positive results, a different brine salinity was tested. As it was reported in the literature, Oil recovery can be higher with injection of low salinity brine than with high salinity brine. For this purpose the UER brine was diluted to 5000 ppm concentration and used as the injection brine in the WAG 1:1 technique. The results of this part are illustrated in Fig 4.3, Fig. 4.7 and Fig. 4.12. It can be noticed that, after injection of 8 pore volumes, flooding with low salinity-WAG 1:1 exhibits a little higher oil recovery than flooding with original salinity-WAG 1:1 combination (72.77 % of OOIP versus 70 % of OOIP). This observation seems to agree with some published work on carbonates and sandstones^{55,58} and disagrees with other research results⁵⁹.

In terms of displacement efficiency, Fig. 4.13 illustrates that flooding with low salinity-WAG 1:1 combination yields a little higher level than flooding with original salinity-WAG 1:1 combination (0.73 versus 0.69). Therefore using LoSal WAG seems to have a good potential for further investigation.

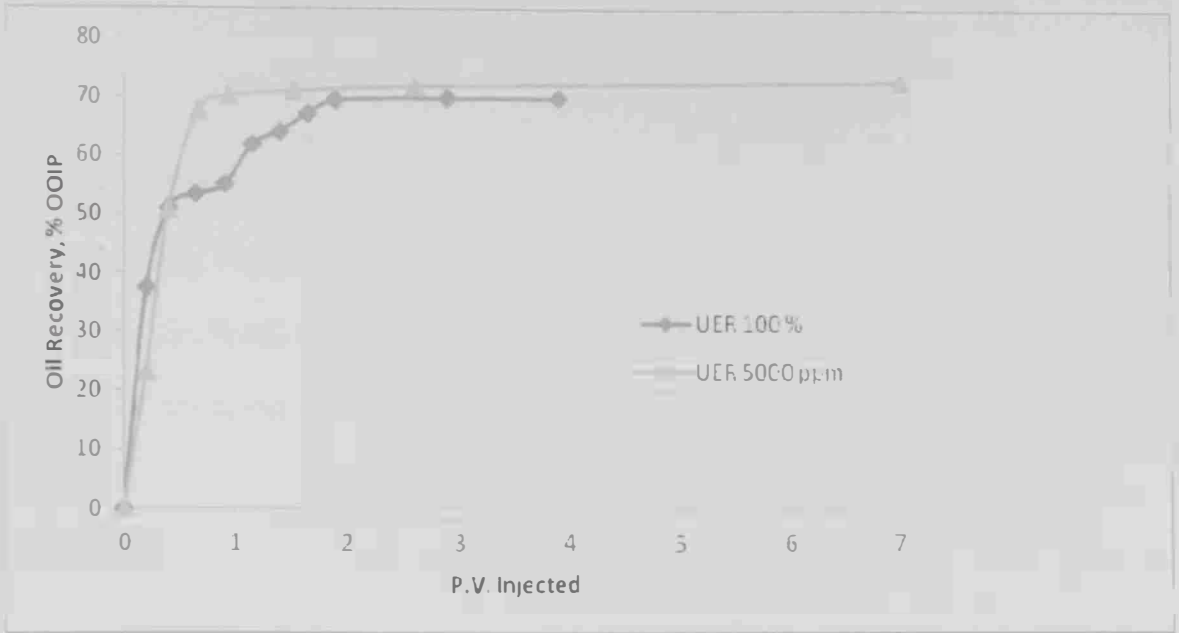


Figure 4.12: Flooding Performance of Original UER Brine and Diluted UER Brine

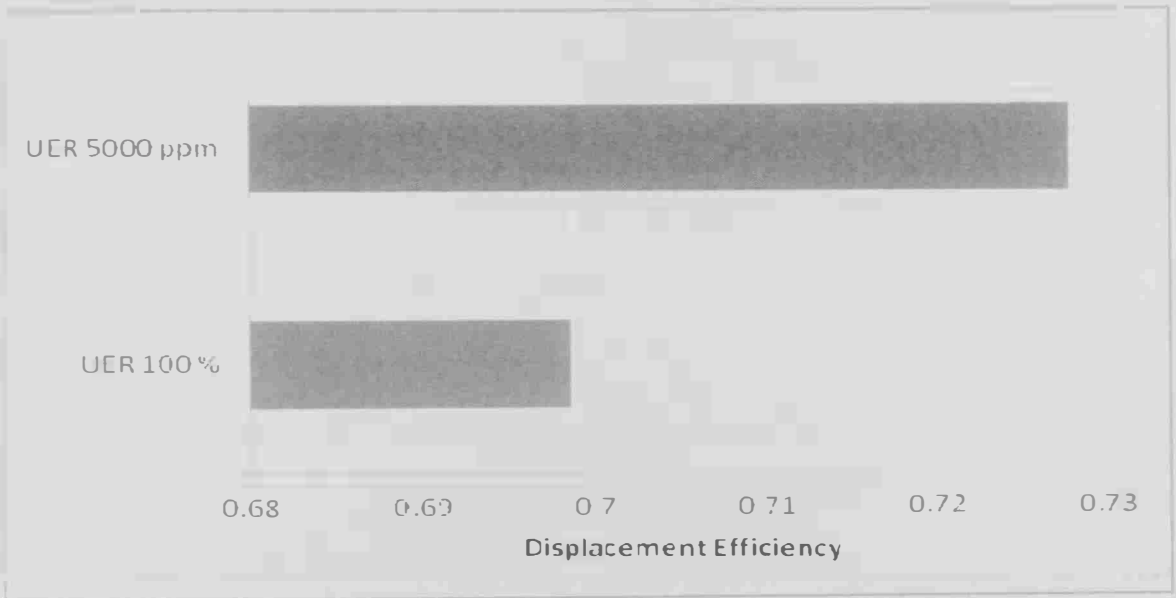


Figure 4.13: Displacement Efficiencies of the Two Brines, Original and Diluted

CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS

5.1. Summary of Present Work:

Core flooding experiments were carried out to evaluate the performance of CO₂-WAG process, WAG ratio, WAG timing, brine composition and the relative merits and demerits of the miscible CO₂-WAG flooding over continuous CO₂ injection or water flooding under specific reservoir conditions. Selected carbonate core samples from Bu-Hassa Field, UAE were used as the porous medium in all runs. Dead crude oil sample from the same field was used as the oleic phase. Umm Erraduma Brine was used as the injection brine, pure CO₂ was used as the Injection gas.

A total of seven different runs were conducted in this study. Three of the tests were performed to investigate the effect of WAG ratio on oil recovery and selecting the optimum of those studied. Two tests in terms of continuous water flooding and Continuous CO₂ Gas Injection (CCGI) were performed as reference tests for comparison purposes. Additional two tests were conducted to investigate the effect of WAG timing on oil recovery and the effect of the salinity of the brine used during the WAG process.

5.2. Conclusions:

Based on the experimental results of this work, the following conclusions may be drawn:

1. The optimum carbon dioxide flooding system for Bu Hassa oil field seems to be for CO₂-WAG ratio of 1:1. Continuous carbon dioxide flooding resulted in a slight improvement in the displacement efficiency over CO₂-WAG 1:1.

2. Continuous carbon dioxide flooding, however, required more than twice the injection pore volume required by the CO₂-WAG 1:1 process to achieve oil recovery of 70% of the OOIP.
3. It was found that implementing CO₂-WAG flooding at early stages of the life of the reservoir can increase the displacement efficiency and subsequently the ultimate oil recovery.
4. Incorporating low salinity brine in the WAG process improved the ultimate oil recovery compared to using high salinity brines.

5.3. Recommendations:

The recommendations for future work could include:

1. Attempting longer core samples, composite cores or whole cores, to better understand the effect of the miscibility bank on the oil recovery.
2. Implementing live reservoir oil instead of dead oil to see the effect on the gas dissolved in oil on the miscibility between CO₂ and oil.
3. Incorporating sophisticated laboratory systems equipped with X-ray facilities to detect and visualize the miscibility bank during the experiment. It would be also possible with such advanced laboratory equipment to determine the in-situ saturation profiles of the various flowing fluids.
4. Performing a complete suite of low salinity CO₂-WAG experiments to reach a definite conclusion regarding the effect of low salinity brine on CO₂-WAG performance.
5. Investigate the slug size effect for 1:1 WAG process (eg. 0.1PV of CO₂ followed by 0.1PV of Brine; 0.2PV CO₂ : 0.2PV Brine; 0.3PV CO₂: 0.3PV Brine).

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APPENDIX A:

Results of Core Flooding Experiments

Table A-1: Experimental Results of Continuous Water Flooding.

Tube	Volume Injected cm ³	PV Injected	Cum. PV Injected	Vol. of oil recovered cm ³	Cum. Oil Recovered , cm ³	Cum Oil Recovered %	Vol. of recovered Water , cm ³
1	1.30	0.07	0.07	1.00	2.10	19.81	0.30
2	2.10	0.12	0.19	0.60	2.70	25.47	1.50
3	3.30	0.19	0.38	0.40	3.10	29.25	2.90
4	4.00	0.23	0.60	0.40	3.50	33.02	3.60
5	4.30	0.24	0.85	0.25	3.75	35.38	4.05
6	7.50	0.42	1.27	0.50	4.25	40.09	7.00
7	13.30	0.75	2.02	0.40	4.65	43.87	12.90
8	25.95	1.47	3.49	0.45	5.10	48.11	25.50
9	52.00	2.94	6.43	0.20	5.30	50.00	51.80
10	100.60	5.68	12.11	0.20	5.50	51.89	100.40

Table A-2: Experimental Results of Continuous CO₂ Injection

Tube	Volume Injected cm ³	PV Injected	Cum. PV Injected	Vol. of oil recovered cm ³	Cum. Oil Recovered, cm ³	Cum Oil Recovered %	Vol. of recovered Water , cm ³
1	1.82	0.10	0.10	1.76	2.86	31.78	0.00
2	4.45	0.25	0.35	1.05	3.91	43.44	0.00
3	4.45	0.25	0.60	0.65	4.56	50.67	0.00
4	4.45	0.25	0.85	0.30	4.86	54.00	0.00
5	4.45	0.25	1.09	0.50	5.36	59.56	0.00
6	4.45	0.25	1.34	0.15	5.51	61.22	0.00
7	8.90	0.50	1.84	0.20	5.71	63.44	0.00
8	8.90	0.50	2.33	0.30	6.01	66.78	0.00
9	8.90	0.50	2.83	0.30	6.31	70.11	0.00
10	17.80	0.99	3.82	0.20	6.51	72.33	0.00
11	17.25	0.96	4.78	0.10	6.61	73.44	0.50

Table A-3: Experimental Results of WAG Ratio1:1 in Secondary Recovery Scheme

Tube	Volume Injected cm ³	PV Injected	Cum. PV Injected	Vol. of oil recovered cm ³	Cum. Oil Recovered, cm ³	Cum Oil Recovered %	Vol. of recovered Water , cm ³
1	3.93	0.20	0.20	3.35	4.90	37.40	0.00
2	3.93	0.20	0.40	1.80	6.70	51.15	0.00
3	4.92	0.25	0.65	0.30	7.00	53.44	0.00
4	4.92	0.25	0.90	0.20	7.20	54.96	0.00
5	4.92	0.25	1.15	0.90	8.10	61.83	1.00
6	4.92	0.25	1.40	0.30	8.40	64.12	2.50
7	4.92	0.25	1.65	0.40	8.80	67.18	3.90
8	4.92	0.25	1.90	0.30	9.10	69.47	12.30
9	19.66	1.00	2.90	0.05	9.15	69.85	24.90
10	19.66	1.00	3.90	0.00	9.15	69.85	25.00

Table A-4: Experimental Results of WAG Ratio 1:2 in Secondary Recovery Scheme

Tube	Volume Injected cm ³	PV Injected	Cum. PV Injected	Vol. of oil recovered cm ³	Cum. Oil Recovered, cm ³	Cum Oil Recovered %	Vol. of recovered Water , cm ³
1	6.00	0.32	0.32	2.20	3.40	26.98	0.30
2	6.00	0.32	0.64	3.30	6.70	53.17	0.40
3	4.50	0.24	0.88	1.40	8.10	64.29	1.10
4	4.50	0.24	1.11	0.20	8.30	65.87	6.00
5	9.00	0.48	1.59	0.10	8.40	66.67	7.70
6	19.00	1.01	2.60	0.40	8.80	69.84	18.50

Table A-5: Experimental Results of WAG Ratio 2:1 in Secondary Recovery Scheme

Tube	Volume Injected cm ³	PV Injected	Cum. PV Injected	Vol. of oil recovered cm ³	Cum. Oil Recovered, cm ³	Cum Oil Recovered %	Vol. of recovered Water , cm ³
1	5.98	0.30	0.30	0.00	1.90	15.45	0.00
2	5.98	0.30	0.60	1.70	3.60	29.27	0.00
3	4.98	0.25	0.85	2.40	6.00	48.78	1.80
4	4.98	0.25	1.10	0.40	6.40	52.03	3.50
5	4.98	0.25	1.35	0.20	6.60	53.66	3.90
6	4.98	0.25	1.60	0.10	6.70	54.47	3.20
7	4.98	0.25	1.85	0.10	6.80	55.28	3.10
8	9.97	0.50	2.35	0.10	6.90	56.10	9.90
9	14.95	0.75	3.10	0.00	6.90	56.10	15.00
10	24.91	1.25	4.35	0.00	6.90	56.10	25.00

Table A-6: Experimental Results of WAG Ratio 1:1 in Tertiary Recovery Scheme

Tube	Volume Injected cm ³	PV Injected	Cum. PV Injected	Vol. of oil recovered cm ³	Cum. Oil Recovered, cm ³	Cum Oil Recovered %	Vol. of recovered Water , cm ³
1	3.54	0.20	0.20	0.30	5.80	54.72	0.00
2	3.54	0.20	0.40	0.20	6.00	56.60	0.00
3	4.20	0.24	0.64	0.02	6.02	56.79	1.80
4	8.40	0.47	1.11	0.02	6.04	56.98	3.50
5	16.81	0.95	2.06	0.20	6.24	58.87	3.90
6	101.00	5.71	7.77	0.00	6.24	58.87	3.20

Table A- 7 Experimental Results of WAG 1:1 in Secondary Recovery Scheme Using Diluted UER Brine (5000 ppm)

Tube	Volume Injected cm³	PV Injected	Cum. PV Injected	Vol. of oil recovered cm³	Cum. Oil Recovered, cm³	Cum Oil Recovered %	Vol. of recovered Water , cm³
1	3.70	0.20	0.20	1.00	2.60	23.21	0.00
2	3.70	0.20	0.40	3.10	5.70	50.89	0.00
3	5.00	0.27	0.67	1.90	7.60	67.86	1.80
4	5.00	0.27	0.94	0.25	7.85	70.09	3.50
5	10.80	0.58	1.52	0.10	7.95	70.98	3.90
6	20.00	1.08	2.60	0.10	8.05	71.88	3.20
7	101.00	5.46	8.06	0.10	8.15	72.77	3.10

المخلص

يجري التحقيق حاليا في إمكانية استخدام طريقة حقن الممتزج للماء والغاز باستخدام غاز ثاني أكسيد الكربون كعملية لتحسين إنتاجية البترول لعدد من مكامن دولة الامارات العربية المتحدة. العوامل الرئيسية التي تؤثر على تنفيذ عمليات ثاني أكسيد الكربون هي توافره بأسعار اقتصادية، ونسبة الاستخدام الصافي لثاني أكسيد الكربون لكل برميل صافي مستخرج من النفط تقبيل نسبة الاستخدام الصافي يتطلب السيطرة على نسبة الحركية العالية والتي تقلل من الاجتياح. وللتحكك في نسبة حركية، يقترح استخدام تقنية تبادل ثاني اكسيد الكربون والماء.

والهدف من هذا العمل هو تقييم انتاج النفط مع حقن ثاني اكسيد الكرون معمليا في مكامن كلسي مختار من دولة الإمارات العربية المتحدة. وقد اجري نوعين من تجارب الازاحة باستخدام ثاني اكسيد الكربون، الازاحة الممتزجة المستمرة لثاني اكسيد الكربون و الازاحة المتبادلة للماء و ثاني أكسيد الكربون. وقد تم التحقق من تأثير تغيير نسبة ثاني أكسيد الكربون للماء، ملوحة الماء و التسبب الاولي للماء. وقد تمت كل التجارب المعملية تحت ظروف من الضغط والحرارة تتوافق مع ظروف الحقل نتاج هذا التحقيق المعملية تكشف عن اتجاه عام لتحسن انتاجية الزيت مع زيادة حجم ثاني أكسيد الكربون داخل العينات الصخرية أثناء عملية الازاحة. وقد لوحظ ان الانتاج الاقصى للزيت يتراوح من 52 % في حالة الازاحة المستمرة بالماء إلى 72 % من الحجم الأولي للزيت باستخدام الازاحة المستمرة لثاني اكسيد الكربون مع وقوع الانتاج الاقصى للزيت في حالة الازاحة المتبادلة للماء و ثاني أكسيد الكربون بينهم. وقد تم التوصل إلى ان نسبة الماء لثاني اكسيد الكربون المثالية هي 1:1.

وينبغي ان تسهم نتائج هذا العمل في فهمنا للازاحة المتبادلة لثاني أكسيد الكربون والماء لخزانات الامارات العربية المتحدة المختارة، وتدعم جهود البحث والتطوير المستمرة التي بذلتها الشركات النفطية العاملة في دولة الإمارات العربية المتحدة من أجل تطبيق هذه التقنية.



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