LOW SALINITY CYCLIC WATER INJECTION FOR ENHANCED OIL RECOVERY IN ALASKA NORTH SLOPE

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A

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ABSTRACT

Properties and flow pattern of injected water have an impact on properties like rock wettability and oil saturation. Researchers have observed increased oil recovery with low salinity brines and reduced water production with cyclic injection. Low salinity cyclic water injection is an interesting combination to be evaluated for further implementation.

Two-phase water-oil flow experiments were conducted on cleaned and oil-aged sandstone cores in a core holder apparatus. At connate water saturation, modified Amott-Harvey tests were performed to study wettability. Cyclic waterfloods were conducted to recover oil. Residual oil saturation (S_{or}) was calculated after every step. The experiments were repeated with reconstituted brines of different salinity and Alaska North Slope (ANS) lake water. The effect of low salinity waterfloods and oil-aging on wettability alteration was studied. The results were compared with available data from conventional floods performed on the same cores. Cyclic floods were also tested for different pulse intervals. Conventional waterflooding was conducted on recombined oil-saturated cores at reservoir conditions.

Faster reduction in S_{or} and additional oil recovery was observed consistently with low salinity cyclic injection. Oil-aging reduced water wetness of cores. Subsequent low salinity floods restored the water wetness marginally. Shorter pulses yielded better results than longer intervals.

TABLE OF CONTENTS

Page

Page

LIST OF FIGURES

Page

Page

Page

LIST OF TABLES

Page

DISCLAIMER

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DEDICATION

In Fond Memory of My Father

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CHAPTER 1 INTRODUCTION

1.1 Background

Petroleum reservoir fluids are fossil fuels formed from dead plants and animals buried deep in the earth millions of years ago. Rapid burial and subsequent deposition and compaction allowed this organic matter to decay in the absence of oxygen to form carbon-rich compounds in the sedimentary layers. Over geologic times, extremely high pressure (due to burial and depth) and temperature (due to geothermal gradient related to depth) resulted in the conversion of these compounds into reservoir fluids (hydrocarbons) in source rocks. These fluids migrated from the source through interconnected pore spaces in sedimentary rocks. They were then trapped by impermeable barriers, which we call “petroleum reservoirs”. Petroleum reservoirs consist of an impermeable layer (cap rock) that surrounds the porous and permeable rocks which hold hydrocarbons in place. Depending on temperature and pressure conditions, these hydrocarbons mature into oil and gas in the reservoirs.

When the cap rocks are drilled through for oil production, the inherent energy present in the reservoir provides the necessary driving force to push oil to the surface. This is called “primary oil recovery.” This energy is characterized by the reservoir pressure that rises from expansion of rock and fluids (free gas, solution gas, oil and water) in the reservoir. The pressure differential between the wellbore and reservoir causes oil to flow towards the producing well. Due to the depletion of reservoir pressure, primary recovery accounts for a limited amount of oil production. Secondary or artificial recovery involves injection of fluids into the reservoir to maintain reservoir pressure that facilitates the displacement of hydrocarbons towards the wellbore. Gas injection and waterflooding are the most common mechanisms of secondary recovery. Usually, gas is injected in the gas cap and water is injected in the production zone to sweep oil from the reservoir.

Successful implementation of primary and secondary production methods could yield up to 40% oil recovery. When injected fluids are produced in larger quantities than the oil itself, rendering the production uneconomical, other artificial methods are implemented for tertiary oil recovery. Also called improved or enhanced oil recovery (EOR), this oil recovery technique is targeted at improving oil displacement apart from maintaining the formation pressure. Thermal recovery, alkaline flooding, and miscible injection are major techniques employed as a part of EOR.

It is a well-known fact that oil and natural gas are the world's most used sources of energy. To meet the exponential increase in demand for energy, it is essential to maintain the supply chain by producing enough hydrocarbons. There has been a declining trend in oil production over the years.

In the present work, the Alaska North Slope (ANS) is being considered. ANS is located in the northern-most region of Alaska and contains the National Petroleum Reserve – Alaska (NPRA) and Prudhoe Bay oil field. The ANS contributes 15-20% of oil production in the U.S.A. Prudhoe Bay is the single largest oil field in the U.S.A., producing 58% of the output from the ANS. Since achieving its peak oil production in 1988, the crude oil production from the ANS has declined rapidly. Figure 1.1 shows the declining production trend of the ANS over time.

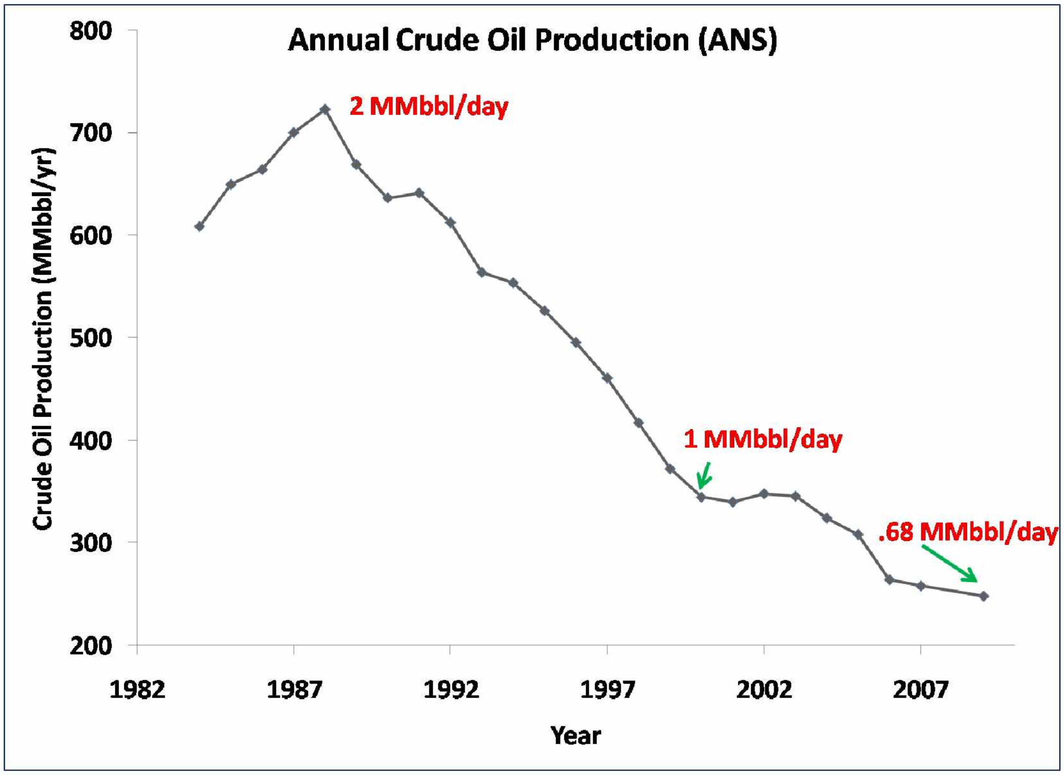

Figure 1.1 Declining Crude Oil Production Trend in ANS (Data from Energy Information Administation)

Novel EOR methods and other technologies have been explored to increase crude oil production. The increased estimated ultimate recovery from the Prudhoe Bay field is an example that has resulted from improvements in technology since the field's discovery in 1968 (Energy Information Administration Report 2001). Much field work and laboratory research has been conducted in an effort to develop different approaches that can boost the ANS oil production.

Anderson (1986, 1987) conducted a detailed literature survey on the factors affecting waterflooding, and stated that low salinity waterflooding appears to be a promising option for improved oil recovery. Oil recovery efficiency is a function of many variables including reservoir rock wetting state, pore size, geometry and distribution, salinity of the connate and invading brine, rock mineralogy, and other rock and fluid properties (Agbalaka 2006). Ivanov and Araujo (2006), after their extensive literature survey and tests, stated that cyclic water injection is a potential alternative to the inherent difficulties of waterflooding and leads to additional oil recovery. In the present work, concepts from the aforementioned points — wettability, residual oil saturation, oil recovery, low salinity waterflooding, and cyclic water injection — are investigated and analyzed in detail with the help of experimental studies.

1.2 Wettability – Fundamentals and Measurements

Wettability is a key factor that affects the petrophysical properties of reservoir rocks (Dandekar 2006). Since it influences the distribution of gas, oil, and water within a reservoir that consequently has a direct effect on the production of hydrocarbons, it is essential to know the fundamental concepts of wettability. Wettability is defined as the relative ability of a fluid to spread on a solid surface in the presence of another fluid. Reservoir wettability is determined by complex interface boundary conditions acting within the pore space of sedimentary rocks (Dandekar 2006).

When two immiscible fluids like water and oil are present in a reservoir, one of them tends to preferentially adhere to the rock surface. Whether the reservoir is water-wet or oil-wet is determined by many factors like chemical composition of the oil and water influencing their molecular attraction with rocks, mineralogy and type of the reservoir rock, depth of the reservoir structure, brine chemistry, reservoir pressure, and temperature. Based on these, the reservoir may exhibit strongly water-wet or strongly oil-wet or intermediate/neutral-wet (equal tendency to wet oil and water) characteristics in a uniformly wet media.

A reservoir is a huge mass of rock with varying conditions and properties. Research studies state that heterogeneous wettability is the normal condition in reservoirs (Brown and Fatt 1956). Under non-uniform wetting conditions, wettability has been further classified into mixed-wet (distinct and continuous conditions of water-wet and oil-wet surfaces), dalmatian or fractionally wet (discontinuous water-wet or oil-wet surfaces) and speckled or spotted wet (continuous oil-wet regions enclosing discontinuous water-wet regions or vice versa) conditions.

A number of techniques are available to measure wettability. They are classified into two categories: qualitative and quantitative methods. Qualitative methods include imbibitions rate, microscopic examination, flotation, glass slide, relative permeability curves, capillarimetric method, displacement capillary pressure, permeability/saturation techniques, nuclear magnetic resonance (NMR), and reservoir logs. Brief descriptions of the qualitative methods can be found in Agbalaka (2006) and Patil (2007). Quantitative methods include contact angle, U.S. Bureau of Mines (USBM) test and Amott-Harvey test. Quantitative methods are more widely used in laboratory measurements (Anderson 1987). Details on contact angle and USBM method have been mentioned in Agbalaka (2006).

1.2.1 Amott Wettability Test

The Amott wettability test is one of the traditional methods used to determine reservoir wettability by studying displacement of fluids. It works on the principle that the wetting fluid will imbibe spontaneously into the core thus displacing the non-wetting fluid. In other words, the core will spontaneously imbibe a higher volume of the wetting phase than the non-wetting phase. Core plugs used in this test are either 1 or 1.5” in diameter with lengths ranging from 2-3” (Dandekar 2006). Amott (1959) proposed this method, which involves a series of spontaneous and forced displacement of water and oil by each other. This method enables us to calculate the average wettability of the core, which is expressed as Amott-Harvey Wettability Index. The process involves a five-step procedure that includes establishment of residual oil saturation by waterflooding an oil-aged core, spontaneous and forced displacement of water followed by spontaneous and forced displacement of oil. In the present work, a modified Amott test called the "Amott-Harvey Relative Displacement Index test" is discussed in detail.

1.2.2 Amott-Harvey Relative Displacement Index Test

The Amott-Harvey Relative Displacement Index test is very similar to the Amott test except that the displacement sequences are reversed. Forced displacement is performed by using centrifuge or a displacement apparatus. The steps involved in this process are as follows:

1. The core is saturated completely with brine and then reduced to initial/connate/interstitial/irreducible water saturation by flooding it with oil (forced brine displacement).
2. The core is immersed in brine for 20 hours, and the amount of oil displaced is noted as volume of oil spontaneously displaced, V_{osd} (see Figure 1.2).
3. Forced displacement of oil is done by flooding brine through the core. The volume of forced oil displacement is noted as V_{ofd}.
4. The core is now immersed in oil for 20 hours, and the amount of water displaced is noted as volume of water spontaneously displaced, V_{wsd} (see Figure 1.2).
5. Forced displacement of water is done by flooding oil through the core. The volume of forced water displacement is noted as V_{wfd}.

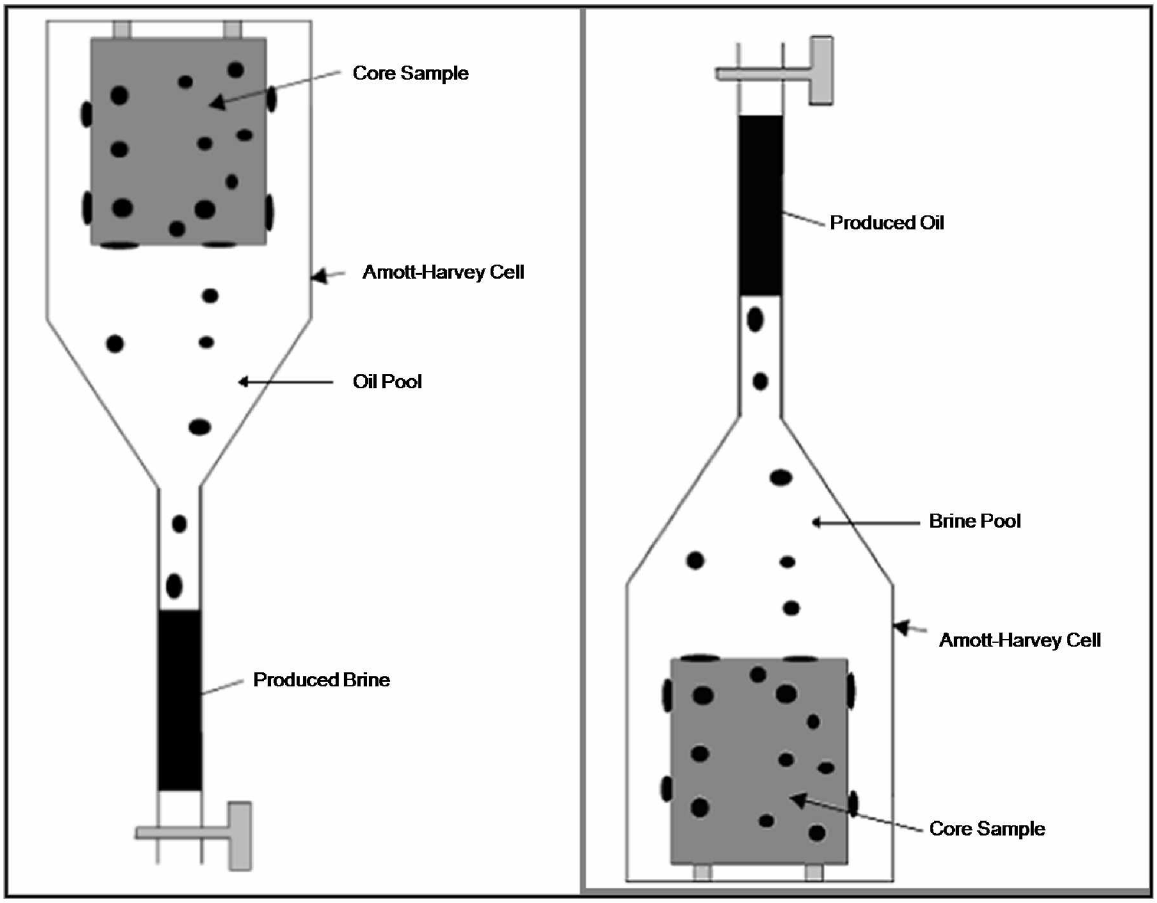

Figure 1.2 Spontaneous Displacement of Brine and Oil (Modified after Karabakal et al. 2003)

Determination of the wettability index involves calculation of two different ratios. They are:

i. The displacement by water ratio, I_W, which is the ratio of the volume of oil spontaneously displaced by water (V_{osd}) to the total volume of oil displaced by water, by spontaneous (V_{osd}) and forced displacement (V_{ofd}),

$$I_W = V_{osd} / (V_{osd} + V_{ofd}) \tag{1.1}$$

ii. The displacement by oil ratio, I_O, which is the ratio of the volume of water spontaneously displaced by oil (V_{wsd}) to the total volume of water displaced by oil, by spontaneous (V_{wsd}) and forced displacement (V_{wfd}),

$$I_O = V_{wsd} / (V_{wsd} + V_{wfd}) \tag{1.2}$$

I_W will be positive and I_O will be zero for preferentially water-wet cores. This indicates that oil does not displace water spontaneously. The displacement by water ratio approaches unity as water wetness increases. Similarly, I_O will be positive and I_W will be zero for strongly oil-wet cores. Both I_W and I_O will be zero for neutrally wet cores, indicating that neither water nor oil is able to imbibe the core spontaneously.

Dandekar (2006) stated that use of the term "spontaneous imbibition" is inappropriate, since imbibition describes the displacement of non-wetting phase by wetting phase under known conditions of wettability. For the current experimental work, the wettability of the cores is not known; thus, this work will restrict its usage to spontaneous displacement of water/oil.

The present study will make use of the 'Amott-Harvey Relative Displacement Index' (I_{AH}), which is expressed as displacement by water ratio (I_W) minus displacement by oil ratio (I_O).

$$I_{AH} = I_W - I_O \tag{1.3}$$

Since the maximum and minimum values of the displacement ratios are 1 and 0 respectively, the Amott-Harvey Relative Displacement Index gives a single wettability index value that ranges between +1 (strongly water-wet) and –1 (strongly oil-wet) with zero indicating neutral wetting conditions. Cuiec (1984) further classified the wettability index based on Amott's work. Table 1.1 displays Cuiec's wettability classification.

Table 1.1 Cuiec's Wettability Classification

I_{AH} Range	Wettability
+0.3 to +1.0	Water-wet
+0.1 to +0.3	Slightly water-wet
–0.1 to +0.1	Neutral
–0.3 to –0.1	Slightly oil-wet
–1.0 to –0.3	Oil-wet

1.3 Factors Affecting Wettability

From the saturation history analysis, the reservoirs were assumed to be strongly water-wet initially, since they were completely saturated with water. When crude oil started migrating, it caused a significant displacement of water thus coming into contact with the reservoir rock. Since then, the reservoirs have departed in their wetting states, from strongly water-wet to weakly water-wet, neutral-wet or strongly oil-wet conditions, depending on many factors. The composition of crude oil and aging time are two important factors that determine wettability alteration. Studies (to be discussed in literature survey) have proved that wettability can be altered in cores by oil-aging. Wettability is an important function that influences residual oil saturation and oil recovery. If the oil phase has a high affinity towards the clay, a strong clay-oil bond is formed. To recover this oil, the bond must be broken. Though reports with contrasting results in optimal oil recovery for water-wet, intermediate-wet and oil-wet conditions (Agbalaka 2006) have been published, many studies suggest that brine salinity affects wettability, which in turn influences oil recovery. Low salinity water injection has been proved to be an option that yields increased oil production.

1.4 Cyclic Water Injection

In conventional waterflooding, continuous water injection is performed to restore reservoir pressure, which promotes increase in oil production. But, there are some inherent disadvantages with continuous injection. The reservoir is not homogeneous with unique rock and fluid properties throughout (Brown and Fatt 1956). Reservoir heterogeneity paints a different picture of the reservoir structure, with many interconnected vugs in the larger pores forming fracture channels with high permeability, while the smaller pores are present in layers with low permeability. Continuous water injection might guarantee an efficient sweep in the regions of high permeability, but it also tends to form rapid water channels with plug flow in the fracture networks, restricting access to the smaller pore matrix. This condition leads to water bypassing the oil that is present in the smaller pores (Felsenthal and Ferell 1967). High injection rates might lead to reservoir pressurization and cause fingering. Fingering or channeling of water causes an early breakthrough of water, thereby increasing the water cut in the reservoir. Oil production tends to drop after water cut. Increased water production has a direct ill effect on oil production, since oil in the low permeability layers remains unswept.

To overcome these shortcomings of conventional waterflooding, pressure pulsing/cyclic water injection and improvisation of these techniques have been proposed, tested, and used since the 1950s. Cyclic injection is based on alternating pressurizing and depressurizing of the reservoir, leading to reallocation of injection volumes between waterflood well patterns (Surguchev et al. 2008). The first response to this problem was implemented in the fractured low permeability reservoirs in Spraberry, Texas (Elkins and Skov 1963). This operation included restoration of reservoir pressure by capacity water injection, followed by many months of oil production without injection and repetition of the cycle. Injection is interrupted to facilitate flow of oil from the rock matrix to the fracture channels. Expansion of gas, oil, rock, and water during the pressure decline (non-injection period) expels part of the fluids from the smaller pore structure with capillary forces holding back much of the injected water. Pressure pulsing by water injection takes advantage of imbibition, fracturing, presence of free gas/solution and compression and decompression of reservoir rock and fluids. Typically, a pressure pulse consists of two phases performed as a cycle.

1. Pressurizing half cycle – The reservoir is pressurized by water injection. Sometimes it is increased to a pressure higher than capacity pressure. This increased pressure might help in opening connectivity to discontinuous micro-zones by pushing in water to low permeable zones. Oil production continues at a constant rate.
2. Depressurizing half cycle – Injection is stopped, and fluid production from the reservoir is continued at a constant rate. In the low permeability zones, imbibed water is capillary-retained and oil is pushed out. Reservoir pressure starts dropping. Reduction in pressure causes counter-current flow of oil from the micro-fractures to the high permeable zones and hence to the producing wells.

Studies suggest that the main contribution of cyclic waterflooding to oil recovery comes from acceleration of cross-flow between low and high permeability zones/layers in the reservoir (Shchipanov et al. 2008). Usually, cross-flows are dominated by capillary action and gravity, but in cyclic injection, fluid re-distribution is comparatively slow. Compressibility effects that are controlled by differential pressure existing between layers of contrasting permeabilities have a direct influence on cross-flows in cyclic water injection. The displacement of oil by water and propagation of the displacement front occur faster in high permeability regions when compared to low permeability zones. Due to differences in oil and water compressibility, the rock-fluid compressibility varies for the two fluids, causing a difference in pressure. In a stratified reservoir with vertical connectivity and contrasting permeabilities, conditions favor vertical pressure drop and inter-layer cross-flow. During the pressurizing first phase, water washes off the oil that is present in the high permeability zones. Cross-flow of water is directed from high to low permeability zones. During the depressurizing second half cycle, cross-flow happens in the opposite direction, with additional oil flowing from low to high permeability zones. Sweep coverage volume and efficiency in the low permeability zones during the second half are enhanced by the mobility ratio of oil. With high oil saturation and mobility of oil in a low permeability layer, vertical cross-flow during the second half of cyclic waterflooding yields additional oil drainage from low permeability regions. Higher oil production and decreased water production is thus observed with cyclic waterflooding. Shchipanov et al. present the typical changes of well injection rate with cyclic and continuous floods (Figure 1.3).

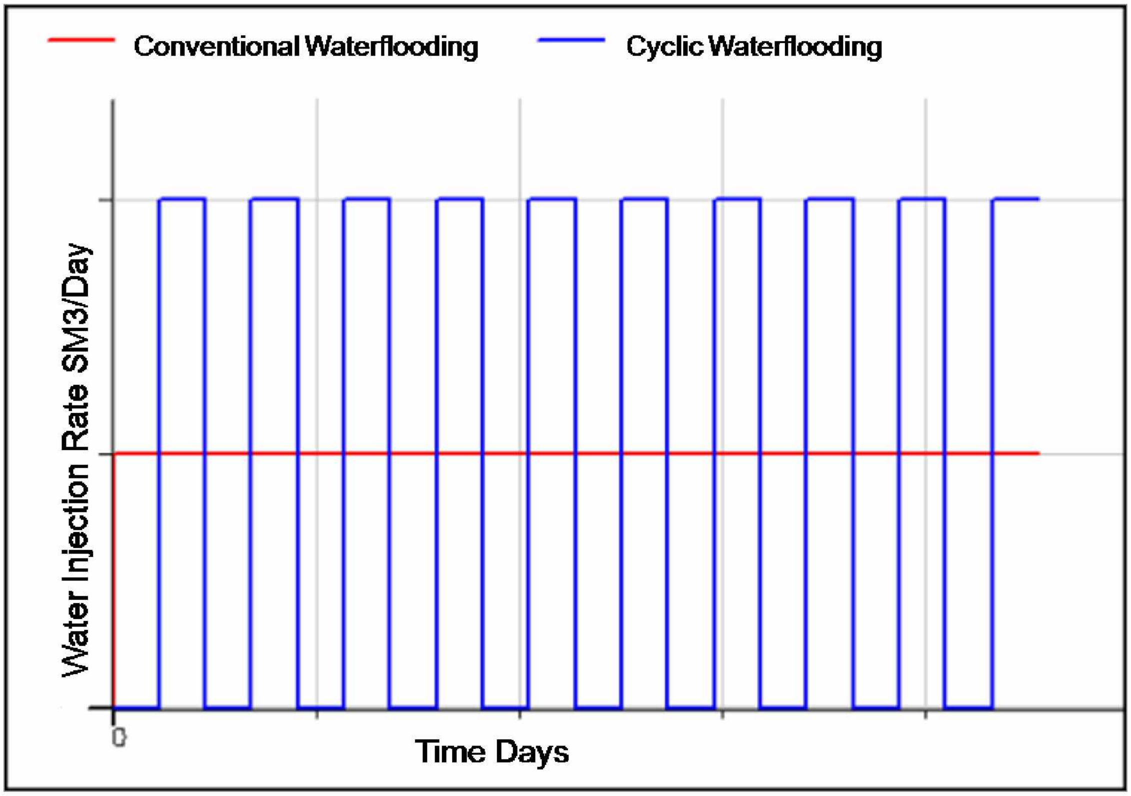

Figure 1.3 Water Injection Scheme in Cyclic and Conventional Floods (Shchipanov et al. 2008)

Cyclic injection yields better oil recovery and minimal water production. It has been observed that additional oil was produced during the period when injection was ceased. The waterflooding efficiency pattern can be optimized by fine-tuning cyclic injection parameters, such as injection rate and time period of the cycle. The cycle periods at field scale are in the range of days to months, while the pulsed pressure technique uses application of several pulses in time intervals of minutes (Surguchev et al. 2008). A cyclic process also utilizes the reservoir gas energy to maximum advantage, unlike the traditional waterflooding process. Simple implementation and virtually zero additional cost make the option attractive. Since maximum oil recovery is achieved at the expense of reduced amounts of water, residual oil saturation is reached earlier when compared with conventional waterflooding. With minimal water production, capital and operational expenses associated with water handling and maintenance are brought down. In the literature survey, research, implementation, and improvisation of cyclic water injection in the U.S.A., Canada, North Sea, Russia, China, and Middle East are discussed.

1.5 Objectives

The primary goal of this research project was to characterize rock wettability and analyze the effect of wettability alteration on residual oil saturation and hence oil recovery efficiency using representative cores from the ANS. Another important objective of all the experiments was to gauge the potential of low salinity cyclic injection of water as an effective secondary oil recovery mechanism. The experimental work concentrated on influencing wettability through injection of brines with varying salinity as a means of enhancing oil recovery, like that of a typical EOR process at the ANS. To simulate actual reservoir conditions, oil-aging of cores and use of live oil at reservoir temperature and pressure were also investigated. Within the scope expansion of the same project, cyclic water injection was evaluated as an option to improve the recovery efficiency at lesser amounts of injected water.

Miscible gas injection and waterflooding are the principal EOR methods employed at the ANS. Despite their application, significant amounts of oil in place are yet to be recovered. Industry production data suggest that a better understanding of mixed-wet states and measures to alter wettability of Alaskan reservoirs by applying various techniques could help in an efficient recovery of the remaining oil. With limited data on wetting states of Alaskan reservoirs, characterization of wettability of ANS reservoirs, understanding of injected and resident fluid composition influencing wettability and hence oil recovery, and developing methods that improve wettability to achieve higher recovery efficiencies are crucial to the EOR mission of the Arctic Energy Technology Development Laboratory(AETDL) (Dandekar 2003).

To achieve this mission, experimental determination and characterization of the wettability of Alaskan cores were performed. The use of brines with varying salinity on new/oil-aged cores at atmospheric/reservoir conditions facilitated the study of factors influencing wettability. Application of cyclic water injection, to alter wetting states that would enhance oil recovery, was also implemented. Representative cores, crude oil, and lab-reconstituted synthetic brines were used for the experiments. The specific objectives of this research work were to observe the effects of the following:

1. Cyclic water injection and variation in the salinity of the injected brine on residual oil saturation and oil recovery, with dry (and already used by a previous researcher to evaluate low salinity conventional waterflooding) cores in a secondary oil recovery mode at atmospheric conditions.
2. Cyclic water injection and use of ANS lake water (ultra-low salinity water) on residual oil saturation and oil recovery, with used cores in a secondary oil recovery mode at atmospheric conditions.
3. Cyclic water injection and variation in the salinity of the injected brine on residual oil saturation and oil recovery, with oil-aged cores in a secondary oil recovery mode at atmospheric conditions.
4. Changing time intervals in the pulse periods in cyclic water injection on residual oil saturation and oil recovery, with new cores in a secondary oil recovery mode at atmospheric conditions.
5. Conventional waterflooding and variation in the salinity of injected brine on residual oil saturation and oil recovery, with new cores and “live” oil in a tertiary oil recovery mode at reservoir conditions.
6. Wettability alteration and characterization, using Amott-Harvey Wettability Index (I_{AH}) in all the cases mentioned above.

CHAPTER 2 LITERATURE SURVEY

Waterflooding is one of the most widely used methods for EOR, whereby water is injected into the reservoir to displace the oil that remains after the primary recovery process. Raza et al. (1968) stated that the waterfront behavior inside the reservoir varies for strongly water-wet and strongly oil-wet systems. In a completely water-wet system, water gets imbibed into smaller pore structures due to favorable capillary forces and oil displaced into larger pores. The water phase moves as a uniform front with oil phase moving ahead of it. Any oil left behind is trapped as spherical globules surrounded by water. In a strongly oil-wet system, waterflooding is not efficient. The injected water forms continuous channels of fingers, sweeping off oil present in the larger pores. Remaining oil exists as continuous films in smaller pores and pore throats. A detailed description of the mechanism can be found in Raza et al. (1968).

2.1 Effect of Wettability on Oil Recovery

Owens and Archer (1971) reported that wettability is one of the primary factors that affect oil recovery while waterflooding. Oil-water relative permeability, a function of wettability, controls the waterflood oil recovery. Owens and Archer also reported that the effective permeability of oil at connate water saturation decreases as the core gets increasingly oil-wet. It was concluded that waterflood oil recovery is the most effective under strong water-wet conditions. On the contrary, Salathiel (1973) proposed that oil recovery is the highest at mixed-wet conditions. Salathiel stated that strongly oil-wet regions in the rock matrix are present in those pore spaces that are in longer contact with crude oil. These pore spaces are connected by a path that ensures the flow of oil even at low oil saturations. Salathiel concluded that, even if a larger part of the rock matrix stays water-wet, mixed-wet conditions help in higher oil recovery.

Donaldson et al. (1985) stated that measuring relative permeability on core samples at reservoir conditions is an accepted method of determining wettability effects in waterflooding. Morrow et al. (1973) studied the effect of wettability variation on relative permeability with mineral oil and water. They noted that the relative permeability of water increased at the expense of mineral oil as the system became more oil-wet.

Morrow et al. (1986) observed that strongly water-wet conditions are not often encountered, and other wetting conditions are preferable. Jadhunandan and Morrow (1991) confirmed this observation by pointing out that recovery from strongly water-wet or oil-wet cores is actually less than the oil recovery obtained from cores at intermediate wettability. They investigated the influence of wettability on oil recovery by waterflooding COBR (crude oil brine rock) systems using Berea sandstone cores. They reported a number of factors like oil-aging temperature, initial water saturation, and brine composition that determine the wettability of COBR systems. It was noticed that maximum oil recovery was attained close to the water-wet side of neutral-wet conditions (wettability index = 0.2). Tweheyo et al. (1999) also reported that highest oil recovery was obtained with neutral-wet systems, and lowest, with oil-wet systems. Jadhunandan and Morrow (1991) pointed out wettability as a function of water saturation. They also stated a rule of thumb that connate water saturation is greater than 20-25% of pore volume (PV) for water-wet rocks and frequently less than 15% for oil-wet rocks. All the results mentioned above were from uniformly wet systems.

The normal wetting state in a reservoir may not be uniform. Heterogeneous wettability, characterizing different and distinct wetted areas within the same system that can be clearly categorized as oil-wet or water-wet, may be present. These non-uniform wetted systems can be either mixed-wet with continuous oil-wet paths in the larger pores and water-wet paths in the smaller pores, or fractionally wet with specific wettability at certain locations (Dandekar 2006). The

Endicott field in Alaska is an example of a mixed-wet system. Wood et al. (1991) reported that the residual oil saturation in mixed-wet reservoirs is a function of the number of PVs of water injected. From the coreflood experiments conducted, they observed a significant reduction in residual oil saturation with increase in the number of pore volumes of water injected. It was also observed that no significant increase in oil recovery occurred after water breakthrough (at one PV injected). It was reported that oil recovery was higher in mixed-wet systems when compared to water-wet conditions. Huang et al. (1995) and Wang (1986) also confirmed that mixed-wet systems are more favorable than water-wet reservoirs in yielding higher oil recoveries. It was explained that mixed-wet systems have a continuous oil-wet path in the larger pores that can be swept off by water. The amount of oil isolated by water in mixed-wet systems is much lesser than that of water-wet systems.

Tang and Morrow (1997) investigated the effect of asphaltenes on wettability. Test results showed that the addition of alkanes to crude oil reduced water wetness and the removal of lighter components from crude oil increased water wetness. Dandekar (2006) found instances from literature to discuss the factors affecting wettability and focused on brine and oil composition, depth of the reservoir structure, reservoir temperature, and pressure.

2.2 Effect of Brine Salinity on Residual Oil Saturation

Following up on the work of Jadhunandan and Morrow (1991), Yildiz and Morrow (1996) investigated brine salinity as a factor influencing wettability and hence oil recovery. They found that changes in brine salinity can improve oil recovery. Tang and Morrow (1997) found that the salinity of connate and invading brine affected wettability. Tang and Morrow (1998) progressed with the research and revealed that brine properties like pH, ionic species, and salinity affect the interaction of rock with brine/crude oil thus altering wettability and affecting oil recovery efficiency. Tang and Morrow (1999) studied the effect of brine composition on microscopic displacement efficiency of oil by flooding. They reported an increase of 8-13% oil recovery with decrease in salinity. As the salinity of the brine decreased, a notable change in wettability towards water wetness also was seen.

Field trials were conducted to study the impact of brine salinity on oil recovery. Webb et al. (2004) conducted log-inject-log tests in the Middle East and noticed a reduction in residual oil saturation in the range of 25-50%. McGuire et al. (2005) also performed an extensive research program in the ANS with a series of experiments that included numerous coreflood experiments at reservoir conditions (live oil, high temperature, and pressure) in secondary and tertiary mode and single-well chemical tracer tests (SWCTT). These tests showed a significant decrease in residual oil saturation and an increase in oil recovery of 8-19%. Webb et al. (2005) conducted coreflood studies at reservoir conditions and confirmed that oil recovery increased in decreased brine salinity. It was reported that no water was produced with the oil till water breakthrough occurred. After breakthrough, little or no production of oil was observed. Though seawater salinity is less than formation brine salinity, no significant increase in oil production was observed by injecting seawater.

Tang and Morrow (1998) tried to explain the mechanism behind the increase in oil recovery with low salinity brine injection. They attributed it to the fines mobilization that happened during low salinity brine injection. In their experiment, fine particles of clay (kaolinite) that retained oil droplets became mobile on low salinity waterflooding thus increasing oil recovery. Lager et al. (2006) proposed that multi-component ionic exchange (MIE) between the clay surface and the injected low salinity brine is responsible for the increase in oil recovery. They explained the mechanism behind the adsorption of crude oil components on to the reservoir rock surface rendering oil wetness to certain regions, as follows: Multivalent cations adsorbed to the clay surface have an affinity towards the negatively charged molecules in the oil. Since these cations are multivalent, they are able to bond with anions from both oil and rock surface, thus acting as a bridge between the negatively charged oil and negatively charged clay surface. Thus, oil gets adsorbed to the clay surface. High salinity water has a high concentration of multivalent ions, while H^+ and OH^- ions are present in higher concentrations in low salinity water. Ionic exchange is a function of concentration of the ions present in the region where it takes place.

During low salinity waterflooding, excess of H^+ ions from the invading brine exchange with the multivalent cations previously adsorbed to the surface. The bonds holding the oil onto the rock are thus broken making the oil mobile. Interfacial tension between oil and water is reduced resulting in higher oil recovery. Due to cation exchange, there is a decrease in the concentration of H^+ ions in the liquid phase. Excess concentration of OH^- results in the increase of pH, making the liquid phase basic. If the increased pH goes above 9, it is equivalent to an alkaline waterflood. Figure 2.1 shows the clay-oil attraction process discussed above. There has been evidence of increase in the effluent pH with low salinity waterflooding. Lager et al. (2008) succeeded in alleviating the uncertainty of Lager et al. (2006) with respect to inter-well distance. Test results on one hydraulic unit yielded a decrease of 10% in residual oil saturation and doubled oil production in one year with a measurable drop in water-oil ratio.

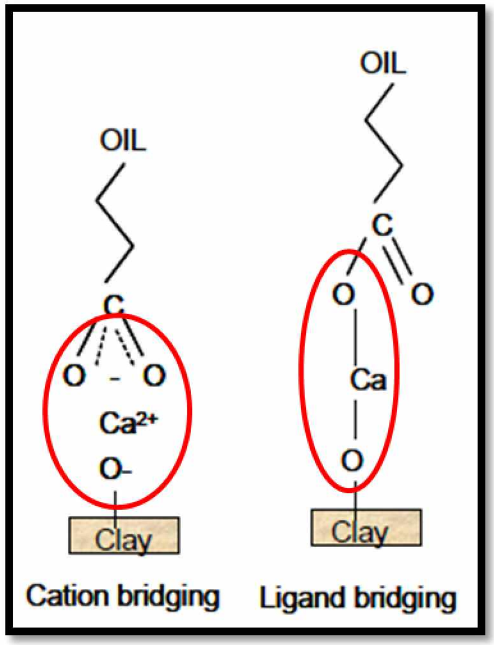

Figure 2.1 Clay-Oil Attraction Process (Lager et al. 2008)

Agbalaka (2006) investigated the impact of brine salinity and temperature on wettability alteration that affects residual oil saturation and oil recovery. Agbalaka used decane and an NaCl brine system to flood cores provided by the Alaska Department of Natural Resources (DNR). Of the 4%, 2%, and 1% NaCl saline solutions, the recovery factor increased with a decrease in brine salinity. An elevation of temperature assisted in reduction of residual oil saturation. The increase in oil recovery and decrease in residual oil saturation were accompanied by an increase in water wetness.

Patil (2007) and Patil et al. (2008) researched the use of ANS lake water as a means of ultra-low salinity water apart from low salinity coreflood experiments. Crude oil from ANS, three sets of brines (22,000, 11,000 and 5,500 ppm total dissolved solids) and ANS lake water were tested on ANS representative cores. The effect of oil-aging was also studied. Injection of low salinity brine yielded a consistent trend of increase in oil recovery and decrease in residual oil saturation. Water wetness decreased when core samples were aged in oil. Amott Harvey Wettability Index shifted from strongly water-wet to slightly water-wet but an increase in water wetness was observed with the injection of low salinity brine. It was reported that ANS lake water could be a potential source for waterflooding operations at the ANS. Dilution of high salinity brine using ANS lake water was also recommended. Results (Patil 2007) agreed with some of the published results in the same field. A pilot plant has been installed in the Endicott field, ANS by BP to investigate the potential of low salinity waterflooding (BP Technology Webcast 2005).

2.3 Effect of Oil-Aging on Wettability

Wettability has a pronounced effect on fluid flow behavior in pore spaces of the rock matrix. Oil-aging is widely believed to be one of the factors affecting wettability. Literature studies show that carbonate reservoirs are more oil-wet when compared with sandstone reservoirs. Anderson (1986) reported that silica has a negatively charged acidic surface, while carbonates have positively charged basic surfaces. These surfaces preferentially adsorb components of opposite polarity. Carbonates adsorb crude oil, which are relatively acidic and hence more oil-wet. Silica will be affected by organic bases. It is believed that the reservoirs were strongly water-wet and were initially occupied by water. As oil started migrating into the reservoirs, water was displaced from the large fracture networks and then from the small pore spaces until the capillary forces holding water in the small pores could not be overcome by the displacing force. Over geologic time, contact of oil with the reservoir and further deposition of high molecular hydrocarbon could have altered the rock wettability. It was reported that crude oil composition and the ability of oil to contact the reservoir rock surface are the factors that influence the effect of oil-aging on wettability.

Jia et al. (1991) studied the control of wetting using crude oils at various aging conditions. Crude oil composition, aging temperature, initial water saturation, and aging time were identified as the predominant factors influencing wettability. Dried Berea sandstone cores were saturated in brine solution and then flushed with crude oil. The cores were then oil-aged under varying temperatures and aging time. Amott-Harvey tests were conducted to find the wettability indices. The results provided a guideline to applying crude oil marination to oil/brine/rock systems. Results concluded that strongly water-wet cores became weakly water-wet or neutral-wet after the aging process. It was reported that the extent of wettability transition is a function of connate water saturation. Zhou and Morrow (2000) conducted a similar laboratory study with Berea sandstone core/synthetic formation brine/Prudhoe Bay oil. Results showed that the rate of spontaneous imbibitions was highly sensitive to wettability. An increase in aging time decreased the water wetting nature of the core. For varying aging time, imbibition of oil and oil recovery by waterflooding increased with a decrease in water wetness from strongly water-wet conditions.

Hirasaki (1991) attributed wettability alteration to presence of water films between the rock surface and oil. If there are stable thick-water films, the system behaves water-wet. Unstable water films rupture, allowing oil to contact the rock surface for possible adsorption in the future. It was reported that asphaltenes in oil are highly responsible for the binding force between oil-rock interactions. From these experiments, oil-aging at laboratory scale seems to restore the native wetting conditions of the core, i.e., at reservoir conditions. In the present work, secondary oil recovery has been investigated at oil-aged conditions to study the parameters at native wetting states. For this purpose, the cores used for secondary oil recovery were oil-aged.

2.4 Cyclic Water Injection

The first attempt to conceive the idea of cyclic waterflooding started in the 1950s. Fracture networks are a threat to conventional waterflooding, as they cause water channeling and oil by-passing. The basic imbibition flooding process was extensively researched in the Spraberry oil field of West Texas in 1952. Elkins and Skov (1963) summarized the first response to large-scale waterflooding in the highly fractured low permeability Spraberry field. With a primary recovery of less than 10% of oil in place, restoration of reservoir pressure by water injection up to capacity rates and production without water injection were performed in a cycle. Oil production increased at a 50% faster rate with less water production.

Owens and Archer (1966) coined the term, “pressure pulsing,” which describes how the interconnected vugs are used alternately as channels of injection and production. Oil recovery occurs by imbibition of water from the fracture network into the fine pores, followed by countercurrent flow of oil from the pore structure into the fractures. Pressure pulsing offers faster injection rates and facilitates flow of oil from the rock matrix into the fracture network when injection is interrupted. Owens and Archer used the “same” wells for injection during the pressurizing phase as well as production during the depressurizing phase. They concluded that cyclic water pulsing can be used as an effective technique for oil recovery in water-wet regions. They also noted a gradual decreasing trend in oil production with successive pulses.

Felsenthal and Ferrell (1967) provided analogous field evidence about “ocean frac” method, which involves mass injection of water at fracturing rates followed by normal production. However, high injection rates were used on isolated wells compared to pressure pulsing, which pulses the whole or part of a reservoir. Felsenthal and Ferrell analyzed the application of pressure pulsing on the Grayburg limestone reservoir in 1964. Field studies showed that oil rates declined definitely during the pressurizing phase. Felsenthal and Ferrell observed that peak oil rates occurred when the injection rates declined. They explained it as accidental pressure pulsing that interfered with the countercurrent flow of oil from the pore matrix. Felsenthal and Ferrell also conducted laboratory studies to compare the efficiency of conventional waterflooding and the pressure pulsing technique. Tests conducted on “fracture matrix blocks” confirmed that conventional waterflooding was highly inefficient, with a recovery of only 7% of oil in place after a 99% water cut. About 90% of the reservoir model was unswept. Pressure pulsing tests were conducted with injection and production through the same wells as a means to conserve and utilize the reservoir gas energy. Oil recovery after the first pulse was 15%. At the end of primary recovery, 20% oil in place was recovered. Additional oil was produced in successive pulses, on a declining trend, with marked increase in water production. Figure 2.2 shows the comparison of conventional waterflood with pressure pulsing in this experiment. Less gas energy left in the reservoir to propel the lower amounts of oil left to recover was quoted as the reason for decline. Felsenthal and Ferrell (1967) also compared the effect of injecting gas prior to water and the effect of gas injection without water. Results confirmed that the former fared better with excellent oil recovery. They recommended pressure pulsing to be conducted in high-capacity fractured wells with free gas saturation. Felsenthal and Ferrell (1967), Owens and Archer (1966), and Elkins and Skov (1963) concluded that fractures in a reservoir favor cyclic waterfloods. Hester et al. (1965) reported that pressure pulse technique was unsuccessful in the Austin and Buda formations of the Darst Creek and Salt Flat fields, Texas. The reservoirs were extremely tight, with low solution/free gas saturation and no natural fractures.

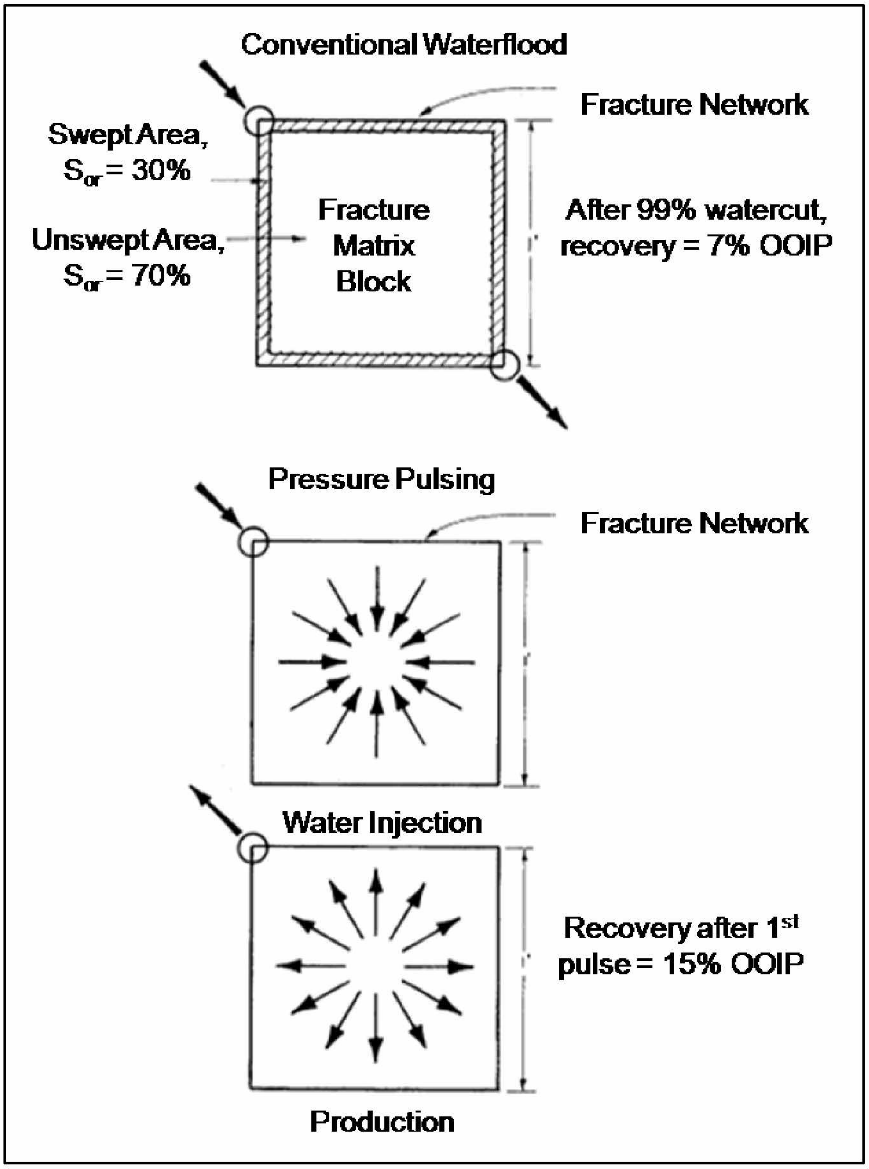

Figure 2.2 Comparison of Conventional Floods and Cyclic Injection (Felsenthal and Ferell 1967)

Raza (1971) compared cyclic gas pulsing to cyclic water pulsing. Preliminary experiments on water-wet Berea, Bandera (both sandstone), and Austin (limestone) cores proved that both cyclic periods yielded the same oil recovery. It was concluded that initial oil saturation affects cyclic water pulsing and previous production history influences cyclic gas pulsing. Qingfeng et al. (1995) proposed that additional cross-flow caused by the pressure differentials between layers of contrasting permeabilities enhances production. In a layered reservoir with vertical communication, cross-flow is common due to gravity, capillary forces, and the drive caused by differential pressure between the layers. This pressure transient accelerates the cross-flow thereby causing forced imbibition. Qingfeng named reservoir heterogeneity, inter-layer communication, permeability, saturation differentials, and pressure with respect to bubblepoint as critical variables that affect cyclic water injection (CWI). It is reported that cyclic pulsing improves with oil of high viscosity, as there will be increased control over viscous fingering. Qingfeng also mentioned that CWI functions effectively above bubblepoint pressure, since fall in pressure below saturation pressure could cause a solution gas drive.

Zhongrong et al. (1995) came up with an interesting and different proposal that cyclic waterflooding should be implemented in low permeability reservoirs with low water cuts and at early stages of oil field development. Based on their extensive experience with the southern fields of Daqing Placanticline in China, which have weakly water-wet, thin oil layer sandstone reservoirs with low permeability, they claimed that cyclic waterflooding helps in improving the water injection efficiency. Additional oil recovery of 3-10% more than conventional waterflooding has been reported. In an attempt to study the sweep efficiency of injected water, they determined the proper intermittent cycle of water injection. Results showed that in low water cut stages, long pauses in injection resulted in a higher decrease of oil production than water cut decrease, thus defeating the purpose. They mentioned that the injection pause period should be kept short for low water cut stages and prolonged for high/medium water cut stages. It was also reported that the injection time should be kept long when flowing pressure is close to the minimum flowing pressure limit. It was concluded that cyclic waterflooding must be held to the principle of equilibrium of injection and production. Proper intermittent injection cycle and CWI rate must be determined from the field.

Wang et al. (1998) and Davidson et al. (1999) investigated the use of rapid pressure pulses on flooding of core samples. Water injection was combined with rapid pressure pulses, pulsing several times each minute. Laboratory results concluded that pulsing improved areal and vertical efficiency, apart from enhancing liquid injection and production.

Surguchev et al. (2002) proposed that forced imbibition causes improved cross-flow between layers of different permeability, which allows a better sweep of oil present in low permeability regions in contact with layers of high permeability. This improved vertical efficiency plays a part in oil recovery with CWI. They also attributed better oil recovery to the hysteresis of the capillary pressure and relative permeability curves between different saturation (imbibition/drainage) paths. This condition might lead to water retention in the low permeability regions (after driving out the oil) thus explaining lesser water production in cyclic water injection. They performed simulation studies on Heidrun field in the Norwegian Sea with oil samples of different viscosity. It was reported that oil recovery efficiency is a function of matrix permeability. Results showed that cyclic was better than conventional water injection, and additional recovery decreased with increasing oil viscosity. With low viscosity of 1 cP, 12% additional recovery over conventional injection was noted. As the oil viscosity rose to 6 cP, 5% additional recovery was obtained with cyclic pulsing.

Surguchev et al. (2002) and Alvarez et al. (2001) listed some of the reservoir features that favor CWI. Layered heterogeneous reservoirs with fractures and interconnected vugs, thereby providing effective communication between regions of low and high permeability, play a crucial role in improved oil recovery. They also pointed out that larger pressure differentials between reservoir units help in improved pulsing. Zschuppe (2001) noticed increased oil production along with

20% reduction in water cut when experimenting pulsed injection with viscous oil in large bead packing.

Groenenboom et al. (2003) quoted the term “Pressure Pulse Technology (PPT),” which has been used as a well-stimulation technique in Canada to stimulate oil production with sand co-production. This strategy is called CHOPS (Cold Heavy Oil Production with Sand) and is used in unconsolidated reservoirs. PPT has increased production from 1-20 bbl/day to 50-200 bbl/day. Groenenboom et al. reviewed a field test using pressure pulsing in a heavy oil reservoir in Germany. A hydraulic pulsing tool exerted pulses in the range of 4-17 bars with 5-6 pulses per minute. Due to the absence of high-quality data, details on oil production were not available. Groenenboom et al. recommended that optimum injectivity be achieved to improve the recovery rate. Arenas and Dolle (2003), in their simulation studies, introduced the new term “pressure cycling,” in which a specific segment in the injector is pressure pulsed to yield additional benefits.

Stirpe et al. (2004) mentioned that wettability affecting CWI is still a topic of conflicting theories. While some researchers claimed that water-wet cores assist CWI, others claim that oil-wet cores enhance production with CWI. Rock and fluid compressibility are also viewed as factors that affect the pressure response of a reservoir and, hence, the cycle periods for injection and shut-in time. It has been claimed that, below “critical” oil saturation, no benefits are seen with pulsing. Since maximum oil recovery is seen after the first pulse and the production trend declines from then, this condition has an impact on deciding the pulsing time periods. Stirpe et al. conducted simulation studies for cyclic waterflooding in Lagocinco field, Venezuela. From their results, it was concluded that cyclic injection yields higher oil production and minimal water production. Stirpe et al. also stated that shorter well spacing and pressures above bubblepoint enhanced CWI. They added that oil recovery increases with vertical transmissibility, but there is a threshold value above which the benefits are negligible.

Araujo and Araujo (2005) conducted a series of laboratory experiments with continuous and cyclic injection on wettability controlled core plugs and summarized the results. Two samples of oil with varying viscosity were used. At breakthrough, an additional recovery of 23% over continuous waterflooding was obtained with the less-viscous oil using cyclic injection. However, Araujo concluded that the overall additional recovery with cyclic injection was no more than 15% over continuous waterflooding for the most favorable less-viscous oil and water-wet cores.

Al-Mutairi and Al-Harbi (2006) reported cyclic production mode as one of the four field practices employed to reduce operating expenses with water handling in the North Uthmaniyah area of Ghawar field, Saudi Arabia, since 2000. The objective was to yield maximum oil recovery with minimal water production. It was found that most water production came from the high water cut wells located in proximity to the injection system. Wells were shut-in and produced on a six-month cycle. During the shut-in period, the segregated water was pushed down the reservoir while oil accumulated in the top, due to density differences. Field results showed that water cut stabilized at 46% over five years with a 200 MBD reduction in cumulative water production. The water management project was a success economically (significant reduction in water maintenance and handling charges) and technically (conservation of reservoir energy leading to increased well life).

Ivanov and Araujo (2006) performed laboratory experiments to study the effectiveness of cyclic injection with respect to various parameters. A bead pack apparatus was used in the runs, and the effect of bead size, injection rate, oil viscosity, and cyclic period have been studied. Comparative studies with continuous waterflooding also have been reported. As for bead size, coarse-grade medium pack resulted in a high oil recovery with 75% PV for continuous injection and 80% PV for cyclic injection. At water breakthrough, 12%

incremental recovery was reported in cyclic over continuous injection. The fine-grade medium reported a higher oil-water ratio after breakthrough compared with the coarse-grade medium. Coarse-grade medium had a higher oil recovery before water breakthrough compared to fine-grade beads. With a varied range of cycling period from 15 sec to 2 min, it was found that the highest oil recovery was achieved with shorter cyclic periods. After 1 PV of water injection, 8% additional oil recovery was observed in the 30 sec on/off period over the 1 min on/off period in the fine-grade medium. The authors observed that cycling period has more effect on the flow pattern at early stages, before the water front has been fully formed. They reported that shorter pulses improve the water front with better fluid spreading into pore spaces in the early stages. This provided a greater number of flow paths to sweep oil in the later stages.

Ivanov and Araujo described low-rate cyclic injection as the best case when various injection rates were tested. With low viscosity oil, recovery after water breakthrough was much better in cyclic injection compared with continuous injection. Water spreading also happened quickly in cyclic injection. With high-viscosity oil, residual oil saturation was reached just after 2 PV of cyclic injection and 3.5 PV during continuous flooding. It was observed that when water migrates into new pores during rest, it reduced the entry capillary pressure thus enabling easy entry of water when injection recommenced. During the rest period, water migrated across regions of distorted fronts, softening the saturation profiles and removing discontinuities. It was concluded that, though the total oil recovery was in the order of same magnitude in both cases, residual oil saturation was achieved much earlier in the case of cyclic water injection.

Shchipanov et al. (2008) performed simulation studies on cyclic injection and production at a North Sea heterogeneous sandstone reservoir with high vertical permeability contrast. They reported that interlayer cross-flow and sweep in low permeability regions are improved using cyclic injection, with an increase of 9-

11% oil recovery. Reservoir heterogeneity, current saturation distribution, well control parameters, perforation intervals, and rock-fluid compressibility were identified as the key parameters that exert direct influence on cyclic injection. Having analyzed the cyclic time periods, Shchipanov et al. concluded that longer cycles allowed up to 5% extra oil recovery while shorter cycles contributed to 3% additional oil. They also reported that the shorter time-cycle values are likely to be underestimated due to inaccurate representation of a small-scale reservoir model.

Surguchev et al. (2008) carried out laboratory, analytical and numerical simulation studies to evaluate the performance of cyclic injection in a carbonate reservoir under reservoir conditions. To determine the effect of gas in the reservoir, their experiments included an initial waterflooding, pressure cycling above and below bubblepoint pressure, and final blowdown. Simulation predicted an additional recovery of 3% of original oil in place (OOIP) above conventional waterflooding. Experimental results showed that 37% recovery of OOIP was obtained during the normal waterflood. An additional 2.9% during cycling above bubblepoint, 5.9% during cycling below bubblepoint and another 4% of OOIP with final pressure blowdown was achieved. A total recovery factor of 50% of OOIP meant that the study was a success. It was noted that cycling below bubblepoint pressure yielded better results compared with cycling above bubblepoint pressure. These improved results were attributed to gas energy released from the solution below bubblepoint pressure, which provided better sweep efficiency. Surguchev et al. concluded that gas energy remaining in the reservoir is utilized to maximum advantage in cyclic injection rather than traditional waterflooding.

CHAPTER 3 EXPERIMENTAL SETUP

The main objective of this work was to evaluate the influence of variation in brine salinity and cyclic injection of water on oil recovery and rock wettability, on a core scale. Hence, experiments were conducted on a coreflood rig designed by a previous researcher (Agbalaka 2006) who studied the effect of brine salinity on rock wettability. All experiments conducted with dead oil were in the secondary recovery mode. Some modifications were made to the original setup to suit experimental needs. In this chapter, a brief description of the overall setup is mentioned. Also addressed here are the modifications made according to needs, the programming of ISCO pump for cyclic flow, and recombination of oil and gas for coreflooding at reservoir conditions.

3.1 Description of Coreflood Rig

In this section, the setup used for cyclic injection involving dead oil is briefly discussed. This basic setup was used for all the experiments conducted. Figure 3.1 shows a schematic of the coreflooding rig. The coreflooding rig consists of a TEMCO RCHR series Hassler type core holder rated at a maximum working pressure of 7,500 psi and temperature of 350°F. It consists of an outer metal jacket and an inner rubber sleeve placed concentric to each other. The rubber sleeve holds the core plugs (1.5” in length and up to 6” in diameter). The annular space between the metal jacket and rubber sleeve is filled with hydraulic oil. The condition of overburden pressure is simulated by applying radial pressure on the rubber sleeve. This is achieved by pressurizing the hydraulic oil using a hand pump. There are spacers, distributers, and retainers that complete the core holder setup and help in holding the core plug in position within the rubber sleeve.

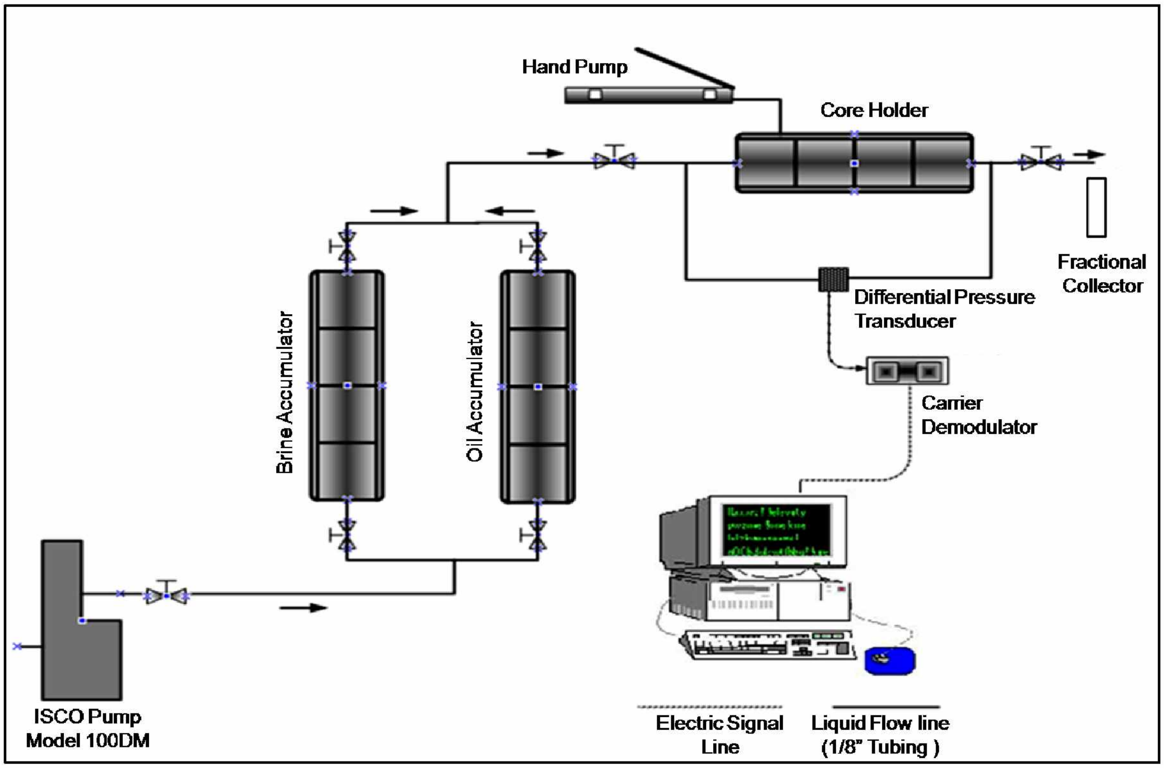

Figure 3.1 Coreflood Apparatus Used for Dead Oil Runs (Modified after Patil 2007)

There are two accumulator cylinders (500 cc volume), rated at operating conditions of 10,000 psi and 350°F, that contain water and oil, respectively. An ISCO pump is used to pump in the fluids (at constant pressure/flow rate) from the accumulator into the coreflood rig. These accumulators have a cylindrical floating piston that separates the liquid columns above and below it. De-ionized water is pumped from the ISCO pump into the lower end of the accumulator at constant pressure or flow rate. The pump pressurizes the fluid (brine/oil) in the accumulator into the core holder, by pushing the piston upwards in the accumulator. Valves are used accordingly to facilitate the flow of either brine or oil. The fluid pushed from the accumulators flows to the injection face of the core plugs held in place under overburden pressure in the core holder. A Validyne differential pressure transducer (maximum working pressure = 125 psi) is used to measure the differential pressure across the core. For experiments using dead oil, the produced fluids were collected in a fractional collector.

3.2 Modified Setup for Reservoir Condition Runs

Figure 3.2 shows the setup used for flooding recombined oil. The original setup used for dead oil is modified. In this case, recombined oil under reservoir conditions is contained in one of the accumulators. To maintain reservoir temperature, the accumulator, core holder, and tubing are wrapped and heated with heat tape. The temperature is measured using a thermocouple. Additional pressure gauges and valves were fitted at the ends of the accumulator and core holder to monitor and regulate the pressure.

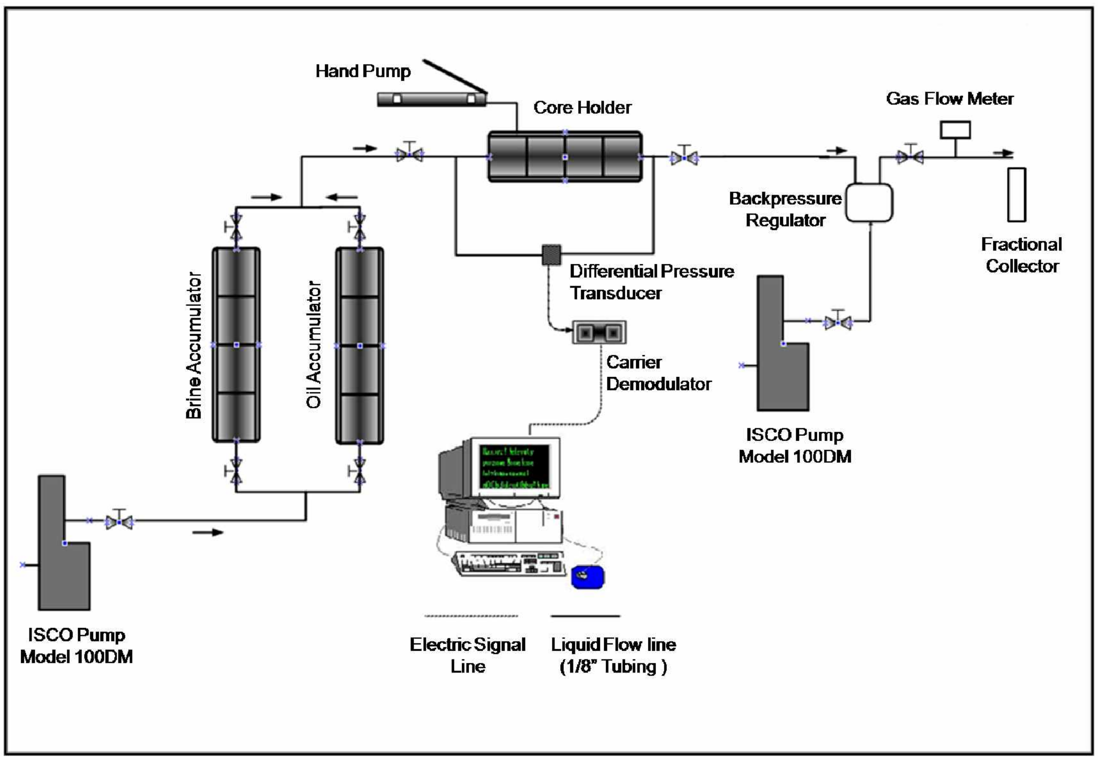

Figure 3.2 Coreflood Apparatus Used for Coreflooding at Reservoir Conditions (Modified after Patil 2007)

Additionally, a backpressure regulator and a gas flow meter (GFM) are incorporated into the setup. The backpressure regulator is connected at the end of the setup to build pressure in the coreflood rig, to achieve reservoir pressure. An ISCO pump is used to pressurize the backpressure regulator. A gas flow meter is used to measure the flow rate of gas at the outlet. The readings are logged with respect to time, and later used for calculating the volume of gas. Oil and water produced are measured in the fractional collector.

Agbalaka (2006) provides a detailed description of the setup, equipment used, and the principle of operation.

3.3 Recombination of Oil

To simulate live oil conditions, recombination of oil and gas above bubblepoint conditions is necessary for the fluids to remain in a single phase. Oil is recombined with gas at reservoir temperature and pressure in a rocker apparatus (Figure 3.3). Oil and gas at the desired gas-oil ratio (GOR) are injected into an accumulator. Heat tapes and insulation are wrapped around the accumulator. It is then mounted onto the rocker. The accumulator is heated to reservoir temperature. On reaching the reservoir temperature, the accumulator is pressurized to reservoir pressure using an ISCO pump. The sample is then rocked at reservoir conditions for 3-4 days to form recombined oil. A pressure gauge and temperature controller are mounted to read values and control them when necessary.

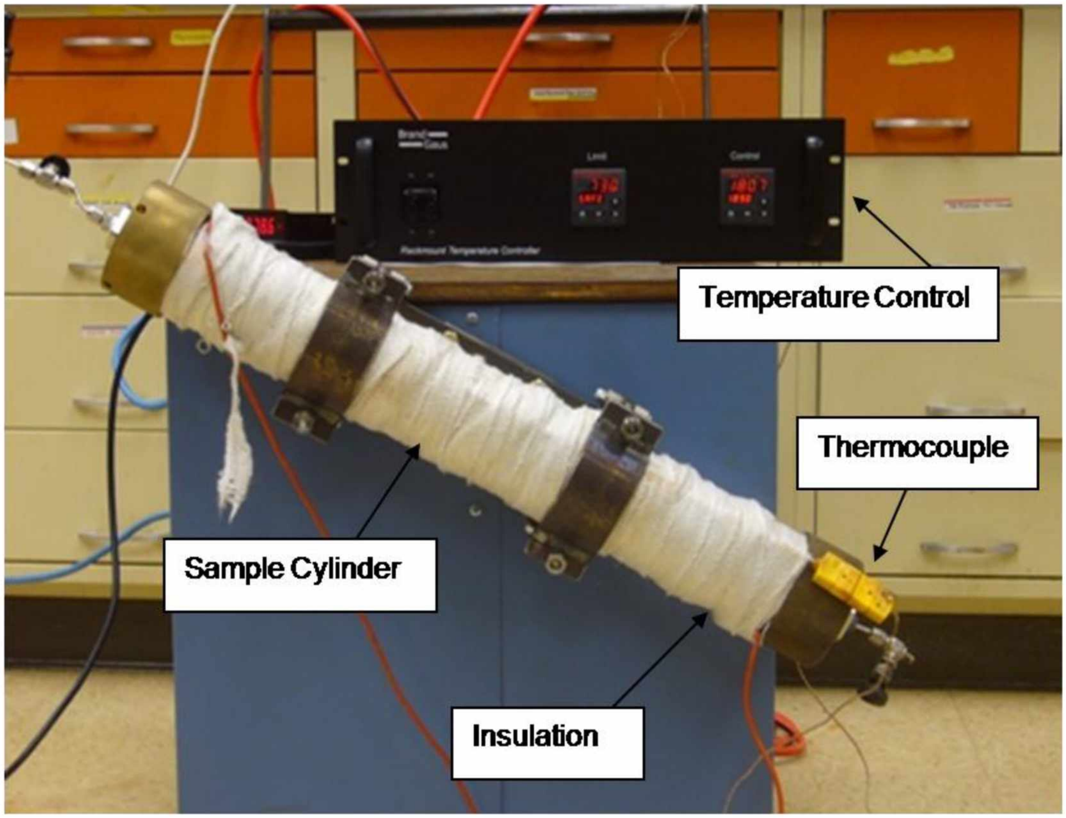

Figure 3.3 Rocker Apparatus for Oil-Gas Recombination

3.4 Programming ISCO Pump for Cyclic Injection

The coreflood setup is the same for continuous and cyclic injection. The ISCO pump can be programmed to deliver an output that simulates cyclic injection. It is done using the “Program Gradient” section of the ISCO pump. A constant injection rate is to be entered every time the program is to be run. The program can be set such that the flow delivered from the pump is expressed as a percentage of the flow rate mentioned at the start of the program. The time of flow can also be set according to requirements. When the program is started, the desired flow rate is entered in cc/min. To set a flow of particular injection rate, Q_1 for a specific time, t_1 and then another injection rate, Q_2 for another time, t_2, Q_1 and Q_2 are expressed as fractions of the initial flow rate entered. Times t_1 and t_2

are expressed in minutes. It should be noted that the minimum time that the pump takes for transition from one flow rate to another is 0.1 minute. Let us consider this transition flow rate as Q_3 and transition time as t_3. Even if alternating injection rates of only Q_1 and Q_2 are required, the transition flow rate Q_3 has to be set for t_3 minutes between every Q_1 and Q_2. This sequence has to set up as a loop that keeps running till the end. The ISCO pump allows up to 100 steps in a program, which can be programmed for different flow rates and time.

For instance, in the present study, cyclic injection of brine at a flow rate of 0.5 cc/min for one minute is to be followed by an idle injection for a minute. In this case, the initial flow rate is set as 0.5 cc/min. Then, a simple four-step cycle is created which is to be repeated in a loop. The steps are as follows:

1. A flow rate of 0.5 cc/min for one minute is required. Thus, the start flow rate and final flow rate are expressed as 100% for a time of 1 minute.
2. This is the transition step wherein the flow declines from 0.5 cc/min to 0 cc/min. Thus, the start flow rate is set as 100%, and the final flow rate is set to 0% for 0.1 minute. As mentioned earlier, 0.1 minute is the minimum time it takes for transition between two flow rates.
3. Injection has to cease for one minute to characterize an idle flow situation. Thus, the start flow rate and final flow rate are expressed as 0% for 1 minute.
4. This transition step increases the flow to 0.5 cc/min. Thus, the start flow rate is set as 0% and final flow rate is set to 100% for 0.1 minute.

These four steps are repeated in a loop till the 100^{th} step. A cycle has thus been formed with the desired flow conditions. After saving the program, the settings can be changed such that the program repeats itself from step 1 once the 100^{th} step is complete. This assures that an infinite loop of a CWI pattern is created in the program. The injection rate was maintained at 0.5 cc/min. Table 3.1 gives the steps followed to create the pattern discussed above.

Table 3.1 ISCO Pump Output for Cyclic Injection

Step	Initial Flow Rate (%)	Final Flow Rate (%)	Time (min)	Resulting flow (cc/min)
1	100	100	1	0.5
2	100	0	0.1	Transition: 0.5 to 0
3	0	0	1	0
4	0	100	0.1	Transition: 0 to 0.5

This type of program simulates the actual conditions in a reservoir. If an injection has to be stopped, it cannot be completed in a split second. The transition time taken by the pump is similar to the time taken to close/open the valves that control the flow. Figure 3.4 shows a graphical representation comparing the desired output pattern from cyclic injection and the actual output by ISCO pump.

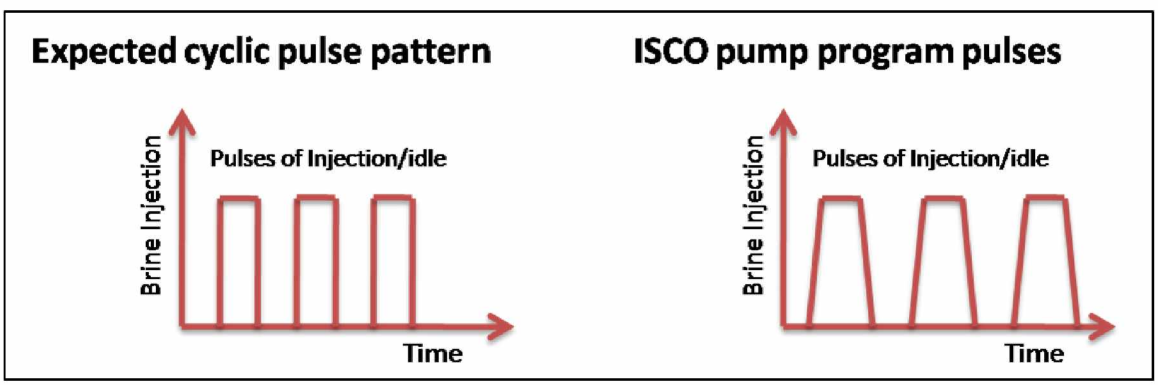

Figure 3.4 Expected vs. Actual Cyclic Pulses

CHAPTER 4 EXPERIMENTAL DESCRIPTION AND PROCEDURE

As part of the current work, the experiments were primarily designed to evaluate the influence of change in brine salinity and cyclic water injection (CWI) on rock wettability and oil recovery. It is believed that the results from the experiments will serve as a pointer to similar tests being conducted, because the evaluation of a combination of cyclic water injection and brine salinity variation has not been reported yet. To assess the effect of low salinity brine, synthetic reconstituted brines of different salinity were prepared in the lab. Reduction in salinity was achieved by reducing the amount of total dissolved solids (tds) in the brine. As a source of ultra-low salinity water, ANS lake water was investigated as a potential low salinity waterflooding option. In addition to dead oil, the tests were conducted with recombined oil as well to examine the properties at reservoir conditions. In an attempt to study wettability alteration, oil-aging of cores and subsequent low salinity cyclic injection was performed. As a fine-tuning option, cyclic injection was tested with two different pulse intervals. On the whole, the experiments can be divided into two sections: coreflooding at ambient conditions and coreflooding at reservoir conditions.

Coreflooding at ambient conditions used dead oil and cyclic injection in the following cases:

1. Evaluation of brines of different salinity
2. Investigation of ANS lake water as a source for secondary recovery
3. Assessment of wettability alteration by oil-aging and low salinity waterflooding
4. Testing of different pulse intervals in cyclic injection for optimization

The main aim of coreflooding at reservoir conditions was to test the potential of low salinity cyclic injection at actual field conditions. Due to operational constraints, cyclic injection could not be implemented. Flooding of recombined oil at reservoir conditions demanded a high operating pressure (above bubblepoint) to keep the fluids in single phase. Pressure control and optimum fluids production in cyclic injection mode were difficult to achieve at high operating pressure and backpressure conditions. Thus, the plan of cyclic water injection was dropped. Continuous waterflooding at constant pressure was performed with a high saline brine followed by flooding a lesser saline brine in tertiary recovery mode.

4.1 Core Samples

Thirteen representative core samples from ANS were used in the current study. They were all cylindrical sandstone cores cored from a depth of 10,640-10,800 ft. The cores were approximately 1" in length and 1.5" in diameter. Porosity and permeability of all the core samples were determined in the laboratory. Porosity was in the range of 18-23% and permeability values were between 60 mD-160 mD.

Porosity was determined using the saturation method discussed later in this section. The core was flooded with brine, and differential pressure across the brine-saturated core after reaching steady state was determined. Absolute permeability was calculated from Darcy's law based on the differential pressure value. Table 4.1 gives the porosity and permeability values of the cores that were used.

Table 4.1 Porosity and Permeability of Core Samples

Core Number	Porosity (%)	Permeability (mD)
149	20.3	77.13
151	18.7	154
152	18.03	100.23
43	20.49	50.45
45	18.3	84.08
46	20.3	89.36
1	20.4	60.79
51	20.7	80.38
141	19.34	118.88
180	19.8	102.53
181	20.04	71.24
49	21.38	93.26
145	22.1	96

4.2 Brine Sample

Alaska North Slope lake water from Kuparuk Dead Arm (KDA lake 5) (approximately 60 ppm) was used. Other brines were reconstituted in the lab. Figure 4.1 shows the tds composition of representative ANS formation water as reported by McGuire et al. (2005). Based on this data, brines of different salinity (22,000 ppm, 11,000 ppm, and 5,500 ppm) were synthesized in the lab by dissolving different salts in de-ionized water in fixed proportions. The salts used were sodium chloride (NaCl), potassium chloride (KCl), sodium bicarbonate ($NaHCO_3$), sodium sulfate (Na_2SO_4), calcium chloride ($CaCl_2$), strontium chloride ($SrCl_2$) and magnesium chloride ($MgCl_2$). McGuire's data lists the tds with respect to ions present in the formation water. The number of moles of ions is calculated from the ANS formation water data. Mole balance is done to find the number of moles of each salt to be added to the solution.

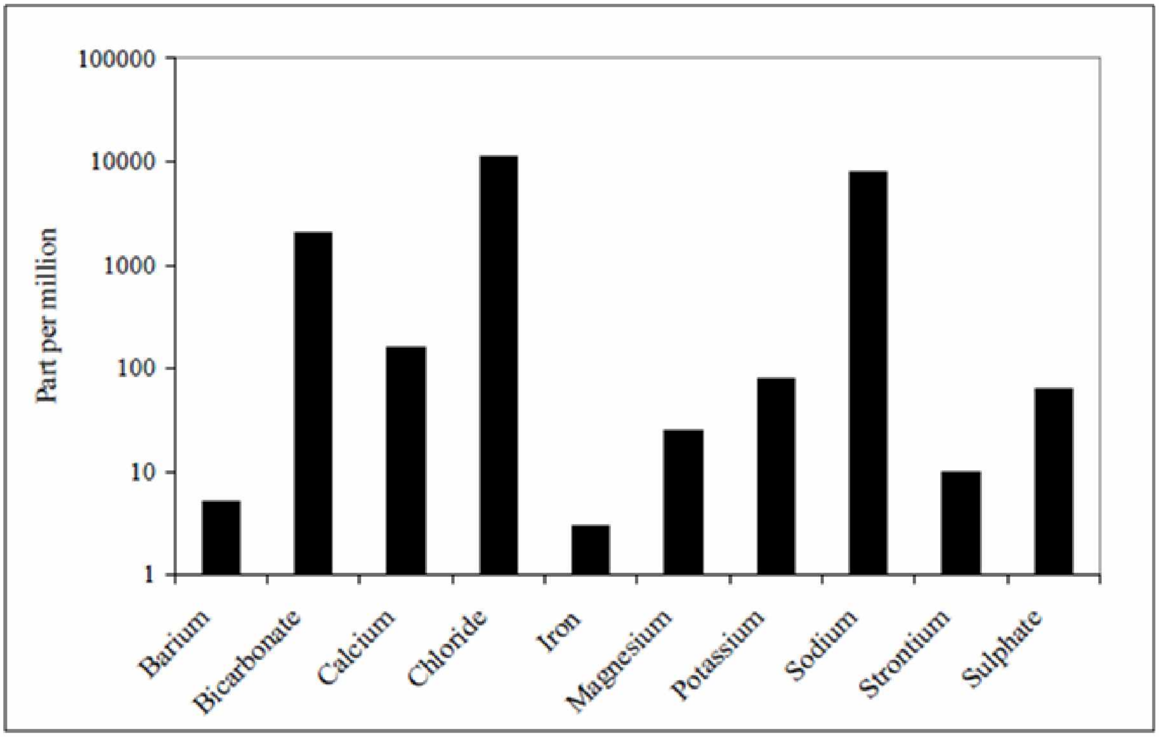

Figure 4.1 Ionic Composition in ANS formation Water as Reported in McGuire et al. 2005 (Patil et al. 2008)

The required mass (*W*) of each salt is calculated as follows:

$$W = (M * Mol.\ Wt * L * \rho) / 10^6 \qquad (4.1)$$

where ,

M - Moles of salt

Mol. Wt - Molecular weight of salt

L - Liters of solution (brine) to be prepared

ρ - Density of solution (brine) to be prepared.

The density of formation water at standard conditions can be estimated from the following correlation (McCain 1991):

$$Density = 62.368 + 0.438603S + 0.00160074S^2 \tag{4.2}$$

where, S is the weight percent of total dissolved solids.

Density of the brines was measured using an Anton-Paar Densitometer. The values are tabulated and listed in Table 4.2 . At room temperature, the viscosity of brine was measured to be 1.12 cP using a Brookfield Viscometer.

Table 4.2 Density of Brine Samples

Brine Salinity (ppm)	22,000 tds	11,000 tds	5,500 tds	ANS Lake Water
ρ at 77°F (g/cc)	1.0139	1.0065	1.0028	1.0002

4.3 Crude Oil

Representative ANS crude oil (dead oil) was used for the current work. The density and viscosity of the crude oil were measured using an Anton-Paar densitometer and a micro-viscometer, respectively. At room temperature, the density of the crude oil was 0.9108 g/cc, and the viscosity was 6.3 cP. Table 4.3 and Table 4.4 give details of density and viscosity of the dead crude oil sample at various temperatures.

Table 4.3 Density of Crude Oil

Temperature (°C)	Oil Density (g/cc)
20	0.9108
25	0.90753
30	0.90419
35	0.90083
40	0.89749
50	0.89077
60	0.88403
70	0.87725
75	0.87384
80	0.87043
90	0.86355

Table 4.4 Viscosity of Crude Oil

Temperature (°C)	Viscosity (cP)
20	6.3041
40	2.9758
60	1.2963
80	0.7537

4.4 Pre-experimental Procedure

4.4.1 Core Sample Preparation

All the cores used for the experiments were cleaned prior to using. The refrigerated new cores were first brought to atmospheric temperature conditions.

Then they were flushed with toluene followed by acetone. Toluene serves the purpose of cleaning out hydrocarbon-based compounds, if any. Acetone dissolves the toluene and/or water, if any were present in the core. To check if cleaning of cores using toluene and acetone made any difference to the mineral properties of the rock, X-ray diffraction (XRD) tests were performed on a portion of an end trim from one of the cores. A small segment of an end trim portion was subject to XRD tests to read the minerals present in it. It was then cleaned with toluene followed by acetone. The test was repeated. Results showed that rock mineralogy remained constant and chemical cleaning did not have any effect on it. Figure 4.2 is a graphical representation of the XRD results. The peaks indicate quartz.

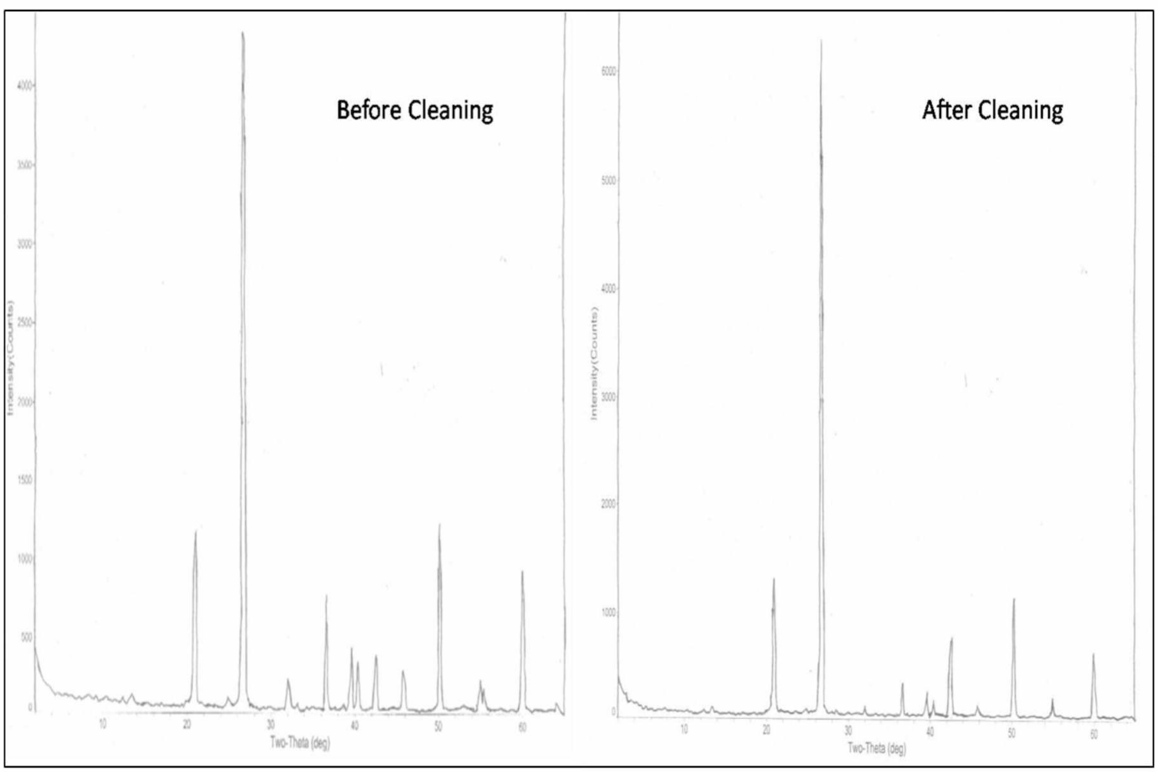

Figure 4.2 Results from X-Ray Diffraction Done on a Portion of an End Trim

After cleaning, the core plugs were dried in an air oven at 175°F for 3-4 days. The cores were weighed consistently upon their removal from the refrigerator. When in the oven, the cores were weighed every day till it arrived at a constant weight, indicating the removal of all fluids from the pores.

4.4.2 Core Saturation

The dried core samples were weighed on a mass balance and then placed in a flask containing 22,000 ppm salinity brine. The core samples were saturated for 5-7 days under vacuum. Placing under vacuum ensured de-aeration of brine and facilitation of the brine in filling the pore spaces of the core. At the end of saturation, it is believed that the brine has achieved ionic equilibrium with the core plug.

4.4.2.1 Pore Volume and Porosity Determination

The porosity of the core plugs was calculated by the saturation method. The pore volume is calculated as the gain in weight by saturating a dry core sample with a fluid of known density. Porosity is determined as the ratio of pore volume over bulk volume of the core of known dimensions.

$$PV = (M_{wet} - M_{dry}) / \rho_{brine} \tag{4.3}$$

where PV is the pore volume (cc), M_{dry} is the weight of the dry core (g), M_{wet} is the weight (g) of the core after saturating with brine of known density (g/cc), ρ_{brine}.

$$\Phi = (PV/BV)*100 \tag{4.4}$$

where φ is the porosity, PV is the pore volume (cc), and BV is the bulk volume (cc). The bulk volume is calculated as the volume of a cylinder with a known diameter and length.

The accuracy of the porosity calculation by saturation method was cross-verified by measuring the wet weights of the cores after brine floods for differential pressure measurement to calculate absolute permeability. In most cases, there was a difference of 0.1-0.3 g in the wet weights measured after saturation and brine flooding, causing marginal deviations in the calculated porosity values. Agbalaka (2006) had cited similar observations in his experimental work. For the current work, porosity values obtained from wet weight after brine floods were used. This was because all experimental runs were conducted in the coreflood apparatus, and brine flood is an integral part of the experiments.

4.4.2.2 Absolute Permeability Determination

The absolute permeability of the core was calculated after determining the differential pressure across the core during a continuous brine flood. According to an assumption of Darcy's law, the core must be completely saturated with brine. A differential pressure transducer was connected to the inlet and outlet ends of the core holder to measure the pressure drop across the core plug. For the experiments with dead crude oil, the outlet was open to atmospheric pressure. As brine injection started, the pressure drop increased continuously for some time because of the resistance to brine flow by the core sample placed in the core holder. As time passed on, the brine managed to flow through more pore spaces of the core to the outlet. This was characterized by a pressure drop across the core. A steady state was achieved when the pressure drop stabilized at a value and did not change with time. At this stage, it was assumed that the core was completely saturated with water and was at equilibrium with the flow across it. Typical injection rates were between 200-300 cc/hr. Initially, up to 50 pore volumes of brine were injected to arrive at an accurate pressure drop. Based on experience, steady state was achieved at 30-35 PVs of water injected. The pressure drop value across the core was noted as dP.

Absolute permeability (k) was calculated using Darcy's law:

$$K = (Q*L*\mu)/(A*dP) \tag{4.5}$$

where,

k - absolute permeability, Darcy

A - cross-sectional area, cm^2

dP - differential pressure, atm

L - length, cm

Q - flow rate, cc/sec

μ - viscosity, cP

4.5 Experimental Procedure - Dead Crude Oil

As discussed earlier, the experiments involving dead oil were designed to evaluate the effect of low salinity cyclic water injection on oil recovery, residual oil saturation, and rock wettability. Dead oil and cyclic injection were employed in all experiments. Two sets of cores were tested: used and new cores. Used cores were already employed by a previous researcher (Patil 2007) for the evaluation of low salinity continuous water injection. New cores were freshly taken out of the refrigerated storage unit. For oil-aged experiments, the used cores were oil-aged and tested. Based on that, the experiments were divided into four sets:

1. Use of 22,000 ppm, 11,000 ppm, and 5,500 ppm tds salinity brines on three used cores
2. Use of ANS lake water and 22,000 ppm tds salinity brine on three used cores
3. Use of 22,000 ppm, 11,000 ppm, and 5,500 ppm tds salinity brines on three oil-aged cores
4. Use of 22,000 ppm tds salinity brine on five new cores with two different symmetric pulse intervals – 1 minute and 0.3 minute

All the experiments were conducted at atmospheric temperature conditions. An overburden pressure of 500 psi was applied. For absolute permeability measurements, brine floods were conducted at a constant flow rate of 200-300 cc/hr with 22,000 tds salinity brine. Forced displacements of oil and brine were carried out at a constant pressure of 30-50 psi. Wettability characterization was done using the Amott-Harvey Relative Displacement Index (I_{AH}) obtained from modified Amott-Harvey tests. For all waterflooding runs, cyclic injection with a flow rate of 30 cc/hr was used. The cores were weighed after every flooding or displacement run. Figure 4.3 is a pictorial representation of the dead crude oil experiments on a secondary recovery mode.

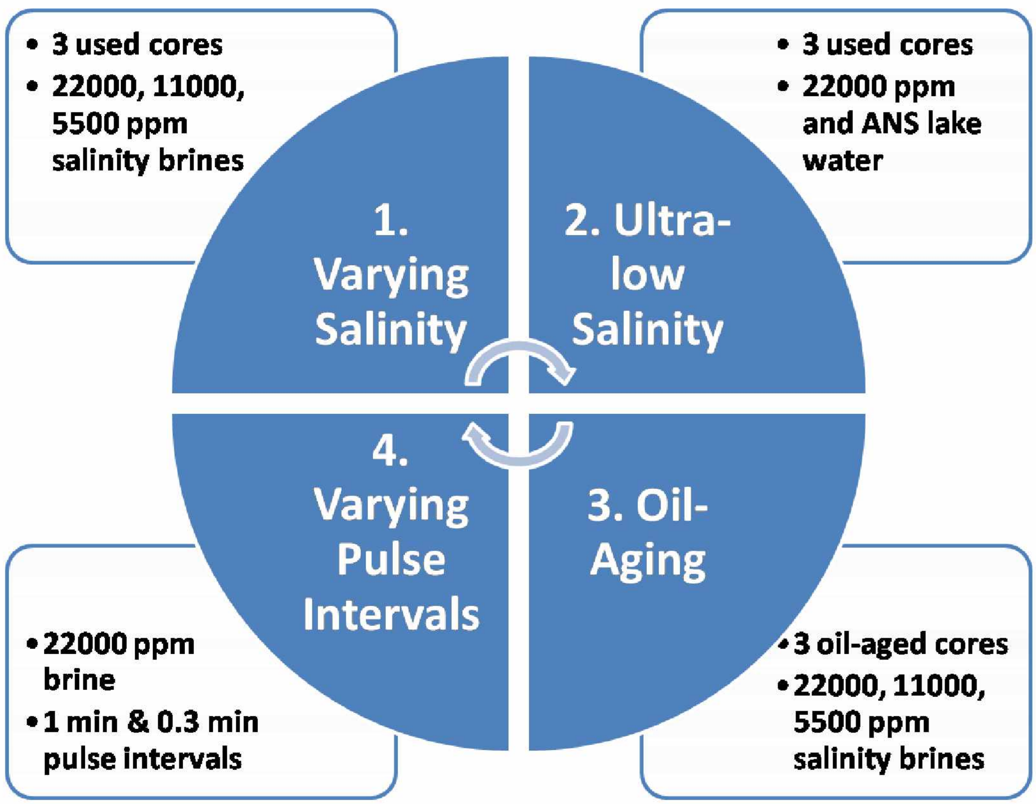

Figure 4.3 Experiments Conducted with Dead Crude Oil

4.5.1 First Set (Varying Salinity)

This set involved the usage of 22,000 ppm, 11,000 ppm and 5,500 ppm tds salinity brines for waterflooding. Three cores used for continuous injection by a previous researcher were used.

4.5.1.1 Connate Water Saturation Establishment

The porosity of the core was measured using saturation method. For calculating absolute permeability, continuous waterflood at a constant flow rate (200-300 cc/hr) was conducted. From the obtained differential pressure, absolute permeability was calculated. To establish connate water saturation, the completely brine-saturated core was flooded with oil in the core holder. Oil started displacing water from the core. The volumes of the produced fluids were measured. The oil could not displace all of the water present in the core due to rock wettability and capillary forces favoring the presence of water inside the core. The volume of water produced indicated the volume of oil present inside the core. Displacement of water by oil continued until no more water was produced at the outlet, indicating the attainment of connate water saturation in the core sample. Oil-water equilibrium was established inside the core. This is the estimated initial oil in place for the experiment.

4.5.1.2 Wettability Index Determination

As mentioned earlier, wettability characterization was done by calculating the wettability index using the modified Amott-Harvey wettability test. This method started with the core at connate water saturation. Connate water saturation was established by flooding oil through the brine-saturated core to displace water.

The core at connate water saturation was weighed and immersed in brine for 20 hours. During this time, spontaneous displacement of oil by brine took place. If the core is completely water-wet, the brine would displace oil spontaneously to waterflood residual oil saturation (S_{or}). After 20 hours, the volume of oil displaced was noted as V_{osd}. The core was weighed and placed in the core holder, followed by forced displacement of oil by brine at constant pressure. If water is the wetting phase, it imbibes into the pore spaces, displacing oil with ease. Injection of brine was stopped when no more oil was produced. This indicated the residual oil saturation (S_{or}). The volume of oil displaced by the brine by forced brine flooding was noted as V_{ofd}.

The core was removed from the core holder, and a reverse process was executed. The core was weighed and immersed in oil for 20 hours. The oil displaced brine spontaneously. If the core is strongly water-wet, little brine is displaced by oil. After 20 hours, the volume of water displaced was noted as V_{wsd}. The core was weighed and placed in the core holder, followed by forced displacement of brine by oil at constant pressure. Injection of oil was stopped when no more water was produced. The volume of water forcefully displaced by the oil was noted as V_{wfd}.

The Amott-Harvey Relative Displacement or Wettability Index (I_{AH}) was calculated as specified in the formula mentioned earlier. For convenience, it is shown here again:

$$I_{AH} = (V_{osd}/(V_{osd}+ V_{ofd})) – (V_{wsd}/(V_{wsd}+ V_{wfd})) \tag{4.6}$$

The Amott-Harvey Wettability Index ranges from –1 to +1, representing strongly oil-wet and strongly water-wet states, respectively, with zero indicating neutral wettability.

4.5.1.3 Cyclic Waterflooding

After forced water displacement, the core was weighed and then put back into the core holder. Using 22,000 ppm tds salinity brine, cyclic water injection was conducted at a flow rate of 30 cc/hr and 0 cc/hr in a symmetric pulse interval of 1 minute. This meant a flow of 30 cc/hr for a minute, followed by an idle injection period of one minute. Water displaced oil in this process. The volume of oil produced was recorded as a function of PVs of brine injected. Injection was stopped when no more oil was produced. Initially, about 10 PVs of brine was injected to find if residual oil saturation was attained. Based on experience, it was found that residual oil saturation is reached much earlier than 10 PVs, in cyclic water injection.

After waterflooding, the wettability of the core plug was determined. It was followed by cyclic water injection using 11,000 ppm tds salinity brine. The same procedure was repeated with 5,500 ppm tds salinity brine. Residual oil saturation was calculated at the end of every step. The Amott-Harvey Wettability Index was calculated after each cyclic waterflood. In all these cases, it was decided to keep the connate water salinity as 22,000 ppm. This was done because the formation brine salinity is always high and connate water salinity in the reservoir would be as high as 22,000 ppm, if not higher. The invading brine salinity was reduced to evaluate the effect of the low salinity waterflooding. All the experiments began at the same initial conditions, with the cores at initial oil saturation (S_{oi}) and connate water saturation (S_{wi}) stage.

Since the wetting state of the core had to be determined after each waterflood, the core had to be restored to initial conditions (oil-saturated core at connate water saturation) after each cyclic water injection. Once cyclic waterflooding by 22,000 ppm was over, continuous brine (22,000 ppm) injection and subsequent oilflooding was attempted to restore initial water saturation conditions. The same procedure had to be followed after waterflooding with 11,000 ppm and 5,500 ppm salinity brines. Similar values (with slight variations) of connate water saturation were obtained for all the cyclic waterfloods. To normalize the effect of marginal deviations in the restored connate water saturation, oil recovery was calculated as a function of original/initial oil in place (OOIP) with respect to the particular waterflood.

Apart from the wettability index, oil recovery and residual oil saturation were calculated for each cyclic waterflood. Oil recovery was calculated as:

$$RF = V_{OR}/V_{OOIP} \tag{4.7}$$

where,

RF - Oil recovery factor *100 (%)
V_{OR} - Volume of oil recovered after cyclic waterflooding (cc)
V_{OOIP} - Volume of original/initial oil in place at connate water saturation conditions for the set using that particular salinity brine (cc)

The residual oil saturation was calculated as:

$$S_{or} = (PV - V_{OR})/PV \tag{4.8}$$

where,

S_{or} - Residual oil saturation of core at the end of cyclic waterflooding *100 (% PV)
PV - Pore Volume of the core (cc)
V_{OR} - Volume of oil recovered after cyclic waterflooding (cc)

The volume of oil recovered was determined using a fractional collector under visual observations. The same procedure is followed for all three used cores in the first set. Figure 4.4 shows a pictorial representation of the whole sequence of experiments conducted.

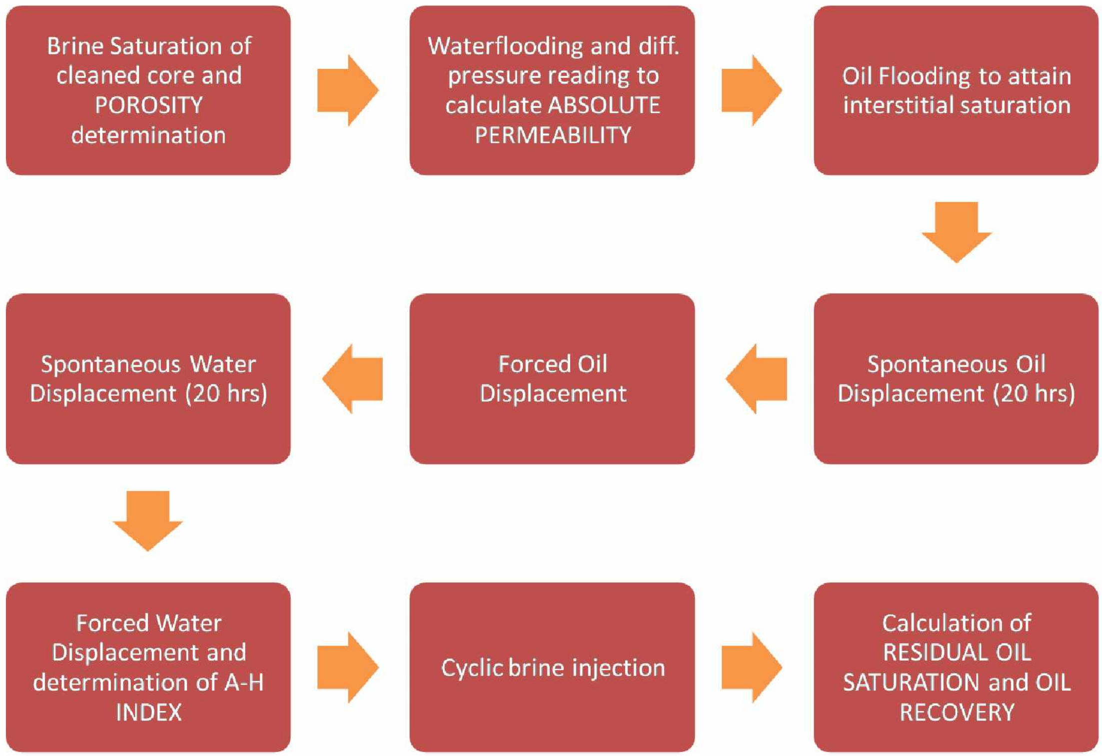

Figure 4.4 Sequence of Experimental Runs with Dead Oil

4.5.2 Second Set (22,000 ppm and ANS Lake Water)

In addition to the 22,000 ppm salinity brine reconstituted in the lab, ANS lake water from Kuparuk Dead Arm (KDA lake 5) was used for this experiment. Since melting snow and rainwater mainly contribute to the water accumulation in ANS lakes (Patil 2007), this is considered to be a ultra-low salinity source. The salinity was measured to be 50-60 ppm tds. The investigation of ANS lake water as a potential low salinity option for ANS operators was the main objective of this set of experiments.

Until cyclic waterflooding by 22,000 ppm tds salinity brine, the sequence and procedure followed in this case was the same as the first set of experiments. After that, instead of using 11,000 ppm and 5,500 ppm tds salinity brines, ANS lake water was used for the cyclic waterfloods. Wettability, oil recovery, and residual oil saturation were calculated after every waterflood.

4.5.3 Third Set (Oil-aging)

The purpose of this set of experiments was to assess the effect of oil-aging on core wettability and residual oil saturation followed by subsequent low salinity cyclic injection to enhance oil recovery. Three used cores were used.

For the oil-aging case, the first step was to establish connate water saturation. Then, the cores were put in a steel tin filled with dead crude oil. The cores were oil-aged at 180°F for 30 days. After aging, the cores were cooled to room temperature. Then the same procedure followed for the first set of experiments was followed. Reconstituted brines of 22,000 ppm, 11,000 ppm, and 5,500 ppm salinity were used. Wettability and residual oil saturation were calculated after every waterflood.

4.5.4 Fourth Set (Varying Pulse Intervals)

In the varying pulse intervals case, the main objective was to evaluate the influence of change in pulse intervals in cyclic water injection on residual oil saturation and oil recovery. The experiments were conducted on five new cores with 22,000 ppm tds salinity brine. Two symmetric pulse intervals of 1 minute and 0.3 minute were used to test longer and shorter time periods of injection and inactivity. Two programs in a cyclic injection pattern with the mentioned time intervals were created in the ISCO pump.

The procedure used for the first set of experiments was used in this case too. During cyclic waterfloods, the change in brine salinity was replaced by change in pulse intervals. Cyclic injection was achieved by using the program with 1 minute pulse intervals in the first set and switching over to the one with 0.3 minute in the second set. The salinity of brine injected was kept constant at 22,000 ppm. As usual, wettability, S_{or}, and oil recovery were calculated after every waterflood.

4.6 Coreflooding at Reservoir Conditions - Experimental Procedure

Dead oil experiments do not simulate the actual reservoir conditions completely. In real-time reservoir conditions, there might be gas caps and solution gas present that affect oil production and recovery. Thus, it is necessary to mimic actual reservoir conditions with elevated temperature and pressure conditions. It is necessary to recombine the dead oil sample with gas and continue waterflooding experiments with brines of different salinities.

The objective of this experiment was to evaluate the effect of change in brine salinity on oil recovery and residual oil saturation, at reservoir conditions. Two new cores and brines of 2 different salinities — 22,000 and 11,000 ppm tds— were used for waterflooding. Since cyclic injection was dropped due to operational constraints, continuous injection of water was practiced. Representative crude oil from ANS was recombined with methane gas at high pressure and temperature to form a representative live oil sample. Since recombined oil remains as a solution only above bubblepoint pressure and temperature, these runs were conducted above bubblepoint conditions.

For recombination of gas-oil, methane gas was used as a representative since most of the gas produced in the reservoir contains methane in higher proportions. Details of the well from which the dead oil sample was acquired were obtained from the well data archives of the Alaska Oil and Gas Conservation Commission (AOGCC). The gas-oil ratio was 1080 SCF/STB on average. The solution gas-oil ratio was calculated and the methane-dead oil mixture was recombined in a rocker apparatus at 200°F and 2,400 psi for 3-4 days to prepare recombined oil.

The new cores were saturated under vacuum in 22,000 ppm salinity brine for 5-7 days. After calculating the porosity values, the cores were waterflooded at high flow rates to find the differential pressure and, thus, absolute permeability. Live oil floods were conducted at constant pressure to establish connate water saturation. Backpressure was maintained to prevent flashing and build the operating pressure to reservoir conditions. Increased overburden pressure of 2,500 psi was maintained to keep the core in place. Continuous injection of water (22,000 ppm salinity) was performed to produce oil and gas (at surface conditions). Gas flow meter data was logged to calculate the volume of gas produced. When no more oil was being produced by this injection, 11,000 ppm salinity brine was continually injected to recover any additional oil, in the tertiary oil recovery mode. Oil recovery and residual oil saturation were calculated at the end of each waterflood.

Results of all experiments conducted using dead and recombined oil are presented in the next chapter.

CHAPTER 5 RESULTS AND DISCUSSIONS

In general, oil recovery increased with a decrease in brine salinity. Reduction in residual oil saturation was more pronounced with brines of lesser salinity. Alaska North Slope lake water yielded the highest oil recovery. Compared to continuous injection, residual oil saturation was reached within lesser pore volumes of water injected. Wettability index shifted towards water wetness accompanied by increased oil production, as brine salinity was reduced. Overall oil production was higher in cyclic injection when compared to continuous waterflooding, given similar salinity of brine injected. Oil-aging caused an impact on wettability by reducing the water wetness of the core. For the same brine injected, shorter pulses yielded higher production than longer pulses. In coreflooding at reservoir conditions, the initial oil saturation established was not as high as that observed in dead oil cores. Incremental oil was produced in the tertiary mode with low (11,000 ppm) salinity brine. Additional decrease in residual oil saturation was noted in the tertiary recovery mode. All these general observations were consistent.

5.1 Effect of Varying Salinity

Three cores were used with brines of 22,000 ppm, 11,000 ppm and 5,500 ppm. Another three cores were used with 22,000 ppm salinity brine and ANS lake water. All six cores were already employed for continuous waterflooding by a previous researcher, (Patil 2007). Figure 5.1 shows a graphical representation of the recovery percentage from original oil in place when brines of different salinity were used for cyclic injection. A gradual increase in oil recovery was observed with a decrease in brine salinity for all the cores. The recovery factor was in the range of 48-58% of the original oil in place. As brine salinity was reduced from 22,000 ppm to 5,500 ppm, additional oil recovery of 5-10% was observed.

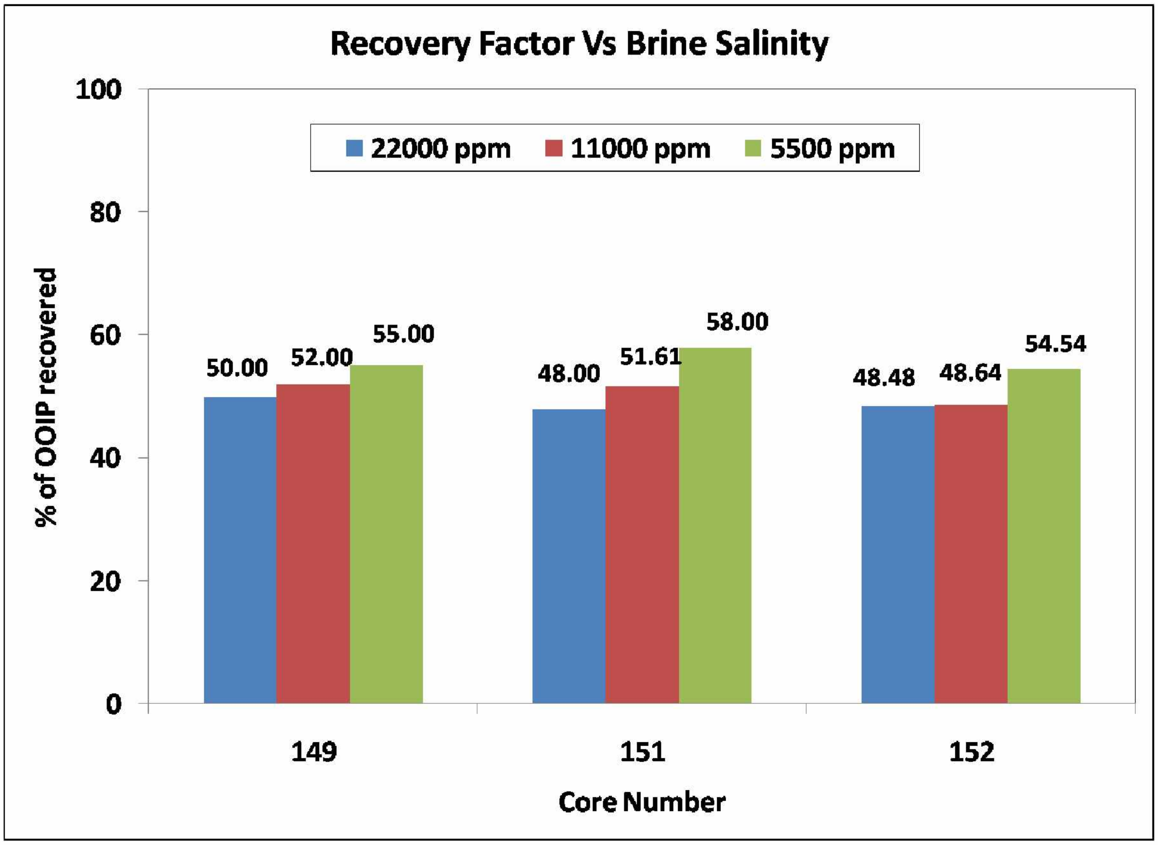

Figure 5.1 Effect of Varying Brine Salinity on Recovery Factor

The increase in oil recovery was accompanied by a marked decrease in residual oil saturation in all the cores. On decreasing brine salinity from 22,000 ppm to 5,500 ppm, a 15-35% reduction in residual oil saturation was noticed. Results are presented in Figure 5.2.

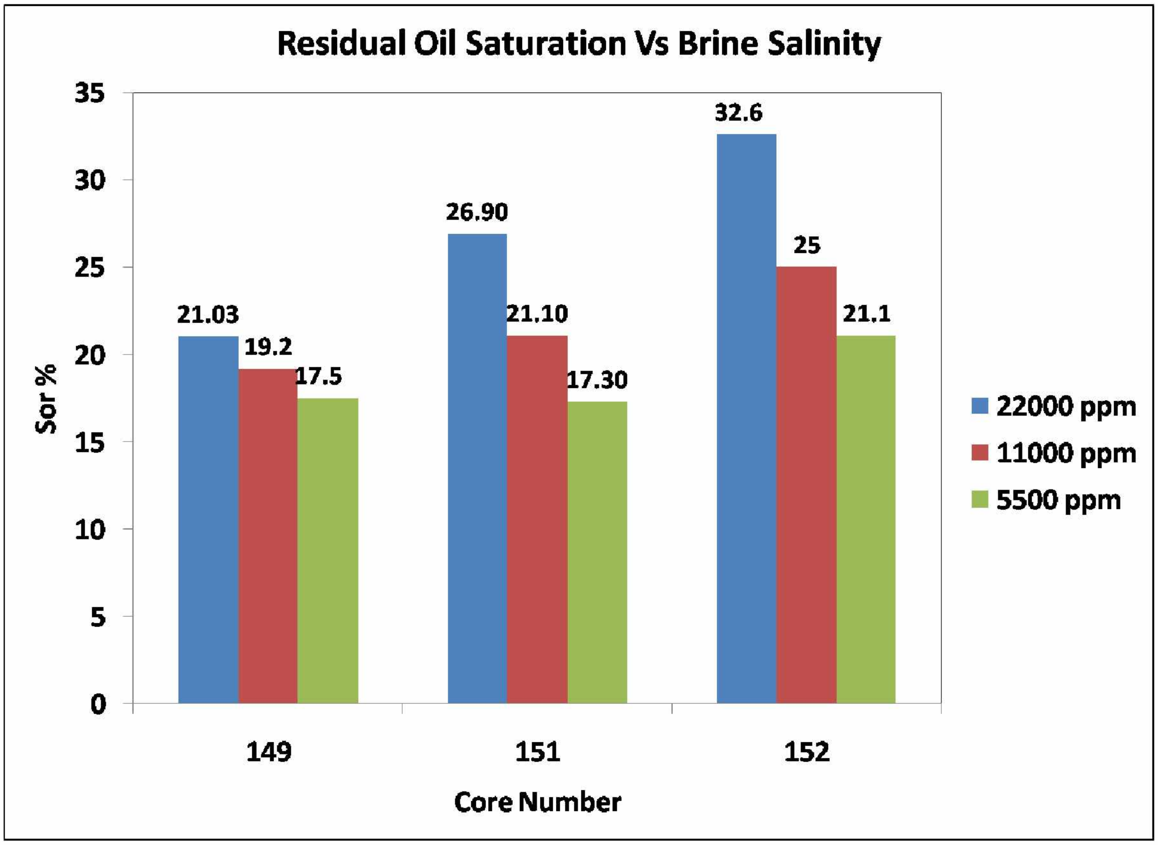

Figure 5.2 Effect of Varying Brine Salinity on Residual Oil Saturation

It was confirmed that low salinity waterflooding yields reduction in residual oil saturation. To investigate if cyclic injection caused any difference in the reduction of S_{or}, results from the previous experiments involving conventional waterflooding were compared with the current results. Figure 5.3 shows the graphical representation of S_{or} obtained from core 152, which was used for both continuous and cyclic injection. Both results show that brine salinity reduction caused a definite decrease in S_{or}. It was noted that the reduction in S_{or} was higher in cyclic when compared with continuous injection. Cyclic injection by 22,000 ppm was done after conventional waterflooding by 5,500 ppm, which had contributed to increased recovery and decreased oil saturation. Since reduction in oil saturation was accompanied by an increase in water wetness (Patil 2007), it might be expected that cyclic injection started with more water wetness than continuous waterflooding did, favoring better reduction of S_{or}. Though the aforementioned factors influence the results, an additional reduction of 15% in S_{or} with cyclic over continuous injection confirms that the former has a better effect than the latter in the reduction of S_{or}.

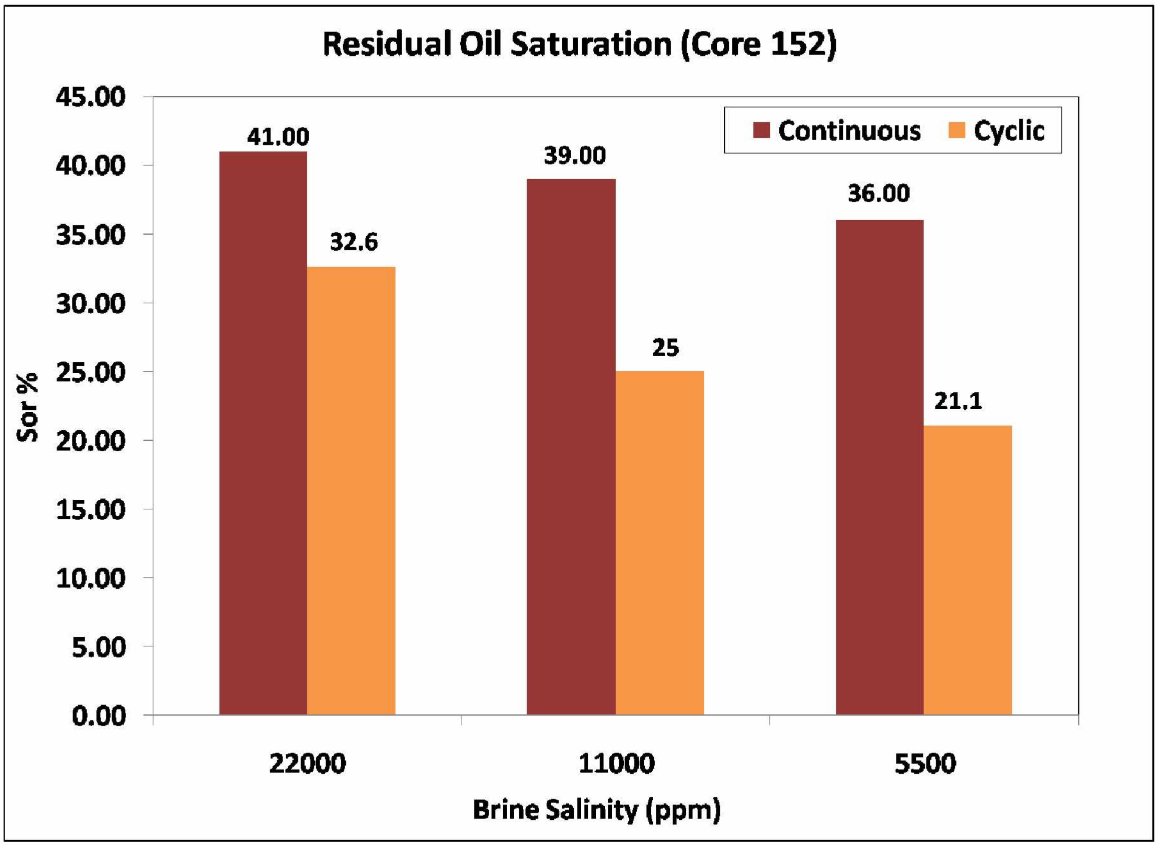

Figure 5.3 Residual Oil Saturation (Cyclic vs. Continuous Floods)

The amount of oil produced was recorded as a function of brine injected. A consistent trend of increased oil production with brines of low salinity was noticed. The cores were restored to initial oil saturation in all cases. Accurate data on water breakthrough could not be recorded because water was produced along with oil, and it was difficult to visually observe the exact instance of water cut. But visual observations confirmed that water breakthrough was observed less than 1 PV of brine injected. In most of the cases, the reduction in brine salinity did not delay water breakthrough.

Figure 5.4 shows the results of the amount of oil produced plotted against PVs of brine injected in core 151. The amount of oil produced increased as the salinity of the invading brine was reduced. It was noted that maximum oil production was achieved within 4-5 PVs of brine injected in cyclic waterfloods as compared to 6-8 PVs of brine injected in continuous waterfloods. This difference indicates that residual oil saturation is achieved much earlier in cyclic injection when compared with conventional waterflooding, implying that cyclic injection yields a faster and better recovery than conventional waterflooding.

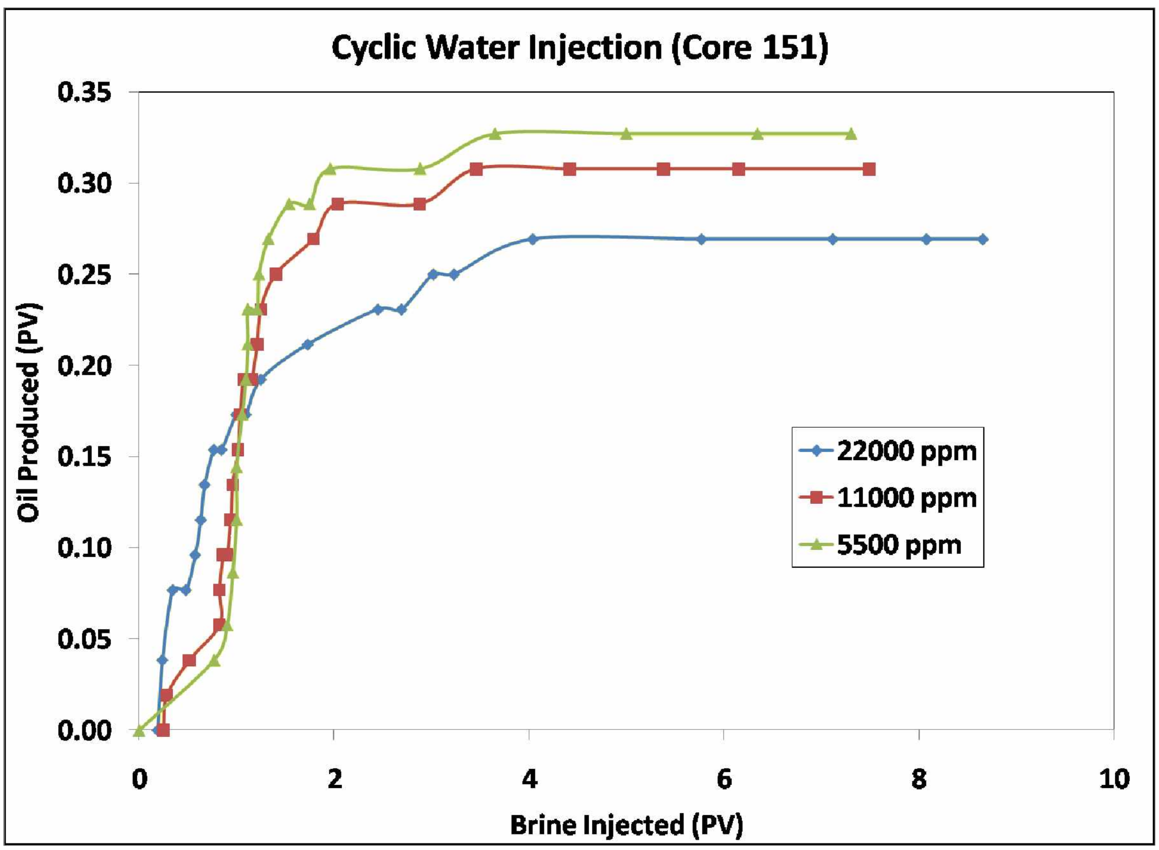

Figure 5.4 Oil Recovery Profile (Varying Salinity)

The amount of oil produced could be divided into two zones: pre water breakthrough and post water breakthrough. As mentioned earlier, the water breakthrough point could not be fixed exactly. Visual observations and experience suggest that the amount of oil produced in the intermediary stages (after water breakthrough) contributed to most of the additional oil recovered using low salinity brines. The present experimental results suggest that the effect of lesser saline invading brines is better pronounced after water breakthrough. It is understood that the amount of oil displaced from the core before water breakthrough is primarily due to imbibition of water by cyclic injection which promotes forced displacement of oil. The impact of decreased salinity is higher once most of the oil has already been produced.

According to the multi-component ionic exchange (MIE) mechanism proposed by Lager et al. (2006), lesser saline brines have more H^+ ions that are ready to exchange with multivalent ions that serve as the binding force holding clay and oil together. On exchange, the bridge between oil and clay is broken thereby setting the oil free to be displaced by the brine. From the present study, it is proposed that, when using lesser saline brines, MIE may have taken place after water breakthrough, leading to additional oil recovery compared to the use of higher saline brines. However, data from effluent pH is needed to support this hypothesis.

Similar results were obtained with usage of ANS lake water, with increased oil production accompanied by reduced S_{or} within lesser PVs of brine injected. As the salinity was reduced from 22,000 ppm to 60 ppm (ANS lake water), a 20-30% decrease in S_{or} was noted. An additional oil recovery of 12-16% was observed with ANS lake water. When compared to continuous injection, an additional 4-10% reduction in S_{or} was observed in cyclic injection with core 46. Figure 5.5, Figure 5.6, Figure 5.7, and Figure 5.8 depict a graphical presentation of the aforementioned points.

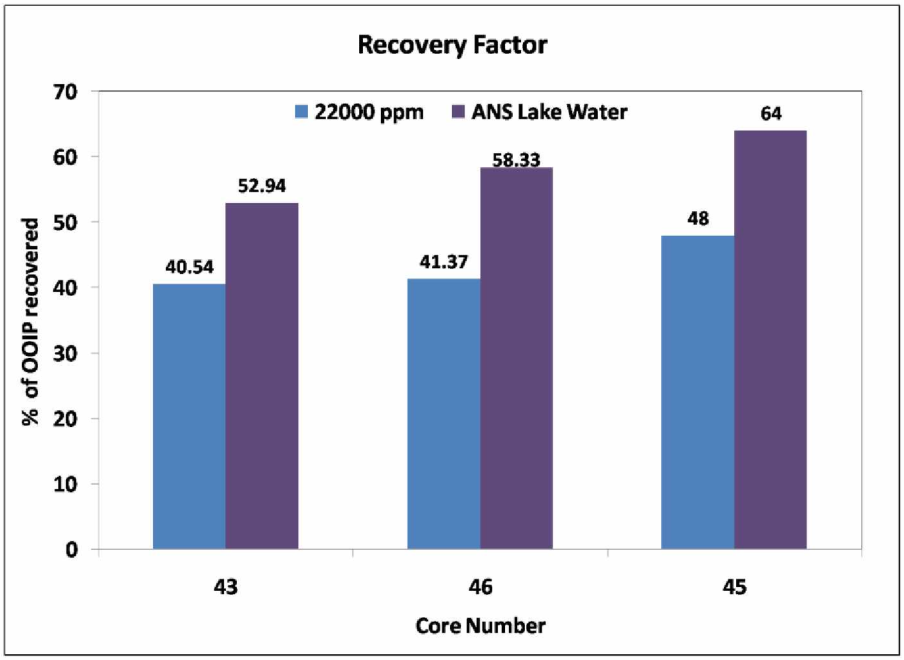

Figure 5.5 Recovery Factor (Usage of ANS Lake Water)

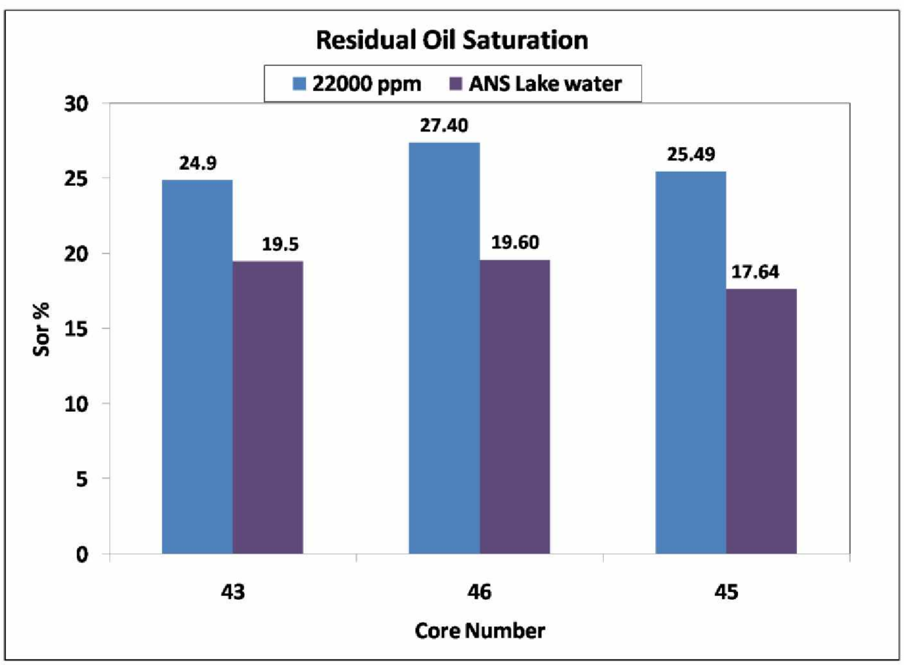

Figure 5.6 Residual Oil Saturation (Usage of ANS Lake Water)

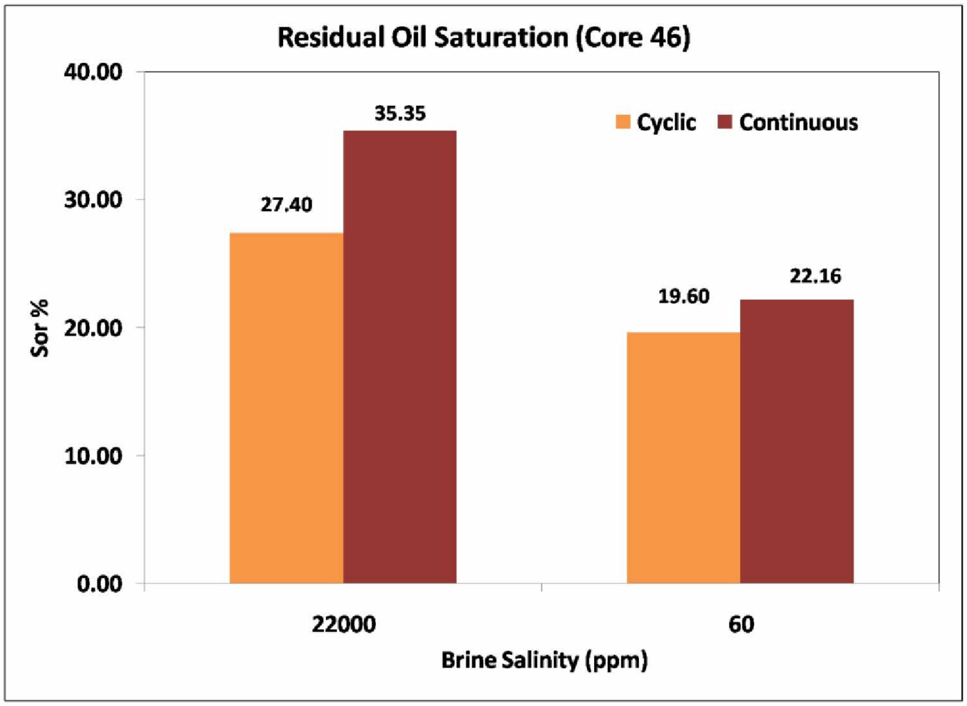

Figure 5.7 Residual Oil Saturation (Cyclic vs. Continuous Floods with ANS Lake Water)

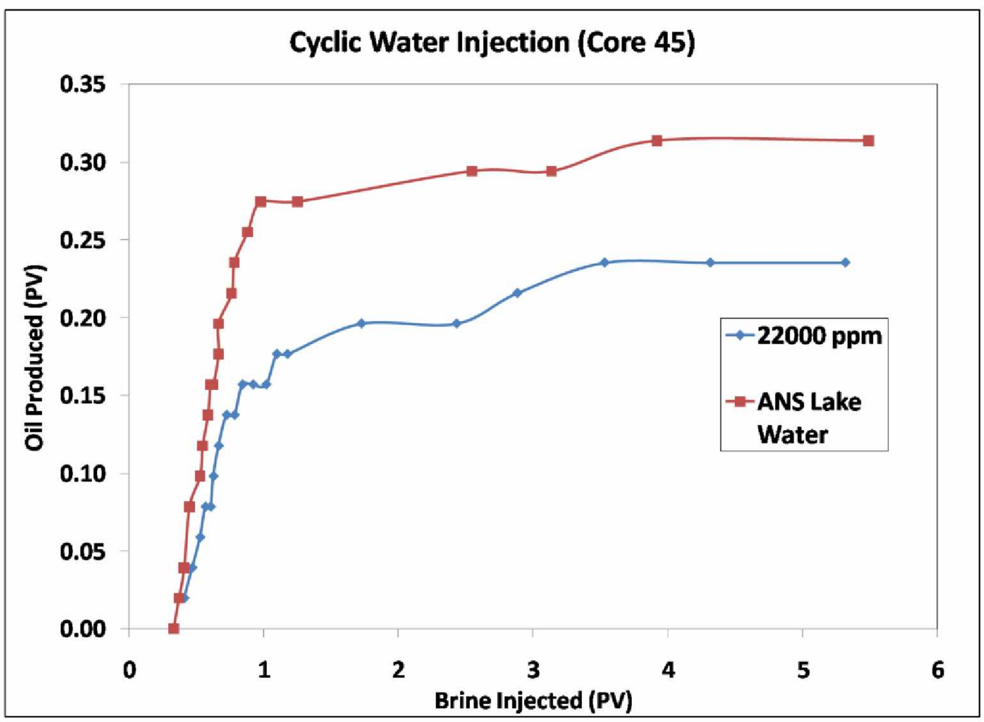

Figure 5.8 Oil Recovery Profile (Usage of ANS Lake Water)

5.2 Effect of Oil-Aging

The same three cores that were employed for the first set of experiments were oil-aged for 30 days. After oil-aging, just like the first set, brines of different salinity (22,000 ppm, 11,000 ppm, and 5,500 ppm) were used for flooding. Residual oil saturation and wettability were calculated after each waterflood. Due to oil-aging, S_{or} values increased from the previous values obtained from flooding them when they were not oil-aged. Low salinity cyclic injection of water succeeded in reducing the S_{or} values, but the reduction in S_{or} values was marginal for the oil-aged cores. Figure 5.9 shows the reduction in S_{or} by low salinity cyclic brine injection of oil-aged cores.

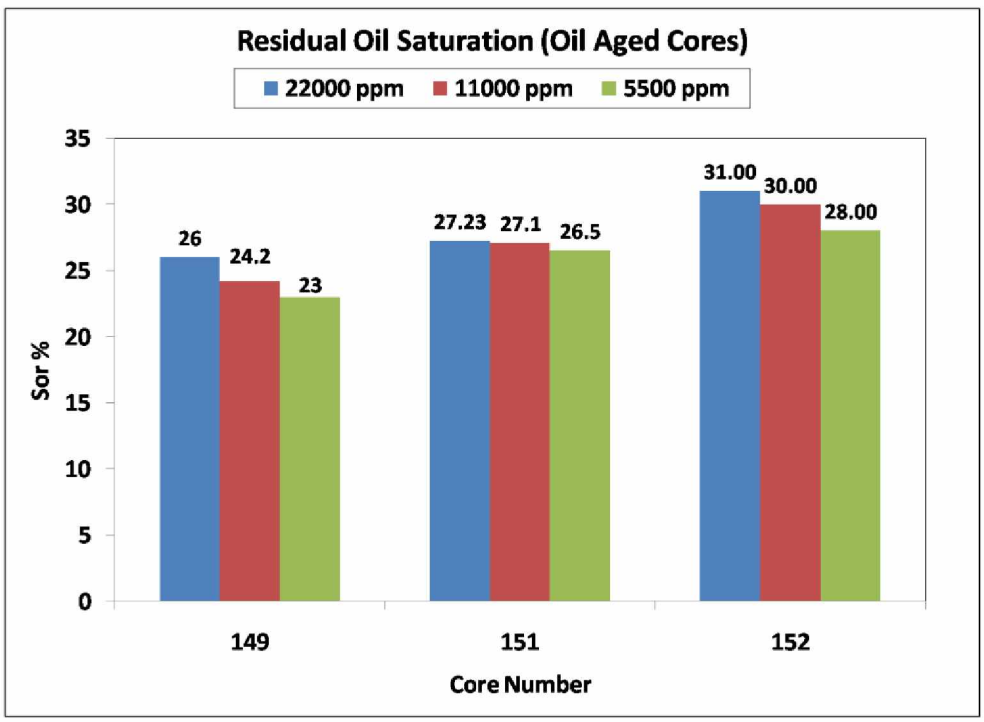

Figure 5.9 Effect of Oil-Aging on Residual Oil Saturation

As for the wettability of the cores before they were aged, the Amott-Harvey index of the cores shifted towards increased water wetness as they were flooded by lesser saline brines. Oil-aging of the cores reduced water wetness to some extent. After flooding the oil-aged cores with lesser saline brine, water wetness was restored in the cores. However, the cores could not be restored to a higher water-wet value that was seen earlier when the cores were not oil-aged. Figure 5.10 shows the wettability alteration in core 151 in an oil-aged and unaged state.

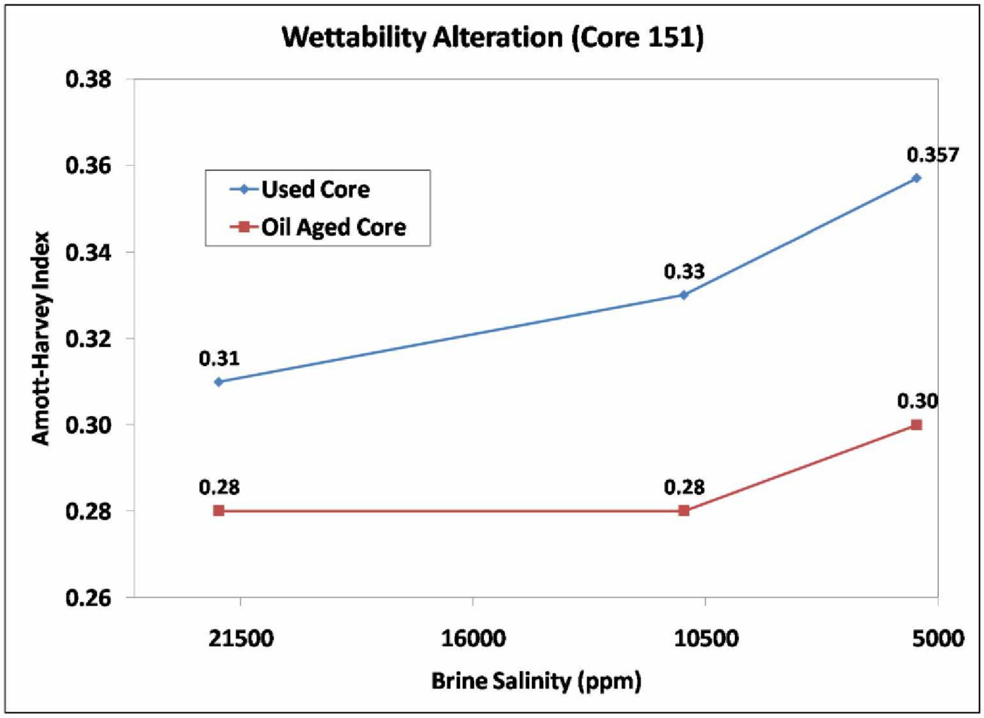

Figure 5.10 Effect of Oil-Aging on Wettability

This could be attributed to the presence of adsorbed polar compounds on the rock surface, due to oil-aging of cores. Wettability alteration in oil-aged cores could thus be credited to the polar compounds present in crude oil. In the present study, the shift of the Amott-Harvey index towards water wetness on low salinity waterflooding was accompanied by decreased S_{or}.

5.3 Effect of Varying Pulse Intervals

The first three set of experiments were performed using cyclic water injection at a constant flow rate of 30 cc/hr and a symmetric pulse interval of 1 minute flow and idle time. Reduction of invading brine salinity was primarily considered to evaluate low salinity brine as a potential source of secondary oil recovery. Decreasing brine salinity yielded good results, with cyclic injection assisting much better than continuous waterflooding.

Once it was determined that cyclic injection has a better effect on oil production than continuous waterflooding, the effect of parameters like injection flow rate and pulse time period on cyclic injection had to be evaluated. Thus, in the next set of experiments, two symmetric pulse intervals of 1 and 0.3 minute were evaluated at a constant injection rate of 30 cc/hr and constant brine salinity of 22,000 ppm tds. Five new cores were employed in this test. Oil recovery, S_{or} and wettability were measured after each waterflooding. One core (core 51) was damaged in the process.

Results showed that shorter pulses yielded marginally better results. Additional oil recovery of 2-8% was obtained with 0.3 minute pulses over 1 minute intervals. Up to 4% extra reduction in S_{or} values was also observed. For the 0.3 minute over 1 minute interval, an increase towards water wetness, if any, was very little, in most cases. Under visual observations, water breakthrough was marginally delayed in the case of 0.3 minute pulse periods. In most of the cores, residual oil saturation was attained at the expense of the same amount of brine injected. Figure 5.11, Figure 5.12, and Figure 5.13 show a graphical representation of the discussed results.

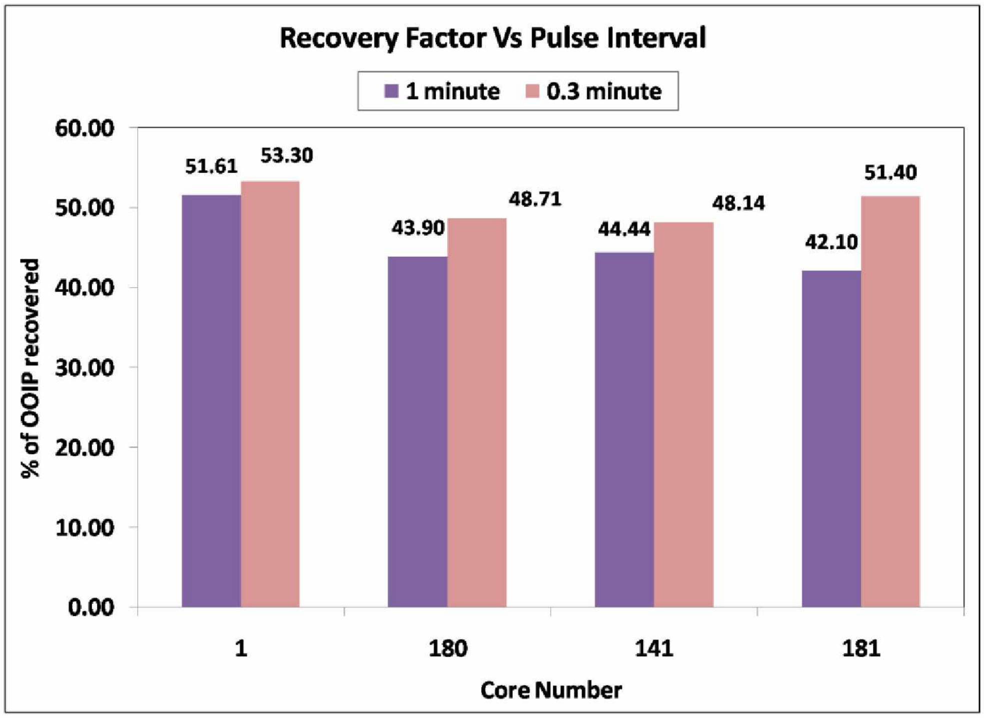

Figure 5.11 Effect of Pulse Intervals on Oil Recovery

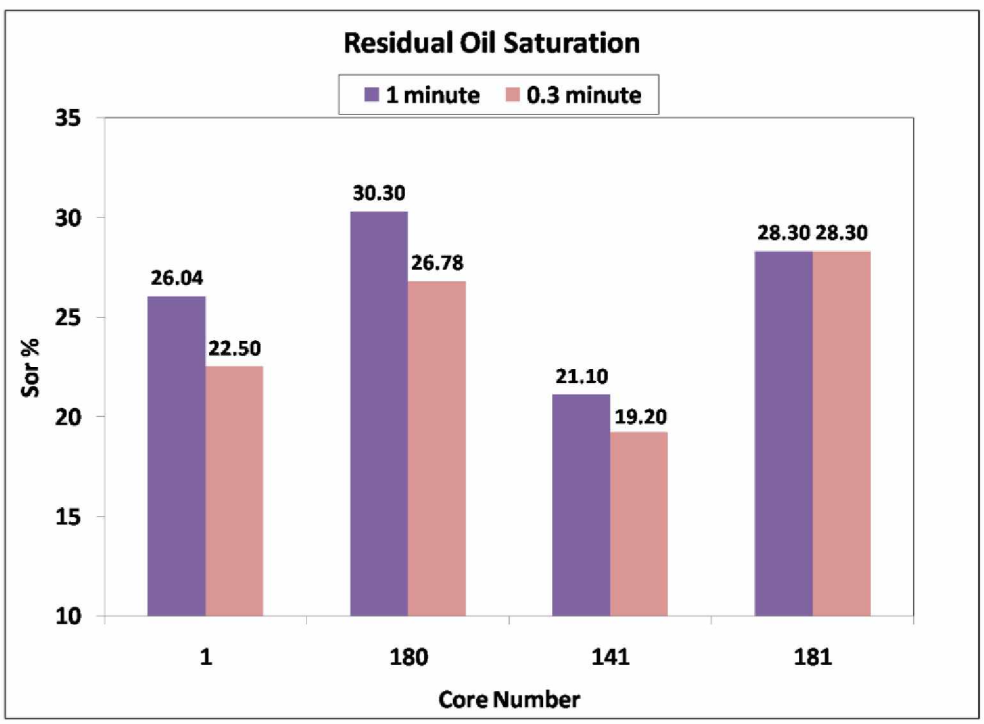

Figure 5.12 Effect of Pulse Intervals on Residual Oil Saturation

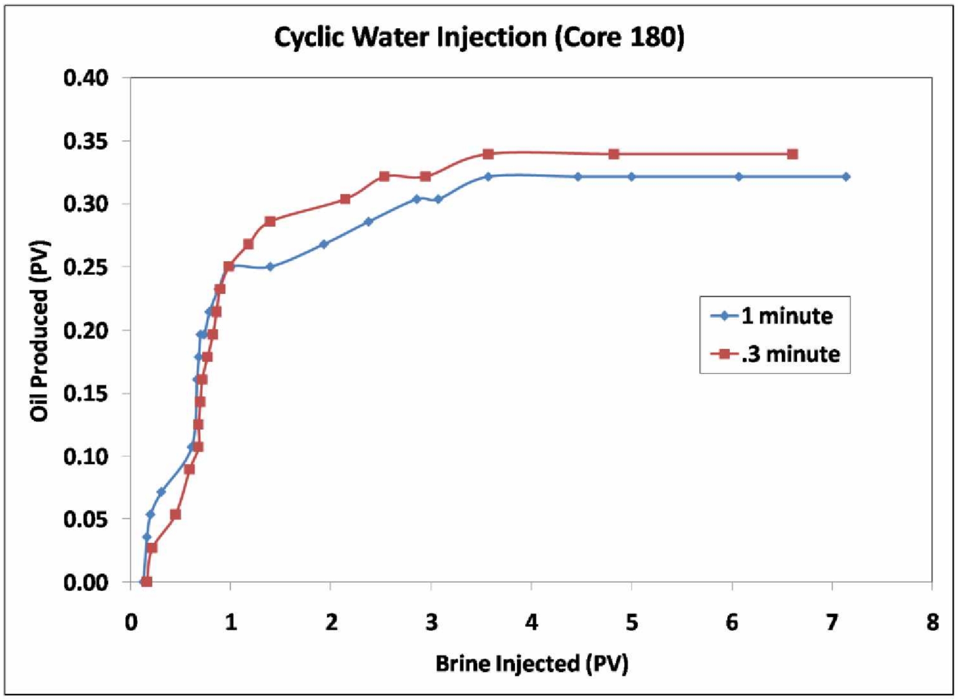

Figure 5.13 Oil Recovery Profile (Varying Pulse Intervals)

From the results, for the same amount of brine injected, a marginal increase in oil recovery and decrease in residual oil saturation favor 0.3 minute pulses over 1 minute pulses. However, this might not be a generalized assumption for all cases. Fine-tuning the pulse intervals to upscale cyclic injection to reservoir conditions depends on various parameters like reservoir size, injection rate, well spacing and water cut.

In the present study, an attempt has been made to explain the additional oil recovery with shorter pulses. In longer pulses, the injection period becomes long enough to cause channeling due to water bypassing the oil. This condition leaves some oil behind in the smaller pores or trapped as globules surrounded by water. After water breakthrough, the idle time becomes long enough to decrease oil production itself more than decreasing the water production. Apart from sweeping oil in the larger pores, water is forced into the smaller pore structures, during the injection period of shorter pulses. During idle time, oil swept by the injected water in the micro-fractures makes a countercurrent flow towards larger pore channels. When injection happens in the next cycle, this additional oil is swept off from the channels towards the outlet. During the intermediary stages, more oil was obtained with the shorter pulses compared to longer pulses. The cores used were of 1” length and 1.5” diameter with PVs of approximately 5 cc. it is understood that this process is more efficient in shorter pulses because of favorable smaller dimensions. However, this hypothesis needs to be supported by sufficient data on the pore structure of core plugs used as well as fluid flow behavior through this porous media.

5.4 Coreflooding at Reservoir Conditions

To simulate reservoir conditions, recombined oil was flooded through brine-saturated cores to establish initial oil saturation. Continuous waterflooding was conducted with 22,000 ppm tds brine followed by 11,000 ppm tds brine. Oil saturation and recovery were calculated after every step. Two new cores were used for these runs.

Results showed that the initial oil saturation was less than 40% and was not as high as it was with the dead oil experiments. Most of the gas is recovered in the secondary recovery mode. On flooding with 22,000 ppm tds brine in a secondary recovery mode, a 10% decrease in oil saturation was observed. A further 5% decrease in residual oil saturation was achieved by flooding 11,000 ppm tds brine in the tertiary recovery mode. Up to 40% reduction from the initial oil saturation was observed. The recovery factor was around 25-30% in the secondary recovery mode and additional 10-15% oil was recovered in tertiary recovery mode, contributing to a cumulative recovery of 40%. Results are shown in Figure 5.14 and Figure 5.15

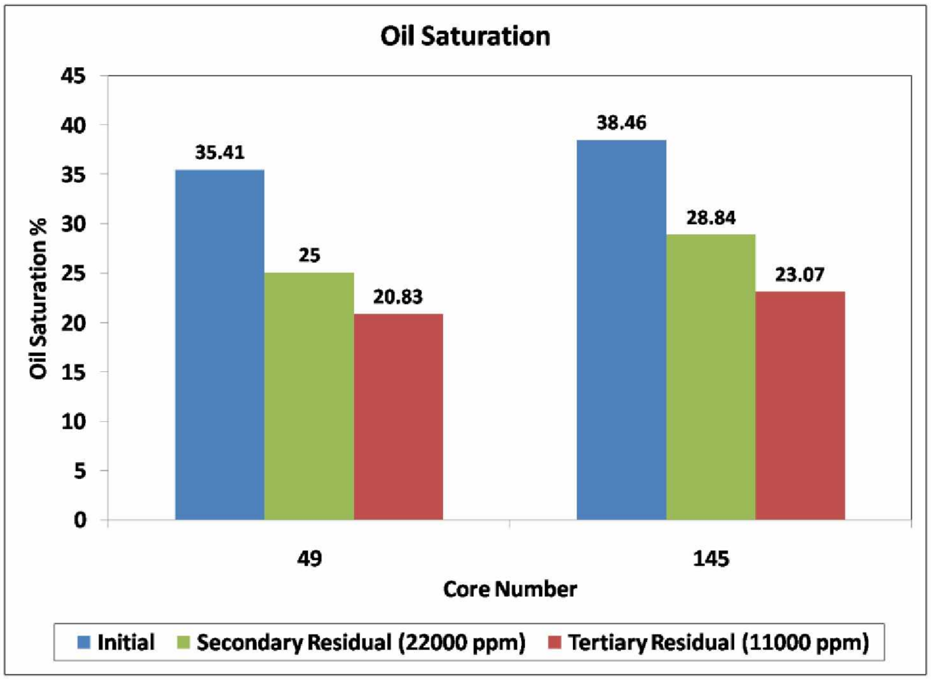

Figure 5.14 Oil Saturation Profile (Coreflooding at Reservoir Conditions)

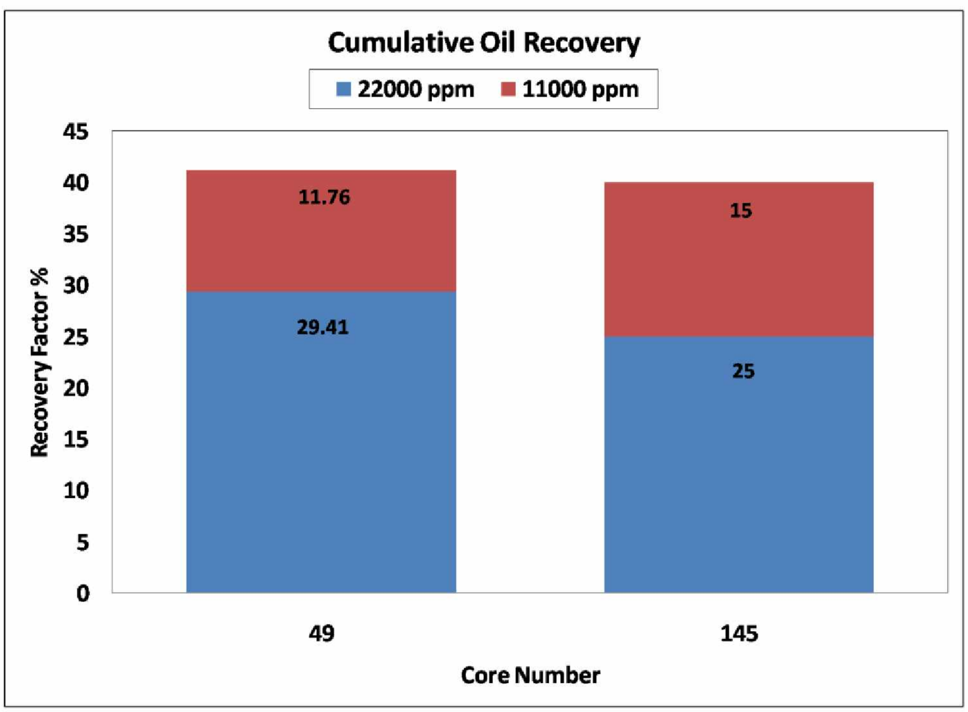

Figure 5.15 Oil Recovery (Reservoir Conditions)

5.5 Rock Wettability vs. Residual Oil Saturation

In most of the cores, reduction in residual oil saturation was accompanied by an increase in water wetness. In an effort to conclude about the effect of wetting states on the reduction in residual oil saturation, Amott-Harvey index was plotted against the residual oil saturation values of the cores after all waterfloods (Figure 5.16). As a part of wettability characterization, it was found that all the cores used were intermediate wet, with an Amott-Harvey index between 0.18 and 0.38. Within such a small range of wettability index values, it is difficult to comment on the best wetting condition (oil-wet or water-wet) that results in a larger reduction in residual oil saturation. Results suggest that cores with a wide range of wettability index values are needed to arrive at a conclusion about if water-wetness favors an increased reduction in residual oil saturation.

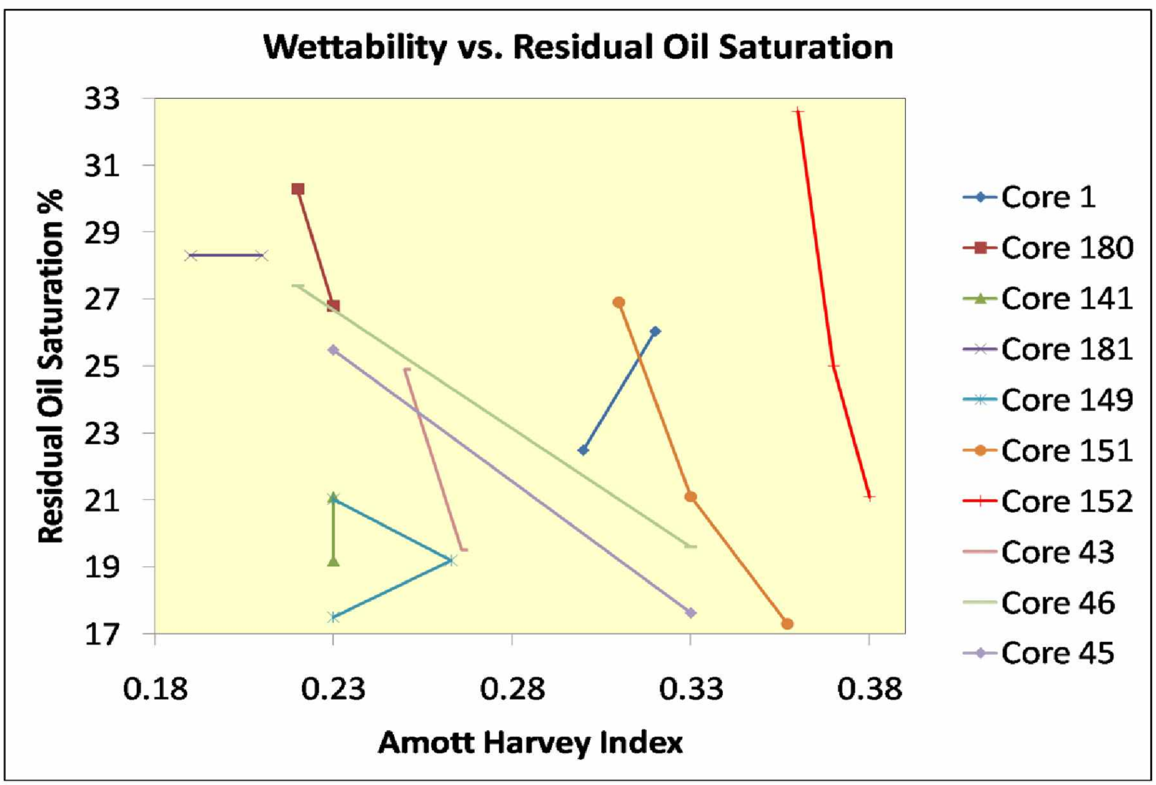

Figure 5.16 Rock Wettability vs. Residual Oil Saturation

CHAPTER 6 CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

1. Low salinity cyclic water injection resulted in faster and higher oil recovery accompanied by reduction in residual oil saturation. As the brine salinity was reduced from 22,000 ppm to 5,500 ppm tds, additional oil production was witnessed at the expense of same amounts of brine injected.
2. Low salinity cyclic water injection also resulted in changing the wetting state of the core by shifting the wettability index towards water wetness. No sharp changes in the Amott-Harvey index values were observed in most cases. The results suggest an intermediate wetting condition in the representative ANS cores. The results do not provide a definite conclusion about the wetting state that favors the highest reduction in residual oil saturation.
3. The results were compared with those from continuous waterflooding. Cyclic injection has better oil recovery efficiency than continuous waterflooding. Additional oil was produced even during the idle time in cyclic water injection.
4. ANS lake water was investigated as a potential source for ultra-low salinity water. ANS lake water yielded better results than brines of higher salinity. From the results, it is concluded that water from ANS lakes could be utilized for an enhanced oil recovery option on the Alaska North Slope.
5. Oil-aging reduced the water wetness of the cores. Low salinity cyclic water injection restored the water wetness marginally. The experimental results obtained are consistent with those reported by many researchers.
6. With a brine of constant salinity (22,000 ppm), change in pulse intervals was tested for efficiency of cyclic injection. Shorter pulses yielded a marginally better recovery and reduction in S_{or} than longer pulse intervals. This is consistent with the results reported by Ivanov and Araujo (2006).
7. An interesting observation made from the results was that cyclic injection with same pulse intervals and brine salinity, employing used cores has 5-7%

additional oil recovery compared to that with new cores. Though properties of cores differ, a consistent difference in oil recovery suggests that the already used cores have their wettability shifted towards strongly water wetting states while the new cores are slightly water-wet.

8. Coreflooding was performed at reservoir conditions by employing higher saline brine (22,000 ppm) in secondary recovery mode followed by a comparatively lesser saline brine (11,000 ppm) in tertiary recovery mode. Additional oil recovery and reduction in S_{or} was observed in the tertiary mode with lesser saline brine.
9. Current waterflooding operations in ANS employ seawater (high salinity) or formation water with even higher salinity for enhanced oil recovery operations. Research and field tests have been conducted investigating the potential of low salinity waterflooding. Cyclic injection of water offers an extra advantage with increased oil recovery than conventional waterfloods, assuming that the brine salinity is constant. Implementation of cyclic injection at virtually zero additional cost is an added bonus to the operators. Thus, cyclic injection can be considered as an attractive option for enhanced oil recovery.
10. Low salinity cyclic water injection is a potential option for enhanced oil recovery as it has a combined advantage of the effects from both low salinity brine usage and cyclic water injection. This is concluded on the basis of results from the four sets of experiments conducted using crude oil and cores from Alaska North Slope.

6.2 Recommendations

1. Cyclic water injection was conducted only with dead oil saturated cores at atmospheric conditions. Coreflood runs may have to be repeated with live oil at reservoir conditions to assess the effect of cyclic injection under an actual field production scenario. Coreflooding at reservoir conditions was operated at above bubblepoint conditions in the experiments. Further investigation with

runs conducted below bubblepoint could evaluate the presence of gas and utilization of gas energy in the waterflooding process.

2. The representative cores from ANS were of 1” length, 1.5” diameter, and around 5 cc in pore volume. Oil-water separation was carried out in a fractional collector after gravity settling of fluids. These results were made under visual observations and are limited to manual errors. Smaller pore volumes limit the choice of other separation methods. Longer cores with higher pore volumes may help in better characterization of rock and fluid properties and quantification of results. It may be essential to repeat the experiments with longer ANS representative cores to confirm the results from these runs.
3. Fine-tuning of cyclic injection by investigating various injection rates and time pulse intervals can be done for optimum oil recovery. Imaging technology like MRI scans could assist in visualizing the pore structure and flow of fluids in porous media. This could help us calculate exact amounts of oil and water present in the pore spaces.
4. Low salinity cyclic water injection has shown promising results. ANS operators can consider this option of employing low salinity floods by desalination of formation brine/seawater or dilution by adding ANS lake water. After detailed economic evaluation, cyclic injection can be considered for implementation to reach S_{or} at the expense of lesser quantities of water injected. It is believed that the gains from increased oil production by implementing low salinity cyclic injection will be profitable enough to compensate for the logistical expenses incurred.

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CHAPTER 8 APPENDIX

In Chapter 5, results on oil recovery and residual oil saturation in all the cores were presented. Sample results on wettability alteration and oil production profile were also presented. This chapter lists rest of the results obtained with all the core samples. Core 51 (which was to be employed for varying pulse intervals) got damaged after the very first run with 1 minute pulse interval (22,000 ppm). All the results are as follows (Figures 8.1-8.17, Tables 8.1-8.4):

Oil Production Profile

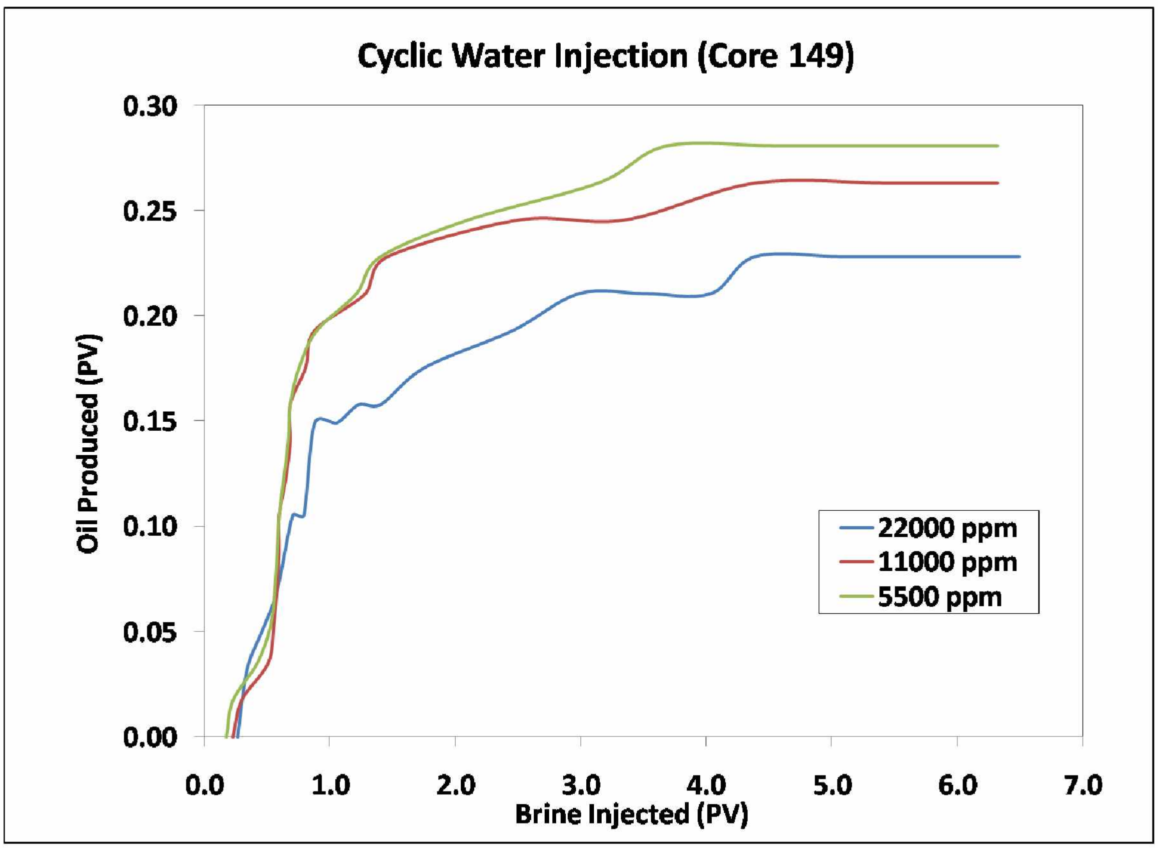

Figure 8.1 Oil Recovery Profile (Core 149 - Varying Brine Salinity)

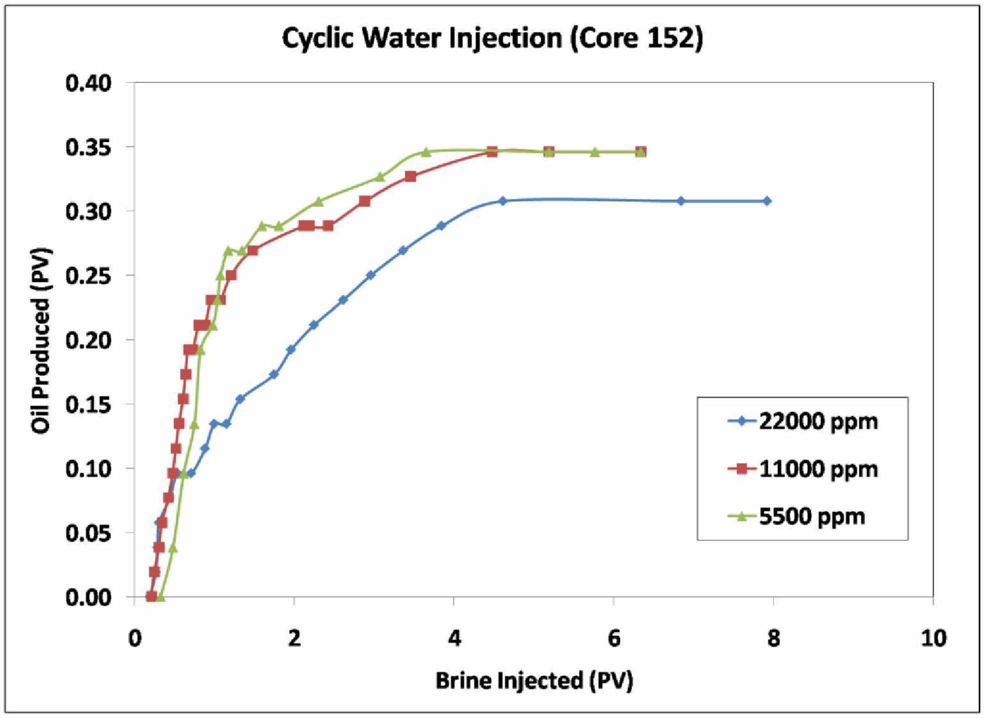

Figure 8.2 Oil Recovery Profile (Core 152 - Varying Brine Salinity)

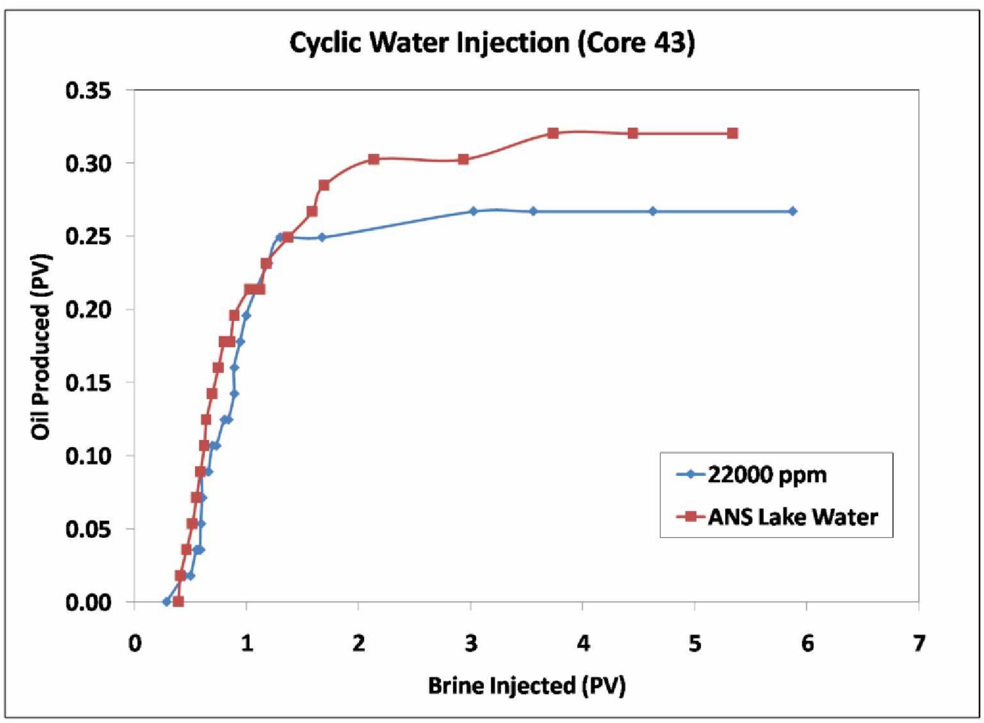

Figure 8.3 Oil Recovery Profile (Core 43 - Usage of ANS Lake Water)

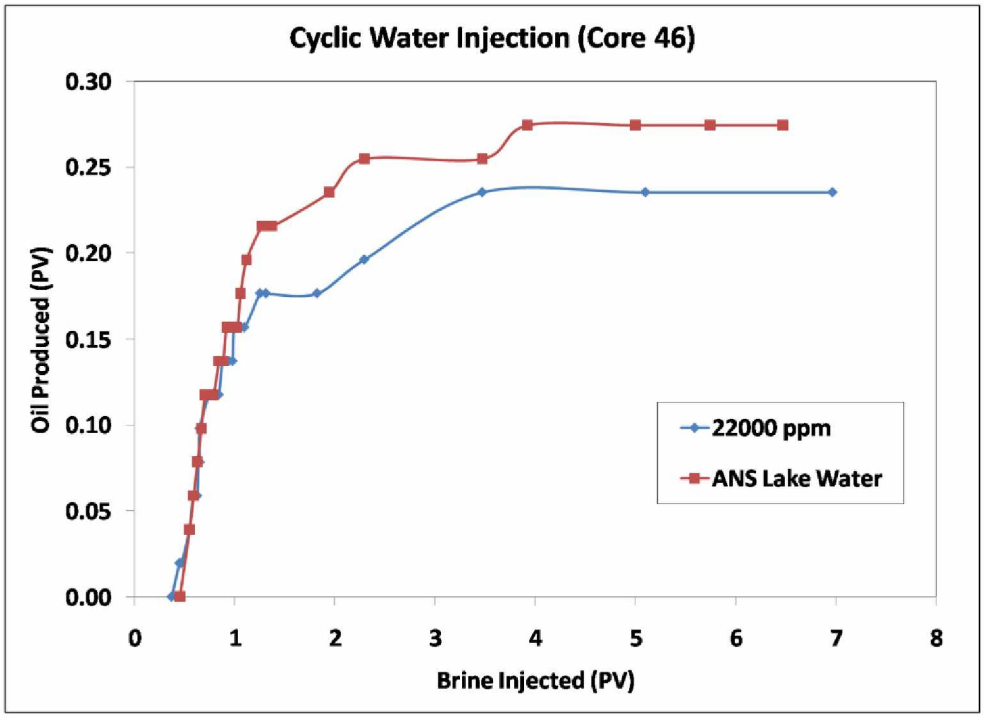

Figure 8.4 Oil Recovery Profile (Core 46 - Usage of ANS Lake Water)

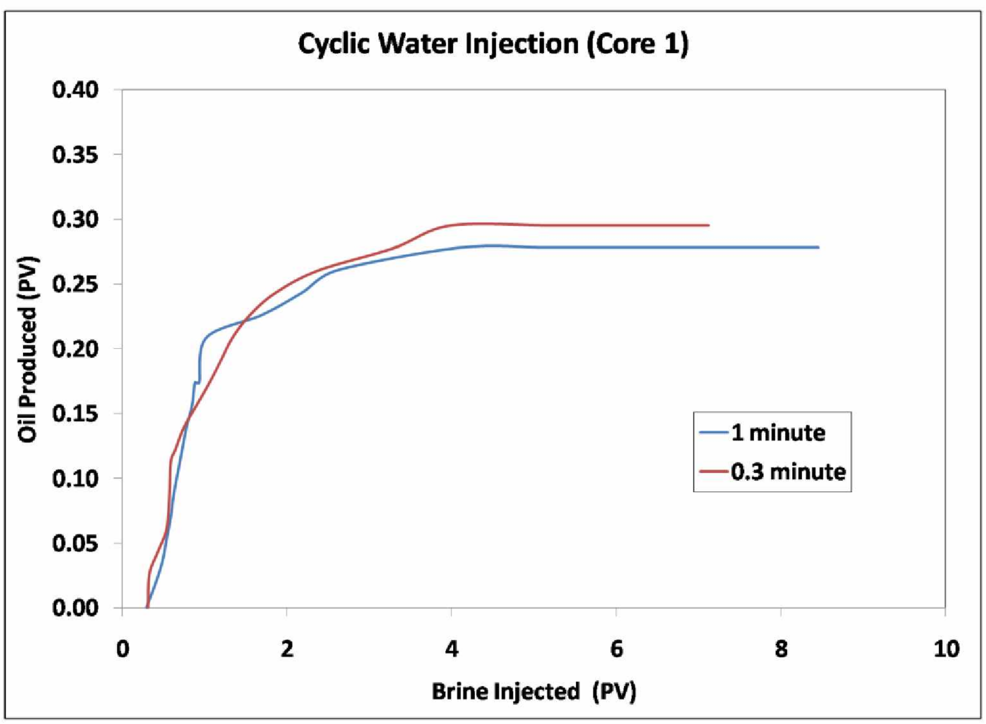

Figure 8.5 Oil Recovery Profile (Core 1 - Varying Pulse Intervals)

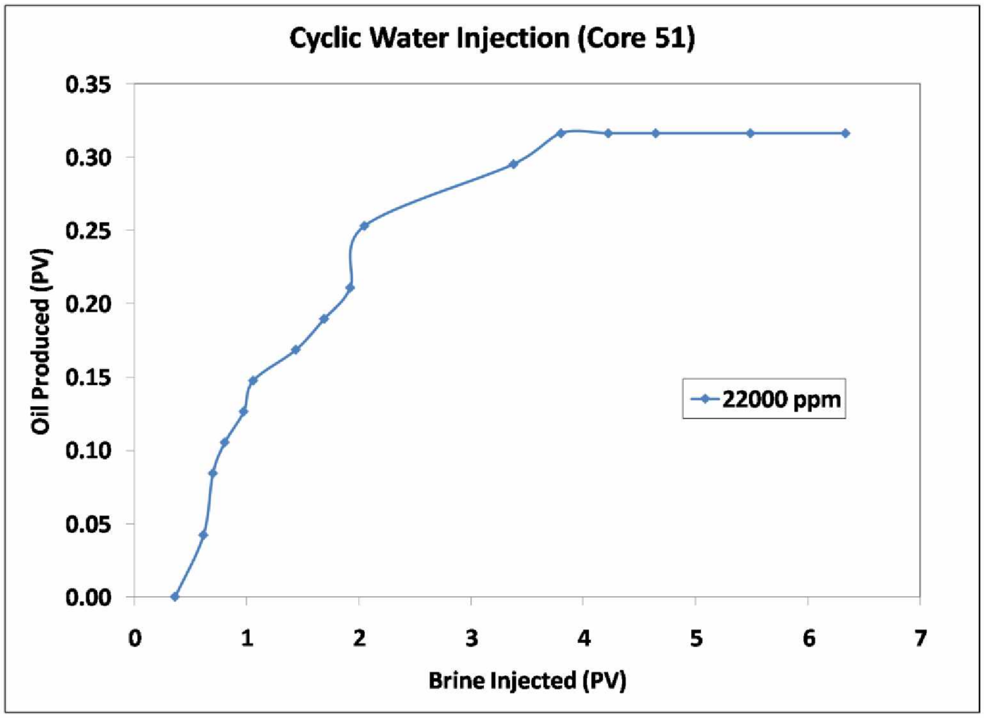

Figure 8.6 Oil Recovery Profile (Core 51 - Damaged After One Run)

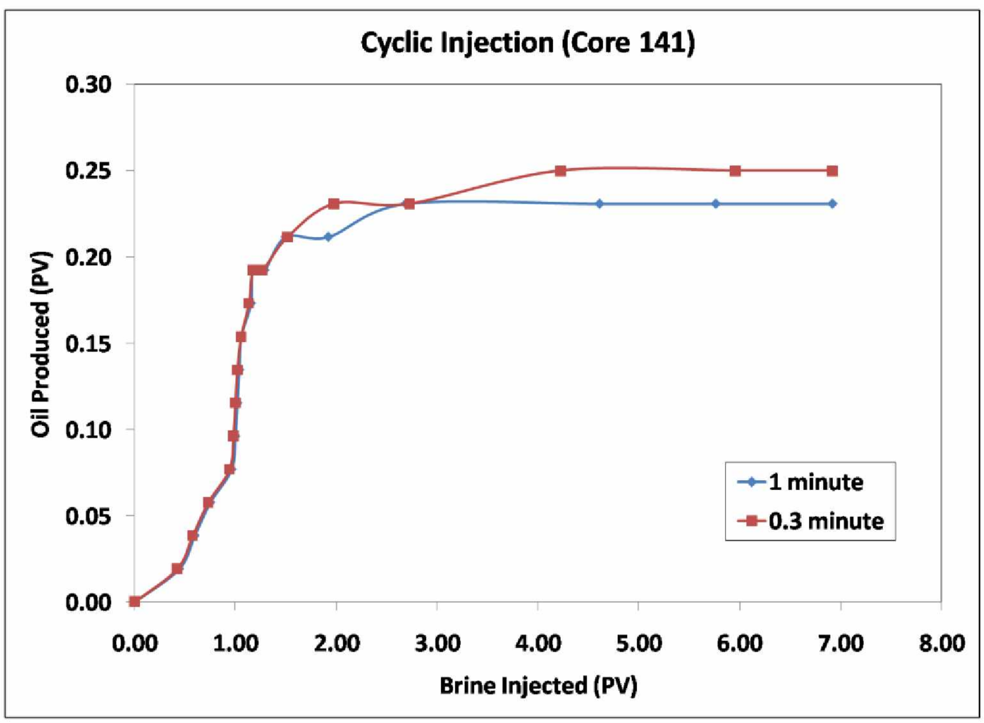

Figure 8.7 Oil Recovery Profile (Core 141 - Varying Pulse Intervals)

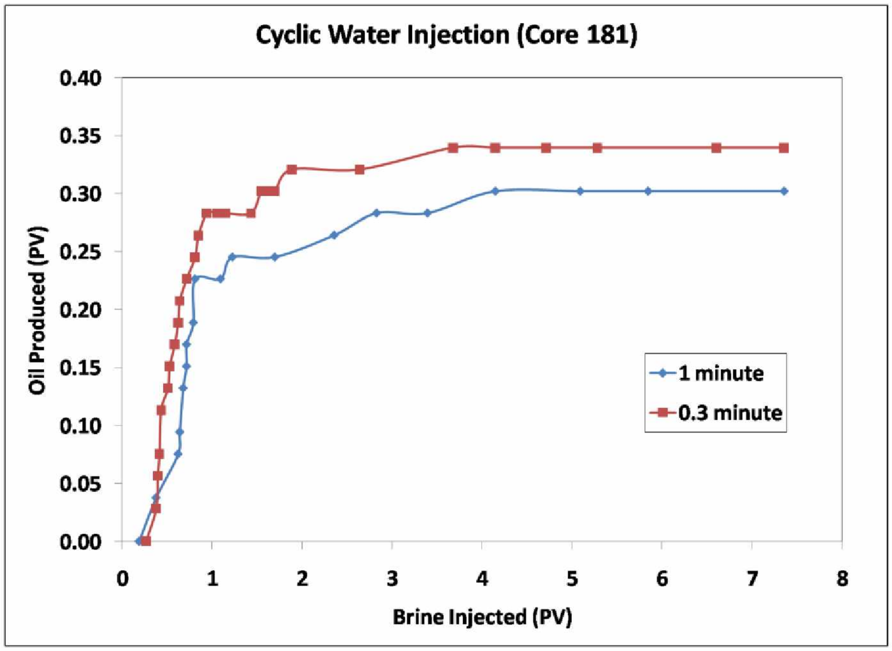

Figure 8.8 Oil Recovery Profile (Core 181 - Varying Pulse Intervals)

Wettability Alteration

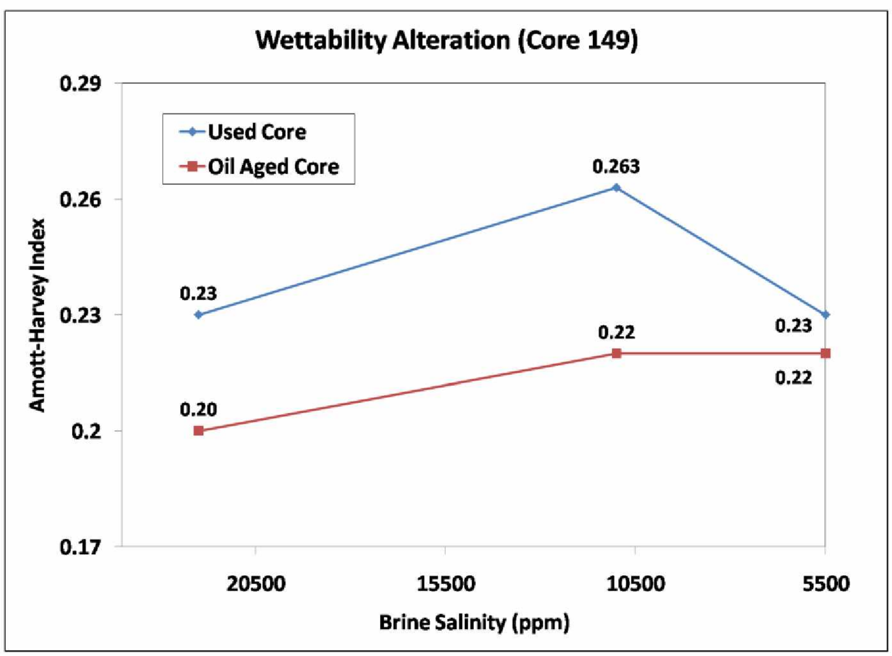

Figure 8.9 Wettability Alteration (Core 149 - Oil-Aging and Varying Brine Salinity)

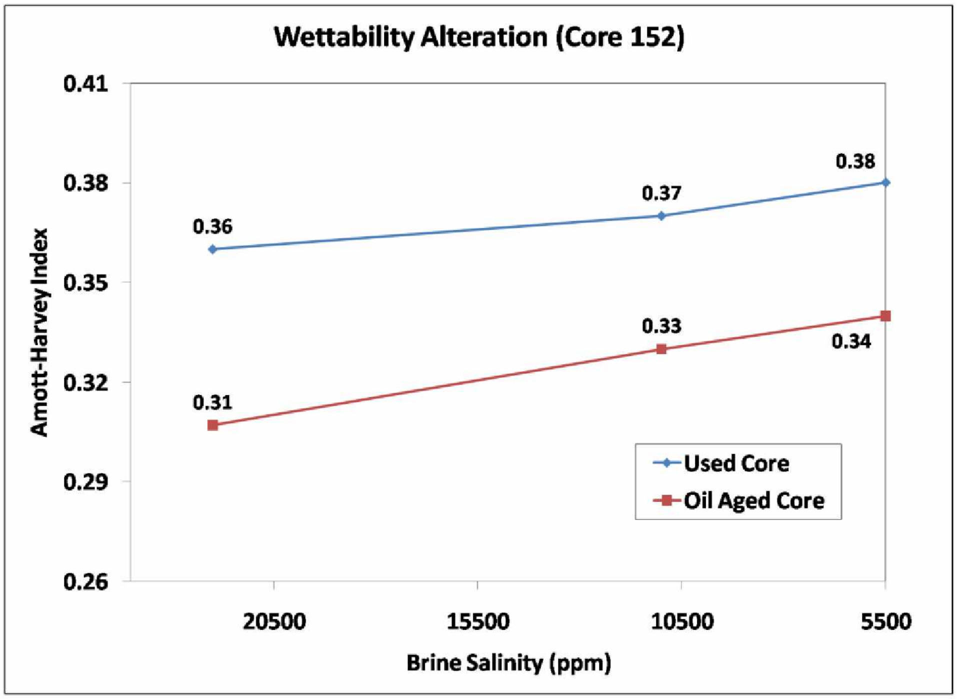

Figure 8.10 Wettability Alteration (Core 152 - Effect of Oil-Aging and Varying Brine Salinity)

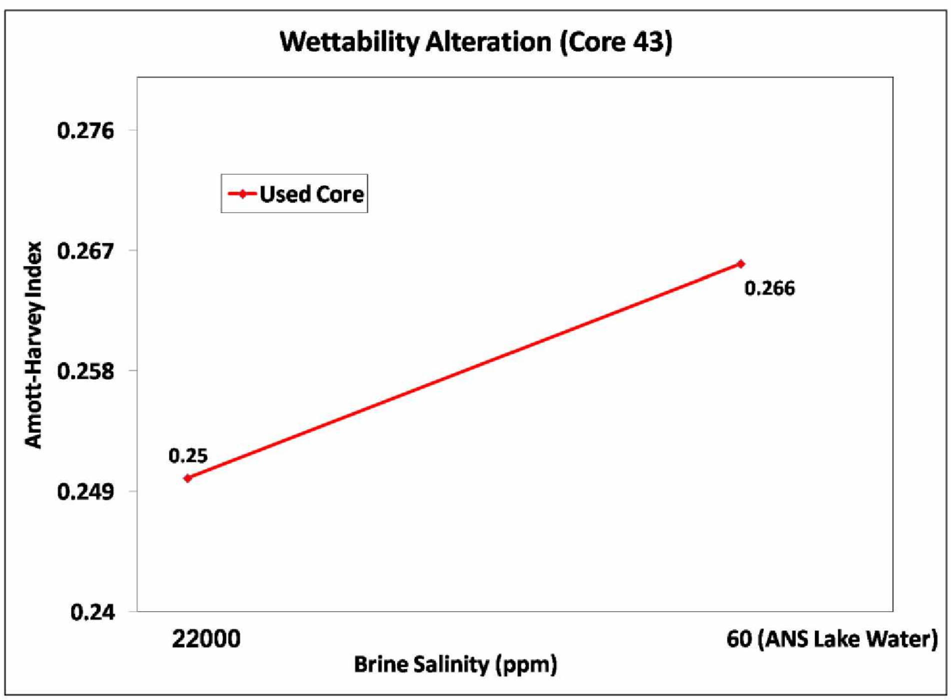

Figure 8.11 Wettability Alteration (Core 43 - Usage of ANS Lake Water)

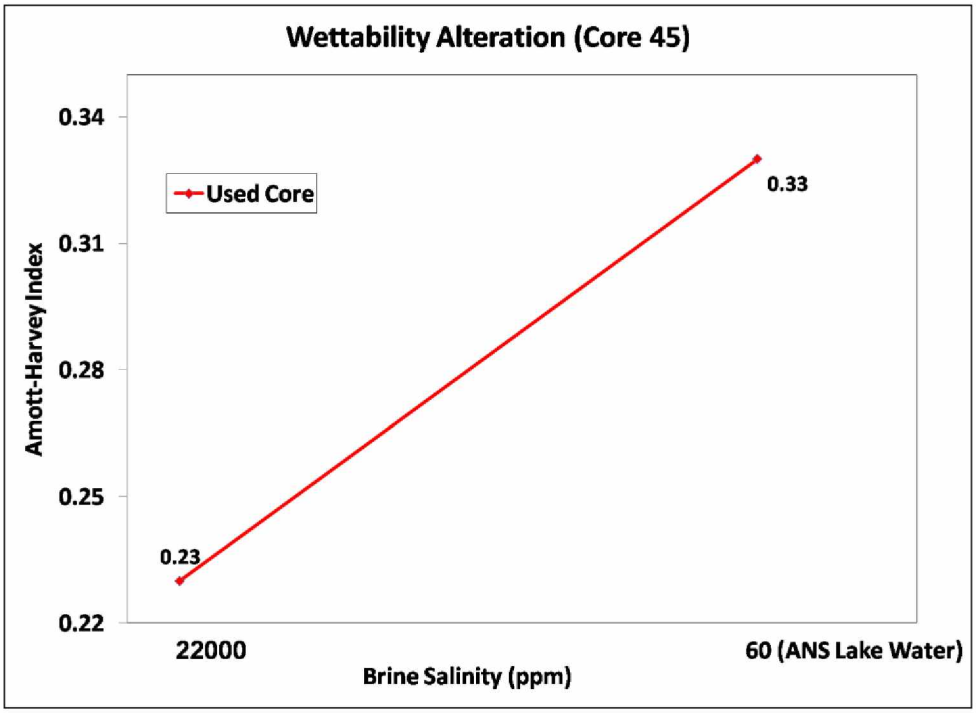

Figure 8.12 Wettability Alteration (Core 45 - Usage of ANS Lake Water)

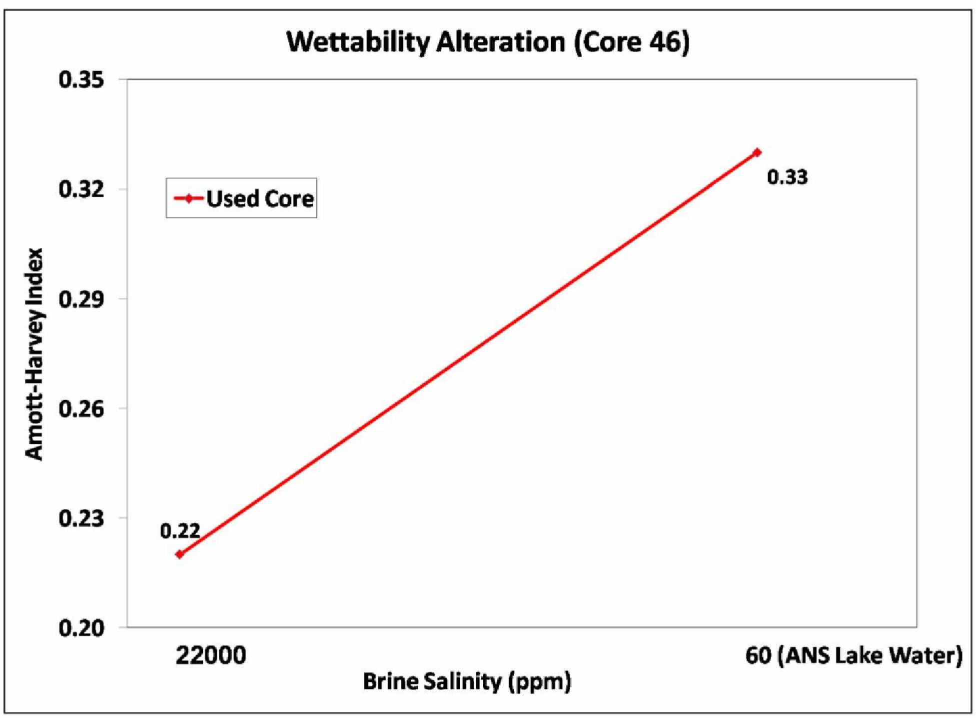

Figure 8.13 Wettability Alteration (Core 46 - Usage of ANS Lake Water)

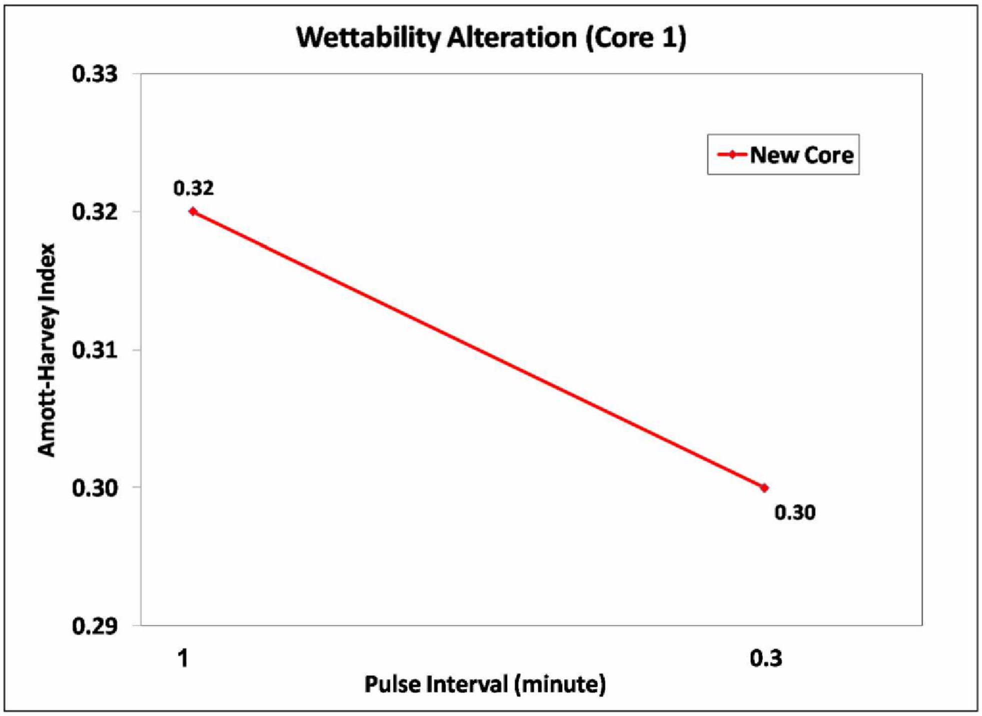

Figure 8.14 Wettability Alteration (Core 1 - Varying Pulse Intervals)

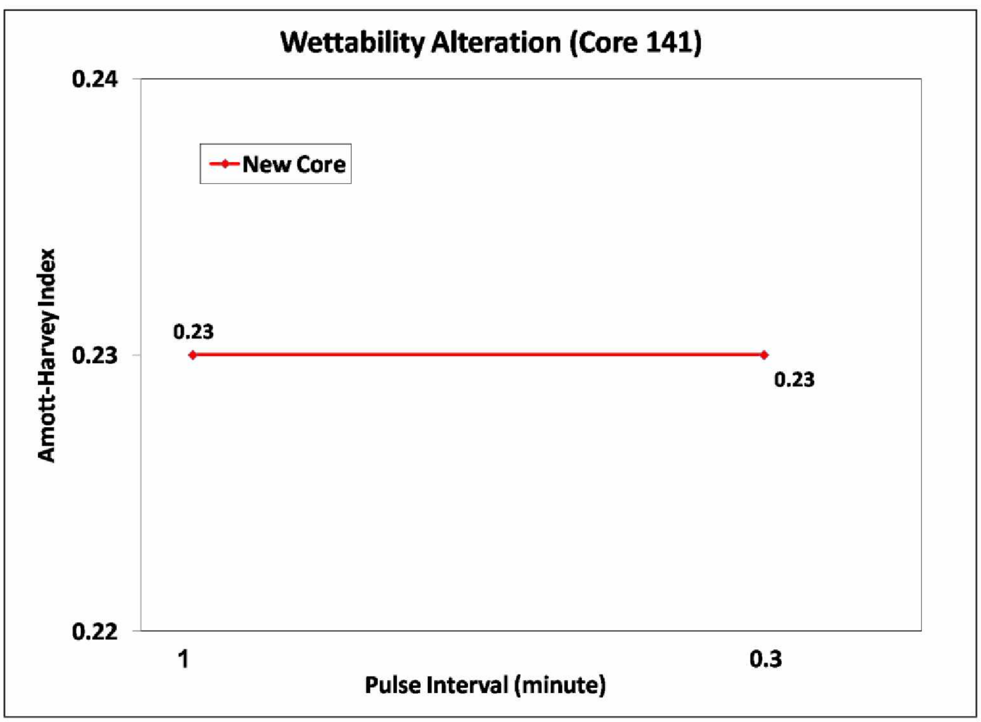

Figure 8.15 Wettability Alteration (Core 141 - Varying Pulse Intervals)

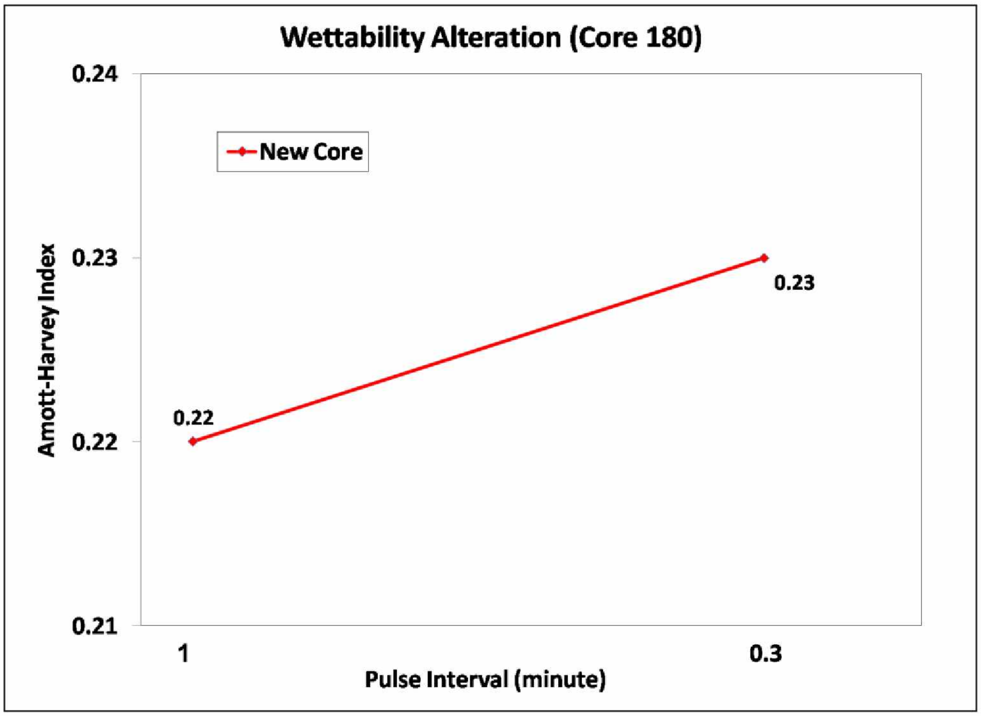

Figure 8.16 Wettability Alteration (Core 180 - Varying Pulse Intervals)

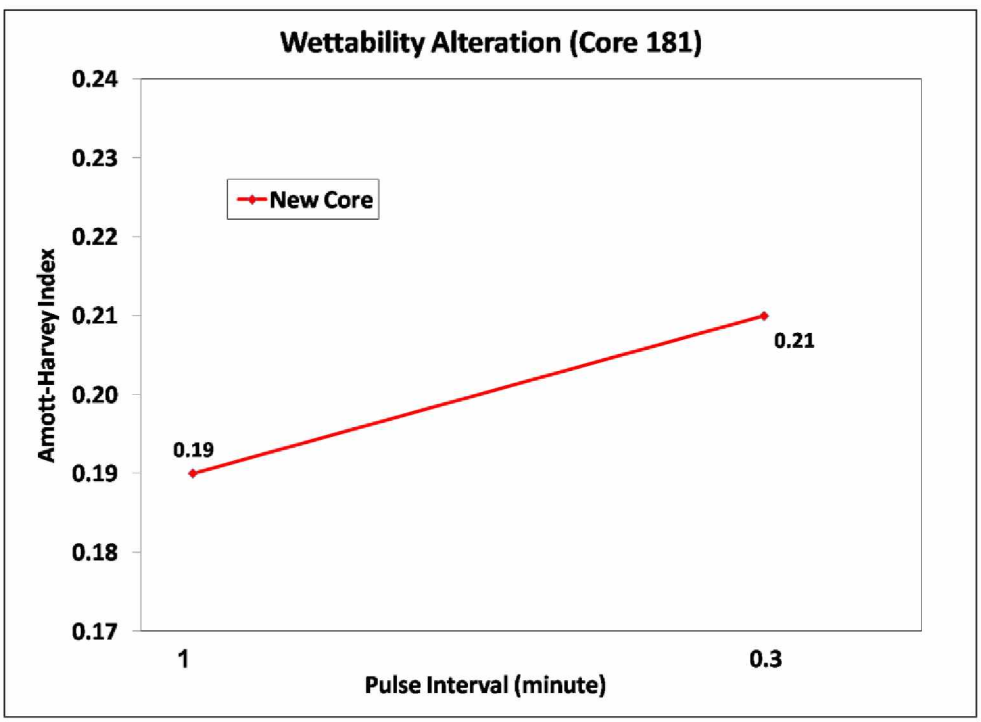

Figure 8.17 Wettability Alteration (Core 181 - Varying Pulse Intervals)

Table 8.1 Results (Effect of Varying Salinity and Oil-Aging)

Core Number	Brine Salinity (ppm)	Used Cores			Oil-Aged Cores	
		Recovery Factor (% OOIP)	Residual Oil Saturation (%)	Amott-Harvey Index	Residual Oil Saturation (%)	Amott-Harvey Index
149	22,000	50	21.03	+ 0.23	26	+ 0.20
	11,000	52	19.2	+ 0.263	24.3	+ 0.22
	5,500	55	17.5	+ 0.23	23	+ 0.22
151	22,000	48	26.9	+ 0.31	27.23	+ 0.28
	11,000	51.61	21.1	+ 0.33	27.1	+ 0.28
	5,500	58	17.3	+ 0.357	26.5	+ 0.30
152	22,000	48.48	32.6	+ 0.36	31	+ 0.31
	11,000	48.64	25	+ 0.37	30	+ 0.33
	5,500	54.54	21.1	+ 0.38	28	+ 0.34

Table 8.2 Results (Usage of ANS Lake Water)

Core Number	Brine Salinity (ppm)	Recovery Factor (% OOIP)	Residual Oil Saturation (%)	Amott-Harvey Index
43	22,000	40.54	24.9	+ 0.25
	ANS Lake	52.94	19.5	+ 0.266
45	22,000	48	25.49	+ 0.22
	ANS Lake	64	17.64	+ 0.33
46	22,000	41.37	27.4	+ 0.23
	ANS Lake	58.33	19.6	+ 0.33

Table 8.3 Results (Effect of Varying Pulse Intervals)

Core Number	Pulse Intervals (minute)	Recovery Factor (% OOIP)	Residual Oil Saturation (%)	Amott-Harvey Index
1	1	51.61	26.04	+ 0.32
	0.3	53.3	22.5	+ 0.3
51	1	41.60	25.3	+ 0.25
	0.3	Core was Damaged		
141	1	44.44	21.1	+ 0.23
	0.3	48.14	19.2	+ 0.23
180	1	43.9	30.3	+ 0.22
	0.3	48.71	26.78	+ 0.23
181	1	42.1	28.3	+ 0.19
	0.3	51.40	28.3	+ 0.21

Table 8.4 Results (Coreflooding at Reservoir Conditions)

Core Number	Brine Salinity (ppm)	Recovery Factor (% OOIP)	Residual Oil Saturation (%)
49	22,000	29.41	25
	11,000	11.76	20.83
145	22,000	25	28.84
	11,000	15	23.07