DETERMINATION OF WETTABILITY AND ITS EFFECT ON
WATERFLOOD PERFORMANCE IN LIMESTONE MEDIUM

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ABSTRACT

DETERMINATION OF WETTABILITY AND ITS EFFECT ON WATERFLOOD PERFORMANCE IN LIMESTONE MEDIUM

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Previous studies of crude oil/brine/rock system showed that oil recovery from a reservoir rock depends on numerous complex interactions and one of the factors that has strong influence on reservoir fluid mechanics is rock wettability.

In this study, wettability measurement methods, effect of wettability on fluid distribution and fluid flow in porous media were discussed and, the influence of rock wettability on relative permeability and recovery of crude oil by waterflooding were investigated. Experimental studies were conducted on a total of 23 core plugs from two different limestone formations. Synthetic brine (NaCl solution) and mineral oil, having a viscosity ratio of approximately 10, were used as the test fluids.

In the first part of the study, core samples, saturated with synthetic brine, were flushed with mineral oil to establish the initial conditions and wettability of the samples was measured by Amott-Harvey method. Test results showed that

wettability of the samples was ranging from strongly water-wet to intermediately-wet. Wettability measurements were repeated and it was obtained that Amott-Harvey wettability indices were reproducible.

In the second part of the study, effects of aging time, brine salinity and saturation procedure on wettability were examined. Long time aging in mineral oil altered wettability of a water-wet core sample to intermediately-wet. Unfortunately, there was only one water-wet sample and it was not possible to correlate alteration of wettability with respect to aging time. Increasing brine salinity also reduced water wetness. However, saturation procedure had almost no effect on wettability of the core samples. Wettability of the intermediately-wet samples could not be altered by aging, by varying brine salinity and by changing saturation procedure, therefore, it was concluded that, intermediate wettability was more stable than water wetness.

Finally, relative permeability and waterflood studies were conducted on core samples having different wettability levels. In water-wet medium, water breakthrough occurred relatively late and considerable amount of oil was produced before the breakthrough. After the breakthrough, oil production rate was decreased very sharply. Decreasing water wetness resulted in decreasing breakthrough recovery. In intermediately-wet system, breakthrough occurred very early and most of the oil was produced after the breakthrough. Water breakthrough had almost no effect on oil production rate. Waterflood in water-wet system seemed more economical because in order to produce the same amount of oil, less volume of water was required.

Key Words: Wettability Measurement, Amott-Harvey Method, Relative Permeability Measurement, Waterflooding

ÖZ

ISLANIMLILIĞIN ÖLÇÜLMESİ VE KİREÇTAŞI ORTAMINDAKİ SU ÖTELEMESİ PERFORMANSINA ETKİLERİNİN BELİRLENMESİ

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Petrol/su/kayaç sistemlerinde daha önce yapılan çalışmalar, petrol üretiminin sayısız ve karmaşık etkileşimler tarafından belirlendiğini ve bu konudaki en önemli faktörlerden birinin de ıslanımllık olduğunu ortaya koymuştur.

Bu çalışmada, ıslanımllık ölçüm metotları, ıslanımllığın gözenekli ortamdaki akışkan dağılımı ve akış üzerindeki etkileri ele alınmış, kayaç ıslanımllığının görelî geçirgenliğe ve su ötelemesi ile petrol kurtarımına etkileri incelenmiştir. Deneyler, iki farklı kireçtaşı formasyonuna ait toplam 23 adet tapa örneğı üzerinde yapılmıştır. Test akışkanı olarak, viskozite oranı yaklaşık 10 olan yapay tuzlu su (NaCl çözeltisi) ve laboratuvar petrolü kullanılmıştır.

Çalışmanın ilk bölümünde, yapay tuzlu su ile doyurulan tapa örnekleri, laboratuvar petrolü ile ötelenerek teste hazır hale getirilmiş ve Amott-Harvey metodu kullanılarak söz konusu örneklere ait ıslanımllık değeri belirlenmiştir. Test sonuçları, ıslanımllık değeri ortası ıslanımllıdan kuvvetli su ıslanımllıya doğru

değiştirdiğini göstermiştir. İslanımllık testleri tekrarlandığında, Amott-Harvey İslanımllık İndekslerinin tekrarlanabilir olduğu tespit edilmiştir.

Çalışmanın ikinci bölümünde, yaşlandırma (aging) zamanının, tuzluluğun ve doyurma yöntemindeki değişikliğin ıslanımllık üzerindeki etkileri incelenmiştir. Laboratuvar petrolü kullanılarak yapılan uzun süreli yaşlandırma işlemi, su ıslanımllı bir örneği orta ıslanımllı hale getirmiştir. Fakat, yalnızca bir tane su ıslanımllı örnek olmasından dolayı, yaşlandırma zamanı ile ıslanımllılığın değişimi arasında korelasyon oluşturulamamıştır. Tuzluluktaki artış da kayaçların su tarafından ıslatılma eğilimlerinin azalmasına neden olmuştur. Doyurma yöntemindeki değişim ise, kayaçlara ait ıslanımllık değerlerini etkilememiştir. Orta ıslanımllı tapalara ait ıslanımllık değerleri, yaşlandırma işlemi, tuzluluk ve doyurma yöntemindeki değişiklikten etkilenmemiş ve durum orta ıslanımllılığın, su ıslanımllılığa göre daha kararlı (kalıcı) olduğu şeklinde yorumlanmıştır.

Çalışmanın son kısmında, değişik ıslanımllık değerlerine sahip tapa örnekleri üzerinde göreceli geçirgenlik testleri ve su ötelemesi çalışmaları yapılmıştır. Su ıslanımllı ortamda basılan suyun, karotun üretim ucuna ulaşması daha geç olmuş ve petrol üretiminin önemli bir bölümü bu zamandan önce gerçekleşmiştir. Basılan suyun karotun üretim ucuna ulaştığı andan itibaren, petrol üretimi oranı hızlı bir düşüş göstermiştir. Su ıslanımllılığındaki azalma, suyun üretim ucuna ulaştığı zamana kadar yapılan petrol üretiminde de azalmaya sebep olmuştur. Orta ıslanımllı sistemlerde, basılan suyun üretim ucuna ulaşması çok daha erken olmuş ve petrolün önemli bir bölümü bu andan sonra üretilmiştir. Basılan suyun üretim ucuna ulaşmasının, petrol üretimi oranına önemli bir etkisi olmamıştır. Su ıslanımllı ortamlarda yapılan su ötelemesi, aynı miktardaki petrolü üretmek için daha az su gerektirdiğinden dolayı, daha ekonomik gibi görünmüştür.

Anahtar Sözcükler: İslanımllık Ölçümü, Amott-Harvey Metodu, Göreceli Geçirgenlik Ölçümü, Su Ötelemesi

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NOMENCLATURE

Roman Symbols :

A	Cross sectional area, cm ²
d	Diameter, cm
I	Wettability index
k	Permeability, milidarcy
L	Length, cm
P	Pressure, atm or psi
S	Saturation, percent or fraction
q	Flow rate, cc/sec
T	Temperature, °F or Time, sec
V	Volume, cc
W	Weight, g

Greek Symbols :

ϕ	Porosity, percent or fraction
Δ	Difference
μ	Viscosity, cp

ρ	Density, g/cc
Σ	Cumulative
θ	Contact angle, degree
σ	Interfacial tension, dyne/cm

Abbreviations :

EOR	Enhanced Oil Recovery
IW	Intermediately-Wet
OOIP	Original Oil in Place
OW	Oil-Wet
PV	Pore Volume
WW	Water-Wet

Subscripts :

a	Air or atmosphere
AH	Amott – Harvey
b	Bulk
g	Grain
i	Initial
L	Liquid
o	Oil

nw	Non-wetting phase
p	Produced or pore
r	Residual or relative
s	Rock surface
sp	Spontaneously
t	Total
w	Water or wetting phase

CHAPTER 1

INTRODUCTION

Oil recovery from porous sedimentary rocks depends mainly on the overall efficiency with which oil is displaced by some other fluid(s). In this process, wettability of reservoir rock is as important as permeability, viscosity, and fluid saturations in determining the characteristics of multiphase flow [1].

Waterflooding is frequently used as a secondary recovery method in which water is injected into the reservoir to displace the oil in front of it. If the reservoir is initially at irreducible water saturation, only oil is produced until water breakthrough, and then, increasing amounts of water and decreasing amounts of oil are produced together. The operation is carried on until the water-oil ratio is so high that the well becomes uneconomical to produce.

Anderson [2] stated that, when a uniformly water-wet core is waterflooded at a moderate oil-water viscosity ratio, most of the oil is produced before breakthrough and water breakthrough occurs relatively late. As the system becomes oil-wet, breakthrough occurs earlier. Waterfloods in an oil-wet system are less efficient, since more water must be injected to recover the same amount of oil.

Wettability is the major factor controlling the spatial distribution of fluids in a reservoir [2, 3]. In a strongly water-wet rock initially at the irreducible water saturation, water, the wetting phase, will occupy the small pores and form a thin film over all of the rock surfaces. Oil, the non-wetting phase, will occupy the

centers of the larger pores. Any oil placed in the small pores would be displaced into the center of the larger pores by spontaneous water imbibition which is an important phenomenon in oil recovery especially from fractured reservoirs where the rate of mass transfer between the rock matrix and the fractures determines the oil production [4, 5, 6, 7]. If a rock is strongly oil-wet, it is preferentially in contact with the oil and the location of the two fluids is reversed from the water-wet case and the connate water saturation appears to be located as separate droplets in the centers of the pore spaces.

Most of the clean rock mineral surfaces tend to be preferentially wet by water rather than by crude oil [8, 9, 10, 11, 12, 13, 14]. However, the original strong wetness of the most reservoir minerals can be altered by the adsorption of polar compounds and / or deposition of organic matters that were included in the crude oil [11, 14, 15, 16, 17, 18, 19]. Pore structure, mineralogy, pH and salinity of brine, reservoir temperature and historical maximum capillary pressure are reported as the other factors controlling the wettability of a reservoir [8, 14].

Wettability of a core sample affects all type of special core analysis including capillary pressure, relative permeability, waterflood behaviour, electrical properties and simulated tertiary recovery and the analysis must contain effect of wettability variation.

Aim of this study includes; (1) measurement of wettability, (2) investigating the possibility of changing or artificially controlling the wettability of the core samples, (3) examining the effect of wettability on relative permeability and waterflood performance, in limestone medium.

For this purpose, all the studies were conducted on 23 plug samples taken from two different limestone formations. After cleaning by toluene extraction and measuring the porosity and air permeability, wettability of the samples was determined by Amott-Harvey method. Mineral (laboratory) oil and NaCl solution

were used as the test fluids. Wettability measurements were repeated to check the reproducibility of the wettability data.

In the next step, fifteen plug samples having different wettability characteristics were chosen for the further studies. Then, the effect of aging duration, brine salinity and saturation history on wettability were examined.

At the end of the study, by using seven core samples with different wettability characteristics, relative permeability and waterflood studies were conducted to determine the effect of wettability on these parameters.

CHAPTER 2

LITERATURE REVIEW

2.1. WETTABILITY

Wettability is defined as “the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids” [15]. Anderson [14] defines the wettability for crude oil / brine / rock system as the measure of the preference that the rock has for either the oil or water. The wettability of the rock fluid system is important because it is the major factor controlling the location, flow, and distribution of fluids in a reservoir.

Interaction between the surface of the reservoir rock and the fluid phases confined in the pore space influences fluid distribution in rock as well as flow properties. When two immiscible phases are placed in contact with a solid surface, one of the phases is usually attracted to the surface more strongly than the other phase. This phase is identified as the wetting phase while the other phase is the non-wetting phase. When the rock is water-wet, there is a tendency for water to occupy the small pores and to contact the majority of the rock surface. Similarly, in an oil-wet system, the rock is preferentially in contact with the oil; the location of the two fluids is reversed from the water-wet case. If the rock has no strong preference for oil and water, the system is said to be of neutral (or intermediate) wettability. It is important to note that, the term wettability is used for the wetting preference of the rock and does not necessarily refer to the fluid that is in contact with the rock at any given time.

In the early stages of reservoir engineering, it was generally considered that all formations are preferentially water-wet. This based on; (1) sandstone reservoirs are deposited in an aqueous environment and only later did oil migrate into these sands and (2) most sedimentary rock minerals are water-wet in their natural state [11]. However, it was recognized that some producing formations are different from the water-wet condition particularly in the case of carbonate rocks [14, 15, 17, 20, 21, 22]. Carbonate rocks are generally hydrophobic, i.e. dislikes water and if subjected to choice of oil or water, they will prefer oil and become oil-wet since the carbonate particles usually adsorb organic coating which protect them from dissolution in the slightly acidic formation waters [23]. It was reported that [15, 19], adsorption of the polar molecules and deposition of hydrocarbon film on the solid surface leaves the surface hydrophobic and the wettability of a reservoir rock is strongly affected by the presence or the absence of molecules in the crude oil that absorb or deposit on the mineral surface in the rock.

Marzouk et al. [23] explains the oil accumulation mechanism (or saturation history) of the petroleum reservoirs in the following manner; the oil accumulation started when the oil globules rise up / float by buoyancy in the formation, which is initially water-wet and all of the pore spaces are filled with water. The oil globules continued rising up in the high permeable layers below the cap rock until they reach the reservoir top. They replaced the formation water in the relatively larger pores, where lower capillary pressure resistance exists. As the trap becomes partially filled with oil during the different stages of oil migration, the level of the water oil contact is gradually pushed down. The force, which pushes down the oil into the water-filled porosities, is the differential pressure between the oil and water phases. Macropore throat will respond immediately to this pressure and oil will be pushed easily down in the macropores. On the other hand, micropore throats will resist the entry of oil due to their great capillary forces. Therefore, micropores will be difficult or even impossible to be invaded by oil and accordingly, they will remain water-wet. However, oil / grain surface interaction in the macropores and part of the mesopores will last for millions of years, which

would lead to wettability change from water-wet to oil-wet. Since the carbonate rocks were originally water-wet, oil accumulation process in the reservoir is considered as drainage process, where non-wetting phase replaces wetting phase i.e. oil replaces water from pores with larger throat.

2.1.1. Different Wettability States

Morrow [11] stated that, reservoir wettability is not a simply defined property and classification of reservoirs as oil-wet or water-wet is a gross oversimplification. Wettability studies showed that, reservoir wettability could cover a broad spectrum of wetting conditions from very strongly water-wet to very strongly oil-wet.

For simplicity, it is generally assumed that the pore surface within a reservoir rock is uniformly (homogenously) wetted. Water-wet, oil-wet and intermediately-wet states are uniform wettability states in which the every portion of the entire rock surfaces shows the same preference for oil and water. However, many reservoirs have heterogeneous wettability where some portions of the rock surface are water-wet while others are oil-wet. This non-uniform wettability state is named as fractional wettability [21, 24, 25] and it is more common than the uniform one [3, 11].

Anderson [14] defined the generation of the fractional wettability in the following way; the surface of reservoir rock is composed of many minerals with different surface chemistry and adsorption properties, which may lead to variations in wettability. In fractional wettability, crude oil components are strongly adsorbed in certain areas of the rock, so a portion of the rock is strongly oil-wet, while the rest is strongly water-wet. Fractional wettability is conceptually different from intermediate wettability, in which it is assumed that all portions of the rock surface have a slight but equal preference to being wetted by water or oil.

For the fractional wettability, there are two possibilities. In the first one, the oil-wet and the water-wet portions are randomly distributed and these parts have a size approximately equal to pore size, or even to a unit including several pores. However, they are not continuous through the media. For this type of wettability, expression such as spotted, speckled, dalmation wettability is used [14]. For the second one, both oil-wet and water-wet surfaces are continuous through the reservoir and for this case; the expression mixed wettability was proposed by Salathiel [17].

Mixed wettability is a special type of fractional wettability in which the oil-wet surfaces form continuous paths through the larger pores. The smaller pores remain water-wet and contain no oil and all of the oil in a mixed-wettability reservoir is located in the larger oil-wet pores. This results in a small but finite oil permeability to exist down to very low oil saturation and permits the drainage of oil during a waterflood to continue until very low oil saturations are reached. It was reported [3, 14, 17] that, the main distinction between mixed and fractional wettability is that the latter implies neither specific location for the oil-wet surfaces nor continuous oil-wet paths.

Several authors [14, 17, 24] defined the generation of the mixed wettability in the way that, when oil initially invades the originally water filled and water-wet reservoirs, it displaces water from the larger pores while the smaller pores remain water filled because of capillary forces. In the larger pores where the invaded oil resides, the pore walls are covered by a thin layer of original water. The water film becomes thinner and thinner as more and more oil enters the rock until a critical thickness is reached where the film becomes unstable and displaced allowing the oil to contact the rock surface. Since the invading oil is in a continuous form, the oil-contacted surface in the larger pores also forms a continuous path. If the oil deposits an oil-wet organic material on the rock surfaces contacted by it, it would result in a continuous oil-wet path through the larger pores, while the smaller pores not invaded by the oil would remain water-

wet. In a waterflood, oil would flow easily through these oil-wet paths resulting in low residual oil saturations or high oil recoveries.

Salathiel [17] noted that, the pore geometry of the reservoir and the connate water saturation present during the deposition of the oil-wet film affects the degree of development of continuous oil-wet paths by controlling the degree of contact of crude oil with solid surfaces. Figure 2.1 illustrates a simplified description of the effect of pore geometry and the connate water saturation. It was also noted that [8], since the historical maximum capillary pressure has an important effect on the initial water saturation, the degree of mixed wettability is also controlled by this parameter.

Figure 2.1. Effect of pore geometry and connate water saturation in generation of continuous oil-wet paths [17].

2.2. ALTERATION OF THE ORIGINAL WETTABILITY

To understand the reservoir wettability, displacement test should be conducted at conditions that are representative of reservoir. So, cores with unaltered wettability are essential. This requires that coring, core recovery, storage and testing procedures be designed to recover the cores without change in surface properties. However, Morrow [19] noted that, during coring the core is at least partially flushed with mud filtrate and the wettability of the sample is altered. The factors altering the original wettability of a core sample may be considered in two groups as; (1) before testing and (2) during testing.

2.2.1. Wettability Alteration Before Testing

Alteration of the original wettability of core samples during cutting, surfacing and subsequent handling can be caused by number of reasons includes (1) drilling fluid contamination, (2) temperature and pressure reduction (3) oxidation (4) drying (5) flashing of connate water with pressure reduction (6) packaging (7) preservation (8) cleaning [11, 14, 26].

It was reported that both water based [27, 28] and oil based mud [9, 13, 27, 28] components changed the wettability of a core sample. Although, filtrates from water based drilling muds caused little change in rock wettability, oil based mud components may change the wettability of core sample from strongly water-wet to some other degree of wettability. Ballard and Dawe [28] reported that, alteration of rock wettability by an oil base mud, could also mobilize the immobile water near the wellbore probably by lowering the interfacial tension between the water and oil phase. Bobek et al. reported that [26], weathering makes the cores more oil-wet.

2.2.2. Wettability Alteration During Testing

Factors that affect the wettability during testing are reported as; (1) properties of the test fluids (such as salinity), (2) test temperature (3) aging time and temperature and (4) established initial water saturation [16, 20, 29]. Tang and Morrow [29], studied the effect of each parameter. Result of their study is given in Table 2.1. In the table, increasing water imbibition rate means increasing water wetness while decrease of the same parameter means increasing oil wetness. Detail of imbibition rate evaluation will be given in the following sections.

Table 2.1. Observed Effect of Variables on Wettability and Oil Recovery [29]

<i>VARIABLES</i>	<i>Water Imbibition Rate</i>	<i>Waterflood Recovery</i>
Increase in aging time	Decrease	Increase
Decrease in initial water saturation	Decrease	Increase
Increase in aging temperature	Decrease	Increase
Increase in valency of cation, Na^+ , Ca^{2+} , Al^{3+}	Decrease	Increase
Decrease in radius of hydration, Li^+ , Na^+ , Cs^+	Decrease	?
Decrease in brine concentration (invading and initial)	Increase	Increase
Decrease in initial brine concentration	Increase	Increase
Decrease in invading brine concentration	Increase	Increase
Increase in run temperature	Increase	Increase
Increase in displacement temperature during run	Increase	Increase
Removal of light ends	Increase	?
Addition of light ends	Decrease	Increase

2.3. CORE CLEANING

There are two main reasons to clean a core; the first one is to remove all liquids from the core, so that porosity, permeability, and fluid saturations can be measured, the second one is that, the core may be cleaned as a first step in restoring the wettability [9, 11, 14].

The usual objective of core cleaning by flow of organic solvents or extraction is to remove all organic compounds without altering the basic pore structure of the rock. A wide range of combinations and / or sequences of solvents have been proposed but procedures are far from standardized [11]. Determining which solvents will successfully clean the cores is still a trial and error process [12, 14].

Toluene, which is the mostly used solvent, used alone is one of the least effective one and it may or may not remove the adsorbed organic film from the core surface depending on the rock type and composition [3, 9, 13, 14]. However, although it is often less efficient than other solvents, toluene extraction also alter the wettability [3]. When the toluene is combined with other solvents, such as methanol or ethanol, it becomes often very effective [10, 14]. In addition to toluene / methanol and toluene / ethanol, successful cleaning has also been reported with chloroform / acetone as well as a number of different series of solvents [14].

As previously discussed, the surfactants included in drilling fluids may alter the wettability of core. Since routine cleaning methods can not remove these surfactants, core that is to be used for special core analyses is left with an altered wettability. Therefore, in order to obtain reliable results, cleaning methods must also be developed to remove these surfactants, allowing restoration of plugs to their original wettability. Once the core is cleaned, wettability of the core can be restored [9].

If the cleaning process is successful, the core is left strongly water-wet because almost all of the clean reservoir minerals without adsorbed compounds are known to be strongly water-wet (see Table 2.2) [8, 9, 10, 11, 12, 13, 14]. However, Anderson [14] reported that, if the cores contain coal, they could be cleaned only to a neutral-wet condition since they are also neutrally-wet in their clean states.

Cores are generally cleaned by distillation-extraction methods (Soxhlet or Dean-Stark). In this method, core sample is cleaned with hot, refluxing solvent. The solvent is continuously distilled, condensed, and then distributed over the top of the sample. One drawback of the distillation-extraction methods is that the solvent may not contact all of the core. Core samples often have very small pore throats, allowing solvents to flow through them only when a pressure is applied [9]. Another drawback of this method is that it may change an originally water-wet rock to an oil-wet one. The extraction process may quickly boil off the connate water, allowing the remaining oil to contact the rock surface and form oil-wet deposits that are difficult to remove [9, 30].

Table 2.2. Wettability of Rocks in Natural (Clean) Conditions [21]

Water-wet	Oil-wet
Quartz	Coal and Graphite
Carbonates	Sulphur
Sulfates	Talc-like silicates
Chlorides	Sulfides

2.4. RESTORATION OF THE ORIGINAL WETTABILITY

The objective of the restoration process is to re-establish reservoir wettability conditions as representative as possible (see Figure 2.2) by contacting the core with reservoir crude oil and it requires a three-step process [9, 12, 22, 31, 25].

Many special core analyses, including capillary pressure, relative permeability, and saturation exponent, are affected by the wettability of the core and the most accurate measurements could be made on native-state cores, where special precautions are taken to minimize alteration of the reservoir wettability [9, 12]. However, most of the time, representative reservoir fluids are more easily obtainable than the native-state cores and only the core with altered wettability is available. In this case, the best possible multiphase measurements are obtained by restoring the reservoir conditions [9, 32, 12]. Several experimenters [10, 11, 12, 14, 17, 23, 29, 31, 32] have compared measurements made on core in the native, cleaned, and restored states and they concluded that, measurements in the restored state were almost identical to the previous native state ones (see Figure 2.3 and 2.4).

Cuiec [22] reported that, the first and most difficult step in wettability restoration is to clean the contaminated core to remove all compounds from the surface. All compounds must be removed from the core because we have no knowledge of which compounds were adsorbed on the original rock and which were deposited afterward.

In the second step, the reservoir fluids are flowed through the core sequentially. After saturating with synthetic or real formation brine, the core sample is flushed with live or dead crude oil until a correct S_{wi} value is established [12, 32]. The crude oil sample must be taken either before any chemicals are added into or as long as possible after any well treatments, to allow time for these chemicals to be

flushed from the well. Also, the crude should be sealed in airtight to minimize oxidation and loss of light ends [12].

The last step is to age the core sample in reservoir crude at the reservoir temperature (sometimes at reservoir pressure with live crude oil [32]) for a sufficient time to establish adsorption equilibrium between the rock surface and the crude oil. The aging time varies depending on the crude, brine, and reservoir rock. Wendel et al. [12] reported that, aging time required to establish the equilibrium from only a few to 1000 hours and the core samples aged for a period longer than the minimum necessary is not a serious drawback. He recommended that 1000 hours could be used for aging. Another possibility is to determine the minimum aging time by measuring the wettability of the cores at frequent intervals during the aging period. The aging is stopped when the wettability reaches its equilibrium value. In Figure 2.5, results of different studies are shown. Although this minimizes aging time, it is much less suitable because it requires frequent disturbances to the plug.

Wendel et al. [12] also reported three disadvantages of working with the restored-state cores in place of native ones; (1) the procedure adds greatly to the cost and time for special core analyses, (2) a successful cleaning method must be determined by a trial-and-error process and (3) the cleaning methods may damage the clays in the cores. Another disadvantage is that, since the laboratory conditions are very different from the conditions existing in oil reservoirs, the wettability might not be changed in the same way it occurs in a reservoir [33].

Figure 2.2. Method for obtaining “restored-state core samples” as representative as possible [22].

Figure 2.3. Wettability of different state core samples. The restored ones are very close to the preserved ones [23].

Figure 2.4. Relative permeability of different state core samples. The restored one is very close to the preserved one [31].

Figure 2.5. Effect of aging time on the wettability of a core sample. After a certain time, wettability of a core sample is stabilized. ((a) from Jia et al. [20], (b) from Graue et al.[24], (c) from Graue et al.[6])

2.5. WETTABILITY MEASUREMENT

Many different methods have been proposed to determine the wettability of a crude oil / brine / rock system. They may be divided into two main groups as quantitative and qualitative methods. The former includes; contact angle measurement, Amott method (imbibition and dynamic displacement) and USBM method, and the latter mainly includes; imbibition (rate) method, estimation from shape of relative permeability curves, estimation from shape of recovery curves, microscope examination, flotation, glass slide method, permeability / saturation relationships, capillary pressure curves, capillarymetric method, displacement capillary pressure, reservoir logs, nuclear magnetic resonance, and dye adsorption [25, 35].

Contact angle measurement, Amott method, USBM method, imbibition method and estimation from the relative permeability are widely used ones today by oil and service companies [11, 35]. In the following sections, these methods will be discussed.

2.5.1. Contact Angle Measurement Method

Contact angle is used as the fundamental definition of wettability. When two liquids are in mutual contact and also in contact with a solid surface, the liquid, which makes an angle of less than 70° with the solid surface, is said to preferentially wet the surface [36]. Quantification of the wettability by the contact angle is defined in Figure 2.6, which represents a drop of water placed on a flat rock surface immersed in oil. If angle θ is less than 90° the surface is said to be water-wet. The smaller the angle the higher the water-wetness. Conversely, if θ is more than 90° the surface is oil-wet. For angles of about 90° , the solid is said to have neutral wettability.

Figure 2.6. Contact angle as a measure of wettability. If θ is less than 90° , the surface is water-wet, if θ is larger than 90° , the surface is oil-wet. If θ is close to 90° , the surface is known to have intermediate wettability.

This method consists of placing a drop of oil or water on a flat surface of a solid and of submerging this solid in water or oil. Some devices may also even operate at reservoir temperature and pressure and the angle can be measured under static or dynamic condition [25].

Although it is the most universal measure of the wettability of surface, contact angle measurement cannot be used for porous media [11]. It can only measure the wettability of crude and brine on a polished mineral surface. It is the best method to use when pure fluids and artificial cores are used. It is also used to examine the effects of experimental conditions on wettability, such as pressure, temperature, and brine chemistry. Even though it is possible with great care, to get exact and reproducible contact-angle measurements, these results are not representative of the wettability of reservoir cores. The contact angle cannot take into account the roughness, heterogeneity, and complex geometry of reservoir rock [25, 35].

2.5.2. Amott Method

The method was first proposed by Amott [13]. Amott method and a modification of its known as Amott-Harvey method are the mostly used wettability determination methods in the oil industry. Number of researchers used these two methods in their study [10, 20, 22, 24, 31, 32].

The Amott method combines imbibition and forced displacement to measure the average wettability of a core. Both reservoir core and fluids can be used in the test. The method is based on the fact that the wetting fluid will generally imbibe spontaneously into the core, displacing the non-wetting one. The ratio of spontaneous imbibition to forced displacement is used to reduce the influence of other factors, such as porosity, permeability, viscosity, and the initial saturation of the rock [33, 35]. Amott defined the test procedure as follows;

1. Flush core with water and with kerosene to remove most of the crude oil and formation water,
2. Evacuate under kerosene to remove gas,
3. Centrifuge under water for 1 hour to obtain core under residual oil saturation,
4. Immerse the core in kerosene. Record volume of water spontaneously released after 20 hours,
5. Centrifuge under kerosene for 1 hour and record total volume of water displaced,
6. Immerse the core in water. Record volume of oil spontaneously released after 20 hours,
7. Centrifuge under water and record total volume of oil displaced,

The test results are expressed by two numbers, the ratio of spontaneous to total oil volumes displaced by water (displacement by water ratio, I_w) and the ratio of spontaneous to total water volumes displaced by oil (displacement by oil ratio, I_o). If nearly all of the oil recovery occurs by spontaneous imbibition, I_w is close to 1.0

and the system is described as very strongly water-wet. Systems are increasingly less water-wet for smaller values of I_w .

Amott chooses an arbitrary time period of 20 hrs. for the spontaneous oil and water imbibition steps. However, it is recommended [22, 35] that, the cores should be allowed to imbibe until imbibition is complete. In addition, in the third and seventh steps, a flow system rather than a centrifuge can also be used for the forced displacement of oil and water.

The evaluation of the Amott test is given in Table 2.3. From the table it is seen that, for the reservoir core sample, at least one of the wettability indices is zero. However, this is not true if the core sample has heterogeneous wettability. If a core samples has fractional wettability (or sometimes mixed wettability), it will spontaneously imbibe both oil and brine [24, 17, 32, 35]. Cuiec [25] reported that good reproducibility is obtained with the Amott test.

Table 2.3. Evaluation of the Amott's Wettability Indices (R45)

	Water-Wet	Neutrally-Wet	Oil-Wet
Displacement by water ratio, I_w	Positive	Zero	Zero
Displacement by oil ratio, I_o	Zero	Zero	Positive

2.5.3. Amott – Harvey Method

Amott-Harvey Method was modified from the Amott Method. Wettability of the sample is expressed by an index named as Amott-Harvey wettability or relative displacement index, (I_{AH}). It has an additional step with respect to Amott test in core preparation before the test is run. The core is first flooded with water then with oil to reduce the plug to irreducible water saturation (S_{wi}). Then, the displacement by water and displacement by oil ratios are calculated by the Amott method. The Amott-Harvey wettability index is equal to the displacement by water ratio minus displacement by oil ratio [35, 25]. Evaluations of the Amott-Harvey test results are shown in Figure 2.7.

2.5.4. USBM Method

The USBM (U. S. Bureau of Mines) is another popular method and has been used by some of researchers to determine wettability of porous media containing brine and crude oil [12, 32]. The method has been developed by the USBM [1]. It is rapid, reproducible and requires only a minimum handling of the cores before testing. It also establishes a numerical wettability scale for systems ranging from strongly water-wet to strongly oil-wet. It is independent of pore geometry and fluid viscosity used in the measurements [1, 25].

-1.0	-0.3	-0.1	0.1	0.3	+1.0
	Slightly Oil-Wet	Neutral	Slightly Water-Wet		
Oil-Wet	Intermediate			Water-Wet	

Figure 2.7. Evaluation of the Amott-Harvey relative displacement index [22].

The method uses capillary pressure versus average fluid saturation data determined with a centrifuge. It compares the work necessary for one fluid to displace another. It is basically a correlation between the degree of wetting and the areas under the capillary pressure curves [1, 35, 25]. In other words, when a core is water-wet, the area under the capillary pressure curve when the water displaces the oil is smaller than the area under the capillary pressure curve for the reverse displacement. In fact, if the sample is strongly water-wet, most of the water will spontaneously imbibe into the core, and the area under the brine-drive curve will be very small.

In the USBM test, after S_{wi} is established, the sample is subjected to forced displacement of oil by centrifuging with the speed increased by increments. A capillary pressure curve (I) is derived from the centrifuge data and the area under the forced imbibition curve is determined (A2) (see Figure 2.8). The core sample is then subjected to forced displacement of water by oil (II). The area under the drainage curve is designated (A1). The USBM wettability number is then defined by the logarithm of the ratio of the areas [7],

$$I_{USBM} = \log \left[\frac{A1}{A2} \right] \dots\dots\dots (2.1)$$

Evaluation of the test results are shown in Figure 2.8.

Figure 2.8. Effect of wettability on the area of capillary pressure curves for core samples having (a) water-wet, (b) oil-wet and (c) neutral wettability characteristic [1].

2.5.5. Combined Amott/USBM Method

This method is combination of Amott and USBM methods. It allows calculation of both USBM and Amott wettability indices. Test procedure includes five steps [35]; (1) initial oil drive, (2) spontaneous brine imbibition, (3) brine drive, (4) spontaneous oil imbibition, (5) oil drive (see Figure 9). Amott and USBM indices are calculated by the same way explained in each section.

Figure 2.9. Test Procedure of the Combined Amott / USBM method [37].

2.5.6. Estimation from Relative Permeability Curves

Relative permeability is defined as the ability of the porous system to conduct one fluid when more than one fluids are present [3]. Wettability affects relative permeability because it is a major factor controlling the location, flow, and spatial distribution of fluids in the core. This method is based on the relationship between the relative permeability and wettability.

In order to estimate the wettability of a crude oil / brine / rock system, Craig's rules of thumbs [15] are used. They consider initial water saturation (S_{wi}), water saturation at crossover point at which water and oil relative permeabilities are

equal and end point water relative permeability (k_{rw} at S_{or}). The rules of thumbs are given in Table 2.4. In addition to these, end point oil effective permeability (k_{ro} at S_{wi}) also changes with wettability and it could also be considered during the evaluation [38]. However, relative permeability curves can be normalized with either (1) the absolute permeability of the core, or (2) the effective permeability of oil at S_{wi} and if the relative permeability curves are normalized with the effective oil permeability, this wettability effect have already been factored out, hence all of the curves will start at the same point, even though the wettability is changed (see Figure 2.10) [3].

Since relative permeability is function of many other parameters such as pore structure, interfacial tension, saturation and saturation history, it is too simplistic to consider the changes alone with wettability and it is recommended to make independent measurements of wettability if possible [3, 38]. Because, especially when the rock has intermediate wettability, it is more difficult to deduce the wettability from the relative permeability curves [25].

Table 2.4. Craig's Rule of Thumbs for Estimation of Wettability from Relative Permeability [15]

		Water-Wet	Oil-Wet
1	S_{wi}	Usually greater than 20-25 percent pore volume	Generally less than 15 percent pore volume, frequently less than 10 percent
2	Crossover Point	Greater than 50 percent water saturation	Less than 50 percent water saturation
3	k_{rw} at S_{or}	Generally less than 30 percent	Greater than 50 percent approaching 100 percent

Figure 2.10. Typical water-oil relative permeability curves based on the effective permeability to oil at the reservoir connate water saturation. (a) strongly-water-wet rock (b) strongly oil-wet rock [15].

2.5.7. Imbibition (Rate) Method

It is the most commonly used qualitative wettability measurement method [5, 7, 18, 20, 26]. Because, it gives quick idea about wettability of the crude oil / brine / rock system without requiring any complicated equipment.

The spontaneous imbibition phenomenon is largely controlled by the capillary pressure that is function of the interfacial tension between the two fluids, the cosine of the contact angle and pore size distribution. Consequently, imbibition which may be characterized by its rate and by the total amount of fluid displaced, depends strongly on the wettability of the sample besides the other parameters like permeability, viscosity ratio of the test fluids, and the initial oil and water saturation [25, 26, 35].

In an imbibition test, a core at S_{wi} , is submerged in brine and the rate and amount of oil is determined either volumetrically or gravimetrically. Imbibition of brine with higher rates and higher volumes means the stronger water-wetness [7, 25,

35]. It was reported that [43], especially in the very strongly water-wet rock samples with high values of displacement by water index, rate of imbibition measurement could be a useful method for characterization of wettability.

2.5.8. Discussion of the Wettability Measurement Methods

Evaluation of reservoir wettability from core samples frequently involves the use of refined oil and laboratory-prepared brines. Craig [15] reported that the tests are meaningful if the natural wetting preference of the rock sample is not destroyed by any factor including surfactants in the drilling mud, cleaning process etc.

There are two quantitative methods, suitable to evaluate the average wettability of reservoir cores; the Amott method and the USBM method and both have serious weaknesses [6]. The major advantages of the USBM test over the Amott test are; it is relatively quick, requiring 1 day to test four to eight core plugs and it is sensitive near neutral wettability. However, the USBM wettability index can only be measured on plug-size samples because the samples must be spun in a centrifuge [18, 35].

The main problem with the methods based on spontaneous imbibition experiment is that, they are insensitive near neutral wettability. The test measures the ease with which the wetting fluid can spontaneously displace the non-wetting one. However, neither fluid will spontaneously imbibe and displace the other near neutral wettability. Neither imbibition rate methods nor the Amott tests can discriminate between systems, which do not imbibe either oil or water in significant quantity. For such cases the USBM method is recommended [7, 12, 25, 35].

Imbibition of brine and crude oil of approximately the same amount into a core sample indicates mixed wettability of bicontinuous type such that there are continuous pathways of both the water-wet and oil-wet kind in the pore spaces.

For the mixed wet system, Amott's displacement by water ratio (I_w) and displacement by oil ratio (I_o) may have certain values and Amott-Harvey wettability index (I_{AH}) may be very close to 0.0. The USBM test cannot determine whether a system has fractional or mixed wettability, while the Amott test is sometimes sensitive [10, 32, 35].

Anderson [35] reported that, there are two advantages of the combined USBM/Amott method over the standard USBM method; (1) the resolution of the USBM method is improved by accounting for the saturation changes that occur at zero capillary pressure, (2) the Amott index is also calculated. As discussed earlier, the Amott method will sometimes indicate that a system is non-uniformly wetted.

For a very strongly water-wet system that achieves residual oil saturation by spontaneous imbibition, the measurement of imbibitions rate provides a useful characterization of wettability [7]. Because, the Amott test does not discriminate adequately between systems that give high values of wettability index to water and are collectively described as very strongly water-wet and the USBM test does not recognize the same system.

The USBM methods, the Amott methods and the other methods based on imbibition studies measure the average wettability of a core. They are superior to the contact-angle method when the wettability of porous medium is measured [25, 26, 35].

An approximated relationship between the mostly used wettability measurement methods is given in Table 2.5.

Table 2.5. Approximate Relationship Between Mostly Used Wettability Measurement Methods [35]

	Water-Wet	Neutrally-Wet	Oil-Wet
Contact Angles, degrees			
Minimum	0°	60° to 75°	105° to 120°
Maximum	60° to 75°	105° to 120°	180°
USBM Wettability Index	Near 1	Near 0	Near -1
Amott Wettability Indices			
Displacement-by-water, I_w	Positive	Zero	Zero
Displacement-by-oil, I_o	Zero	Zero	Positive
Amott-Harvey Index, I_{AH}	1.0 to 0.3	0.3 to -0.3	-0.3 to -1.0

2.6. ARTIFICIALLY CONTROL OF WETTABILITY

In several investigations, wettability of the cores and other porous media was altered artificially [4, 6, 7, 10, 16, 17, 18, 20, 26, 27, 29, 32, 34, 39]. However, none of them could define a generally accepted standard procedure for generating a spectrum of wettability conditions. In the following sections, the methods used to control wettability of core samples will be discussed.

2.6.1. Generating Water-Wet Core Samples

In order to generate water-wet samples, the mostly used technique is to clean the core sample completely and heat at a high temperature (up to 400 °C [26]). Owens and Archer [39] reported that, addition of Orvus K (a detergent) to the water phase was also make the system water-wet.

2.6.2. Reducing the Water-Wetness

In order to reduce water-wetness of core samples, the most popular treatment is aging. Water-wetness decreased systematically from strongly water-wet condition to intermediate wettability with increase in aging time and temperature and the induced wetting state appears to be reproducible and stable [4, 6, 7, 16, 20, 26, 29, 32, 34]. It was also noted that, different crude oils alter wettability to different extents under similar conditions [20].

One method of making a sandstone core uniformly non-water-wet is to treat it with a solution containing an Organochlorosilane compound. Variation of this treatment was also used to create fractionally wetted sandpacks and mixed-wet cores [14]. It was also reported that [18], adsorption of asphaltenes from a solution of asphaltene in toluene provides a useful approach to laboratory studies in which wettability control is achieved.

2.6.3. Generating Oil-Wet Core Samples

Van et al. [27] used a five-step procedure to generate oil-wet Berea cores. The samples were; (1) dried and vacuumed for 4 hours, (2) saturated with 20% solution of Quilon C which is a chrom complex in isopropyl alcohol, (3) vacuumed for 4 hours, (4) flushed with ethyl alcohol until the effluent was only slightly green and (5) heated at 60 °C for 12 hours. By this method, an insoluble layer of polymerized complex, which is chemically adsorbed through chromium on the rock surfaces, is formed and the cores maintained their wettability over extended periods of time. Laurier and Mannhardt [33] also used the same chemical treatment to shift the wettability of Berea sandstone cores toward oil-wetness by a similar method.

Dullien et al. [10] used solution of dichlorodimethylsilane (drilfilm) in heptanes for the same purpose. Ten pore volumes of the solution were passed through the core, initially saturated with heptane. Then, the core was left to age for 72 hrs.

Finally the solution displaced from the core with heptane. The core samples showed strongly oil-wet characteristics.

Anderson [14] reported that, naphthenic acids might be used to render carbonate core more oil-wet. It reacts with calcium carbonates to form calcium naphthenates. However, it will not alter the wettability of sandstone cores.

2.6.4. Generating Mixed-Wet Core Samples

To generate mixed-wet cores, sandstone samples at irreducible water saturation may be flushed or aged with asphaltenic crude oil [10, 14, 17, 27, 32]. Then, the samples are flushed with pentane, which tends to precipitate asphaltenes onto core walls and the pentane is removed by vacuum leaving behind a layer of asphaltenes. By this method, pores with large throats are expected to be preferentially oil-wet and pores that are accessed by small throats are expected to be preferentially water-wet.

2.7. RELATIVE PERMEABILITY

Permeability is defined as the ability of a porous medium to transmit a fluid when it is 100% saturated with the same fluid. However, in the pores of petroleum reservoirs more than one fluid flow simultaneously and each fluid tends to interfere with the flow of the others [40]. Therefore, in order to simulate multi-phase flow behaviour of a porous medium, a new permeability definition, effective permeability, is required. Effective permeability is a direct measure of the ability of the porous medium to conduct one fluid when one or more immiscible fluids are present [15]. To represent the effective permeability in a dimensionless group, another parameter, relative permeability is used. It is the ratio of effective permeability of a phase to the absolute permeability of the

system. A typical two-phase relative permeability relationship is shown in Figure 2.11.

Two-phase relative permeabilities are affected by many parameters such as phase saturations, saturation history, wettability, pore geometry, porosity, permeability, temperature, overburden pressure, flow velocity, interfacial tension, viscosity, density of phases etc. [3, 15, 39, 41].

Morgan and Gordon [42] stated that, rocks with large pores and correspondingly small surface areas have low irreducible water saturation that leave relatively large amount of pore space available for the flow of fluids. This allows high end points to exist and allows a large saturation change to occur during the two-phase flow and different rock type with the same air permeability may have very different relative permeability characteristics. Because, post-depositional alterations can form more than one type of reservoir rock from a single original rock type. Pore filling materials, or other alterations, that reduces pore sizes, causes higher irreducible water saturation, smaller end points, and a narrower range of saturation change during two-phase flow.

Flow direction is another factor affecting the relative permeability. Crotti et al. [43] compared the curves obtained from a cubic core sample as a result of horizontal and vertical floodings, and obtained large differences in residual oil values and in the general displacement performance.

Relative permeabilities are functions of phase saturations. Saturation of a phase increases as it fills a larger portion of the pore space. Therefore, a phase with a higher saturation in general flows more easily because of having more channels to flow and not to be interrupted by the other phase(s) much. This shows us that the relative permeability of a phase increases as its saturation increases. There are two important saturation states, irreducible wetting phase saturation and residual non-wetting phase saturation.

As wetting phase saturation approaches the irreducible amount, the connection between the wetting phase flow channels breaks, and so the pressure cannot be transmitted from one molecule to another, any longer [41]. At irreducible wetting phase saturation, the phase is in the forms of thin films around the grain surfaces. This form of wetting phase may occupy large percentage of the pore space, depending on the nature and shape of individual grains, distribution, as well as degree and type of cementation. For the saturation values greater than the irreducible one, the wetting phase becomes mobile. Due to presence of the adhesive forces between the solid surface and the wetting phase molecules, the relative permeability to wetting phase is less than the relative permeability to non-wetting phase. The wetting phase moves through the smaller channels than the non-wetting phase does. However, as the wetting phase saturation increases, the connection between the non-wetting phase molecules moving inside the large channels starts to break down and so the phase becomes discontinuous. Therefore, the non-wetting phase reaches an immobile state at the residual saturation where none of the phase molecules is in contact with each other.

2.7.1. Two-Phase Relative Permeability Measurement

Measurement of relative permeability is one of the more complex experiments especially if the test is carried out at reservoir conditions. Relative permeability can be measured by using different techniques such as steady-state method, unsteady state method, centrifuge method and capillary pressure method [41]. More commonly used of them are unsteady-state and steady-state measurement methods. The steady-state method is a simple application of Darcy's equation to each fluid phase but it is time consuming. The unsteady state method is more commonly used, because it more directly models the reservoir process of a dynamic front and it is quicker [44].

Figure 2.11. Plot of a typical relative permeability versus water saturation curves.

2.7.1.1. Steady-State Method

The steady-state measurement technique is the most direct laboratory measurement technique for two-phase relative permeability determination. In this method, both phases are flowing through a porous media simultaneously until saturation and pressure equilibrium have been achieved and a simple application of the Darcy's equation provides the relative permeabilities. Then, injected fluid volumetric ratio is changed over a range of saturation to form relative permeability versus saturation curve for each flowing phase.

The main drawback to this method is the excessive amount of time required, often several hours, to generate a single point on the relative permeability curve [3, 41].

Steady-state methods are the widely acceptable and reliable methods for determining two-phase relative permeabilities because of simplifying assumptions.

2.7.1.2. Unsteady-State Method

Unsteady-state or dynamic displacement method is the most commonly used method of measuring relative permeability [11]. The method basically consist of injecting the displacing phase into the core at initial condition (at initial water saturation) and monitoring the produced flow of both phases together with the differential pressure across the sample. As the ratio of fluids leaving the outlet end of the core is changing with time, continuous measurement of the production of both fluids and the differential pressure across the core is necessary to calculate and to generate two-phase relative permeability points. Viscous oils are normally used to increase the period of two-phase production, because the flow before breakthrough gives no information about the relative permeability. If low viscosity oils are used in a water-wet core, the displacement is pistonlike, and only the end point relative permeabilities can be determined [3]. The JBN method first proposed by Johnson et al. [45] is the most common procedure to obtain relative permeability from the unsteady-state test data.

Unsteady-state method is used more often than steady-state method, because, it is less time consuming by which the entire set of relative permeability versus saturation curve can be obtained in a few hours and experiments are simple to perform [3, 41]. Chang et al. [8] reported that, at high flow rates, the unsteady-state relative permeability curves are in agreement with the steady-state measurements and reducing the flow rate during unsteady-state measurements, reduce the relative permeability.

2.7.2. Effect of Wettability on Relative Permeability

Wettability affects relative permeability by controlling the flow and spatial distribution of fluids in a porous medium. In strongly wetted rock, the relative permeability of the non-wetting phase depends on the saturation path while the relative permeability of the wetting phase is often path independent [8]. The wetting phase relative permeability is a function only of its own saturation and is not influenced by the direction of saturation change or the nature of non-wetting phase. At any given saturation, as the degree of rock preferential water wettability decreases, the relative permeability to oil decreases and the relative permeability to water increases (see Figure 2.12) [15, 39, 46].

In a uniformly wetted system, the wetting fluid will generally be located in the smaller pores and as a thin film in the larger pores, while the non-wetting fluid is located in the centers of the larger pores. In general, at a given saturation, the relative permeability of a fluid is higher when it is the non-wetting phase. For example, the water relative permeability is larger in an oil-wet system than it would be if the system were water-wet. This occurs because the wetting fluid tends to travel through the smaller, less permeable pore, while the, non-wetting fluid travels more easily in the larger pores. In addition, at lower non-wetting phase saturation, the non-wetting phase will come trapped as discontinuous globules in the larger pores. These globules block pore throats, lowering the wetting-phase relative permeability. On the other hand, the non-wetting phase relative permeability is high, since the non-wetting phase flows through the centers of the larger pores. At low wetting phase saturations, the non-wetting phase effective permeability will often approach the absolute permeability, demonstrating that the wetting phase does not greatly restrict the flow of the non-wetting phase [3].

The effective (and relative) permeability of a fluid is a function of the mobility of that phase at a given saturation. In turn, the mobility is a function of the wetting properties and of the average cross-sectional area of the fluid channels, i.e. of

saturation. The wetting fluid has a relatively low mobility compared to the non-wetting fluid, since the wetting fluid is located next to the pore walls, while the non-wetting fluid is located in the centers of the large pores. [3].

Wettability of the medium affects also the relative permeability ratio [3, 36]. Anderson [3] noted that, when the wetting fluid displaces the non-wetting one, the relative permeability ratio (displacing to the displaced phase) is nearly vertical and extends over a relatively short saturation interval. In contrast, when the non-wetting fluid displaces the wetting one, the relative permeability ratio is higher at a given saturation and extends over a greater saturation range (see Figure 2.13).

Figure 2.12. Effect of wettability on relative permeability of rock / oil / brine system [47].

Figure 2.13. Effect of wettability on relative permeability ratio [36].

2.8. EFFECT OF WETTABILITY ON WATERFLOOD PERFORMANCE

Oil recovery from porous sedimentary rocks depends mainly on the overall efficiency with which oil is displaced by some other fluid and interfacial phenomena in porous rock determine the fraction of oil that moves from the swept region toward a producing well. In this process, the wettability of reservoir rock is as important as permeability, viscosity, and fluid saturations in determining the characteristics of multiphase flow [1].

Waterflooding is a frequently used secondary recovery method in which water is injected into the reservoir to displace the oil in front of it. If the reservoir is initially at irreducible water saturation, only oil is produced until breakthrough. After breakthrough, increasing amounts of water and decreasing amounts of oil are produced and the operation is carried on until the water-oil ratio is so high that the well becomes uneconomical to produce.

Dullien et al. [10] noted that, although macroscopic to megascopic reservoir heterogeneities affect waterflood performance, oil displacement occurs at the pore level, because the oil resides in the pore spaces and it must be displaced from there in order to produce it. So, microscopic efficiency of oil recovery must also be studied and it is primarily influenced by the wettability, the saturation history, the viscosity ratio and the pore structure.

It is generally accepted that, a waterflood in a strongly water-wet rock is much more efficient than the one in an oil-wet rock. However, there is no agreement in the comparison of the waterflood performance of water-wet and intermediately-wet system. Some researchers [31, 34, 39, 46] noted that oil recovery was reduced as the wettability was changed towards less water-wet conditions. However, others [6, 7, 11, 13, 16, 18, 29, 48] reported that oil recovery increases with decreasing water-wetness and pass through the maximum when the system has intermediate wettability (see Figure 2.14).

2.8.1. Oil Displacement in Water-Wet Rock

During a waterflood of a water-wet system at moderate oil-water viscosity ratios, the injected water will tend to imbibe into any small or medium-sized pores, moving oil into the larger pores where it is easily displaced (see Figure 2.15.a). In the ahead of the front, only oil is moving. In the frontal zone, each fluid moves through its own network of pores, but some wetting fluid located in each pore. In the zone, where both oil and water are flowing, a portion of the oil exists in

continuous channels with some dead end branches, while the remainder of the oil is trapped in discontinuous globules. After the water front passes, almost all of the remaining oil is immobile. Because of such immobility in this water-wet case, there is little or no production of oil after water breakthrough and the total oil recovery is essentially independent of the volume of water injected. The disconnected, residual oil exists in two basic forms; (1) small spherical globules in the center of the larger pores and (2) larger patches of oil extending over many pores which are completely surrounded by water [2, 16, 17, 46].

2.8.2. Oil Displacement in Oil-Wet Rock

A waterflood in a strongly oil-wet rock is much less efficient than one in a water-wet rock. When the waterflood is started, the water will form continuous channels or fingers through the centers of the larger pores, pushing out the oil in front of it and early breakthrough occurs (see Figure 2.15.b). As water injection continues, water invades the smaller pores to form additional continuous channels, and the water-oil ratio of the produced fluids gradually increases and oil flow falls to a very low level. Oil recovery before breakthrough is relatively small, with most of the oil produced after breakthrough. The residual oil after the waterflood is found; (1) filling the smaller pores, (2) as a continuous film over the pore surfaces, and (3) as larger pockets of oil trapped and surrounded by water. Since much of this oil is still continuous through the thin oil films, it can still be produced at a very slow rate. The residual oil saturation is not well defined. In contrast to the water-wet case, oil recovery is strongly dependent on the volume of water injected [2, 17, 46].

Donaldson and Thomas [46] noted that, the size of trapped oil pockets behind the waterfront depends upon the wettability of the system and migration of these pockets could be induced only when the injection rate was drastically increased. At extremely high flow rates, some of the oil pockets broke up and entered the

water-flow channels and were produced. However in the field, such a high flow rates could probably not be achieved.

2.8.3. Oil Displacement in Mixed-Wet Rock

As previously described, mixed wettability system have continuous oil-wet paths through the larger pores, while the small pores are water filled. It combines the best aspects of water and oil-wet systems. Compared with a water-wet system, trapping is reduced in the large, oil-wet pores. Compared with an oil-wet system, trapping is reduced because the small pores in a mixed-wettability system are water filled. When mixed-wettability cores are waterflooded, film drainage causes very low residual oil saturations. After the injection of many pore volumes of water, a small but finite permeability to oil exist even at very low oil saturations [2, 17]. However, bicontinuous mixed wettability may cause an early water breakthrough by water-wet and oil-wet-channels [10].

Figure 2.14. Effect of wettability on oil production. Oil recovery increases with decreasing water-wetness and becomes maximum near neutral wettability [49].

Figure 2.15. Water is displacing oil from a pore during a waterflood; (a) imbibition process, oil displacement by water in water-wet sand, (b) drainage process, oil displacement by water in oil-wet sand [47].

CHAPTER 3

STATEMENT OF THE PROBLEM

Wettability is one of the most important rock properties that controls distribution and flow of fluids in porous media. Wettability of a core sample affects almost all types of special core analysis such as capillary pressure, relative permeability, waterflood behaviour, electrical properties and simulated tertiary recovery. There are many methods that have been used to measure wettability.

From this point of view, this study will focus on experimental investigation of wettability measurement, artificially controlling the wettability of a core sample and the effect of wettability on relative permeability and oil recovery in limestone medium.

The main objectives of this study are;

1. To measure wettability of a core sample and to check reproducibility of the results,
2. To determine the effect of aging duration, brine salinity and saturation history (procedure) on wettability of core samples,
3. To determine the effect of wettability on measured relative permeability data,
4. To determine the effect of wettability on waterflood performance.

CHAPTER 4

EXPERIMENTAL EQUIPMENT

4.1. CORE CLEANING SYSTEM

In order to clean the remaining hydrocarbon of the core samples, a traditional Soxhlet extraction system was used. After the extraction was completed, in order to verify that the plug samples were sufficiently clean, toluene was injected into the samples under pressure and it was observed that effluent of the toluene was clear.

4.2. HELIUM GAS EXPANSION POROSIMETER

Porosity of the core samples was determined by using “Helium Gas Expansion (Boyle’s Law) Porosimeter”. Helium was used as the gas phase. Schematic diagram of the porosimeter is given in Figure 4.1.

It may be seen from the figure that the system from the source and core holder valves may be pressurized to a standard reference pressure generally 100 psig. By opening the core holder valve, the 100 psig is permitted to expand into the unknown volume that was originally 0 psig. When the two pressures have attained equilibrium as indicated by pressure gauge, “Boyle’s Law” may be used to calculate the magnitude of the unknown volume.

Figure 4.1. Flow diagram of the helium gas expansion porosimeter.

4.3. GAS PERMEAMETER

Absolute air permeability of the core samples was determined by “Gas Permeameter”. The permeameter permits the core sample partially enclosed (sealed), such that two opposite faces of the sample is exposed. This is accomplished through the use of a Hassler type core holder. The core holder uses compressed air or Nitrogen to squeeze the core sample in a rubber sleeve. A vacuum usually applied to expand the sleeve so that the sample can be inserted into or removed from the holder. Approximately 250 psi air forces the sleeve tightly against the sample, preventing the inlet air from flowing between the sample and the sleeve. The vent valve is used to remove the sleeve pressure prior to appearing the vacuum valve to prevent overloading of the vacuum pump.

The path of airflow through the permeameter is shown in Figure 4.2. Air is introduced through the source valve to the permeameter regulator and a selected differential pressure is adjusted. The air flows through the core sample and orifice in proportion to the applied differential air pressure. The differential pressure developed across the calibrated orifice is used to determine the air volume flow rate.

Figure 4.2. Flow diagram of the gas permeameter.

4.4. CORE FLOODING SYSTEM

Core flooding system consists of a constant volume positive displacement pump, two accumulators, one for oil and another one for brine, a pressure gauge for the determination of inlet pressure and a triaxial core holder. The schematic diagram of the core flooding system is shown in Figure 4.3.

4.5. SPONTANEOUS IMBIBITION APPARATUS

The spontaneous brine imbibition experiment was performed using the imbibition apparatus schematically shown in Figure 4.4. As it can be seen from the figure, the apparatus basically is a simple glass container having a graduated glass cap. To perform a spontaneous imbibition test, for example brine imbibition, a core sample at initial water saturation (S_{wi}) is immersed in the glass container filled with brine. Due to capillary imbibition action, oil is displaced from the core sample by imbibing the brine. The displaced oil is accumulated in the graduated cap by gravity segregation.

Figure 4.3. The schematic diagram of the core flooding system.

Figure 4.4. Spontaneous imbibition apparatus.

CHAPTER 5

EXPERIMENTAL MATERIALS AND PROCEDURES

5.1. EXPERIMENTAL MATERIALS

5.1.1. Core Samples

The core samples used in this study were taken from two different limestone formations, 18 samples (Sample Id: 51-69) from M-1 and 5 samples (Sample Id: 71-75) from B-1. The cores were cut into 3.80 cm (1.5 inch) in diameter and 4 to 7 cm (1.6 to 2.75 inch) in length. Air permeabilities of the samples were measured, varying from 2 to 80 md and the porosity ranged from 9 to 20 percent. The absolute permeabilities to brine ranged from 0.43 to 31.62 md. Detailed information about the core samples is shown in Appendix-A.

5.1.2. Brine Samples

The brine samples used in the experiments were NaCl solutions in different salinity changing from 10,000 ppm to 60,000 ppm. They were prepared by dissolving NaCl in distilled water. Most of the measurement was carried out by using 10,000 ppm solution. Viscosity and density of the 10,000 ppm brine sample versus temperature is shown in Figure 5.1.

Figure 5.1. Viscosity and density of 10,000 ppm NaCl solutions at elevated temperature.

Figure 5.2. Viscosity and density of mineral oil at elevated temperature.

5.1.3. Oil Samples

Mineral (refined) oil was used as the oil phase in the investigations. Viscosity and density of the mineral oil were determined by reverse flow tube method in a kinematic viscosity bath and by a digital density meter respectively. Viscosity and density versus temperature relationship of the oil is shown in Figure 5.2.

5.2. EXPERIMENTAL PROCEDURES

All of the experimental studies were conducted on TPAO Research Center. Details of the experimental procedures and the test systems used in this study are illustrated in the following sections.

5.2.1. Core Cleaning

A traditional Soxhlet extraction method was used to clean the core samples. Hot toluene was continuously distilled, condensed and distributed over the top of the samples. After the extraction was completed, in order to verify that the plug samples were sufficiently clean, toluene was injected into the samples under pressure and it was observed that effluent of the toluene was clear. Then, the plug samples were heated in an oven at 70 °C at least two days to dry completely.

5.2.2. Air Permeability Measurement

Air permeability (k_{air}) of the plug samples were measured by the gas permeameter illustrated in the previous chapter. The permeability resulted from injection of dry air into the clean and dry sample. At a constant differential pressure, dry air was injected through the sample until a constant flow rate was attained. Then the permeability was calculated by appropriate form of the “Darcy’s Equation”, derived for compressible fluid flow through porous media. It was assumed that the

sample is at room temperature and the temperature is constant during measurement. The equation is given below.

$$k_{air} = \frac{2\mu_{air}(q_{air})(L)(P_a)}{A(P_1 + P_2)(P_1 - P_2)} \dots\dots\dots(5.1)$$

where;

k_{air} , permeability (darcies),

μ_{air} , air viscosity at mean pressure and temperature (cp),

q_{air} , air flow rate at atmospheric pressure and temperature (cc/sec),

P_1 , inlet pressure (standard atmospheres absolute),

P_2 , outlet pressure (standard atmospheres absolute),

P_a , atmospheric pressure (standard atmospheres).

5.2.3. Porosity and Grain Density Measurement

Porosity of the core samples was determined by using “Helium Gas Expansion Boyle’s Law Porosimeter” that was illustrated in the previous chapter. Helium was used as the gas phase. Two chambers of known volumes were connected, one (reference cell) containing helium at a given pressure and another one (matrix cup) with a clean and dry core plug. The helium was expanded into the matrix cup and the equilibrium pressure was recorded to determine the unknown volume that was matrix cup with clean and dry plug sample. By using the “Boyle’s Law”, grain volume of the given core plug was calculated. Bulk volume of the sample was determined by measuring its dimensions. Porosity was calculated by equation 5.2.

Grain density of a core plug is a function of the grain volume and the weight of the clean and dry core sample. Grain densities of the samples were calculated by equation 5.3.

$$\phi = \frac{V_b - V_g}{V_b} * 100 \dots\dots\dots(5.2)$$

$$\rho = \frac{W_{dry}}{V_g} \dots\dots\dots(5.3)$$

where;

ϕ , porosity (percent),

V_b , bulk volume (cc),

V_g , grain volume (cc).

ρ , grain density (g/cc),

W_{dry} , weight of the clean and dry core sample (g),

V_g , grain volume (cc).

5.2.4. Saturation of the Core Samples with Brine

First, the dry and clean sample with known porosity and permeability, was evacuated up to -24 mm Hg pressure (-12 psig) for 8 hours using a vacuum pump. Then, they were saturated by pressurising up to 1000 psig by a positive displacement pump and by using brine as the displacing phase. After saturating the core samples with brine, a period of about two days was allowed for the brine to achieve ionic equilibrium with the rock.

5.2.5. Brine Permeability Measurement

After saturating with brine, the core sample was inserted into a Hassler type core holder and a net confining pressure of 500 psig was applied. Brine permeability resulted from the injection of brine into the samples at a constant flow rate until a constant pressure of the brine through the sample is attained. Permeability was calculated by using an appropriate form of the Darcy's Equation, equation 5.4.

Permeability (k_{brine}) is a function of flow rate, viscosity of the fluid, length of the core plug, cross sectional area of core plug, and drop in flow pressure;

$$k_{\text{brine}} = \frac{q\mu L}{A\Delta P} \dots\dots\dots(5.4)$$

where;

- k_{brine} , absolute brine permeability (darcies),
- q , flow rate (cc/sec),
- μ , viscosity of the fluid (cp),
- L , length of the core plug (cm),
- A , cross sectional area of core plug (cm²),
- ΔP , drop in flow pressure (atm),

5.2.6. Aging

After measurement of absolute brine permeability, oil was flooded through the core samples until no more water comes out and S_{wi} established. Then, the samples were immersed in an oil bath and placed in a temperature-controlled oven. Temperature was set to 158°F (70°C). To investigate the effect of aging time on the wettability of the core samples, the aging period was varied from 31 to 71 days.

5.2.7. Determination of Core Wettability

Wettability of the core samples were determined by using the Amott-Harvey Method. Test results were expressed by the Amott-Harvey relative displacement index (I_{AH}). In order to determine the wettability index, brine saturated core sample was flooded by oil to reach its irreducible water saturation and the following steps were carried out; (1)Spontaneous brine imbibition, (2)Forced brine displacement, (3)Spontaneous oil imbibition, (4)Forced oil displacement.

5.2.7.1. Spontaneous Brine Imbibition

The spontaneous brine imbibition experiment was performed using the spontaneous imbibition apparatus illustrated in the previous chapter. To perform the imbibition test, a core sample was immersed in the glass container filled with brine solution. Due to capillary imbibition action, oil was displaced from the core sample by the imbibing brine. The displaced oil accumulated in the graduated cap by gravity segregation.

It is possible that, the imbibition phenomenon does not start up immediately or its rate can be very slowly, particularly when the sample has low permeability. Because of this reason, the spontaneous oil and water imbibition tests were carried on until the imbibition finishes or no more oil comes out from the core samples.

At the end of the experiment, the total volume of produced oil was recorded. Before taking the oil volume reading (V_{osp}), the glass container was gently shaken to expel oil drops adhering to the core surface and the lower part of the cap so that all of the produced oil accumulated in the graduated portion of the glass cap.

5.2.7.2. Forced Brine Displacement

After the spontaneous imbibition in brine was completed, the core sample was placed in the Hassler type core holder and subjected to forced displacement by brine. Depending on the transmissibility capacity of the plug sample, an appropriate and constant flow rate was used. At the end of the test, the amount of oil produced was recorded.

5.2.7.3. Spontaneous Oil Imbibition

After the brine displacement test completed, the spontaneous oil imbibition experiment was performed using the spontaneous imbibition apparatus. However, the glass container was turned upside down and it was filled with oil (see Figure 5.3). The displaced water was accumulated in the graduated cap by gravity segregation. At the end of the experiment, the glass container was gently shaken

again for the same reason explained before and the total volume of produced water was recorded (V_{wsp}).

5.2.7.4. Forced Oil Displacement

After the spontaneous imbibition in oil was completed, the core sample was subjected to forced displacement by oil using an appropriate and constant flow rate. At the end of the test, the amount of oil produced was recorded.

5.2.7.5. Calculation of the Amott-Harvey Relative Displacement Index

As it was mentioned previously, results of the wettability tests were expressed by a simple displacement index. It was calculated by the following formula:

$$I_{AH} = I_w - I_o = \frac{V_{osp}}{V_{ot}} - \frac{V_{wsp}}{V_{wt}} \dots\dots\dots(5.4)$$

where;

I_{AH} , Amott-Harvey relative displacement index

I_w , displacement by water ratio (ratio),

I_o , displacement by oil ratio (ratio),

V_{osp} , oil volume displaced by spontaneous water imbibition (cc),

V_{ot} , total oil volume displaced by spontaneous water imbibition and forced water displacement (cc),

V_{wsp} , water volume displaced by spontaneous oil imbibition (cc),

V_{wt} , total water volume displaced by spontaneous oil imbibition and forced oil displacement (cc).

Figure 5.3. Spontaneous displacement experiments. (a) Spontaneous oil imbibition. (b) Spontaneous water imbibition.

5.2.8. Artificially Control (Change) of Wettability

During the laboratory studies, wettability of the samples were tested three times. Aim of the first two was to prove that wettability measurements are reproducible. Then, the third one was carried out to determine whether the wettability of a core sample could be controlled or changed artificially. Details of each test group are explained below.

First Group of Experiments: After determining porosity, permeability and grain density, wettability of the all samples was measured by using refined oil and 10,000 ppm NaCl solution as the test fluids. Besides the wettability data, end point relative permeability and fluid saturations of the core samples were also measured.

Second Group of Experiments: Core samples were cleaned and wettability of the all samples was re-measured by using the same fluids. The aim of this part was to determine the reproducibility of the wettability data.

Third Group of Experiments: The aim of the third group of experiments was to determine the effect of salinity, aging time and saturation procedure on wettability.

After cleaning all the core samples, porosity, permeability and grain density measurement were conducted again. Fifteen core samples were selected and they were divided into three sample sets having approximately the same wettability distribution.

The first set was used to determine the effect of salinity on wettability of the core samples. All the procedure and the test material except brine salinity were the same with the first two run. Wettability of the each core sample was determined by using different brine samples salinity of which changing from 20,000 – 60,000 ppm.

The second set was used to determine the effect of aging period on wettability of the core sample. Salinity of the brine was 10,000 ppm for all samples. In this case, after establishing the S_{wi} of the each sample, the core samples were aged by immersing in refined oil. Aging temperature was kept constant at 158 °F (70 °C) by a temperature-controlled oven. Aging periods were changed from 30-70 days. When it is finished, wettability of the samples was determined.

The third set was used to determine effect of saturation history on wettability of the core sample. After cleaning, the core samples were saturated 100% with mineral oil instead of brine. Then the wettability of the samples was determined.

5.2.9. Relative Permeability Measurement

Relative permeability measurements were carried on by unsteady state displacement method. After the third group of experiments, the plug sample was flooded by refined oil until no more water comes out and the initial water saturation was re-established. Effective permeability to oil was measured. Then, brine was injected through the sample at a constant flow rate and the pressure drop across the plug sample, produced oil and water volumes were recorded instantly with respect to time. During the flow studies, net overburden pressure, which is the difference between overburden pressure and flow pressure, was set to 200 psig for all samples. Waterflood tests were carried on until value of produced water cut becomes 99.95% or higher. At this condition, effective permeability to water was measured. Then the water-oil relative permeability of the core plug was calculated by JBN method [45]. Finally, waterflood performance of the system was determined.

CHAPTER 6

EXPERIMENTAL RESULTS AND DISCUSSION

6.1. INTRODUCTION

Experimental studies were conducted on 23 core samples. All of the samples were cleaned and petrophysical properties were determined. Then, wettability of the samples was measured by using refined oil and 10,000 ppm NaCl solution and the first group of the tests was completed.

In the second part of the study, in order to be sure that the test conditions and techniques were sufficient to repeat the measurements, core samples were cleaned by toluene extraction and wettability tests were repeated. Similar test results were obtained.

Finally, wettability of the core samples was tried to be altered artificially by changing the saturation procedure, salinity of the brine and by aging the core samples in refined oil for different length of times. Then, by using core samples with different wettability indices, relative permeability measurements and waterflood recovery calculations were carried on. Order of the tests conducted on each core sample is given in Table 6.1.

Row test data and the results of the calculations are given in Appendix A-D. In the following sections, experimental results will be discussed.

Table 6.1. Order of the Tests Conducted on Each Plug Sample

		Conducted Experiments												
Sample		1 st Group				2 nd Group				3 th Group				k _r
Id.	Form.	ϕ	k	ρ	I	ϕ	k	ρ	I	ϕ	k	ρ	I	
51	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	
52	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓
54	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓
55	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	
56	M-1	✓	✓	✓	✓				✓	✓	✓	✓		
57	M-1	✓	✓	✓	✓				✓	✓	✓	✓		
58	M-1	✓	✓	✓	✓				✓	✓	✓	✓		
59	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	
60	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	
61	M-1	✓	✓	✓	✓				✓	✓	✓	✓		
62	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	
63	M-1	✓	✓	✓	✓				✓	✓	✓	✓		
64	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	
65	M-1	✓	✓	✓	✓				✓	✓	✓	✓		
66	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	
67	M-1	✓	✓	✓	✓				✓	✓	✓	✓		
68	M-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓
69	M-1	✓	✓	✓	✓				✓	✓	✓	✓		
71	B-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓
72	B-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	
73	B-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓
74	B-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓*
75	B-1	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓

* Measured twice for two different wettability conditions.

LEGEND	
φ..... porosity	Form..... formation
k..... air permeability	
ρ..... grain density	☒ performed
I..... wettability	
k _r relative permeability	☐ not performed

6.2. PETROPHYSICAL PROPERTIES

Porosity, air permeability and grain density of the core samples were measured twice; first, at the beginning of the study (Measurement-I), second, after the second group of experiments were completed (Measurement-II). Purpose of the second measurements was to determine whether any damage had occurred in the rock samples. Both measurements were in good consistency with each other meaning that no damage had happened. Results of the measurements are compared in Figure 6.1 and 6.2.

6.3. WETTABILITY STUDIES

First Group of Experiments: At the end of the first group of measurements, it was determined that B-1 samples (71 to 75) were all water-wet in different levels. Amott-Harvey Wettability Indices (I_{AH}) changed from 0.56 to 0.92. However, all of the M-1 samples showed intermediate wettability characteristics and the wettability indices were very close to zero.

During the wettability measurements, irreducible fluid saturations and end point relative permeabilities were also determined. There was a very good correlation between the end point water relative permeability (k_{rw} at S_{or}) data and the wettability characteristics of the core samples. Relative permeabilities of the water-wet samples were all lower than the intermediately-wet ones as it was stated by Craig [15]. However, Morgan and Gordon [42] proposed that, besides the wettability, similar effect could also be caused by the differences in the pore size distribution of the core samples. Variations of the end point relative permeabilities with respect to the wettability characteristics of the core samples are shown in Figure 6.3.

Figure 6.1. Comparison of the porosity measurements.

Figure 6.2. Comparison of the permeability measurements.

Figure 6.3. Variation of the end point relative permeabilities with respect to the wettability characteristics of the core sample.

Second Group of Experiments: At the second part of the study, core samples were all cleaned by toluene extraction and wettability of the all samples was measured again. It was just a repetition of the first group studies. The aim of the second part was to verify that the wettability indices of the core samples were reproducible. Results of the second measurements were very similar to the first ones. There was a good consistency between the two data sets. Wettability indices obtained from the first (Measurement-I) and second group of experiments (Measurement-II) are compared in Figure 6.4.

Figure 6.4. Comparison of the Amott-Harvey wettability indices obtained from the first and the second group of experiments.

Third Group of Experiments: The aim of this part was to determine the effect of salinity, saturation procedure (history) and aging period on wettability. For this purpose, plug samples were cleaned and three sets of samples each having five plugs with a wettability distribution as homogenous as possible was arranged. Results of the third group of experiments are compared with the measurements of first two in Figure 6.5 – 6.7.

There was not a good correlation between the factors varied during the measurements and measured wettability indices. Especially the samples having intermediate wettability did not respond to variation of any factors. However,

strongly water-wet samples loosed their strong affinity to water in each measurement. Most probably it was caused by insufficient cleaning procedure. One should note that, maximum wettability indices (water-wetness) of the water-wet samples were obtained at the first study.

Before the first wettability measurement, the core samples had been cleaned for a long period toluene extraction (approximately 1.5 month) process to clean included heavy crude oil completely. Extraction had stopped when appearance of the condensed toluene was absolutely clean. By this method, B-1 samples were cleaned successfully and all of them became strongly water-wet [8, 9, 10, 11, 12, 13, 14]. However, toluene extraction was not a sufficient method to clean the M-1 formation. Many researchers had already noted that, success of a cleaning method depends on rock type and composition [3, 9, 13, 14].

When the first group of measurements was completed, the core samples were cleaned again. The samples were extracted about 5 days thinking that it would be enough to clean the light mineral oil. There was no chance to check the color of the toluene since mineral oil was already colorless. Probably, core samples were removed from the Soxhlet apparatus before complete cleaning occurred. Reduction of the water wetness could be the result of such an interaction between the rock and mineral oil.

Effect of aging on wettability of core samples is shown in Figure 6.5. Wettability of the M-1 samples (sample 55-60) could not be changed by aging although the duration was very long (63 days) especially for sample 68. Measured Amott-Harvey wettability indices of the samples were very close to the first two measurements. However, aging changed the wettability of the B-1 sample (sample 74) from water-wet to intermediately-wet condition. There was a significant change at the wettability index of the sample. Unfortunately, there was only one sample from B-1 and correlation of the alteration of wettability and aging time was not possible. However, it was enough to determine the effect of wettability on

relative permeability when mineralogy, pore size distribution and fluid properties were kept constant. The sample was used for this purpose and details discussed in the following section.

After third group of the experiments had finished, sample 74 was re-extracted with toluene for 3 weeks and wettability of the sample was checked by spontaneous water imbibition. After 5 days, the amount of water imbibed was 1.2 cc and the test was finished. It was very close to the values obtained during the first two measurements, meaning that, alteration of wettability by aging is a reversible process and it is possible to re-establish initial wettability condition by a successful cleaning.

Shortly, although the wettability of water-wet samples were reduced by aging, intermediately-wet samples were not affected from this process. However, it was not an unusual case. Because, aging is already known as the most useful method to reduce the water wetness and researchers used it to alter the wettability of core samples from strongly water-wet to different degree of wettability [4, 6, 7, 16, 20, 26, 29, 32, 34]. However, there was no sufficient information about the effects of aging on intermediately-wet core samples. In our study, there was almost no change.

Tang and Morrow [29] reported that, water wetness decreased by increasing salinity. In our study similar results were obtained. Wettability indices of the nearly all samples (except for sample 54) were reduced in different degree. However, the change occurred on M-1 samples (52-66) were not in considerable amount (see Figure 6.6). Alteration occurred in B-1 samples were more meaningful. However, it was very difficult to state that it was caused only by salinity change. Because the reductions were in the range of the ones occurred during the first two measurements. It was important to note that, as it happened in the previous study, significant amount of wettability reductions were occurred only at the water-wet samples.

Effect of the saturation procedure did not caused important change on the wettability of the core samples. Most of the wettability data remained almost constant with respect to the second measurements.

Figure 6.5. Effect of the variation of aging period on wettability of the core samples. Wettability of the intermediately-wet samples is not affected by aging.

Figure 6.6. Effect of the variation of brine salinity on the wettability of the core samples. There is no significant effect on the wettability of intermediately-wet sample.

Figure 6.7. Effect of changed saturation procedure (history) on wettability. Wettability of the samples was not affected by changing procedure.

6.4. RELATIVE PERMEABILITY STUDIES

Eight relative permeability tests were conducted on seven core samples from both formations. Relative permeability of the sample 74 was measured two times for two different wettability conditions. During the core flood studies, volume of the displacing phase was extended up to 65 pore volumes to obtain the end point relative permeabilities as correctly as possible.

Although porosity and permeability of the samples were ranging from 13 – 23 % and 3 - 83 md respectively, neither oil nor water relative permeability curves of M-1 formation varied too much (see Figure 6.8). This behavior could only be explained by wettability of the system because; wettability indices of the samples were very close to each other. It was previously noted that wettability is one of the most important factor affecting relative permeability [3, 8, 15, 39, 46].

Results of the relative permeability tests conducted on B-1 samples were quite different. Although petrophysical properties of the samples was not varying so much, both water and oil relative permeability of the samples showed differences. Effect of wettability was greater especially in oil relative permeability curves. Variations of the oil relative permeabilities with respect to the measured wettability indices are given in Figure 6.9. Decreasing water wetness decreased end point oil relative permeability (k_{ro} at S_{wi}) values significantly. Maximum permeability value was obtained for the sample having highest wettability index. The permeability was minimum for the intermediately-wet sample. Similar condition had already been reported by Dandina [38].

Note that, especially for the water-wet samples, end point oil effective permeability values were even greater than the absolute brine permeability of the medium. It was an unexpected result. However, McPhee and Arthur [50] reported that this value might reach up to 2.4 times of the absolute permeability in strongly

water-wet rocks. They explained this condition as lubrication effect in which, the presence of water in a strongly water-wet rock acts as a lubricant, easing the flow of oil through the pores and this effect should be considered while evaluating the relative permeability data. They also stated that, the effect of lubrication is greater for the non-wetting phase.

During the study, relative permeability of the sample 74 was measured twice for two different wettability conditions. Results of the measurements were very good to see the effect of wettability on relative permeability while the other parameters such as pore size distribution, mineralogy, viscosity ratio, salinity were kept constant (see Figure 6.10). Both measurements were conducted with similar laboratory condition as much as possible.

Figure 6.8. Relative permeability curves of the M-1 samples. Similar wettability indices caused similar relative permeability curves although porosity and permeability of the samples varied.

Figure 6.9. Oil relative permeability curves for B-1 samples. Different wettability indices caused variation in relative permeability curves although porosity and permeability of the samples not varied so much.

When the relative permeability curves were based on the absolute brine permeability, Figure 6.10 (a), decrease of the oil relative permeability with decreasing water wetness could be seen easily. For the all water saturation values, oil relative permeability of the sample was higher than the ones obtained when the sample was water-wet [15, 39, 46], meaning that oil flowed more easily in water-wet medium.

In order to see the influence of wettability on water relative permeability, the curves based on effective oil permeability at initial water saturation (Figure 6.10 (b)) were more helpful. Water relative permeability of the sample was lower when the system was water-wet, meaning that increasing water-wetness reduced flow of the water.

Figure 6.10. Relative permeability of the sample 74 at two different wettability conditions; (a) based on the absolute brine permeability (b) based on the effective oil permeability at initial water saturation.

In water-wet condition, relative permeability curves of the sample 74 in which, initial water saturation was 27 percent, crossover point was greater than 50 percent water saturation and end point water relative permeability was less than 30 percent were a characteristic example of the Craig's rules of thumbs for water-wet case [15].

Relative permeability ratios were also affected by wettability (see Figure 6.11). For the water-wet samples, the relative permeability ratios were more vertical and extended over a relatively shorter saturation interval [3, 36].

Figure 6.11. Effect of wettability on the relative permeability ratio of the core samples. For water-wet samples it is more vertical and extended over a relatively shorter saturation interval.

6.5. EFFECT OF WETTABILITY ON OIL RECOVERY

For all of the relative permeability data, waterflood performance calculations were also executed. There were certain differences between the recovery curves of the two formations.

Intermediately-wet samples were characterized by early water breakthrough. Breakthrough took place approximately when 0.04 PV of water injected. However, for the water-wet samples it reached up to 0.3 PV of water injection (see Figure 6.12).

In the water-wet samples, breakthrough oil recoveries were higher than the intermediately-wet ones. Approximately, half of the recoverable oil was produced before the water breakthrough. However, in the intermediately-wet case, most of the production was done after the breakthrough. Breakthrough oil recoveries were in the range of 10-15 percent of cumulative production.

Shape of the recovery curves was also affected by the wettability of the medium. Unlike the water-wet case, in intermediately-wet samples, amount of the ultimate oil recovery seemed to be related to the volume of water injected. If the water injection continued, probably more oil would be produced. It was noted that this kind of behaviour should be expected for oil-wet and sometimes fractionally-wet (or mixed-wet) medium [2, 17, 46]. In our case it occurred at intermediately-wet conditions. However, many researchers stated that Amott and Amott-Harvey Methods are not sensitive near neutral wettability [7, 12, 35, 25]. So, one should also consider these details when evaluating the results.

Figure 6.12. Waterflood oil recovery curves for all samples in terms of original oil in place.

Figure 6.13. Waterflood oil recovery curves for all samples in terms of cumulative oil production.

Waterflood recovery curves were also created for both water-wet and intermediately-wet condition of the sample 74. In intermediately-wet case, breakthrough recovery was still lower. In this case, reducing water wetness also reduced overall oil recovery (see Figure 6.13). Overall and breakthrough oil recoveries increased with increasing water wetness.

Figure 6.14. Waterflood oil recovery curves for the sample 74 at two different wettability conditions.

CHAPTER 7

CONCLUSIONS

1. Wettability affected both relative permeability and end point effective permeability of the core samples. When wetting properties of a phase increased, both relative permeability and end point effective permeability of that phase decreased.
2. It was obtained that, in strong wetting condition, end point relative permeability of non-wetting phase could be greater than the absolute permeability of the system because of the lubrication effect of the wetting phase.
3. Amott-Harvey wettability test gave reproducible results when the test conditions were kept constant.
4. Aging reduced water-wetness of a core sample meaning that it could be used to control wettability artificially. Alteration of wettability by aging was a reversible process and initial water-wet condition of the sample was re-established by a successful core cleaning operation.
5. Intermediate wettability was a more stable condition than water wetness. Wettability of the intermediately-wet samples could not be altered by any of the techniques applied during the study.

6. Wettability affected waterflood performance. In water-wet condition, before the breakthrough, most of the recoverable oil was produced. There was a very little production after the breakthrough. Decreasing water wetness decreased breakthrough oil recovery and increased the amount of oil produced after the breakthrough.
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APPENDIX A

PETROPHYSICAL PROPERTIES

Table A.1. Location of the Core Samples

Field	Formation	Well No.	Plug Id.	Depth Interval (m)	Depth (m)
R	M-1	74	51	1284-1293	1286.3
R	M-1	74	52	1284-1293	1287.3
R	M-1	74	54	1284-1293	1290.8
R	M-1	107	55	1347-1356	1353.4
R	M-1	107	56	1347-1356	1353.8
R	M-1	123	57	1355-1364	1355.2
R	M-1	123	58	1355-1364	1358.9
R	M-1	123	59	1376-1385	1377.7
R	M-1	123	60	1376-1385	1378.9
R	M-1	123	61	1376-1385	1379.4
R	M-1	134	62	1325-1334	1326.5
R	M-1	134	63	1325-1334	1327.7
R	M-1	134	64	1325-1334	1329.1
R	M-1	134	65	1325-1334	1330.5
R	M-1	114	66	1423-1430	1428.9
R	M-1	114	67	1423-1430	1430.7
R	M-1	115	68	1333-1344	1333.1
R	M-1	115	69	1333-1344	1334.6
DS	B-1	4	71	2368-2377	2368.6
DS	B-1	4	72	2368-2377	2369.7
DS	B-1	4	73	2368-2377	2370.5
DS	B-1	4	74	2368-2377	2371.9
DS	B-1	4	75	2368-2377	2373.5

**Table A.2. Petrophysical Properties of the Core Samples
"First Group of Tests"**

Plug Id.	Length (cm)	Diameter (cm)	k_{air} (md)	Grain Density (g/cc)	Pore Volume (cc)	Porosity (%)
51	6.29	3.70	5.01	2.67	7.26	10.74
52	5.03	3.70	30.14	2.66	10.78	19.93
54	6.77	3.70	2.49	2.69	9.26	12.72
55	6.22	3.70	7.24	2.70	8.03	12.00
56	4.89	3.70	4.08	2.71	6.16	11.71
57	6.17	3.70	8.84	2.67	10.73	16.18
58	5.93	3.70	12.93	2.67	11.24	17.63
59	6.86	3.70	8.85	2.70	9.72	13.17
60	6.48	3.70	10.42	2.69	12.09	17.35
61	6.75	3.70	12.14	2.69	11.08	15.27
62	6.64	3.70	6.31	2.71	8.54	11.96
63	6.54	3.70	5.84	2.70	9.06	12.89
64	6.75	3.70	4.09	2.71	9.76	13.44
65	6.63	3.70	8.84	2.68	13.81	19.38
66	6.99	3.70	17.54	2.70	12.48	16.61
67	6.86	3.70	2.00	2.70	6.33	8.59
68	6.53	3.70	80.26	2.71	14.41	20.52
69	4.66	3.70	12.86	2.71	9.15	18.26
71	4.88	3.70	18.99	2.70	10.33	19.69
72	4.04	3.71	10.43	2.68	7.47	17.11
73	4.42	3.71	34.18	2.67	8.56	17.91
74	4.52	3.71	5.96	2.69	7.55	15.44
75	4.43	3.71	28.58	2.68	8.26	17.26

Sample Description:

M-1 Samples (51-69): Limestone, light brown colored, cryptocrystalline, hard, brittle, interparticle microporosity and small vugs.

B-1 Samples (71-75): Limestone, light gray colored, calcite fillings between the particles, hard, brittle, interparticle and vuggy porosity.

Table A.3. Petrophysical Properties of the Core Samples
"Second Group of Tests"

Plug Id.	Length (cm)	Diameter (cm)	k _{air} (md)	Grain Density (g/cc)	Pore Volume (cc)	Porosity (%)
51	6.29	3.70	3.30	2.70	8.16	12.07
52	5.03	3.70	27.62	2.69	11.83	21.88
54	6.77	3.70	2.67	2.69	9.42	12.94
55	6.22	3.70	6.37	2.70	8.21	12.27
56	4.89	3.70	4.02	2.71	6.28	11.94
57	6.17	3.70	7.56	2.70	11.57	17.44
58	5.93	3.70	11.28	2.70	12.26	19.23
59	6.86	3.70	7.74	2.69	9.69	13.14
60	6.48	3.70	10.76	2.70	12.49	17.93
61	6.75	3.70	10.66	2.70	11.41	15.72
62	6.64	3.70	6.05	2.70	8.59	12.04
63	6.54	3.70	6.01	2.71	9.49	13.49
64	6.75	3.70	4.57	2.70	9.56	13.17
65	6.63	3.70	9.24	2.70	8.76	12.28
66	6.99	3.70	14.44	2.70	13.07	17.39
67	6.86	3.70	0.78	2.68	5.79	7.85
68	6.53	3.70	83.83	2.70	14.93	21.27
69	4.66	3.70	14.22	2.69	9.14	18.25
71	4.88	3.70	19.19	2.68	10.17	19.38
72	4.04	3.71	10.48	2.68	7.64	17.50
73	4.42	3.71	35.66	2.68	8.88	18.59
74	4.52	3.71	5.88	2.68	7.50	15.35
75	4.43	3.71	29.33	2.76	8.39	17.52

Figure A.1. Porosity-Permeability X-Plot for M-1 and B-1 Samples

APPENDIX B

WETTABILITY DATA

Table B.1. Wettability Test Row Data Sheet (Measurement-I)

Salinity : 10.000 ppm

Plug Id. 51		
L (cm)	6.3	V _p (cc) 7.3
A (cm ²)	10.8	φ (%) 10.7
k _a (md)	5.0	
@ S _w = 100%		
ΔP (psi)	51.7	T (°F) 78
ΔV (cc)	2.05	μ _w (cp) 0.9
ΔT (sec)	231	k _w (md)
Displacement by Oil		
Displaced Water (cc)	4.00	
Injected Oil (cc)	-	
@ S _w = S _{wi}		
ΔP (psi)	270.0	T (°F) 80
ΔV (cc)	1.78	μ _o (cp) 7.8
ΔT (sec)	200	k _o (md)
Spontaneous Water Imbibition		
Date	Imbibed Oil	
09.04.1999	-	
03.05.1999	0.20	
Forced Water Displacement		
Displaced Oil (cc)	4.50	
Injected Water (cc)	-	
Total Production (cc)	4.70	
@ S _o = S _{or}		
ΔP (psi)	163.0	T (°F) 80
ΔV (cc)	3.30	μ _w (cp) 0.9
ΔT (sec)	397	k _w (md)
Spontaneous Oil Imbibition		
Date	Imbibed Water	
04.05.1999	-	
24.05.1999	0.30	
Forced Oil Displacement		
Displaced Water (cc)	2.00	
Injected Oil (cc)	-	
Total Production (cc)	2.30	
@ S _w = S _{wi}		
ΔP (psi)	377.0	T (°F) 79
ΔV (cc)	2.70	μ _o (cp) 7.9
ΔT (sec)	485	k _o (md)

Plug Id. 52		
L (cm)	5.0	V _p (cc) 10.8
A (cm ²)	10.8	φ (%) 19.9
k _a (md)	30.1	
@ S _w = 100%		
ΔP (psi)	4.4	T (°F) 80.5
ΔV (cc)	2.36	μ _w (cp) 0.9
ΔT (sec)	293	k _w (md)
Displacement by Oil		
Displaced Water (cc)	7.35	
Injected Oil (cc)	-	
@ S _w = S _{wi}		
ΔP (psi)	29.3	T (°F) 81
ΔV (cc)	2.10	μ _o (cp) 7.7
ΔT (sec)	252	k _o (md)
Spontaneous Water Imbibition		
Date	Imbibed Oil	
13.04.1999	-	
03.05.199	-	
Forced Water Displacement		
Displaced Oil (cc)	2.00	
Injected Water (cc)	-	
Total Production (cc)	2.00	
@ S _o = S _{or}		
ΔP (psi)	16.0	T (°F) 80
ΔV (cc)	3.90	μ _w (cp) 0.9
ΔT (sec)	380	k _w (md)
Spontaneous Oil Imbibition		
Date	Imbibed Water	
04.05.1999	-	
24.05.1999	-	
Forced Oil Displacement		
Displaced Water (cc)	4.45	
Injected Oil (cc)	-	
Total Production (cc)	4.45	
@ S _w = S _{wi}		
ΔP (psi)	30.0	T (°F) 79
ΔV (cc)	2.10	μ _o (cp) 7.9
ΔT (sec)	257	k _o (md)

Plug Id. 54		
L (cm)	6.8	V _p (cc) 9.3
A (cm ²)	10.8	φ (%) 12.7
k _a (md)	2.5	
@ S _w = 100%		
ΔP (psi)	59.0	T (°F) 80
ΔV (cc)	2.70	μ _w (cp) 0.9
ΔT (sec)	322	k _w (md)
Displacement by Oil		
Displaced Water (cc)	7.35	
Injected Oil (cc)	-	
@ S _w = S _{wi}		
ΔP (psi)	363.0	T (°F) 82
ΔV (cc)	1.80	μ _o (cp) 7.6
ΔT (sec)	253	k _o (md)
Spontaneous Water Imbibition		
Date	Imbibed Oil	
14.04.1999	-	
04.05.1999	0.10	
Forced Water Displacement		
Displaced Oil (cc)	4.20	
Injected Water (cc)	-	
Total Production (cc)	4.30	
@ S _o = S _{or}		
ΔP (psi)	181.0	T (°F) 79
ΔV (cc)	2.78	μ _w (cp) 0.9
ΔT (sec)	342	k _w (md)
Spontaneous Oil Imbibition		
Date	Imbibed Water	
05.05.1999	-	
25.05.1999	0.10	
Forced Oil Displacement		
Displaced Water (cc)	4.30	
Injected Oil (cc)	-	
Total Production (cc)	4.20	
@ S _w = S _{wi}		
ΔP (psi)	325.0	T (°F) 79
ΔV (cc)	2.05	μ _o (cp) 7.9
ΔT (sec)	491	k _o (md)

Table B.1. (Continued)

Salinity : 10.000 ppm

Plug Id.				55			
L (cm)	6.2	V _p (cc)	8.0				
A (cm ²)	10.8	φ (%)	12.0				
k _a (md)	7.2						
@ S _w = 100%							
ΔP (psi)	20.0	T (°F)	80				
ΔV (cc)	2.45	μ _w (cp)	0.9				
ΔT (sec)	305	k _w (md)					
Displacement by Oil							
Displaced Water (cc).....	6.00						
Injected Oil (cc).....	-						
@ S _w = S _{wi}							
ΔP (psi)	144.0	T (°F)	81				
ΔV (cc)	2.90	μ _o (cp)	7.7				
ΔT (sec)	360	k _o (md)					
Spontaneous Water Imbibition							
Date	Imbibed Oil						
14.04.1999	-						
04.05.1999	0.35						
Forced Water Displacement							
Displaced Oil (cc).....	3.10						
Injected Water (cc).....	-						
Total Production (cc).....	3.45						
@ S _o = S _{or}							
ΔP (psi)	70.0	T (°F)	79				
ΔV (cc)	2.20	μ _w (cp)	0.9				
ΔT (sec)	223	k _w (md)					
Spontaneous Oil Imbibition							
Date	Imbibed Water						
05.05.1999	-						
25.05.1999	0.30						
Forced Oil Displacement							
Displaced Water (cc).....	3.40						
Injected Oil (cc).....	-						
Total Production (cc).....	3.70						
@ S _w = S _{wi}							
ΔP (psi)	202.0	T (°F)	79				
ΔV (cc)	2.25	μ _o (cp)	7.9				
ΔT (sec)	265	k _o (md)					

Plug Id.				56			
L (cm)	4.9	V _p (cc)	6.2				
A (cm ²)	10.8	φ (%)	11.7				
k _a (md)	4.1						
@ S _w = 100%							
ΔP (psi)	35.0	T (°F)	78.5				
ΔV (cc)	2.55	μ _w (cp)	0.9				
ΔT (sec)	296	k _w (md)					
Displacement by Oil							
Displaced Water (cc).....	5.10						
Injected Oil (cc).....	-						
@ S _w = S _{wi}							
ΔP (psi)	248.0	T (°F)	79				
ΔV (cc)	3.20	μ _o (cp)	7.9				
ΔT (sec)	360	k _o (md)					
Spontaneous Water Imbibition							
Date	Imbibed Oil						
15.04.1999	-						
05.05.1999	0.25						
Forced Water Displacement							
Displaced Oil (cc).....	3.20						
Injected Water (cc).....	-						
Total Production (cc).....	3.45						
@ S _o = S _{or}							
ΔP (psi)	88.0	T (°F)	81				
ΔV (cc)	2.80	μ _w (cp)	0.9				
ΔT (sec)	300	k _w (md)					
Spontaneous Oil Imbibition							
Date	Imbibed Water						
06.05.1999	-						
26.05.1999	0.20						
Forced Oil Displacement							
Displaced Water (cc).....	3.00						
Injected Oil (cc).....	-						
Total Production (cc).....	3.20						
@ S _w = S _{wi}							
ΔP (psi)	368.0	T (°F)	78				
ΔV (cc)	2.90	μ _o (cp)	8.1				
ΔT (sec)	342	k _o (md)					

Plug Id.				57			
L (cm)	6.2	V _p (cc)	10.7				
A (cm ²)	10.8	φ (%)	16.2				
k _a (md)	8.8						
@ S _w = 100%							
ΔP (psi)	25.0	T (°F)	78.5				
ΔV (cc)	2.15	μ _w (cp)	0.9				
ΔT (sec)	259	k _w (md)					
Displacement by Oil							
Displaced Water (cc).....	7.60						
Injected Oil (cc).....	-						
@ S _w = S _{wi}							
ΔP (psi)	151.0	T (°F)	79				
ΔV (cc)	2.20	μ _o (cp)	7.9				
ΔT (sec)	267	k _o (md)					
Spontaneous Water Imbibition							
Date	Imbibed Oil						
15.04.1999	-						
05.05.1999	0.50						
Forced Water Displacement							
Displaced Oil (cc).....	4.80						
Injected Water (cc).....	-						
Total Production (cc).....	5.30						
@ S _o = S _{or}							
ΔP (psi)	108.0	T (°F)	81				
ΔV (cc)	3.25	μ _w (cp)	0.9				
ΔT (sec)	399	k _w (md)					
Spontaneous Oil Imbibition							
Date	Imbibed Water						
06.05.1999	-						
26.05.1999	0.50						
Forced Oil Displacement							
Displaced Water (cc).....	4.40						
Injected Oil (cc).....	-						
Total Production (cc).....	4.90						
@ S _w = S _{wi}							
ΔP (psi)	205.0	T (°F)	78				
ΔV (cc)	2.20	μ _o (cp)	8.1				
ΔT (sec)	264	k _o (md)					

Table B.1. (Continued)

Salinity : 10.000 ppm

58			
Plug Id.			
L (cm)	5.9	V _P (cc)	11.2
A (cm ²)	10.8	φ (%)	17.6
k _a (md)	12.9		
@ S _w = 100%			
ΔP (psi)	10.0	T (°F)	77.5
ΔV (cc)	1.92	μ _w (cp)	0.9
ΔT (sec)	233	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		7.10	
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)	84.0	T (°F)	78
ΔV (cc)	2.31	μ _o (cp)	8.1
ΔT (sec)	277	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
16.04.1999		-	
06.05.1999		0.05	
Forced Water Displacement			
Displaced Oil (cc).....		4.60	
Injected Water (cc).....		-	
Total Production (cc).....		4.65	
@ S _o = S _{or}			
ΔP (psi)	35.0	T (°F)	80
ΔV (cc)	2.05	μ _w (cp)	0.9
ΔT (sec)	248	k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
07.05.1999		-	
22.05.1999		0.55	
Forced Oil Displacement			
Displaced Water (cc).....		4.10	
Injected Oil (cc).....		-	
Total Production (cc).....		4.65	
@ S _w = S _{wi}			
ΔP (psi)	52.0	T (°F)	77
ΔV (cc)	2.00	μ _o (cp)	8.2
ΔT (sec)	478	k _o (md)	

59			
Plug Id.			
L (cm)	6.9	V _P (cc)	9.7
A (cm ²)	10.8	φ (%)	13.2
k _a (md)	8.9		
@ S _w = 100%			
ΔP (psi)	35.0	T (°F)	77.9
ΔV (cc)	2.25	μ _w (cp)	0.9
ΔT (sec)	259	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		6.30	
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)	198.0	T (°F)	
ΔV (cc)	3.05	μ _o (cp)	
ΔT (sec)	329	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
16.04.1999		-	
06.05.1999		0.05	
Forced Water Displacement			
Displaced Oil (cc).....		2.85	
Injected Water (cc).....		-	
Total Production (cc).....		2.90	
@ S _o = S _{or}			
ΔP (psi)	42.0	T (°F)	80
ΔV (cc)	2.55	μ _w (cp)	0.9
ΔT (sec)	316	k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
07.05.1999		-	
27.05.1999		0.40	
Forced Oil Displacement			
Displaced Water (cc).....		2.90	
Injected Oil (cc).....		-	
Total Production (cc).....		3.30	
@ S _w = S _{wi}			
ΔP (psi)	190.0	T (°F)	77
ΔV (cc)	2.25	μ _o (cp)	8.2
ΔT (sec)	500	k _o (md)	

60			
Plug Id.			
L (cm)	6.5	V _P (cc)	12.1
A (cm ²)	10.8	φ (%)	17.4
k _a (md)	10.4		
@ S _w = 100%			
ΔP (psi)	10.0	T (°F)	78.5
ΔV (cc)	1.75	μ _w (cp)	0.9
ΔT (sec)	211	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		10.00	
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)	86.0	T (°F)	79.5
ΔV (cc)	1.90	μ _o (cp)	7.9
ΔT (sec)	228	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
16.04.1999		-	
07.05.1999		0.80	
Forced Water Displacement			
Displaced Oil (cc).....		6.00	
Injected Water (cc).....		-	
Total Production (cc).....		6.80	
@ S _o = S _{or}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
07.05.1999		-	
31.05.1999		0.20	
Forced Oil Displacement			
Displaced Water (cc).....		6.40	
Injected Oil (cc).....		-	
Total Production (cc).....		6.60	
@ S _w = S _{wi}			
ΔP (psi)	95.0	T (°F)	78
ΔV (cc)	4.15	μ _o (cp)	8.1
ΔT (sec)	500	k _o (md)	

Table B.1. (Continued)

Salinity : 10.000 ppm

Plug Id.				61			
L (cm)	6.8	V _P (cc)	11.1				
A (cm ²)	10.8	φ (%)	15.3				
k _a (md)	12.1						
@ S _w = 100%							
ΔP (psi)	15.0	T (°F)	78.5				
ΔV (cc)	2.18	μ _w (cp)	0.9				
ΔT (sec)	235	k _w (md)					
Displacement by Oil							
Displaced Water (cc).....		8.30					
Injected Oil (cc).....		-					
@ S _w = S _{wi}							
ΔP (psi)	112.0	T (°F)	79.5				
ΔV (cc)	3.15	μ _o (cp)	7.9				
ΔT (sec)	352	k _o (md)					
Spontaneous Water Imbibition							
Date		Imbibed Oil					
16.04.1999		-					
07.05.1999		0.60					
Forced Water Displacement							
Displaced Oil (cc).....		4.40					
Injected Water (cc).....		-					
Total Production (cc).....		5.00					
@ S _o = S _{or}							
ΔP (psi)	78.0	T (°F)	76				
ΔV (cc)	3.05	μ _w (cp)	0.9				
ΔT (sec)	276	k _w (md)					
Spontaneous Oil Imbibition							
Date		Imbibed Water					
07.05.1999		-					
31.05.1999		0.30					
Forced Oil Displacement							
Displaced Water (cc).....		4.60					
Injected Oil (cc).....		-					
Total Production (cc).....		4.90					
@ S _w = S _{wi}							
ΔP (psi)	154.0	T (°F)	78				
ΔV (cc)	4.45	μ _o (cp)	8.1				
ΔT (sec)	500	k _o (md)					

Plug Id.				62			
L (cm)	6.6	V _P (cc)	8.5				
A (cm ²)	10.8	φ (%)	12.0				
k _a (md)	6.3						
@ S _w = 100%							
ΔP (psi)	34.0	T (°F)	79.5				
ΔV (cc)	1.65	μ _w (cp)	0.9				
ΔT (sec)	195	k _w (md)					
Displacement by Oil							
Displaced Water (cc).....		6.50					
Injected Oil (cc).....		-					
@ S _w = S _{wi}							
ΔP (psi)	265.0	T (°F)	80				
ΔV (cc)	2.25	μ _o (cp)	7.8				
ΔT (sec)	269	k _o (md)					
Spontaneous Water Imbibition							
Date		Imbibed Oil					
20.04.1999		-					
10.05.1999		0.25					
Forced Water Displacement							
Displaced Oil (cc).....		3.85					
Injected Water (cc).....		-					
Total Production (cc).....		4.10					
@ S _o = S _{or}							
ΔP (psi)	124.0	T (°F)	76				
ΔV (cc)	2.07	μ _w (cp)	0.9				
ΔT (sec)	248	k _w (md)					
Spontaneous Oil Imbibition							
Date		Imbibed Water					
11.05.1999		-					
01.06.1999		0.50					
Forced Oil Displacement							
Displaced Water (cc).....		3.90					
Injected Oil (cc).....		-					
Total Production (cc).....		4.40					
@ S _w = S _{wi}							
ΔP (psi)	219.0	T (°F)	80				
ΔV (cc)	2.15	μ _o (cp)	7.9				
ΔT (sec)	518	k _o (md)					

Plug Id.				63			
L (cm)	6.5	V _P (cc)	9.1				
A (cm ²)	10.8	φ (%)	12.9				
k _a (md)	5.8						
@ S _w = 100%							
ΔP (psi)	28.0	T (°F)	79.5				
ΔV (cc)	3.45	μ _w (cp)	0.9				
ΔT (sec)	385	k _w (md)					
Displacement by Oil							
Displaced Water (cc).....		6.40					
Injected Oil (cc).....		-					
@ S _w = S _{wi}							
ΔP (psi)	212.0	T (°F)	80				
ΔV (cc)	2.65	μ _o (cp)	7.8				
ΔT (sec)	295	k _o (md)					
Spontaneous Water Imbibition							
Date		Imbibed Oil					
20.04.1999		-					
10.05.1999		0.45					
Forced Water Displacement							
Displaced Oil (cc).....		3.75					
Injected Water (cc).....		-					
Total Production (cc).....		4.20					
@ S _o = S _{or}							
ΔP (psi)	116.0	T (°F)	76				
ΔV (cc)	3.30	μ _w (cp)	0.9				
ΔT (sec)	363	k _w (md)					
Spontaneous Oil Imbibition							
Date		Imbibed Water					
11.05.1999		-					
01.06.1999		0.35					
Forced Oil Displacement							
Displaced Water (cc).....		3.95					
Injected Oil (cc).....		-					
Total Production (cc).....		4.30					
@ S _w = S _{wi}							
ΔP (psi)	208.0	T (°F)	80				
ΔV (cc)	2.35	μ _o (cp)	7.9				
ΔT (sec)	335	k _o (md)					

Table B.1. (Continued)

Salinity : 10.000 ppm

Plug Id. 64			
L (cm)	6.8	V _P (cc)	9.8
A (cm ²)	10.8	φ (%)	13.4
k _a (md)	4.1		
@ S _w = 100%			
ΔP (psi)	35.0	T (°F)	78.5
ΔV (cc)	1.93	μ _w (cp)	0.9
ΔT (sec)	231	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....			
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	276.0	T (°F)	78.5
ΔV (cc)	2.90	μ _o (cp)	8.0
ΔT (sec)	351	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
21.04.1999	-		
11.05.1999	0.25		
Forced Water Displacement			
Displaced Oil (cc).....	5.20		
Injected Water (cc).....	-		
Total Production (cc).....	5.45		
@ S _o = S _{or}			
ΔP (psi)	115.0	T (°F)	77
ΔV (cc)	2.43	μ _w (cp)	0.9
ΔT (sec)	299	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
12.05.1999	-		
02.06.1999	0.45		
Forced Oil Displacement			
Displaced Water (cc).....	5.00		
Injected Oil (cc).....	-		
Total Production (cc).....	5.45		
@ S _w = S _{wi}			
ΔP (psi)	231.0	T (°F)	80
ΔV (cc)	1.32	μ _o (cp)	7.9
ΔT (sec)	317	k _o (md)	

Plug Id. 65			
L (cm)	6.6	V _P (cc)	9.1
A (cm ²)	10.8	φ (%)	13.8
k _a (md)	8.8		
@ S _w = 100%			
ΔP (psi)	12.0	T (°F)	78.5
ΔV (cc)	2.70	μ _w (cp)	0.9
ΔT (sec)	309	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	7.00		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	108.0	T (°F)	78.5
ΔV (cc)	3.30	μ _o (cp)	8.0
ΔT (sec)	360	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
21.04.1999	-		
11.05.1999	0.08		
Forced Water Displacement			
Displaced Oil (cc).....	4.20		
Injected Water (cc).....	-		
Total Production (cc).....	4.28		
@ S _o = S _{or}			
ΔP (psi)	33.0	T (°F)	77
ΔV (cc)	3.25	μ _w (cp)	0.9
ΔT (sec)	379	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
12.05.1999	-		
02.06.1999	0.40		
Forced Oil Displacement			
Displaced Water (cc).....	3.70		
Injected Oil (cc).....	-		
Total Production (cc).....	4.10		
@ S _w = S _{wi}			
ΔP (psi)	138.0	T (°F)	80
ΔV (cc)	2.80	μ _o (cp)	7.9
ΔT (sec)	301	k _o (md)	

Plug Id. 66			
L (cm)	7.0	V _P (cc)	12.5
A (cm ²)	10.8	φ (%)	16.6
k _a (md)	17.5		
@ S _w = 100%			
ΔP (psi)	8.2	T (°F)	80.5
ΔV (cc)	2.08	μ _w (cp)	0.9
ΔT (sec)	249	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	8.70		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	43.3	T (°F)	81
ΔV (cc)	2.15	μ _o (cp)	7.7
ΔT (sec)	376	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
22.04.1999	-		
12.05.1999	0.60		
Forced Water Displacement			
Displaced Oil (cc).....	4.85		
Injected Water (cc).....	-		
Total Production (cc).....	5.45		
@ S _o = S _{or}			
ΔP (psi)	35.0	T (°F)	78
ΔV (cc)	2.68	μ _w (cp)	0.9
ΔT (sec)	321	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
13.05.1999	-		
03.06.1999	0.40		
Forced Oil Displacement			
Displaced Water (cc).....	4.80		
Injected Oil (cc).....	-		
Total Production (cc).....	5.20		
@ S _w = S _{wi}			
ΔP (psi)	49.0	T (°F)	78
ΔV (cc)	1.65	μ _o (cp)	8.2
ΔT (sec)	400	k _o (md)	

Table B.1. (Continued)

Salinity : 10.000 ppm

Plug Id. 67			
L (cm)	6.9	V _p (cc)	6.3
A (cm ²)	10.8	φ (%)	8.6
k _a (md)	2.0		
@ S _w = 100%			
ΔP (psi)	*	T (°F)	*
ΔV (cc)	*	μ _w (cp)	*
ΔT (sec)	*	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	3.30		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	560.0	T (°F)	81
ΔV (cc)	2.95	μ _o (cp)	7.7
ΔT (sec)	877	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
22.04.1999	-		
12.05.1999	0.10		
Forced Water Displacement			
Displaced Oil (cc).....	1.35		
Injected Water (cc).....	-		
Total Production (cc).....	1.45		
@ S _o = S _{or}			
ΔP (psi)	540.0	T (°F)	78
ΔV (cc)	2.55	μ _w (cp)	0.9
ΔT (sec)	531	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
13.05.1999	-		
03.06.1999	0.05		
Forced Oil Displacement			
Displaced Water (cc).....	0.80		
Injected Oil (cc).....	-		
Total Production (cc).....	0.85		
@ S _w = S _{wi}			
ΔP (psi)	684.0	T (°F)	80
ΔV (cc)	0.89	μ _o (cp)	7.9
ΔT (sec)	1000	k _o (md)	

Plug Id. 68			
L (cm)	6.5	V _p (cc)	14.4
A (cm ²)	10.8	φ (%)	20.5
k _a (md)	80.3		
@ S _w = 100%			
ΔP (psi)	2.5	T (°F)	79
ΔV (cc)	1.75	μ _w (cp)	0.9
ΔT (sec)	151	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	7.50		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	24.2	T (°F)	80.5
ΔV (cc)	2.30	μ _o (cp)	7.7
ΔT (sec)	208	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
27.04.1999	-		
13.05.1999	0.10		
Forced Water Displacement			
Displaced Oil (cc).....	4.90		
Injected Water (cc).....	-		
Total Production (cc).....	5.00		
@ S _o = S _{or}			
ΔP (psi)	7.0	T (°F)	77
ΔV (cc)	2.33	μ _w (cp)	0.9
ΔT (sec)	418	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
14.05.1999	-		
07.06.1999	0.50		
Forced Oil Displacement			
Displaced Water (cc).....	5.70		
Injected Oil (cc).....	-		
Total Production (cc).....	6.20		
@ S _w = S _{wi}			
ΔP (psi)	10.0	T (°F)	81
ΔV (cc)	1.65	μ _o (cp)	7.7
ΔT (sec)	206	k _o (md)	

Plug Id. 69			
L (cm)	4.7	V _p (cc)	9.2
A (cm ²)	10.8	φ (%)	18.3
k _a (md)	12.9		
@ S _w = 100%			
ΔP (psi)	7.0	T (°F)	79
ΔV (cc)	1.80	μ _w (cp)	0.9
ΔT (sec)	199	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	6.60		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	58.0	T (°F)	80.5
ΔV (cc)	2.55	μ _o (cp)	7.7
ΔT (sec)	288	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
27.04.1999	-		
13.05.1999	0.30		
Forced Water Displacement			
Displaced Oil (cc).....	4.25		
Injected Water (cc).....	-		
Total Production (cc).....	4.55		
@ S _o = S _{or}			
ΔP (psi)	15.0	T (°F)	77
ΔV (cc)	3.15	μ _w (cp)	0.9
ΔT (sec)	476	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
14.05.1999	-		
07.06.1999	0.05		
Forced Oil Displacement			
Displaced Water (cc).....	4.35		
Injected Oil (cc).....	-		
Total Production (cc).....	4.40		
@ S _w = S _{wi}			
ΔP (psi)	69.0	T (°F)	81
ΔV (cc)	2.45	μ _o (cp)	7.7
ΔT (sec)	276	k _o (md)	

Table B.1. (Continued)

Salinity : 10.000 ppm

Plug Id. 71			Plug Id. 72			Plug Id. 73					
L (cm)	4.9	V _p (cc)	10.3	L (cm)	4.0	V _p (cc)	7.5	L (cm)	4.4	V _p (cc)	8.6
A (cm ²)	10.8	φ (%)	19.7	A (cm ²)	10.8	φ (%)	17.1	A (cm ²)	10.8	φ (%)	17.9
k _a (md)	19.0			k _a (md)	10.4			k _a (md)	34.2		
@ S _w = 100%			@ S _w = 100%			@ S _w = 100%					
ΔP (psi)	5.4	T (°F)	81.5	ΔP (psi)	7.0	T (°F)	81.5	ΔP (psi)	2.4	T (°F)	80.5
ΔV (cc)	2.75	μ _w (cp)	0.9	ΔV (cc)	3.05	μ _w (cp)	0.9	ΔV (cc)	2.35	μ _w (cp)	0.9
ΔT (sec)	330	k _w (md)		ΔT (sec)	361	k _w (md)		ΔT (sec)	290	k _w (md)	
Displacement by Oil			Displacement by Oil			Displacement by Oil					
Displaced Water (cc).....	8.30			Displaced Water (cc).....	5.90			Displaced Water (cc).....	7.00		
Injected Oil (cc).....	-			Injected Oil (cc).....	-			Injected Oil (cc).....	-		
@ S _w = S _{wi}			@ S _w = S _{wi}			@ S _w = S _{wi}					
ΔP (psi)	28.6	T (°F)	81.5	ΔP (psi)	50.0	T (°F)	81.5	ΔP (psi)	18.2	T (°F)	80
ΔV (cc)	3.00	μ _o (cp)	7.6	ΔV (cc)	2.50	μ _o (cp)	7.6	ΔV (cc)	2.72	μ _o (cp)	7.8
ΔT (sec)	536	k _o (md)		ΔT (sec)	295	k _o (md)		ΔT (sec)	327	k _o (md)	
Spontaneous Water Imbibition			Spontaneous Water Imbibition			Spontaneous Water Imbibition					
Date	Imbibed Oil		Date	Imbibed Oil		Date	Imbibed Oil				
28.04.1999	-		28.04.1999	-		29.04.1999	-				
17.05.1999	1.90		17.05.1999	1.60		20.05.1999	2.35				
Forced Water Displacement			Forced Water Displacement			Forced Water Displacement					
Displaced Oil (cc).....	1.50			Displaced Oil (cc).....	0.65			Displaced Oil (cc).....	1.10		
Injected Water (cc).....	-			Injected Water (cc).....	-			Injected Water (cc).....	-		
Total Production (cc).....	3.40			Total Production (cc).....	2.25			Total Production (cc).....	3.45		
@ S _o = S _{or}			@ S _o = S _{or}			@ S _o = S _{or}					
ΔP (psi)	42.5	T (°F)	80	ΔP (psi)	60.0	T (°F)	80	ΔP (psi)	37.0	T (°F)	75
ΔV (cc)	2.50	μ _w (cp)	0.9	ΔV (cc)	2.60	μ _w (cp)	0.9	ΔV (cc)	1.80	μ _w (cp)	0.9
ΔT (sec)	248	k _w (md)		ΔT (sec)	316	k _w (md)		ΔT (sec)	161	k _w (md)	
Spontaneous Oil Imbibition			Spontaneous Oil Imbibition			Spontaneous Oil Imbibition					
Date	Imbibed Water		Date	Imbibed Water		Date	Imbibed Water				
18.05.1999	-		18.05.1999	-		21.05.1999	-				
08.06.1999	-		18.06.1999	0.03		09.06.1999	-				
Forced Oil Displacement			Forced Oil Displacement			Forced Oil Displacement					
Displaced Water (cc).....	4.20			Displaced Water (cc).....	2.70			Displaced Water (cc).....	3.50		
Injected Oil (cc).....	-			Injected Oil (cc).....	-			Injected Oil (cc).....	-		
Total Production (cc).....	4.20			Total Production (cc).....	2.73			Total Production (cc).....	3.50		
@ S _w = S _{wi}			@ S _w = S _{wi}			@ S _w = S _{wi}					
ΔP (psi)	38.0	T (°F)	79	ΔP (psi)	62.0	T (°F)	79	ΔP (psi)	22.0	T (°F)	79
ΔV (cc)	1.50	μ _o (cp)	7.9	ΔV (cc)	2.30	μ _o (cp)	7.9	ΔV (cc)	2.00	μ _o (cp)	7.9
ΔT (sec)	180	k _o (md)		ΔT (sec)	256	k _o (md)		ΔT (sec)	240	k _o (md)	

Table B.1. (Continued)

Salinity : 10.000 ppm

74			
Plug Id.			
L (cm)	4.5	V _p (cc)	7.6
A (cm ²)	10.8	φ (%)	15.4
k _a (md)	6.0		
@ S _w = 100%			
ΔP (psi)	14.0	T (°F)	80.5
ΔV (cc)	2.45	μ _w (cp)	0.9
ΔT (sec)	292	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		6.20	
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)	106.0	T (°F)	80
ΔV (cc)	3.34	μ _o (cp)	7.8
ΔT (sec)	389	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
29.04.1999		-	
21.05.1999		1.40	
Forced Water Displacement			
Displaced Oil (cc).....		0.70	
Injected Water (cc).....		-	
Total Production (cc).....		2.10	
@ S _o = S _{or}			
ΔP (psi)	260.0	T (°F)	78
ΔV (cc)	2.55	μ _w (cp)	0.9
ΔT (sec)	232	k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
21.05.1999		-	
09.06.1999		-	
Forced Oil Displacement			
Displaced Water (cc).....		2.20	
Injected Oil (cc).....		-	
Total Production (cc).....		2.20	
@ S _w = S _{wi}			
ΔP (psi)	105.0	T (°F)	79
ΔV (cc)	2.20	μ _o (cp)	7.9
ΔT (sec)	264	k _o (md)	

75			
Plug Id.			
L (cm)	4.4	V _p (cc)	8.3
A (cm ²)	10.8	φ (%)	17.3
k _a (md)	28.6		
@ S _w = 100%			
ΔP (psi)	3.0	T (°F)	77.5
ΔV (cc)	2.40	μ _w (cp)	0.9
ΔT (sec)	290	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		6.40	
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)	22.2	T (°F)	78.5
ΔV (cc)	2.15	μ _o (cp)	8.0
ΔT (sec)	256	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
30.04.1999		-	
20.04.1999		2.30	
Forced Water Displacement			
Displaced Oil (cc).....		0.20	
Injected Water (cc).....		-	
Total Production (cc).....		2.50	
@ S _o = S _{or}			
ΔP (psi)	30.0	T (°F)	75
ΔV (cc)	2.60	μ _w (cp)	0.9
ΔT (sec)	241	k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
21.05.1999		-	
10.06.1999		-	
Forced Oil Displacement			
Displaced Water (cc).....		2.90	
Injected Oil (cc).....		-	
Total Production (cc).....		2.90	
@ S _w = S _{wi}			
ΔP (psi)	22.5	T (°F)	77
ΔV (cc)	1.83	μ _o (cp)	8.2
ΔT (sec)	218	k _o (md)	

Plug Id.			
L (cm)		V _p (cc)	
A (cm ²)		φ (%)	
k _a (md)			
@ S _w = 100%			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		.	
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
Forced Water Displacement			
Displaced Oil (cc).....		.	
Injected Water (cc).....		-	
Total Production (cc).....		.	
@ S _o = S _{or}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
Forced Oil Displacement			
Displaced Water (cc).....		.	
Injected Oil (cc).....		-	
Total Production (cc).....		.	
@ S _w = S _{wi}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	

Table B.2. Wettability Test Row Data Sheet (Measurement-II)

Salinity : 10.000 ppm

51			
Plug Id.			
L (cm)	6.3	V _p (cc)	7.3
A (cm ²)	10.8	φ (%)	10.7
k _a (md)	5.0		
@ S _w = 100%			
ΔP (psi)	69.0	T (°F)	78.5
ΔV (cc)	1.98	μ _w (cp)	0.9
ΔT (sec)	236	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	3.10		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	390.0	T (°F)	80
ΔV (cc)	2.55	μ _o (cp)	7.8
ΔT (sec)	306	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
15.06.1999	-		
05.07.1999	0.20		
Forced Water Displacement			
Displaced Oil (cc).....	1.80		
Injected Water (cc).....	-		
Total Production (cc).....	2.00		
@ S _o = S _{or}			
ΔP (psi)	123.0	T (°F)	81
ΔV (cc)	1.85	μ _w (cp)	0.9
ΔT (sec)	193	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
06.07.1999	-		
29.07.1999	0.10		
Forced Oil Displacement			
Displaced Water (cc).....	1.80		
Injected Oil (cc).....	-		
Total Production (cc).....	1.90		
@ S _w = S _{wi}			
ΔP (psi)	397.0	T (°F)	87
ΔV (cc)	1.90	μ _o (cp)	7.0
ΔT (sec)	301	k _o (md)	

52			
Plug Id.			
L (cm)	5.0	V _p (cc)	10.8
A (cm ²)	10.8	φ (%)	19.9
k _a (md)	30.1		
@ S _w = 100%			
ΔP (psi)	4.0	T (°F)	78.5
ΔV (cc)	2.75	μ _w (cp)	0.9
ΔT (sec)	282	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	7.20		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	30.0	T (°F)	80
ΔV (cc)	2.85	μ _o (cp)	7.8
ΔT (sec)	341	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
15.06.1999	-		
06.07.1999	0.05		
Forced Water Displacement			
Displaced Oil (cc).....	4.45		
Injected Water (cc).....	-		
Total Production (cc).....	4.50		
@ S _o = S _{or}			
ΔP (psi)	8.0	T (°F)	84
ΔV (cc)	2.70	μ _w (cp)	0.8
ΔT (sec)	301	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
07.07.1999	-		
29.07.1999	0.05		
Forced Oil Displacement			
Displaced Water (cc).....	4.30		
Injected Oil (cc).....	-		
Total Production (cc).....	4.35		
@ S _w = S _{wi}			
ΔP (psi)	37.0	T (°F)	88
ΔV (cc)	1.70	μ _o (cp)	7.0
ΔT (sec)	184	k _o (md)	

54			
Plug Id.			
L (cm)	6.8	V _p (cc)	9.3
A (cm ²)	10.8	φ (%)	12.7
k _a (md)	2.5		
@ S _w = 100%			
ΔP (psi)	63.0	T (°F)	78
ΔV (cc)	1.25	μ _w (cp)	0.9
ΔT (sec)	152	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	6.70		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	349.0	T (°F)	79
ΔV (cc)	1.70	μ _o (cp)	7.9
ΔT (sec)	300	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
16.06.1999	-		
06.07.1999	0.05		
Forced Water Displacement			
Displaced Oil (cc).....	4.35		
Injected Water (cc).....	-		
Total Production (cc).....	4.40		
@ S _o = S _{or}			
ΔP (psi)	184.0	T (°F)	84
ΔV (cc)	2.25	μ _w (cp)	0.8
ΔT (sec)	278	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
07.07.1999	-		
02.08.1999	0.15		
Forced Oil Displacement			
Displaced Water (cc).....	3.10		
Injected Oil (cc).....	-		
Total Production (cc).....	3.25		
@ S _w = S _{wi}			
ΔP (psi)	350.0	T (°F)	84
ΔV (cc)	1.60	μ _o (cp)	7.3
ΔT (sec)	385	k _o (md)	

Table B.2. (Continued)

Salinity : 10.000 ppm

Plug Id.		55		Plug Id.		56		Plug Id.		57	
L (cm)	6.2	V _p (cc)	8.0	L (cm)	4.9	V _p (cc)	6.2	L (cm)	6.2	V _p (cc)	10.7
A (cm ²)	10.8	φ (%)	12.0	A (cm ²)	10.8	φ (%)	11.7	A (cm ²)	10.8	φ (%)	16.2
k _a (md)	7.2			k _a (md)	4.1			k _a (md)	8.8		
@ S _w = 100%				@ S _w = 100%				@ S _w = 100%			
ΔP (psi)	18.0	T (°F)	78	ΔP (psi)	44.0	T (°F)	80.5	ΔP (psi)	46.0	T (°F)	83
ΔV (cc)	2.10	μ _w (cp)	0.9	ΔV (cc)	2.10	μ _w (cp)	0.9	ΔV (cc)	1.50	μ _w (cp)	0.9
ΔT (sec)	244	k _w (md)		ΔT (sec)	247	k _w (md)		ΔT (sec)	180	k _w (md)	
Displacement by Oil				Displacement by Oil				Displacement by Oil			
Displaced Water (cc).....		6.40		Displaced Water (cc).....		4.20		Displaced Water (cc).....		6.00	
Injected Oil (cc).....		-		Injected Oil (cc).....		-		Injected Oil (cc).....		-	
@ S _w = S _{wi}				@ S _w = S _{wi}				@ S _w = S _{wi}			
ΔP (psi)	163.0	T (°F)	79	ΔP (psi)	373.0	T (°F)	82.5	ΔP (psi)	99.0	T (°F)	84.5
ΔV (cc)	3.05	μ _o (cp)	7.9	ΔV (cc)	2.25	μ _o (cp)	7.5	ΔV (cc)	1.70	μ _o (cp)	7.3
ΔT (sec)	360	k _o (md)		ΔT (sec)	275	k _o (md)		ΔT (sec)	620	k _o (md)	
Spontaneous Water Imbibition				Spontaneous Water Imbibition				Spontaneous Water Imbibition			
Date		Imbibed Oil		Date		Imbibed Oil		Date		Imbibed Oil	
16.06.1999		-		17.06.1999		-		18.06.1999		-	
12.07.1999		0.15		12.07.1999		0.05		13.07.1999		0.10	
Forced Water Displacement				Forced Water Displacement				Forced Water Displacement			
Displaced Oil (cc).....		3.10		Displaced Oil (cc).....		2.60		Displaced Oil (cc).....		3.60	
Injected Water (cc).....		-		Injected Water (cc).....		-		Injected Water (cc).....		-	
Total Production (cc).....		3.25		Total Production (cc).....		2.65		Total Production (cc).....		3.70	
@ S _o = S _{or}				@ S _o = S _{or}				@ S _o = S _{or}			
ΔP (psi)	62.0	T (°F)	90	ΔP (psi)	104.0	T (°F)	90	ΔP (psi)	215.0	T (°F)	89
ΔV (cc)	1.85	μ _w (cp)	0.8	ΔV (cc)	2.65	μ _w (cp)	0.8	ΔV (cc)	2.85	μ _w (cp)	0.8
ΔT (sec)	221	k _w (md)		ΔT (sec)	274	k _w (md)		ΔT (sec)	349	k _w (md)	
Spontaneous Oil Imbibition				Spontaneous Oil Imbibition				Spontaneous Oil Imbibition			
Date		Imbibed Water		Date		Imbibed Water		Date		Imbibed Water	
13.07.1999		-		13.07.1999		-		14.07.1999		-	
02.08.1999		-		03.08.1999		-		03.08.1999		0.05	
Forced Oil Displacement				Forced Oil Displacement				Forced Oil Displacement			
Displaced Water (cc).....		3.70		Displaced Water (cc).....		2.80		Displaced Water (cc).....		3.50	
Injected Oil (cc).....		-		Injected Oil (cc).....		-		Injected Oil (cc).....		-	
Total Production (cc).....		3.70		Total Production (cc).....		2.80		Total Production (cc).....		3.55	
@ S _w = S _{wi}				@ S _w = S _{wi}				@ S _w = S _{wi}			
ΔP (psi)	194.0	T (°F)	84	ΔP (psi)	380.0	T (°F)	86	ΔP (psi)	283.0	T (°F)	86
ΔV (cc)	2.50	μ _o (cp)	7.3	ΔV (cc)	2.85	μ _o (cp)	7.2	ΔV (cc)	1.60	μ _o (cp)	7.2
ΔT (sec)	280	k _o (md)		ΔT (sec)	390	k _o (md)		ΔT (sec)	246	k _o (md)	

Table B.2. (Continued)

Salinity : 10.000 ppm

Plug Id. 58			
L (cm)	5.9	V _p (cc)	11.2
A (cm ²)	10.8	φ (%)	17.6
k _a (md)	12.9		
@ S _w = 100%			
ΔP (psi)	11.0	T (°F)	83
ΔV (cc)	2.30	μ _w (cp)	0.9
ΔT (sec)	252	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	7.15		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	35.0	T (°F)	84.5
ΔV (cc)	2.15	μ _o (cp)	7.3
ΔT (sec)	654	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
18.06.1999	-		
13.07.1999	-		
Forced Water Displacement			
Displaced Oil (cc).....	3.65		
Injected Water (cc).....	-		
Total Production (cc).....	3.65		
@ S _o = S _{or}			
ΔP (psi)	25.0	T (°F)	89
ΔV (cc)	3.15	μ _w (cp)	0.8
ΔT (sec)	351	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
14.07.1999	-		
04.08.1999	0.15		
Forced Oil Displacement			
Displaced Water (cc).....	3.35		
Injected Oil (cc).....	-		
Total Production (cc).....	3.50		
@ S _w = S _{wi}			
ΔP (psi)	66.0	T (°F)	87
ΔV (cc)	1.50	μ _o (cp)	7.0
ΔT (sec)	358	k _o (md)	

Plug Id. 59			
L (cm)	6.9	V _p (cc)	9.7
A (cm ²)	10.8	φ (%)	13.2
k _a (md)	8.9		
@ S _w = 100%			
ΔP (psi)	28.0	T (°F)	85
ΔV (cc)	2.35	μ _w (cp)	0.8
ΔT (sec)	293	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	4.20		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	154.0	T (°F)	85
ΔV (cc)	3.20	μ _o (cp)	7.2
ΔT (sec)	400	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
22.06.1999	-		
14.07.1999	0.03		
Forced Water Displacement			
Displaced Oil (cc).....	1.80		
Injected Water (cc).....	-		
Total Production (cc).....	1.83		
@ S _o = S _{or}			
ΔP (psi)	57.0	T (°F)	87
ΔV (cc)	3.20	μ _w (cp)	0.8
ΔT (sec)	388	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
15.07.1999	-		
04.08.1999	0.10		
Forced Oil Displacement			
Displaced Water (cc).....	1.80		
Injected Oil (cc).....	-		
Total Production (cc).....	1.90		
@ S _w = S _{wi}			
ΔP (psi)	104.0	T (°F)	87
ΔV (cc)	1.40	μ _o (cp)	7.0
ΔT (sec)	335	k _o (md)	

Plug Id. 60			
L (cm)	6.5	V _p (cc)	12.1
A (cm ²)	10.8	φ (%)	17.4
k _a (md)	10.4		
@ S _w = 100%			
ΔP (psi)	10.0	T (°F)	85
ΔV (cc)	2.60	μ _w (cp)	0.8
ΔT (sec)	288	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	8.90		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	104.0	T (°F)	85
ΔV (cc)	4.00	μ _o (cp)	7.2
ΔT (sec)	420	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
22.06.1999	-		
14.07.1999	0.15		
Forced Water Displacement			
Displaced Oil (cc).....	5.50		
Injected Water (cc).....	-		
Total Production (cc).....	5.65		
@ S _o = S _{or}			
ΔP (psi)	40.0	T (°F)	87
ΔV (cc)	3.20	μ _w (cp)	0.8
ΔT (sec)	372	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
15.07.1999	-		
05.08.1999	-		
Forced Oil Displacement			
Displaced Water (cc).....	4.80		
Injected Oil (cc).....	-		
Total Production (cc).....	4.80		
@ S _w = S _{wi}			
ΔP (psi)	114.0	T (°F)	82
ΔV (cc)	2.35	μ _o (cp)	7.6
ΔT (sec)	280	k _o (md)	

Table B.2. (Continued)

Salinity : 10.000 ppm

Plug Id.			61		
L (cm)	6.8	V _P (cc)	11.1		
A (cm ²)	10.8	φ (%)	15.3		
k _a (md)	12.1				
@ S _w = 100%					
ΔP (psi)	23.0	T (°F)	83.5		
ΔV (cc)	1.75	μ _w (cp)	0.8		
ΔT (sec)	209	k _w (md)			
Displacement by Oil					
Displaced Water (cc).....	6.40				
Injected Oil (cc).....	-				
@ S _w = S _{wi}					
ΔP (psi)	199.0	T (°F)	86		
ΔV (cc)	1.68	μ _o (cp)	7.1		
ΔT (sec)	201	k _o (md)			
Spontaneous Water Imbibition					
Date	Imbibed Oil				
23.06.1999	-				
15.07.1999	-				
Forced Water Displacement					
Displaced Oil (cc).....	3.40				
Injected Water (cc).....	-				
Total Production (cc).....	3.40				
@ S _o = S _{or}					
ΔP (psi)	84.0	T (°F)	87		
ΔV (cc)	2.35	μ _w (cp)	0.8		
ΔT (sec)	278	k _w (md)			
Spontaneous Oil Imbibition					
Date	Imbibed Water				
16.07.1999	-				
05.08.1999	0.10				
Forced Oil Displacement					
Displaced Water (cc).....	4.50				
Injected Oil (cc).....	-				
Total Production (cc).....	4.60				
@ S _w = S _{wi}					
ΔP (psi)	146.0	T (°F)	85		
ΔV (cc)	2.15	μ _o (cp)	7.2		
ΔT (sec)	260	k _o (md)			

Plug Id.			62		
L (cm)	6.6	V _P (cc)	8.5		
A (cm ²)	10.8	φ (%)	12.0		
k _a (md)	6.3				
@ S _w = 100%					
ΔP (psi)	28.0	T (°F)	83.5		
ΔV (cc)	2.30	μ _w (cp)	0.8		
ΔT (sec)	249	k _w (md)			
Displacement by Oil					
Displaced Water (cc).....	6.50				
Injected Oil (cc).....	-				
@ S _w = S _{wi}					
ΔP (psi)	258.0	T (°F)	86		
ΔV (cc)	2.35	μ _o (cp)	7.1		
ΔT (sec)	261	k _o (md)			
Spontaneous Water Imbibition					
Date	Imbibed Oil				
23.06.1999	-				
15.07.1999	0.05				
Forced Water Displacement					
Displaced Oil (cc).....	3.10				
Injected Water (cc).....	-				
Total Production (cc).....	3.15				
@ S _o = S _{or}					
ΔP (psi)	90.0	T (°F)	87		
ΔV (cc)	3.15	μ _w (cp)	0.8		
ΔT (sec)	347	k _w (md)			
Spontaneous Oil Imbibition					
Date	Imbibed Water				
16.07.1999	-				
09.08.1999	0.15				
Forced Oil Displacement					
Displaced Water (cc).....	3.90				
Injected Oil (cc).....	-				
Total Production (cc).....	4.05				
@ S _w = S _{wi}					
ΔP (psi)	234.0	T (°F)	87		
ΔV (cc)	2.10	μ _o (cp)	7.1		
ΔT (sec)	340	k _o (md)			

Plug Id.			63		
L (cm)	6.5	V _P (cc)	9.1		
A (cm ²)	10.8	φ (%)	12.9		
k _a (md)	5.8				
@ S _w = 100%					
ΔP (psi)	53.0	T (°F)	85		
ΔV (cc)	2.65	μ _w (cp)	0.8		
ΔT (sec)	329	k _w (md)			
Displacement by Oil					
Displaced Water (cc).....	5.20				
Injected Oil (cc).....	-				
@ S _w = S _{wi}					
ΔP (psi)	310.0	T (°F)	86		
ΔV (cc)	1.30	μ _o (cp)	7.1		
ΔT (sec)	155	k _o (md)			
Spontaneous Water Imbibition					
Date	Imbibed Oil				
24.06.1999	-				
19.07.1999	0.20				
Forced Water Displacement					
Displaced Oil (cc).....	3.50				
Injected Water (cc).....	-				
Total Production (cc).....	3.70				
@ S _o = S _{or}					
ΔP (psi)	185.0	T (°F)	83		
ΔV (cc)	1.80	μ _w (cp)	0.9		
ΔT (sec)	215	k _w (md)			
Spontaneous Oil Imbibition					
Date	Imbibed Water				
20.07.1999	-				
09.08.1999	0.20				
Forced Oil Displacement					
Displaced Water (cc).....	3.70				
Injected Oil (cc).....	-				
Total Production (cc).....	3.90				
@ S _w = S _{wi}					
ΔP (psi)	219.0	T (°F)	87		
ΔV (cc)	1.58	μ _o (cp)	7.1		
ΔT (sec)	276	k _o (md)			

Table B.2. (Continued)

Salinity : 10.000 ppm

Plug Id. 64			
L (cm)	6.8	V _p (cc)	9.8
A (cm ²)	10.8	φ (%)	13.4
k _a (md)	4.1		
@ S _w = 100%			
ΔP (psi)	32.0	T (°F)	85
ΔV (cc)	2.80	μ _w (cp)	0.8
ΔT (sec)	314	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	7.30		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	374.0	T (°F)	86
ΔV (cc)	1.45	μ _o (cp)	7.1
ΔT (sec)	215	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
24.06.1999	-		
19.07.1999	0.05		
Forced Water Displacement			
Displaced Oil (cc).....	4.75		
Injected Water (cc).....	-		
Total Production (cc).....	4.80		
@ S _o = S _{or}			
ΔP (psi)	128.0	T (°F)	83
ΔV (cc)	2.40	μ _w (cp)	0.9
ΔT (sec)	269	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
20.07.1999	-		
10.08.1999	0.30		
Forced Oil Displacement			
Displaced Water (cc).....	4.10		
Injected Oil (cc).....	-		
Total Production (cc).....	4.40		
@ S _w = S _{wi}			
ΔP (psi)	202.0	T (°F)	87
ΔV (cc)	2.60	μ _o (cp)	7.1
ΔT (sec)	599	k _o (md)	

Plug Id. 65			
L (cm)	6.6	V _p (cc)	9.1
A (cm ²)	10.8	φ (%)	13.8
k _a (md)	8.8		
@ S _w = 100%			
ΔP (psi)	11.0	T (°F)	82
ΔV (cc)	2.35	μ _w (cp)	0.9
ΔT (sec)	267	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	5.80		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	123.0	T (°F)	81.5
ΔV (cc)	2.80	μ _o (cp)	7.6
ΔT (sec)	319	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
25.06.1999	-		
20.07.1999	-		
Forced Water Displacement			
Displaced Oil (cc).....	3.80		
Injected Water (cc).....	-		
Total Production (cc).....	3.80		
@ S _o = S _{or}			
ΔP (psi)	58.0	T (°F)	83
ΔV (cc)	1.80	μ _w (cp)	0.9
ΔT (sec)	217	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
21.07.1999	-		
10.08.1999	0.05		
Forced Oil Displacement			
Displaced Water (cc).....	3.05		
Injected Oil (cc).....	-		
Total Production (cc).....	3.10		
@ S _w = S _{wi}			
ΔP (psi)	173.0	T (°F)	87
ΔV (cc)	1.45	μ _o (cp)	7.1
ΔT (sec)	164	k _o (md)	

Plug Id. 66			
L (cm)	7.0	V _p (cc)	12.5
A (cm ²)	10.8	φ (%)	16.6
k _a (md)	17.5		
@ S _w = 100%			
ΔP (psi)	11.0	T (°F)	82
ΔV (cc)	1.90	μ _w (cp)	0.9
ΔT (sec)	236	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....	8.00		
Injected Oil (cc).....	-		
@ S _w = S _{wi}			
ΔP (psi)	183.0	T (°F)	81.5
ΔV (cc)	1.50	μ _o (cp)	7.6
ΔT (sec)	181	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
25.06.1999	-		
20.07.1999	0.20		
Forced Water Displacement			
Displaced Oil (cc).....	4.50		
Injected Water (cc).....	-		
Total Production (cc).....	4.70		
@ S _o = S _{or}			
ΔP (psi)	36.0	T (°F)	83
ΔV (cc)	2.38	μ _w (cp)	0.9
ΔT (sec)	260	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
21.07.1999	-		
11.08.1999	0.05		
Forced Oil Displacement			
Displaced Water (cc).....	4.00		
Injected Oil (cc).....	-		
Total Production (cc).....	4.05		
@ S _w = S _{wi}			
ΔP (psi)	906.0	T (°F)	86
ΔV (cc)	1.85	μ _o (cp)	7.1
ΔT (sec)	227	k _o (md)	

Table B.2. (Continued)

Salinity : 10.000 ppm

Plug Id. 67			
L (cm)	6.9	V _p (cc)	6.3
A (cm ²)	10.8	φ (%)	8.6
k _a (md)	2.0		
@ S _w = 100%			
ΔP (psi)	387.0	T (°F)	80
ΔV (cc)	2.10	μ _w (cp)	0.9
ΔT (sec)	702	k _w (md)	
Displacement by Oil			
Displaced Water (cc)	2.15		
Injected Oil (cc)	-		
@ S _w = S _{wi}			
ΔP (psi)	670.0	T (°F)	81
ΔV (cc)	1.65	μ _o (cp)	7.7
ΔT (sec)	1734	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
30.06.1999	-		
21.07.1999	0.05		
Forced Water Displacement			
Displaced Oil (cc)	1.60		
Injected Water (cc)	-		
Total Production (cc)	1.65		
@ S _o = S _{or}			
ΔP (psi)	530.0	T (°F)	86
ΔV (cc)	1.15	μ _w (cp)	0.8
ΔT (sec)	1348	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
26.07.1999	-		
18.08.1999	0.10		
Forced Oil Displacement			
Displaced Water (cc)	1.00		
Injected Oil (cc)	-		
Total Production (cc)	1.10		
@ S _w = S _{wi}			
ΔP (psi)	510.0	T (°F)	87
ΔV (cc)	0.85	μ _o (cp)	7.0
ΔT (sec)	1500	k _o (md)	

Plug Id. 68			
L (cm)	6.5	V _p (cc)	14.4
A (cm ²)	10.8	φ (%)	20.5
k _a (md)	80.3		
@ S _w = 100%			
ΔP (psi)	3.5	T (°F)	82
ΔV (cc)	2.15	μ _w (cp)	0.9
ΔT (sec)	257	k _w (md)	
Displacement by Oil			
Displaced Water (cc)	7.50		
Injected Oil (cc)	-		
@ S _w = S _{wi}			
ΔP (psi)	14.0	T (°F)	83
ΔV (cc)	2.40	μ _o (cp)	7.4
ΔT (sec)	298	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
01.07.1999	-		
21.07.1999	0.05		
Forced Water Displacement			
Displaced Oil (cc)	4.80		
Injected Water (cc)	-		
Total Production (cc)	4.85		
@ S _o = S _{or}			
ΔP (psi)	11.0	T (°F)	81
ΔV (cc)	2.30	μ _w (cp)	0.9
ΔT (sec)	258	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
22.07.1999	-		
11.08.1999	0.40		
Forced Oil Displacement			
Displaced Water (cc)	4.00		
Injected Oil (cc)	-		
Total Production (cc)	4.40		
@ S _w = S _{wi}			
ΔP (psi)	16.0	T (°F)	86
ΔV (cc)	1.40	μ _o (cp)	7.1
ΔT (sec)	157	k _o (md)	

Plug Id. 69			
L (cm)	4.7	V _p (cc)	9.2
A (cm ²)	10.8	φ (%)	18.3
k _a (md)	12.9		
@ S _w = 100%			
ΔP (psi)	6.0	T (°F)	80
ΔV (cc)	1.35	μ _w (cp)	0.9
ΔT (sec)	159	k _w (md)	
Displacement by Oil			
Displaced Water (cc)	6.10		
Injected Oil (cc)	-		
@ S _w = S _{wi}			
ΔP (psi)	56.0	T (°F)	80
ΔV (cc)	2.35	μ _o (cp)	7.8
ΔT (sec)	293	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
29.06.1999	-		
22.07.1999	0.10		
Forced Water Displacement			
Displaced Oil (cc)	4.05		
Injected Water (cc)	-		
Total Production (cc)	4.15		
@ S _o = S _{or}			
ΔP (psi)	21.0	T (°F)	81
ΔV (cc)	2.70	μ _w (cp)	0.9
ΔT (sec)	310	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
23.07.1999	-		
12.08.1999	0.05		
Forced Oil Displacement			
Displaced Water (cc)	4.00		
Injected Oil (cc)	-		
Total Production (cc)	4.05		
@ S _w = S _{wi}			
ΔP (psi)	55.0	T (°F)	88
ΔV (cc)	2.05	μ _o (cp)	6.9
ΔT (sec)	247	k _o (md)	

Table B.2. (Continued)

Salinity : 10.000 ppm

71		
Plug Id.		
L (cm)	4.9	V _p (cc)
A (cm ²)	10.8	φ (%)
k _a (md)	19.0	
@ S _w = 100%		
ΔP (psi)	8.0	T (°F)
ΔV (cc)	2.05	μ _w (cp)
ΔT (sec)	249	k _w (md)
Displacement by Oil		
Displaced Water (cc)	6.20	
Injected Oil (cc)	-	
@ S _w = S _{wi}		
ΔP (psi)	44.0	T (°F)
ΔV (cc)	2.38	μ _o (cp)
ΔT (sec)	283	k _o (md)
Spontaneous Water Imbibition		
Date	Imbibed Oil	
30.06.1999	-	
26.07.1999	1.30	
Forced Water Displacement		
Displaced Oil (cc)	2.10	
Injected Water (cc)	-	
Total Production (cc)	3.40	
@ S _o = S _{or}		
ΔP (psi)	54.0	T (°F)
ΔV (cc)	2.60	μ _w (cp)
ΔT (sec)	280	k _w (md)
Spontaneous Oil Imbibition		
Date	Imbibed Water	
27.07.1999	-	
12.08.1999	-	
Forced Oil Displacement		
Displaced Water (cc)	3.50	
Injected Oil (cc)	-	
Total Production (cc)	3.50	
@ S _w = S _{wi}		
ΔP (psi)	42.0	T (°F)
ΔV (cc)	2.70	μ _o (cp)
ΔT (sec)	312	k _o (md)

72		
Plug Id.		
L (cm)	4.0	V _p (cc)
A (cm ²)	10.8	φ (%)
k _a (md)	10.4	
@ S _w = 100%		
ΔP (psi)	6.0	T (°F)
ΔV (cc)	2.55	μ _w (cp)
ΔT (sec)	304	k _w (md)
Displacement by Oil		
Displaced Water (cc)	6.55	
Injected Oil (cc)	-	
@ S _w = S _{wi}		
ΔP (psi)	61.0	T (°F)
ΔV (cc)	2.95	μ _o (cp)
ΔT (sec)	354	k _o (md)
Spontaneous Water Imbibition		
Date	Imbibed Oil	
01.07.1999	-	
26.07.1999	1.40	
Forced Water Displacement		
Displaced Oil (cc)	1.00	
Injected Water (cc)	-	
Total Production (cc)	2.40	
@ S _o = S _{or}		
ΔP (psi)	108.0	T (°F)
ΔV (cc)	1.85	μ _w (cp)
ΔT (sec)	224	k _w (md)
Spontaneous Oil Imbibition		
Date	Imbibed Water	
27.07.1999	-	
16.08.1999	-	
Forced Oil Displacement		
Displaced Water (cc)	2.60	
Injected Oil (cc)	-	
Total Production (cc)	2.60	
@ S _w = S _{wi}		
ΔP (psi)	62.5	T (°F)
ΔV (cc)	2.10	μ _o (cp)
ΔT (sec)	260	k _o (md)

73		
Plug Id.		
L (cm)	4.4	V _p (cc)
A (cm ²)	10.8	φ (%)
k _a (md)	34.2	
@ S _w = 100%		
ΔP (psi)	2.4	T (°F)
ΔV (cc)	1.85	μ _w (cp)
ΔT (sec)	226	k _w (md)
Displacement by Oil		
Displaced Water (cc)	7.30	
Injected Oil (cc)	-	
@ S _w = S _{wi}		
ΔP (psi)	18.0	T (°F)
ΔV (cc)	1.90	μ _o (cp)
ΔT (sec)	229	k _o (md)
Spontaneous Water Imbibition		
Date	Imbibed Oil	
02.07.1999	-	
27.07.1999	1.80	
Forced Water Displacement		
Displaced Oil (cc)	1.40	
Injected Water (cc)	-	
Total Production (cc)	3.20	
@ S _o = S _{or}		
ΔP (psi)	24.0	T (°F)
ΔV (cc)	3.00	μ _w (cp)
ΔT (sec)	319	k _w (md)
Spontaneous Oil Imbibition		
Date	Imbibed Water	
28.07.1999	-	
16.08.1999	-	
Forced Oil Displacement		
Displaced Water (cc)	3.50	
Injected Oil (cc)	-	
Total Production (cc)	3.50	
@ S _w = S _{wi}		
ΔP (psi)	20.0	T (°F)
ΔV (cc)	2.80	μ _o (cp)
ΔT (sec)	300	k _o (md)

Table B.2. (Continued)

Salinity : 10.000 ppm

Plug Id. 74			
L (cm)	4.5	V _p (cc)	7.6
A (cm ²)	10.8	φ (%)	15.4
k _a (md)	6.0		
@ S _w = 100%			
ΔP (psi)	11.0	T (°F)	82
ΔV (cc)	2.35	μ _w (cp)	0.9
ΔT (sec)	279	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		6.05	
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)	106.0	T (°F)	82.5
ΔV (cc)	2.00	μ _o (cp)	7.4
ΔT (sec)	238	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
02.07.1999		-	
28.07.1999		1.50	
Forced Water Displacement			
Displaced Oil (cc).....		0.75	
Injected Water (cc).....		-	
Total Production (cc).....		2.25	
@ S _o = S _{or}			
ΔP (psi)	181.0	T (°F)	87
ΔV (cc)	2.00	μ _w (cp)	0.8
ΔT (sec)	241	k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
29.05.1999		-	
17.08.1999		-	
Forced Oil Displacement			
Displaced Water (cc).....		2.35	
Injected Oil (cc).....		-	
Total Production (cc).....		2.35	
@ S _w = S _{wi}			
ΔP (psi)	91.0	T (°F)	88
ΔV (cc)	1.70	μ _o (cp)	6.9
ΔT (sec)	202	k _o (md)	

Plug Id. 75			
L (cm)	4.4	V _p (cc)	8.3
A (cm ²)	10.8	φ (%)	17.3
k _a (md)	28.6		
@ S _w = 100%			
ΔP (psi)	2.3	T (°F)	82
ΔV (cc)	1.75	μ _w (cp)	0.9
ΔT (sec)	209	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		7.30	
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)	21.9	T (°F)	85.5
ΔV (cc)	1.95	μ _o (cp)	7.2
ΔT (sec)	234	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
06.07.1999		-	
27.07.1999		2.15	
Forced Water Displacement			
Displaced Oil (cc).....		0.60	
Injected Water (cc).....		-	
Total Production (cc).....		2.75	
@ S _o = S _{or}			
ΔP (psi)	21.0	T (°F)	91
ΔV (cc)	2.00	μ _w (cp)	0.8
ΔT (sec)	240	k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
28.07.1999		-	
17.08.1999		-	
Forced Oil Displacement			
Displaced Water (cc).....		3.10	
Injected Oil (cc).....		-	
Total Production (cc).....		3.10	
@ S _w = S _{wi}			
ΔP (psi)	21.0	T (°F)	88
ΔV (cc)	2.30	μ _o (cp)	6.9
ΔT (sec)	249	k _o (md)	

Plug Id.			
L (cm)		V _p (cc)	
A (cm ²)		φ (%)	
k _a (md)			
@ S _w = 100%			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	
Displacement by Oil			
Displaced Water (cc).....			
Injected Oil (cc).....		-	
@ S _w = S _{wi}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
Forced Water Displacement			
Displaced Oil (cc).....			
Injected Water (cc).....		-	
Total Production (cc).....			
@ S _o = S _{or}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
Forced Oil Displacement			
Displaced Water (cc).....			
Injected Oil (cc).....		-	
Total Production (cc).....			
@ S _w = S _{wi}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	

Table B.3. Wettability Test Row Data Sheet

(Effect of Aging Time on Wettability @ 160 F⁰)

Salinity : 10 000 ppm

Plug Id. 55			Plug Id. 60			Plug Id. 62					
L (cm)	6.22	V _P (cc)	8.03	L (cm)	6.48	V _P (cc)	12.09	L (cm)	6.64	V _P (cc)	8.54
A (cm ²)	10.75	φ (%)	12.00	A (cm ²)	10.75	φ (%)	17.35	A (cm ²)	10.75	φ (%)	11.96
k _a (md)	7.24			k _a (md)	10.42			k _a (md)	6.31		
@ S _w = 100%			@ S _w = 100%			@ S _w = 100%					
ΔP (psi)	17.0	T (°F)	71	ΔP (psi)	14.0	T (°F)	73	ΔP (psi)	38.0	T (°F)	73
ΔV (cc)	2.45	μ _w (cp)	1.0	ΔV (cc)	1.70	μ _w (cp)	1.0	ΔV (cc)	1.60	μ _w (cp)	1.0
ΔT (sec)	435	k _w (md)		ΔT (sec)	153	k _w (md)		ΔT (sec)	139	k _w (md)	
Displacement by Oil			Displacement by Oil			Displacement by Oil					
Displaced Water (cc)	6.45		Displaced Water (cc)	10.10		Displaced Water (cc)	6.50				
Injected Oil (cc)	360		Injected Oil (cc)	280		Injected Oil (cc)	200				
@ S _w = S _{wi}			@ S _w = S _{wi}			@ S _w = S _{wi}					
ΔP (psi)	148	T (°F)	74	ΔP (psi)	50	T (°F)	75	ΔP (psi)	85	T (°F)	75
ΔV (cc)	1.62	μ _o (cp)	9.81	ΔV (cc)	2.35	μ _o (cp)	9.6	ΔV (cc)	1.6	μ _o (cp)	9.6
ΔT (sec)	287	k _o (md)		ΔT (sec)	626	k _o (md)		ΔT (sec)	630	k _o (md)	
Aging Period			Aging Period			Aging Period					
	Date			Date			Date				
Start	15.10.1999		Start	19.10.1999		Start	19.10.1999				
End	15.11.1999		End	29.11.1999		End	09.12.1999				
Spontaneous Water Imbibition			Spontaneous Water Imbibition			Spontaneous Water Imbibition					
Date	Imbibed Oil		Date	Imbibed Oil		Date	Imbibed Oil				
15.11.1999	-		29.11.1999	-		09.12.1999	-				
02.12.1999	0.1		16.12.1999	-		28.12.1999	0.6				
Forced Water Displacement			Forced Water Displacement			Forced Water Displacement					
Displaced Oil (cc)	3.60		Displaced Oil (cc)	6.60		Displaced Oil (cc)	4.60				
Injected Water	444		Injected Water	460		Injected Water	424				
Total Production (cc)	3.70		Total Production (cc)	6.60		Total Production (cc)	5.20				
@ S _o = S _{or}			@ S _o = S _{or}			@ S _o = S _{or}					
ΔP (psi)	26.0	T (°F)	73	ΔP (psi)	16.0	T (°F)	73	ΔP (psi)	25.0	T (°F)	71
ΔV (cc)	1.80	μ _w (cp)	1.0	ΔV (cc)	1.70	μ _w (cp)	1.0	ΔV (cc)	2.25	μ _w (cp)	1.0
ΔT (sec)	319	k _w (md)		ΔT (sec)	290	k _w (md)		ΔT (sec)	715	k _w (md)	
Spontaneous Oil Imbibition			Spontaneous Oil Imbibition			Spontaneous Oil Imbibition					
Date	Imbibed Water		Date	Imbibed Water		Date	Imbibed Water				
03.12.1999	-		17.12.1999	-		29.12.1999	-				
22.12.1999	-		03.01.2000	-		13.01.2000	-				
Forced Oil Displacement			Forced Oil Displacement			Forced Oil Displacement					
Displaced Water (cc)	2.20		Displaced Water (cc)	3.40		Displaced Water (cc)	2.70				
Injected Oil (cc)	400		Injected Oil (cc)	480		Injected Oil (cc)	300				
Total Production (cc)	2.20		Total Production (cc)	3.40		Total Production (cc)	2.70				
@ S _w = S _{wi}			@ S _w = S _{wi}			@ S _w = S _{wi}					
ΔP	148	T (°F)	74	ΔP	240.0	T (°F)	76	ΔP	387.0	T (°F)	69
ΔV	1.65	μ _o (cp)	9.81	ΔV	1.41	μ _o (cp)	9.4	ΔV	2.28	μ _o (cp)	10.9
ΔT	300	k _o (md)		ΔT	255	k _o (md)	1.92	ΔT	503	k _o (md)	1.16

Table B.3. (Continued)

Salinity : 10 000 ppm

Plug Id. 68		
L (cm)	6.53	V _p (cc) 14.41
A (cm ²)	10.75	φ (%) 20.52
k _a (md)	80.26	
@ S _w = 100%		
ΔP (psi)	2.0	T (°F) 76
ΔV (cc)	1.55	μ _w (cp) 0.9
ΔT (sec)	131	k _w (md)
Displacement by Oil		
Displaced Water (cc)	8.20	
Injected Oil (cc)	200	
@ S _w = S _{wi}		
ΔP (psi)	4	T (°F) 77.5
ΔV (cc)	1.55	μ _o (cp) 9.11
ΔT (sec)	456	k _o (md)
Aging Period		
	Date	
Start	20.10.1999	
End	22.12.1999	
Spontaneous Water Imbibition		
	Date	Imbibed Oil
	20.12.1999	-
	11.01.2000	-
Forced Water Displacement		
Displaced Oil (cc)	5.90	
Injected Water	483	
Total Production (cc)	5.90	
@ S _o = S _{or}		
ΔP (psi)	4.0	T (°F) 73
ΔV (cc)	2.20	μ _w (cp) 1.0
ΔT (sec)	201	k _w (md)
Spontaneous Oil Imbibition		
	Date	Imbibed Water
	12.01.1999	-
	24.01.2000	0.10
Forced Oil Displacement		
Displaced Water (cc)	2.40	
Injected Oil (cc)	450	
Total Production (cc)	2.50	
@ S _w = S _{wi}		
ΔP	8.0	T (°F) 67
ΔV	1.85	μ _o (cp) 11.4
ΔT	580	k _o (md) 40.73

Plug Id. 74		
L (cm)	4.52	V _p (cc) 7.55
A (cm ²)	10.81	φ (%) 15.44
k _a (md)	5.96	
@ S _w = 100%		
ΔP (psi)	17.0	T (°F) 76
ΔV (cc)	1.80	μ _w (cp) 0.9
ΔT (sec)	169	k _w (md)
Displacement by Oil		
Displaced Water (cc)	6.20	
Injected Oil (cc)	200	
@ S _w = S _{wi}		
ΔP (psi)	52	T (°F) 77.5
ΔV (cc)	1.55	μ _o (cp) 9.11
ΔT (sec)	453	k _o (md)
Aging Period		
	Date	
Start	20.10.1999	
End	30.12.1999	
Spontaneous Water Imbibition		
	Date	Imbibed Oil
	30.12.1999	-
	12.01.2000	0.08
Forced Water Displacement		
Displaced Oil (cc)	3.90	
Injected Water	483	
Total Production (cc)	3.98	
@ S _o = S _{or}		
ΔP (psi)	53.0	T (°F) 71
ΔV (cc)	3.10	μ _w (cp) 1.0
ΔT (sec)	300	k _w (md)
Spontaneous Oil Imbibition		
	Date	Imbibed Water
	13.01.2000	-
	25.01.2000	0.05
Forced Oil Displacement		
Displaced Water (cc)	2.93	
Injected Oil (cc)	3	
Total Production (cc)	2.98	
@ S _w = S _{wi}		
ΔP	90.0	T (°F) 78
ΔV	2.30	μ _o (cp) 9.3
ΔT	704	k _o (md) 2.07

Plug Id.		
L (cm)		V _p (cc)
A (cm ²)		φ (%)
k _a (md)		
@ S _w = 100%		
ΔP (psi)		T (°F)
ΔV (cc)		μ _w (cp)
ΔT (sec)		k _w (md)
Displacement by Oil		
Displaced Water (cc)		
Injected Oil (cc)		
@ S _w = S _{wi}		
ΔP (psi)		T (°F)
ΔV (cc)		μ _o (cp)
ΔT (sec)		k _o (md)
Aging Period		
	Date	
Start		
End		
Spontaneous Water Imbibition		
	Date	Imbibed Oil
Forced Water Displacement		
Displaced Oil (cc)		
Injected Water		
Total Production (cc)		
@ S _o = S _{or}		
ΔP (psi)		T (°F)
ΔV (cc)		μ _w (cp)
ΔT (sec)		k _w (md)
Spontaneous Oil Imbibition		
	Date	Imbibed Water
Forced Oil Displacement		
Displaced Water (cc)		
Injected Oil (cc)		
Total Production (cc)		
@ S _w = S _{wi}		
ΔP		T (°F)
ΔV		μ _o (cp)
ΔT		k _o (md)

Table B.4. Wettability Test Row Data Sheet

(Effect of Salinity on Wettability)

Salinity : 20 000 ppm				30 000 ppm				40 000 ppm			
Plug Id.		52		Plug Id.		54		Plug Id.		66	
L (cm)	5.03	PV	V _P (cc)	L (cm)	6.77	V _P (cc)	9.26	L (cm)	6.99	V _P (cc)	12.48
A (cm ²)	10.75	φ	φ (%)	A (cm ²)	10.75	φ (%)	12.72	A (cm ²)	10.75	φ (%)	16.61
k _a (md)	30.14			k _a (md)	2.49			k _a (md)	17.54		
@ S _w = 100%				@ S _w = 100%				@ S _w = 100%			
ΔP (psi)	21.0	T (°F)	80	ΔP (psi)	35.0	T (°F)	79	ΔP (psi)	6.0	T (°F)	71
ΔV (cc)	1.93	μ _w (cp)	8.7	ΔV (cc)	1.45	μ _w (cp)	0.9	ΔV (cc)	1.35	μ _w (cp)	1.0
ΔT (sec)	357	k _w (md)		ΔT (sec)	262	k _w (md)		ΔT (sec)	235	k _w (md)	
Displacement by Oil				Displacement by Oil				Displacement by Oil			
Displaced Water (cc).....	7.75			Displaced Water (cc).....	6.30			Displaced Water (cc).....	6.90		
Injected Oil (cc).....	300			Injected Oil (cc).....	250			Injected Oil (cc).....	235		
@ S _w = S _{wi}				@ S _w = S _{wi}				@ S _w = S _{wi}			
ΔP (psi)	21	T (°F)	80	ΔP (psi)	241	T (°F)	80	ΔP (psi)	54	T (°F)	70
ΔV (cc)	1.93	μ _o (cp)	8.67	ΔV (cc)	1.3	μ _o (cp)	8.67	ΔV (cc)	2.17	μ _o (cp)	10.7
ΔT (sec)	357	k _o (md)		ΔT (sec)	296	k _o (md)		ΔT (sec)	392	k _o (md)	
Spontaneous Water Imbibition				Spontaneous Water Imbibition				Spontaneous Water Imbibition			
Date		Imbibed Oil		Date		Imbibed Oil		Date		Imbibed Oil	
08.10.1999		-		08.10.1999		-		13.10.1999		-	
25.10.1999		0.05		26.10.1999		0.05		26.10.1999		0.1	
Forced Water Displacement				Forced Water Displacement				Forced Water Displacement			
Displaced Oil (cc).....	4.50			Displaced Oil (cc).....	4.50			Displaced Oil (cc).....	4.80		
Injected Water.....	452			Injected Water.....	462			Injected Water.....	444		
Total Production (cc).....	4.55			Total Production (cc).....	4.55			Total Production (cc).....	4.90		
@ S _o = S _{or}				@ S _o = S _{or}				@ S _o = S _{or}			
ΔP (psi)	5.0	T (°F)	76	ΔP (psi)	52.0	T (°F)	77	ΔP (psi)	10.0	T (°F)	77
ΔV (cc)	2.55	μ _w (cp)	0.9	ΔV (cc)	2.00	μ _w (cp)	0.9	ΔV (cc)	1.40	μ _w (cp)	1.0
ΔT (sec)	752	k _w (md)	4.39	ΔT (sec)	564	k _w (md)		ΔT (sec)	535	k _w (md)	2.39
Spontaneous Oil Imbibition				Spontaneous Oil Imbibition				Spontaneous Oil Imbibition			
Date		Imbibed Water		Date		Imbibed Water		Date		Imbibed Water	
06.07.1999		-		27.10.1999		-		27.10.1999		-	
29.07.1999				15.11.1999				16.11.1999			
Forced Oil Displacement				Forced Oil Displacement				Forced Oil Displacement			
Displaced Water (cc).....	4.30			Displaced Water (cc).....	4.10			Displaced Water (cc).....	5.30		
Injected Oil (cc).....	375			Injected Oil (cc).....	380			Injected Oil (cc).....	430		
Total Production (cc).....	4.50			Total Production (cc).....	4.15			Total Production (cc).....	5.40		
@ S _w = S _{wi}				@ S _w = S _{wi}				@ S _w = S _{wi}			
ΔP (psi)	12.0	T (°F)	76	ΔP (psi)	193.0	T (°F)	75	ΔP (psi)	67.0	T (°F)	76
ΔV (cc)	2.00	μ _o (cp)	9.4	ΔV (cc)	1.85	μ _o (cp)	9.6	ΔV (cc)	4.20	μ _o (cp)	9.4
ΔT (sec)	700	k _o (md)		ΔT (sec)	870	k _o (md)	0.98	ΔT (sec)	760	k _o (md)	7.41

Table B.4. (Continued)

Salinity : 50 000 ppm

Plug Id.		73	
L (cm)	4.42	PV	V _P (cc)
A (cm ²)	10.81	φ	φ (%)
k _a (md)	34.18		
@ S _w = 100%			
ΔP (psi)	4.0	T (°F)	71
ΔV (cc)	1.40	μ _w (cp)	1.0
ΔT (sec)	251	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		5.95	
Injected Oil (cc).....		200	
@ S _w = S _{wi}			
ΔP (psi)	14	T (°F)	70
ΔV (cc)	2.7	μ _o (cp)	10.7
ΔT (sec)	491	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
13.10.1999		-	
01.11.1999		1.17	
Forced Water Displacement			
Displaced Oil (cc).....		2.10	
Injected Water.....		447	
Total Production (cc).....		3.80	
@ S _o = S _{or}			
ΔP (psi)	11.0	T (°F)	74
ΔV (cc)	2.00	μ _w (cp)	1.0
ΔT (sec)	800	k _w (md)	1.37
Spontaneous Oil Imbibition			
Date		Imbibed Water	
13.07.1999		-	
02.08.1999		0.05	
Forced Oil Displacement			
Displaced Water (cc).....		3.90	
Injected Oil (cc).....		250	
Total Production (cc).....		3.95	
@ S _w = S _{wi}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	

60 000 ppm

Plug Id.		75	
L (cm)	4.43	V _p (cc)	8.26
A (cm ²)	10.81	φ (%)	17.26
k _a (md)	28.58		
@ S _w = 100%			
ΔP (psi)	3.0	T (°F)	71
ΔV (cc)	2.25	μ _w (cp)	1.1
ΔT (sec)	410	k _w (md)	
Displacement by Oil			
Displaced Water (cc).....		6.20	
Injected Oil (cc).....		280	
@ S _w = S _{wi}			
ΔP (psi)	16	T (°F)	73
ΔV (cc)	1.91	μ _o (cp)	10.02
ΔT (sec)	344	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
14.10.1999		-	
01.11.1999		2.1	
Forced Water Displacement			
Displaced Oil (cc).....		1.30	
Injected Water.....		452	
Total Production (cc).....		3.40	
@ S _o = S _{or}			
ΔP (psi)	8.0	T (°F)	74
ΔV (cc)	2.30	μ _w (cp)	1.0
ΔT (sec)	670	k _w (md)	2.64
Spontaneous Oil Imbibition			
Date		Imbibed Water	
02.11.1999		-	
18.11.1999		0.05	
Forced Oil Displacement			
Displaced Water (cc).....		3.20	
Injected Oil (cc).....		250	
Total Production (cc).....		3.25	
@ S _w = S _{wi}			
ΔP (psi)	9.0	T (°F)	72
ΔV (cc)	1.50	μ _o (cp)	10.2
ΔT (sec)	535	k _o (md)	19.22

Plug Id.			
L (cm)		V _p (cc)	
A (cm ²)		ϕ (%)	
k _a (md)			
@ S _w = 100%			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	
Displacement by Oil			
Displaced Water (cc).....			
Injected Oil (cc).....			
@ S _w = S _{wi}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
Forced Water Displacement			
Displaced Oil (cc).....			
Injected Water.....			
Total Production (cc).....			
@ S _o = S _{or}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
Forced Oil Displacement			
Displaced Water (cc).....			
Injected Oil (cc).....			
Total Production (cc).....			
@ S _w = S _{wi}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	

Table B.5. Wettability Test Row Data Sheet
(Effect of Saturation History on Wettability)

Salinity : 10 000 ppm

Plug Id. 51			
L (cm)	6.29	V _p (cc)	7.26
A (cm ²)	10.75	φ (%)	10.74
k _a (md)	5.01		
@ S _o = 100%			
ΔP (psi)	260	T (°F)	76.5
ΔV (cc)	1.65	μ _o (cp)	9.3
ΔT (sec)	295	k _o (md)	
Displacement by Water			
Displaced Oil (cc).....	2.8		
Injected Water (cc).....	341		
@ S _o = S _{or}			
ΔP (psi)	84.0	T (°F)	78
ΔV (cc)	1.95	μ _w (cp)	0.9
ΔT (sec)	342	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
21.10.1999	-		
02.11.1999	-		
Forced Oil Displacement			
Displaced Water (cc).....	1.35		
Injected Oil (cc).....	210		
Total Production (cc).....	1.35		
@ S _w = S _{wi}			
ΔP (psi)	240.0	T (°F)	76
ΔV (cc)	1.15	μ _o (cp)	9.4
ΔT (sec)	549	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
03.11.1999	-		
22.11.1999	0.05		
Forced Water Displacement			
Displaced Oil (cc).....	1.20		
Injected Water (cc).....	380		
Total Production (cc).....	1.25		
@ S _o = S _{or}			
ΔP (psi)	80.0	T (°F)	70
ΔV (cc)	1.55	μ _w (cp)	1.0
ΔT (sec)	540	k _w (md)	

Plug Id. 59			
L (cm)	6.86	V _p (cc)	9.72
A (cm ²)	10.75	φ (%)	13.17
k _a (md)	8.85		
@ S _o = 100%			
ΔP (psi)	191	T (°F)	76.5
ΔV (cc)	1.2	μ _o (cp)	9.3
ΔT (sec)	212	k _o (md)	
Displacement by Water			
Displaced Oil (cc).....	4.6		
Injected Water (cc).....	352		
@ S _o = S _{or}			
ΔP (psi)	88.0	T (°F)	78
ΔV (cc)	2.45	μ _w (cp)	0.9
ΔT (sec)	433	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
21.20.1999	-		
02.11.1999	-		
Forced Oil Displacement			
Displaced Water (cc).....	2.40		
Injected Oil (cc).....	300		
Total Production (cc).....	2.40		
@ S _w = S _{wi}			
ΔP (psi)	132.0	T (°F)	76
ΔV (cc)	2.35	μ _o (cp)	9.4
ΔT (sec)	639	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
03.11.1999	-		
22.11.1999	0.05		
Forced Water Displacement			
Displaced Oil (cc).....	2.05		
Injected Water (cc).....	400		
Total Production (cc).....	2.10		
@ S _o = S _{or}			
ΔP (psi)	35.0	T (°F)	70
ΔV (cc)	1.20	μ _w (cp)	1.0
ΔT (sec)	443	k _w (md)	

Plug Id. 64			
L (cm)	6.75	V _p (cc)	9.76
A (cm ²)	10.75	φ (%)	13.44
k _a (md)	4.09		
@ S _o = 100%			
ΔP (psi)	343	T (°F)	78
ΔV (cc)	1.9	μ _o (cp)	9.02
ΔT (sec)	170	k _o (md)	
Displacement by Water			
Displaced Oil (cc).....	6.5		
Injected Water (cc).....	472		
@ S _o = S _{or}			
ΔP (psi)	96.0	T (°F)	77
ΔV (cc)	2.75	μ _w (cp)	0.9
ΔT (sec)	240	k _w (md)	
Spontaneous Oil Imbibition			
Date	Imbibed Water		
22.10.1999	-		
03.11.1999	-		
Forced Oil Displacement			
Displaced Water (cc).....	4.40		
Injected Oil (cc).....	220		
Total Production (cc).....	4.40		
@ S _w = S _{wi}			
ΔP (psi)	261.0	T (°F)	78
ΔV (cc)	1.60	μ _o (cp)	9.0
ΔT (sec)	570	k _o (md)	
Spontaneous Water Imbibition			
Date	Imbibed Oil		
04.11.1999	-		
25.11.1999	0.03		
Forced Water Displacement			
Displaced Oil (cc).....	4.15		
Injected Water (cc).....	404		
Total Production (cc).....	4.18		
@ S _o = S _{or}			
ΔP (psi)	67.0	T (°F)	73
ΔV (cc)	1.35	μ _w (cp)	1.0
ΔT (sec)	309	k _w (md)	

Table B.5. (Continued)

Salinity : 10 000 ppm

Plug Id.		71	
L (cm)	4.88	V _p (cc)	10.33
A (cm ²)	10.75	φ (%)	19.69
k _a (md)	18.99		
@ S _o = 100%			
ΔP (psi)	38	T (°F)	78
ΔV (cc)	2.3	μ _o (cp)	9.02
ΔT (sec)	210	k _o (md)	
Displacement by Water			
Displaced Oil (cc).....		5.7	
Injected Water (cc).....		440	
@ S _o = S _{or}			
ΔP (psi)	34.0	T (°F)	77
ΔV (cc)	2.00	μ _w (cp)	0.9
ΔT (sec)	181	k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
22.10.1999		-	
03.11.1999		-	
Forced Oil Displacement			
Displaced Water (cc).....		4.00	
Injected Oil (cc).....		360	
Total Production (cc).....		4.00	
@ S _w = S _{wi}			
ΔP (psi)	25.0	T (°F)	78
ΔV (cc)	1.50	μ _o (cp)	9.0
ΔT (sec)	540	k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
04.11.1999		-	
23.11.1999		1.00	
Forced Water Displacement			
Displaced Oil (cc).....		2.50	
Injected Water (cc).....		352	
Total Production (cc).....		3.50	
@ S _o = S _{or}			
ΔP (psi)	16.0	T (°F)	71
ΔV (cc)	1.80	μ _w (cp)	1.0
ΔT (sec)	660	k _w (md)	

Plug Id.		72	
L (cm)	4.04	V _P (cc)	7.47
A (cm ²)	10.81	φ (%)	17.11
k _a (md)	10.43		
@ S _o = 100%			
ΔP (psi)	70	T (°F)	78
ΔV (cc)	2	μ _o (cp)	9.02
ΔT (sec)	177	k _o (md)	
Displacement by Water			
Displaced Oil (cc).....		4.6	
Injected Water (cc).....		383	
@ S _o = S _{or}			
ΔP (psi)	4.0	T (°F)	76
ΔV (cc)	1.80	μ _w (cp)	0.9
ΔT (sec)	161	k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
26.10.1999		-	
04.11.1999		-	
Forced Oil Displacement			
Displaced Water (cc).....		3.70	
Injected Oil (cc).....		270	
Total Production (cc).....		3.70	
@ S _w = S _{wi}			
ΔP (psi)	23.0	T (°F)	73
ΔV (cc)	1.53	μ _o (cp)	9.0
ΔT (sec)	598	k _o (md)	5.51
Spontaneous Water Imbibition			
Date		Imbibed Oil	
05.11.1999		-	
23.11.1999		1.3	
Forced Water Displacement			
Displaced Oil (cc).....		1.75	
Injected Water (cc).....		340	
Total Production (cc).....		3.05	
@ S _o = S _{or}			
ΔP (psi)	38.0	T (°F)	71
ΔV (cc)	2.30	μ _w (cp)	1.0
ΔT (sec)	8	k _w (md)	

Plug Id.			
L (cm)		V _p (cc)	
A (cm ²)		ϕ (%)	
k _a (md)			
@ S _o = 100%			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	
Displacement by Water			
Displaced Oil (cc).....			
Injected Water (cc).....			
@ S _o = S _{or}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	
Spontaneous Oil Imbibition			
Date		Imbibed Water	
Forced Oil Displacement			
Displaced Water (cc).....			
Injected Oil (cc).....			
Total Production (cc).....			
@ S _w = S _{wi}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _o (cp)	
ΔT (sec)		k _o (md)	
Spontaneous Water Imbibition			
Date		Imbibed Oil	
Forced Water Displacement			
Displaced Oil (cc).....			
Injected Water (cc).....			
Total Production (cc).....			
@ S _o = S _{or}			
ΔP (psi)		T (°F)	
ΔV (cc)		μ _w (cp)	
ΔT (sec)		k _w (md)	

Table B.6. Wettability Tests Results (*Measurement-I*)

Plug Id.	kw (md)	ko @ Sw _i (md)	kw @ So _r (md)	Sw _i (%)	So _r (%)	I _w	I _o	I _{AH}	Result
51	1.33	2.22	0.39	44.90	*	0.04	0.13	-0.09	IW
52	11.03	15.04	3.89	31.82	49.63	0.00	0.00	0.00	IW
54	1.16	1.37	0.37	20.63	32.94	0.02	0.02	0.00	IW
55	3.01	3.66	1.07	25.28	31.76	0.10	0.08	0.02	IW
56	1.47	1.90	0.62	17.21	26.79	0.07	0.06	0.01	IW
57	2.51	3.66	0.56	29.17	21.44	0.09	0.10	-0.01	IW
58	6.07	6.51	1.69	36.83	21.80	0.01	0.12	-0.11	IW
59	2.10	3.55	1.59	35.19	34.98	0.02	0.12	-0.10	IW
60	6.60	6.77	*	17.29	26.47	0.12	0.03	0.09	IW
61	5.13	5.81	1.20	25.09	29.78	0.12	0.06	0.06	IW
62	2.00	2.24	0.56	23.89	28.10	0.06	0.11	-0.05	IW
63	2.54	2.96	0.64	29.36	24.28	0.11	0.08	0.03	IW
64	1.98	2.21	0.60	13.93	30.23	0.05	0.08	-0.04	IW
65	5.48	5.70	1.99	22.82	29.99	0.02	0.10	-0.08	IW
66	8.53	9.70	2.07	30.29	26.04	0.11	0.08	0.03	IW
67	*	0.43	0.08	47.87	29.23	0.07	0.06	0.01	IW
68	36.92	31.62	6.50	47.95	17.35	0.02	0.08	-0.06	IW
69	7.34	7.54	2.57	27.87	22.40	0.07	0.01	0.05	IW
71	8.91	9.96	1.40	19.65	47.43	0.56	0.00	0.56	WW
72	5.74	7.10	0.67	21.02	48.86	0.71	0.00	0.71	WW
73	17.78	21.47	1.70	18.22	41.47	0.68	0.00	0.68	WW
74	3.23	3.89	0.23	17.88	54.30	0.67	0.00	0.67	WW
75	15.09	18.27	2.03	22.52	47.22	0.92	0.00	0.92	WW

* Could not be determined because of experimental problems.

Table B.7. Wettability Tests Results (*Measurement-II*)

Plug Id.	kw (md)	ko @ Sw _i (md)	kw @ So _r (md)	Sw _i (%)	So _r (%)	I _w	I _o	I _{AH}	Result
51	0.94	1.44	0.58	57.30	15.15	0.10	0.05	0.05	IW
52	15.04	14.97	6.48	33.21	25.05	0.01	0.01	0.00	IW
54	1.09	1.19	0.34	27.65	24.84	0.01	0.05	-0.03	IW
55	3.67	3.51	0.90	20.30	39.23	0.05	0.00	0.05	IW
56	1.13	1.10	0.49	31.82	25.16	0.02	0.00	0.02	IW
57	1.30	1.70	0.25	44.08	21.44	0.03	0.01	0.01	IW
58	5.72	5.54	2.31	36.39	31.14	0.00	0.04	-0.04	IW
59	2.23	3.52	1.11	56.79	24.38	0.02	0.05	-0.04	IW
60	6.63	5.86	1.55	26.39	26.88	0.03	0.00	0.03	IW
61	2.84	2.76	0.75	42.24	27.08	0.00	0.02	-0.02	IW
62	2.53	2.25	0.74	23.89	39.23	0.02	0.04	-0.02	IW
63	1.13	1.72	0.35	42.60	16.56	0.05	0.05	0.00	IW
64	2.13	1.18	0.55	25.20	25.61	0.01	0.07	-0.06	IW
65	6.24	4.93	1.11	36.05	22.05	0.00	0.02	-0.02	IW
66	6.02	3.30	2.08	35.90	26.44	0.04	0.01	0.03	IW
67	0.06	0.10	0.01	66.03	7.90	0.03	0.09	-0.06	IW
68	18.36	38.23	6.34	52.81	13.53	0.01	0.09	-0.08	IW
69	7.94	7.13	2.30	33.33	21.31	0.02	0.01	0.01	IW
71	5.98	9.49	0.99	39.98	27.11	0.38	0.00	0.38	WW
72	6.61	5.59	0.36	12.32	55.56	0.58	0.00	0.58	WW
73	17.63	20.62	1.82	14.72	47.90	0.56	0.00	0.56	WW
74	4.05	3.63	0.23	19.87	50.33	0.67	0.00	0.67	WW
75	18.86	16.42	1.84	11.62	55.08	0.78	0.00	0.78	WW

Table B.8.1. Effect of Aging Time on Wettability

Plug Id.	k _w (md)	k _o @ S _{w_i} (md)	k _w @ S _{o_r} (md)	S _{w_i} (%)	S _{o_r} (%)	I _w	I _o	I _{AH}	Duration (days)	Result
55	2.76	3.18	1.76	19.68	34.25	0.03	0.00	0.03	31	IW
60	6.84	6.39	3.09	16.46	28.95	0.00	0.00	0.00	41	IW
62	2.68	2.60	1.12	23.89	15.22	0.12	0.00	0.12	51	IW
68	48.55	69.13	23.58	43.10	15.96	0.00	0.04	-0.04	63	IW
74	3.54	3.68	1.18	17.88	29.40	0.02	0.02	0.00	71	IW

Table B.8.2. Effect of Salinity on Wettability

Plug Id.	k _w (md)	k _o @ S _{w_i} (md)	k _w @ S _{o_r} (md)	S _{w_i} (%)	S _{o_r} (%)	I _w	I _o	I _{AH}	Salinity (ppm)	Result
52	8.92	15.35	4.39	28.11	29.68	0.01	0.04	-0.03	20,000	IW
54	1.34	1.46	0.59	31.97	18.90	0.01	0.01	0.00	30,000	IW
66	9.41	10.48	2.39	44.71	16.03	0.02	0.02	0.00	40,000	IW
73	8.74	25.26	1.37	30.49	25.12	0.45	0.01	0.44	50,000	WW
75	11.67	20.95	2.64	24.94	33.90	0.62	0.02	0.60	60,000	WW

Table B.8.3. Effect of Saturation History on Wettability

Plug Id.	k _w (md)	k _o @ S _{w_i} (md)	k _w @ S _{o_r} (md)	S _{w_i} (%)	S _{o_r} (%)	I _w	I _o	I _{AH}	Result
51	1.72	0.71	0.30	19.97	61.43	0.04	0.00	0.04	IW
59	2.59	2.46	0.72	22.63	52.67	0.02	0.00	0.02	IW
64	2.71	0.90	0.57	21.52	33.40	0.01	0.00	0.01	IW
71	17.35	6.69	1.11	16.46	44.82	0.29	0.00	0.29	IW
72	8.00	5.51	0.42	12.05	38.42	0.43	0.00	0.43	WW

APPENDIX C

RELATIVE PERMEABILITY DATA

Table C.1.1. Row Data of Relative Permeability Test for Plug " 52 "

Salinity (ppm): 10,000												
WATER-OIL RELATIVE PERMEABILITY TEST DATA SHEET												
Plug Id. : 62 Length, cm : 5.03 Diameter, cm : 3.71 Bulk Volume, cc : 54 Saturated Weight, g : - Dry Weight, g : - Fluid Weight, g : - Fluid Volume, cc : 10.78 Pore Volume, cc : 10.78 Porosity, % : 19.93 k _{ar} , md : 30.14	Prod. Water (cc) : 7.75 Swi (%) : 28.1 k= $\frac{14.7 \times 10^3 \times L \times \mu \times \Delta V}{\Delta P \times \Delta T \times A}$				Fluid Properties							
					Oil		Brine					
					Density, g/cc		-					
					Viscosity, cp		9.8		1.0			
					Test Temperature, °F		74					
					k _w @ Sw = 1.0				k _o @ Swi			
					ΔP (psi)	4.0	-	-	ΔP (psi)	50.0	-	-
					ΔV (cc)	2.90	-	-	ΔV (cc)	1.55	-	-
					ΔT (sec)	330	-	-	ΔT (sec)	154	-	-
					k _w (md)				k _w (md)			
					k _{wavg}				k _{oavg}			
	ΔP (psi)	T (sec)	ΔT (sec)	ΔV _{oil} (cc)	ΣV _{oil} (cc)	ΣV _{oil} (pv)	ΔV _{brine} (cc)	ΣV _{brine} (cc)	ΔV _{displace} (cc)	ΣV _{displace} (pv)	Water Cut (%)	
1	42.0	59	59	0.35	0.35	0.03	0.05	0.05	0.40	0.40	12.50	
2	33.0	118	58	0.40	0.75	0.07	0.35	0.40	0.75	1.15	46.67	
3	30.0	166	49	0.29	1.04	0.10	0.31	0.71	0.60	1.75	51.67	
4	27.0	240	74	0.25	1.29	0.12	0.55	1.26	0.80	2.55	68.75	
5	26.0	295	55	0.15	1.44	0.13	0.45	1.71	0.60	3.15	75.00	
6	24.0	371	77	0.15	1.59	0.15	0.60	2.31	0.75	3.90	80.00	
7	23.0	455	83	0.18	1.77	0.16	0.67	2.98	0.85	4.75	78.82	
8	22.0	545	90	0.15	1.92	0.18	0.75	3.73	0.90	5.65	83.33	
9	21.5	631	86	0.13	2.05	0.19	0.72	4.45	0.85	6.50	84.71	
10	21.0	723	92	0.17	2.22	0.21	0.73	5.18	0.90	7.40	81.11	
11	20.5	848	125	0.13	2.35	0.22	1.17	6.35	1.30	8.70	90.00	
12	20.0	1013	165	0.23	2.58	0.24	1.42	7.77	1.65	10.35	86.06	
13	19.0	1187	174	0.15	2.73	0.25	1.63	9.40	1.78	12.13	91.57	
14	18.0	1477	290	0.20	2.93	0.27	1.75	11.15	1.95	14.08	89.74	
15	17.0	1947	470	0.20	3.13	0.29	4.60	15.75	4.80	18.88	95.83	
16	16.0	2493	546	0.25	3.38	0.31	5.40	21.15	5.65	24.53	95.58	
17	15.5	3338	845	0.30	3.68	0.34	8.40	29.55	8.70	33.23	96.55	
18	15.0	4471	1133	0.25	3.93	0.36	11.35	40.90	11.60	44.83	97.84	
19	14.5	7027	2556	0.35	4.28	0.40	25.95	66.85	26.30	71.13	98.67	
20	14.0	9738	2711	0.25	4.53	0.42	27.60	94.45	27.85	98.98	99.10	
21	14.0	19802	9864	0.48	5.01	0.46	100.62	195.07	101.10	200.08	99.53	
22	14.0	28668	9066	0.23	5.24	0.49	92.27	287.34	92.50	292.58	99.75	
23	14.0	86268	57600	0.05	5.29	0.49	96.25	383.59	96.30	388.68	99.95	
24												
25												
								k _w @ Swi				
								ΔP (psi)	14.0	-	-	
								ΔV (cc)	1.33	-	-	
								ΔT (sec)	120	-	-	
								k _w (md)				
								k _{wavg}				
30												

Table C.1.2. Row Data of Relative Permeability Test for Plug " 54 "

Salinity (ppm): 10,000

WATER-OIL RELATIVE PERMEABILITY TEST DATA SHEET												
Plug Id. : 54 Length, cm : 6.77 Diameter, cm : 3.71 Bulk Volume, cc : 73 Saturated Weight, g : - Dry Weight, g : - Fluid Weight, g : - Fluid Volume, cc : 9.26 Pore Volume, cc : 9.26 Porosity, % : 12.72 k _{gr} , md : 2.49			Prod. Water (cc) : 6.30 Swi (%) : 32.0 $k = \frac{14.7 \times 10^3 \times L \times \mu \times \Delta V}{\Delta P \times \Delta T \times A}$				Fluid Properties					
									Oil	Brine		
							Density, g/cc		-	-		
							Viscosity, cp		10.0	1.0		
							Test Temperature, °F		73			
			k _w @ Sw = 1.0				k _w @ Swi					
ΔP (psi)			35.0	-	-	ΔP (psi)	364.0	-	-			
ΔV (cc)			1.40	-	-	ΔV (cc)	1.95	-	-			
ΔT (sec)			262	-	-	ΔT (sec)	441	-	-			
k _w (md)						k _w (md)						
k _{wavg} :						k _{oavg} :						
	ΔP (psi)	T (sec)	ΔT (sec)	ΔV _{oil} (cc)	ΣV _{oil} (cc)	ΣV _{oil} (pv)	ΔV _{brine} (cc)	ΣV _{brine} (cc)	ΔV _{oil+brine} (cc)	ΣV _{oil+brine} (pv)	Water Cut (%)	
1	403.0	129	129	0.62	0.62	0.07	0.03	0.03	0.65	0.65	4.62	
2	388.0	190	61	0.28	0.90	0.10	0.42	0.45	0.70	1.35	60.00	
3	365.0	261	71	0.23	1.13	0.12	0.77	1.22	1.00	2.35	77.00	
4	340.0	343	82	0.23	1.36	0.15	0.87	2.09	1.10	3.45	79.09	
5	319.0	425	82	0.13	1.49	0.16	0.87	2.96	1.00	4.45	87.00	
6	300.0	527	102	0.20	1.69	0.18	1.10	4.06	1.30	5.75	84.62	
7	273.0	663	136	0.18	1.87	0.20	1.52	5.58	1.70	7.45	89.41	
8	254.0	845	182	0.12	1.99	0.21	2.08	7.66	2.20	9.65	94.55	
9	243.0	1021	176	0.20	2.19	0.24	1.80	9.46	2.00	11.65	90.00	
10	231.0	1339	318	0.10	2.29	0.25	3.60	13.06	3.70	15.35	97.30	
11	224.0	1699	360	0.20	2.49	0.27	3.85	16.91	4.05	19.40	95.06	
12	216.0	2173	474	0.25	2.74	0.30	5.15	22.06	5.40	24.80	95.37	
13	211.0	2652	479	0.13	2.87	0.31	5.37	27.43	5.50	30.30	97.64	
14	201.0	3526	874	0.20	3.07	0.33	9.70	37.13	9.90	40.20	97.98	
15	195.0	4644	1118	0.18	3.25	0.35	12.27	49.40	12.45	52.65	98.55	
16	189.0	5898	1254	0.08	3.33	0.36	13.84	63.24	13.92	66.57	99.43	
17	181.0	8217	2319	0.22	3.55	0.38	25.88	89.12	26.10	92.67	99.16	
18	171.0	12803	4586	0.23	3.78	0.41	51.25	140.37	51.48	144.15	99.55	
19	165.0	17421	4618	0.13	3.91	0.42	51.57	191.94	51.70	195.85	99.75	
20	165.0	34950	17529	0.15	4.06	0.44	196.35	388.29	196.50	392.35	99.92	
21												
22												
23												
24												
25									k _w @ Sor			
26								ΔP (psi)	165.0	-	-	
27								ΔV (cc)	1.83	-	-	
28								ΔT (sec)	161	-	-	
29								k _w (md)				
30								k _{wavg} :				

Table C.1.3. Row Data of Relative Permeability Test for Plug " 68 "

Salinity (ppm): 10,000											
WATER-OIL RELATIVE PERMEABILITY TEST DATA SHEET											
<div>Plug Id. : 68</div> <div>Length, cm : 6.53</div> <div>Diameter, cm : 3.71</div> <div>Bulk Volume, cc : 71</div> <div>Saturated Weight, g : -</div> <div>Dry Weight, g : -</div> <div>Fluid Weight, g : -</div> <div>Fluid Volume, cc : 14.41</div> <div>Pore Volume, cc : 14.41</div> <div>Porosity, % : 20.52</div> <div>k_{ar}, md : 80.26</div>			<div>Prod. Water (cc) : 9.20</div> <div>Swi (%) :..... 36.2</div> <div>k = $\frac{14.7 \times 10^3 \times L \times \mu \times \Delta V}{\Delta P \times \Delta T \times A}$</div>			Fluid Properties					
						Oil		Brine			
						Density, g/cc		-		-	
						Viscosity, cp		9.9		1.0	
						Test Temperature, °F		73.5			
			k _{ro} @ Sw = 1.0			k _{rw} @ Swi					
			ΔP (psi)	2.0	-	-	ΔP (psi)	23.0	-	-	-
			ΔV (cc)	1.55	-	-	ΔV (cc)	1.30	-	-	-
			ΔT (sec)	131	-	-	ΔT (sec)	123	-	-	-
			k _{ro} (md)				k _{rw} (md)				
			k _{wavg} :			k _{oavg} :					
	ΔP (psi)	T (sec)	ΔT (sec)	ΔV _{oil} (cc)	ΣV _{oil} (cc)	ΣV _{ar} (pv)	ΔV _{brine} (cc)	ΣV _{brine} (cc)	ΔV _{water} (cc)	ΣV _{water} (pv)	Water Cut (%)
1	22.0	78	78	0.50	0.50	0.03	0.05	0.05	0.55	0.55	9.09
2	19.0	121	43	0.33	0.83	0.06	0.27	0.32	0.60	1.15	45.00
3	16.0	171	50	0.23	1.06	0.07	0.47	0.79	0.70	1.85	67.14
4	14.5	223	52	0.15	1.21	0.08	0.50	1.29	0.65	2.50	76.92
5	13.0	295	72	0.15	1.36	0.09	0.75	2.04	0.90	3.40	83.33
6	12.0	376	81	0.17	1.53	0.11	0.73	2.77	0.90	4.30	81.11
7	11.0	501	125	0.10	1.63	0.11	1.25	4.02	1.35	5.65	92.59
8	10.5	635	134	0.10	1.73	0.12	1.30	5.32	1.40	7.05	92.86
9	10.0	778	143	0.20	1.93	0.13	1.40	6.72	1.60	8.65	87.50
10	9.5	1038	260	0.17	2.10	0.15	2.68	9.40	2.85	11.50	94.04
11	9.5	1303	265	0.14	2.24	0.16	2.76	12.16	2.90	14.40	95.17
12	9.2	1767	464	0.15	2.39	0.17	4.78	16.94	4.93	19.33	96.96
13	9.0	2256	489	0.25	2.64	0.18	5.00	21.94	5.25	24.58	95.24
14	8.0	3037	781	0.20	2.84	0.20	8.15	30.09	8.35	32.93	97.60
15	8.0	4177	1140	0.17	3.01	0.21	11.88	41.97	12.05	44.98	98.59
16	7.5	6636	2459	0.38	3.39	0.24	26.10	68.07	26.48	71.46	98.56
17	7.5	11370	4734	0.40	3.79	0.26	50.50	118.57	50.90	122.36	99.21
18	6.5	20844	9474	0.45	4.24	0.29	100.70	219.27	101.15	223.51	99.56
19	6.0	25630	4786	0.15	4.39	0.30	50.70	269.97	50.85	274.36	99.71
20	6.0	43918	18288	0.20	4.59	0.32	193.95	463.92	194.15	468.51	99.90
21	6.0	93010	49092	0.05	4.64	0.32	104.00	567.92	104.05	572.56	99.95
22											
23											
24											
25											
							k _{rw} @ Sor				
26							ΔP (psi)	6.0	-	-	-
27							ΔV (cc)	4.00	-	-	-
28							ΔT (sec)	360	-	-	-
29							k _{rw} (md)				
30							k _{wavg} :				

Table C.1.4. Row Data of Relative Permeability Test for Plug " 71 "

Salinity (ppm): 10,000

WATER-OIL RELATIVE PERMEABILITY TEST DATA SHEET												
<div>Plug Id. : 71</div> <div>Length, cm : 4.88</div> <div>Diameter, cm : 3.71</div> <div>Bulk Volume, cc : 53</div> <div>Saturated Weight, g : -</div> <div>Dry Weight, g : -</div> <div>Fluid Weight, g : -</div> <div>Fluid Volume, cc : 10.33</div> <div>Pore Volume, cc : 10.33</div> <div>Porosity, % : 19.68</div> <div>k_{air}, md : 18.99</div>			<div>Prod. Water (cc) : 7.62</div> <div>Swi (%) : 26.2</div> <div>k = $\frac{14.7 \times 10^3 \times L \times \mu \times \Delta V}{\Delta P \times \Delta T \times A}$</div>				Fluid Properties					
								Oil	Brine			
							Density, g/cc	-	-			
							Viscosity, cp	9.0	0.9			
							Test Temperature, °F	78.0				
			k _w @ Sw = 1.0				k _w @ Swi					
			ΔP (psi)	4.0	-	-	ΔP (psi)	93.0	-	-		
			ΔV (cc)	2.20	-	-	ΔV (cc)	2.00	-	-		
			ΔT (sec)	410	-	-	ΔT (sec)	180	-	-		
			k _w (md)				k _w (md)					
			k _{wavg} :				k _{oavg} :					
	ΔP (psi)	T (sec)	ΔT (sec)	ΔV _{oil} (cc)	ΣV _{oil} (cc)	ΣV _{gas} (pv)	ΔV _{water} (cc)	ΣV _{water} (cc)	ΔV _{airbrine} (cc)	ΣV _{airbrine} (pv)	Water Cut (%)	
1	114.0	245	245	1.80	1.80	0.17	0.05	0.05	1.85	1.85	2.70	
2	113.0	294	49	0.18	1.98	0.19	0.32	0.37	0.50	2.35	64.00	
3	111.0	352	58	0.16	2.14	0.21	0.52	0.89	0.68	3.03	76.47	
4	107.0	440	88	0.08	2.22	0.21	0.92	1.81	1.00	4.03	92.00	
5	103.0	536	96	0.08	2.30	0.22	1.00	2.81	1.08	5.11	92.59	
6	100.0	649	113	0.05	2.35	0.23	1.20	4.01	1.25	6.36	96.00	
7	96.0	831	182	0.08	2.43	0.24	2.08	6.09	2.16	8.52	96.30	
8	94.0	1079	248	0.10	2.53	0.24	2.70	8.79	2.80	11.32	96.43	
9	93.0	1391	312	0.08	2.61	0.25	3.42	12.21	3.50	14.82	97.71	
10	91.0	1909	518	0.05	2.66	0.26	5.75	17.96	5.80	20.62	99.14	
11	90.0	3017	1108	0.07	2.73	0.26	12.33	30.29	12.40	33.02	99.44	
12	88.0	5492	2475	0.15	2.88	0.28	28.05	58.34	28.20	61.22	99.47	
13	101.0	9842	4350	0.07	2.95	0.29	50.98	109.32	51.05	112.27	99.86	
14	98.0	17620	7778	0.03	2.98	0.29	101.67	210.99	101.70	213.97	99.97	
15	28.0	36873	19253	0.05	3.03	0.29	195.15	406.14	195.20	409.17	99.97	
16												
17												
18												
19												
20												
21												
22												
23												
24												
25									k _w @ Sor			
26								ΔP (psi)	28.0	-	-	
27								ΔV (cc)	3.05	-	-	
28								ΔT (sec)	647	-	-	
29								k _w (md)				
30								k _{wavg} :				

Table C.1.5. Row Data of Relative Permeability Test for Plug " 73 "

Salinity (ppm): 10,000												
WATER-OIL RELATIVE PERMEABILITY TEST DATA SHEET												
<div>Plug Id. : 73</div> <div>Length, cm : 4.42</div> <div>Diameter, cm : 3.71</div> <div>Bulk Volume, cc : 48</div> <div>Saturated Weight, g : -</div> <div>Dry Weight, g : -</div> <div>Fluid Weight, g : -</div>			<div>Prod. Water (cc) : 5.90</div> <div>Swi (%) :..... 31.1</div> <div>$k = \frac{14.7 \times 10^3 \times L \times \mu \times \Delta V}{\Delta P \times \Delta T \times A}$</div>				Fluid Properties					
									Oil	Brine		
							Density, g/cc		-		-	
							Viscosity, cp		9.3		0.9	
							Test Temperature, °F		78.0			
			kw @ Sw = 1.0				ko @ Swi					
Fluid Volume, cc : 8.56			ΔP (psi)	2.4	-	-	ΔP (psi)	37.0	-	-		
Pore Volume, cc : 8.56			ΔV (cc)	1.55	-	-	ΔV (cc)	2.30	-	-		
Porosity, % : 17.91			ΔT (sec)	251	-	-	ΔT (sec)	208	-	-		
Keff, md : 34.18			kw (md)				kw (md)					
			kwavg:				koavg:					
	ΔP (psi)	T (sec)	ΔT (sec)	ΔVoil (cc)	ΣVoil (cc)	ΣVsw (pv)	ΔVbrine (cc)	ΣVbrine (cc)	ΔVoil+brine (cc)	ΣVoil+brine (pv)	Water Cut (%)	
1	42.0	255	255	2.40	2.40	0.28	0.05	0.05	2.45	2.45	2.04	
2	41.0	317	62	0.30	2.70	0.32	0.43	0.48	0.73	3.18	58.90	
3	40.0	391	74	0.15	2.85	0.33	0.65	1.13	0.80	3.98	81.25	
4	38.0	481	90	0.10	2.95	0.34	0.93	2.06	1.03	5.01	90.29	
5	36.0	611	130	0.13	3.08	0.36	1.37	3.43	1.50	6.51	91.33	
6	35.0	800	189	0.10	3.18	0.37	2.00	5.43	2.10	8.61	95.24	
7	33.0	1142	342	0.10	3.28	0.38	3.70	9.13	3.80	12.41	97.37	
8	32.0	1623	481	0.10	3.38	0.39	5.35	14.48	5.45	17.86	98.17	
9	31.0	2478	855	0.10	3.48	0.41	9.50	23.98	9.60	27.46	98.96	
10	30.0	3731	1253	0.05	3.53	0.41	13.85	37.83	13.90	41.36	99.64	
11	29.0	6179	2448	0.08	3.61	0.42	25.50	63.33	25.58	66.94	99.69	
12	28.0	10722	4543	0.08	3.69	0.43	51.02	114.35	51.10	118.04	99.84	
13	28.0	20030	9308	0.05	3.74	0.44	101.75	216.10	101.80	219.84	99.95	
14	28.0	37856	17826	0.03	3.77	0.44	192.10	408.20	192.13	411.97	99.98	
15												
16												
17												
18												
19												
20												
21												
22												
23												
24												
25									kw @ Sor			
26								ΔP (psi)	28.0	-	-	
27								ΔV (cc)	2.45	-	-	
28								ΔT (sec)	222	-	-	
29								kw (md)				
30								Kwavg:				

Table C.1.6. Row Data of Relative Permeability Test for Plug "74"
(First Run)

First Run

Salinity (ppm): 10,000

WATER-OIL RELATIVE PERMEABILITY TEST DATA SHEET

Plug Id. : 74 Length, cm : 4.52 Diameter, cm : 3.71 Bulk Volume, cc : 49 Saturated Weight, g : - Dry Weight, g : - Fluid Weight, g : - Fluid Volume, cc : 7.55 Pore Volume, cc : 7.55 Porosity, % : 15.44 k_{air}, md : 5.96			Prod. Water (cc) : 6.20 Swi (%) : 17.9 $k = \frac{14.7 \times 10^3 \times L \times \mu \times \Delta V}{\Delta P \times \Delta T \times A}$				Fluid Properties			
									Oil	Brine
							Density, g/cc		-	-
							Viscosity, cp		10.0	1.0
							Test Temperature, °F		73.0	
			k_w @ Sw = 1.0				k_o @ Swi			
			ΔP (psi)	17.7	-	-	ΔP (psi)	100.0	-	-
			ΔV (cc)	1.80	-	-	ΔV (cc)	1.20	-	-
			ΔT (sec)	169	-	-	ΔT (sec)	400	-	-
			k_w (md)				k_w (md)			
			k_{wavg}				k_{oavg}			

	ΔP (psi)	T (sec)	ΔT (sec)	ΔV_{ad} (cc)	ΣV_{ad} (cc)	ΣV_{del} (pv)	ΔV_{intra} (cc)	ΣV_{intra} (cc)	$\Delta V_{adv intra}$ (cc)	$\Sigma V_{adv intra}$ (pv)	Water Cut (%)
1	308.0	106	106	1.27	1.27	0.17	0.03	0.03	1.30	1.30	2.31
2	281.0	135	29	0.35	1.62	0.21	0.20	0.23	0.55	1.85	36.36
3	260.0	177	42	0.20	1.82	0.24	0.35	0.58	0.55	2.40	63.64
4	244.0	256	79	0.15	1.97	0.26	0.80	1.38	0.95	3.35	84.21
5	226.0	428	172	0.15	2.12	0.28	1.70	3.08	1.85	5.20	91.89
6	218.0	768	340	0.12	2.24	0.30	3.33	6.41	3.45	8.65	96.52
7	214.0	1147	379	0.08	2.32	0.31	3.82	10.23	3.90	12.55	97.95
8	211.0	1568	421	0.08	2.40	0.32	4.17	14.40	4.25	16.80	98.12
9	207.0	2137	569	0.08	2.48	0.33	5.77	20.17	5.85	22.65	98.63
10	203.0	3040	903	0.10	2.58	0.34	9.20	29.37	9.30	31.95	98.92
11	197.0	5612	2572	0.15	2.73	0.38	26.45	55.82	26.60	58.55	99.44
12	189.0	10505	4894	0.12	2.85	0.38	50.38	106.20	50.50	109.05	99.76
13	184.0	20480	9974	0.10	2.95	0.39	102.30	208.50	102.40	211.45	99.90
14	180.0	28154	7675	0.03	2.98	0.39	79.02	287.52	79.05	290.50	99.96
15	172.0	89054	60900	0.05	3.03	0.40	194.10	481.62	194.15	484.65	99.97
16											
17											
18											
19											
20											
21											
22											
23											
24											
25							kw @ Sor				
26							ΔP (psi)	172.0	-	-	
27							ΔV (cc)	4.50	-	-	
28							ΔT (sec)	426	-	-	
29							k_w (md)				
30							k_{wavg}				

**Table C.1.7. Row Data of Relative Permeability Test for Plug "74"
(Second Run)**

Second Run

Salinity (ppm): 10,000

WATER-OIL RELATIVE PERMEABILITY TEST DATA SHEET

<div>Plug Id. : 74</div> <div>Length, cm : 4.52</div> <div>Diameter, cm : 3.71</div> <div>Bulk Volume, cc : 49</div> <div>Saturated Weight, g : -</div> <div>Dry Weight, g : -</div> <div>Fluid Weight, g : -</div> <div>Fluid Volume, cc : 7.55</div> <div>Pore Volume, cc : 7.55</div> <div>Porosity, % : 15.44</div> <div>k_{air}, md : 5.96</div>		<div>Prod. Water (cc) : 5.45</div> <div>Swi (%) : 27.8</div> <div>$k = \frac{14.7 \times 10^3 \times L \times \mu \times \Delta V}{\Delta P \times \Delta T \times A}$</div>		Fluid Properties					
						Oil	Brine		
				Density, g/cc		-	-		
				Viscosity, cp		9.6	0.9		
				Test Temperature, °F		75.0			
		k _w @ Sw = 1.0		k _w @ Swi					
		ΔP (psi)	13.0	-	-	ΔP (psi)	265.0	-	-
		ΔV (cc)	1.95	-	-	ΔV (cc)	2.15	-	-
		ΔT (sec)	331	-	-	ΔT (sec)	195	-	-
		k _w (md)				k _w (md)			
		k _{wavg}				k _{oavg}			

	ΔP (psi)	T (sec)	ΔT (sec)	ΔV _{oil} (cc)	ΣV _{oil} (cc)	ΣV _{oil} (pv)	ΔV _{brine} (cc)	ΣV _{brine} (cc)	ΔV _{brine} (cc)	ΣV _{brine} (pv)	Water Cut (%)
1	259.0	190	190	2.12	2.12	0.28	0.08	0.08	2.20	2.20	3.64
2	257.0	255	65	0.17	2.29	0.30	0.53	0.61	0.70	2.90	75.71
3	251.0	320	65	0.13	2.42	0.32	0.62	1.23	0.75	3.65	82.67
4	235.0	623	303	0.23	2.65	0.35	3.37	4.60	3.60	7.25	93.61
5	230.0	961	338	0.05	2.70	0.36	3.85	8.45	3.90	11.15	98.72
6	231.0	3284	2323	0.25	2.95	0.39	25.93	34.38	26.18	37.33	99.05
7	233.0	7762	4478	0.05	3.00	0.40	50.45	84.83	50.50	87.83	99.90
8	235.0	16710	8948	0.08	3.08	0.41	100.70	185.53	100.78	188.61	99.92
9	234.0	27468	10758	0.05	3.13	0.41	119.95	305.48	120.00	308.61	99.96
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											
26									ΔP (psi)	234.0	-
27									ΔV (cc)	2.95	-
28									ΔT (sec)	262	-
29									k _w (md)		
30									k _{wavg}		

Table C.1.8. Row Data of Relative Permeability Test for Plug " 75 "

Salinity (ppm): 10,000											
WATER-OIL RELATIVE PERMEABILITY TEST DATA SHEET											
Plug Id. : 75			<div>Prod. Water (cc) : 6.20</div> <div>Swi (%) :..... 24.9</div> <div>$k = \frac{14.7 \times 10^3 \times L \times \mu \times \Delta V}{\Delta P \times \Delta T \times A}$</div>				Fluid Properties				
Length, cm : 4.43							Density, g/cc		Oil	Brine	
Diameter, cm : 3.71							Viskoslty, cp		10.4	1.0	
Bulk Volume, cc : 48							Test Temperature, °F		71.5		
Saturated Weight, g : -											
Dry Weight, g : -											
Fluid Weight, g : -			k _w @ Sw = 1.0				k _w @ Swi				
Fluid Volume, cc : 8.26			ΔP (psi)	2.4	-	-	ΔP (psi)	40.0	-	-	-
Pore Volume, cc : 8.26			ΔV (cc)	2.45	-	-	ΔV (cc)	2.05	-	-	-
Porosity, % : 17.26			ΔT (sec)	410	-	-	ΔT (sec)	185	-	-	-
k _{air} , md : 28.58			k _w (md)				k _w (md)				
			k _{wavg}				k _{oavg}				
	ΔP (psi)	T (sec)	ΔT (sec)	ΔV _{oil} (cc)	ΣV _{oil} (cc)	ΣV _{oil} (pv)	ΔV _{brine} (cc)	ΣV _{brine} (cc)	ΔV _{brine} (cc)	ΣV _{brine} (pv)	Water Cut (%)
1	39.8	300	300	1.60	1.60	0.19	0.05	0.05	1.65	1.65	3.03
2	41.0	368	68	0.15	1.75	0.21	0.30	0.35	0.45	2.10	66.67
3	43.0	487	119	0.20	1.95	0.24	0.65	1.00	0.85	2.95	76.47
4	44.2	596	109	0.13	2.08	0.25	0.82	1.82	0.95	3.90	86.32
5	45.4	739	143	0.08	2.16	0.26	1.27	3.09	1.35	5.25	94.07
6	46.6	968	229	0.13	2.29	0.28	2.22	5.31	2.35	7.60	94.47
7	46.6	1234	266	0.08	2.37	0.29	2.87	8.18	2.95	10.55	97.29
8	46.2	1516	282	0.05	2.42	0.29	3.10	11.28	3.15	13.70	98.41
9	45.6	1837	321	0.05	2.47	0.30	3.65	14.93	3.70	17.40	98.65
10	44.5	2308	471	0.05	2.52	0.31	5.45	20.38	5.50	22.90	99.09
11	43.4	3064	756	0.10	2.62	0.32	8.70	29.08	8.80	31.70	98.86
12	42.7	4121	1057	0.10	2.72	0.33	11.95	41.03	12.05	43.75	99.17
13	42.4	6480	2359	0.05	2.77	0.34	26.65	67.68	26.70	70.45	99.81
14	42.0	11026	4546	0.08	2.85	0.35	51.42	119.10	51.50	121.95	99.84
15	42.0	20362	9336	0.08	2.93	0.35	105.32	224.42	105.40	227.35	99.92
16	42.0	37980	17618	0.05	2.98	0.36	196.55	420.97	196.60	423.95	99.97
17											
18											
19											
20											
21											
22											
23											
24											
25											
26								ΔP (psi)	42.0	-	-
27								ΔV (cc)	2.80	-	-
28								ΔT (sec)	251	-	-
29								k _w (md)			
30								k _{wavg}			

Table C.2.1. Calculated Relative Permeability Data for Plug "
52 "

$k_b \text{ (md)} = 14.25$			
$k_o \text{ at } S_{wi} \text{ (md)} = 13.51$		$S_{wi} \text{ (\%)} = 28.11$	
$k_w \text{ at } S_{or} \text{ (md)} = 5.13$		$S_{or} \text{ (\%)} = 22.82$	

Water Saturation (%)	Relative Water Permeability (fraction)	Relative Oil Permeability (fraction)	Relative Permeability Ratio (k_{rw}/k_{ro}) (ratio)
28.11	0.000	0.948	0.000
33.21	0.083	0.365	0.227
36.41	0.097	0.218	0.445
38.91	0.126	0.201	0.625
40.77	0.144	0.193	0.746
42.16	0.148	0.164	0.902
43.69	0.159	0.146	1.089
45.22	0.172	0.139	1.239
46.52	0.176	0.119	1.479
47.91	0.172	0.100	1.722
49.30	0.207	0.100	2.080
50.97	0.196	0.081	2.427
52.74	0.224	0.075	2.999
54.36	0.153	0.042	3.664
56.22	0.262	0.058	4.529
58.30	0.281	0.045	6.223
60.85	0.292	0.034	8.551
63.40	0.304	0.024	12.764
66.19	0.319	0.017	19.055
68.97	0.331	0.011	30.200
72.36	0.332	0.005	67.298
75.65	0.331	0.002	203.704
77.18	0.360	0.000	-

**Table C.2.2. Calculated Relative Permeability Data for Plug
" 54 "**

$k_b \text{ (md)} = 1.35$	
$k_o \text{ at } S_{wi} \text{ (md)} = 1.12$	$S_{wi} \text{ (\%)} = 31.97$
$k_w \text{ at } S_{or} \text{ (md)} = 0.60$	$S_{or} \text{ (\%)} = 24.19$

Water Saturation (%)	Relative Water Permeability (fraction)	Relative Oil Permeability (fraction)	Relative Permeability Ratio (k_{rw}/k_{ro}) (ratio)
31.97	0.000	0.831	0.000
40.17	0.116	0.268	0.434
42.93	0.195	0.283	0.689
45.41	0.204	0.195	1.050
47.35	0.218	0.148	1.469
49.14	0.235	0.125	1.879
51.19	0.268	0.111	2.427
52.81	0.295	0.101	2.924
54.54	0.276	0.080	3.446
56.16	0.321	0.076	4.246
57.78	0.313	0.060	5.224
60.21	0.329	0.041	8.054
62.26	0.348	0.031	11.246
64.04	0.362	0.024	14.825
66.09	0.369	0.017	21.330
67.49	0.382	0.014	26.485
69.11	0.404	0.011	37.757
71.54	0.428	0.005	84.528
73.49	0.443	0.003	157.398
75.81	0.445	0.000	-

**Table C.2.3. Calculated Relative Permeability Data for Plug
" 68 "**

k_o (md) = 50.06			
k_o at S_{wi} (md) = 40.44	S_{wi} (%) = 36.16		
k_w at S_{or} (md) = 15.18	S_{or} (%) = 32.69		

Water Saturation (%)	Relative Water Permeability (fraction)	Relative Oil Permeability (fraction)	Relative Permeability Ratio (k_{rw}/k_{ro}) (ratio)
36.16	0.000	0.808	0.000
40.77	0.056	0.175	0.319
42.71	0.099	0.146	0.681
44.03	0.112	0.113	0.991
45.07	0.135	0.113	1.194
46.18	0.127	0.083	1.538
47.12	0.154	0.076	2.028
47.81	0.156	0.065	2.388
48.85	0.165	0.057	2.904
50.14	0.183	0.052	3.556
51.21	0.185	0.039	4.699
52.22	0.189	0.032	5.902
53.61	0.192	0.025	7.709
55.17	0.220	0.022	10.186
56.45	0.220	0.017	13.002
58.36	0.239	0.013	18.750
61.07	0.240	0.007	32.137
64.02	0.276	0.004	74.989
66.10	0.298	0.002	155.955
67.31	0.299	0.001	294.442
68.36	0.303	0.000	-

**Table C.2.4. Calculated Relative Permeability Data for Plug
" 71 "**

k_b (md) = 8.04			
k_o at S_{wi} (md) = 7.03		S_{wi} (%) = 26.23	
k_w at S_{or} (md) = 1.01		S_{or} (%) = 44.43	

Water Saturation (%)	Relative Water Permeability (fraction)	Relative Oil Permeability (fraction)	Relative Permeability Ratio (k_{rw}/k_{ro}) (ratio)
26.23	0.000	0.875	0.000
44.53	0.043	0.042	1.021
46.18	0.060	0.032	1.897
47.34	0.073	0.025	2.924
48.11	0.075	0.020	3.846
48.74	0.079	0.015	5.176
49.37	0.089	0.013	6.808
50.24	0.086	0.008	10.209
51.11	0.088	0.005	18.239
51.74	0.091	0.004	25.235
52.32	0.092	0.003	34.514
53.39	0.096	0.001	69.502
54.45	0.086	0.000	322.849
54.94	0.102	0.000	623.735
55.57	0.126	0.000	-

**Table C.2.5. Calculated Relative Permeability Data for Plug
" 73 "**

$k_b \text{ (md)} = 14.20$			
$k_o \text{ at } S_{wi} \text{ (md)} = 16.71$	$S_{wi} \text{ (\%)} = 31.07$		
$k_w \text{ at } S_{or} \text{ (md)} = 2.18$	$S_{or} \text{ (\%)} = 24.88$		

Water Saturation (%)	Relative Water Permeability (fraction)	Relative Oil Permeability (fraction)	Relative Permeability Ratio (k_{rw}/k_{ro}) (ratio)
31.07	0.000	1.176	0.000
60.86	0.066	0.060	1.104
63.49	0.085	0.043	1.972
64.95	0.106	0.036	2.979
66.30	0.114	0.027	4.169
67.64	0.118	0.017	6.887
68.81	0.128	0.011	11.940
69.98	0.135	0.007	19.143
71.14	0.139	0.004	36.308
72.02	0.143	0.002	64.269
72.78	0.140	0.001	108.143
73.71	0.156	0.001	257.040
74.47	0.152	0.000	623.735
75.12	0.153	0.000	-

**Table C.2.6. Calculated Relative Permeability Data for Plug
" 74 " (First Run)**

k_b (md) = 3.55	
k_o at S_{wi} (md) = 1.85	S_{wi} (%) = 17.88
k_w at S_{or} (md) = 0.36	S_{or} (%) = 41.99

Water Saturation (%)	Relative Water Permeability (fraction)	Relative Oil Permeability (fraction)	Relative Permeability Ratio (k_{rw}/k_{ro}) (ratio)
17.88	0.000	0.520	0.000
37.02	0.040	0.078	0.519
40.66	0.053	0.048	1.099
42.98	0.069	0.031	2.213
44.97	0.073	0.018	4.046
46.75	0.075	0.011	6.622
48.08	0.078	0.008	10.304
49.14	0.078	0.006	13.836
50.20	0.081	0.004	18.578
51.39	0.083	0.003	28.576
53.05	0.087	0.002	54.828
54.83	0.090	0.001	129.718
56.29	0.093	0.000	322.849
57.15	0.095	0.000	588.844
58.01	0.102	0.000	-

**Table C.2.7. Calculated Relative Permeability Data for Plug
" 74 " (Second Run)**

k_b (md) = 2.61	
k_o at S_{wl} (md) = 2.45	S_{wl} (%) = 27.81
k_w at S_{or} (md) = 0.28	S_{or} (%) = 30.73

Water Saturation (%)	Relative Water Permeability (fraction)	Relative Oil Permeability (fraction)	Relative Permeability Ratio (k_{rw}/k_{ro}) (ratio)
27.81	0.000	0.942	0.000
57.02	0.070	0.053	1.330
59.01	0.084	0.032	2.649
61.39	0.104	0.017	6.295
63.25	0.109	0.007	16.520
65.23	0.107	0.002	47.315
67.22	0.107	0.001	161.808
68.08	0.106	0.000	349.140
68.94	0.105	0.000	691.831
69.27	0.106	0.000	-

Table C.2.8. Calculated Relative Permeability Data for Plug "
75 "

k_b (md) = 14.39			
k_o at S_{wi} (md) =	17.27	S_{wi} (%) =	24.94
k_w at S_{or} (md) =	1.55	S_{or} (%) =	38.98

Water Saturation (%)	Relative Water Permeability (fraction)	Relative Oil Permeability (fraction)	Relative Permeability Ratio (k_{rw}/k_{ro}) (ratio)
24.94	0.000	1.200	0.000
45.22	0.044	0.051	0.871
47.34	0.052	0.034	1.528
49.33	0.070	0.027	2.624
50.61	0.080	0.020	4.046
51.88	0.085	0.013	6.486
53.15	0.095	0.009	10.304
53.93	0.097	0.007	13.836
54.54	0.102	0.006	18.239
55.15	0.106	0.005	23.335
56.05	0.108	0.003	34.514
57.26	0.108	0.002	65.464
58.17	0.109	0.001	109.144
58.96	0.110	0.001	185.780
59.93	0.110	0.000	416.869
61.02	0.108	0.000	-

Table C.3.1. Calculated Waterflood Data for Plug "52"

Flow Rate (cc/hr)..... 25
 Viscosity Ratio (μ_o/μ_w)..... 10
 Test Temperature ($^{\circ}$ F)..... 74

PRESSURE (psi)	TIME (sec)	OIL PRODUCED (cc)	CUM. OIL PRODUCED (cc)	CUM. OIL PRODUCED (%OOIP)	WATER PRODUCED (cc)	CUM. WATER PRODUCED (cc)	WATER INJECTED (cc)	WATER INJECTED (PV)	WATER CUT (%)
42.0	59	0.35	0.35	4.52	0.05	0.05	0.40	0.04	12.50
33.0	118	0.40	0.75	9.68	0.35	0.40	1.15	0.11	46.67
30.0	166	0.29	1.04	13.42	0.31	0.71	1.75	0.16	51.67
27.0	240	0.25	1.29	16.65	0.55	1.26	2.55	0.24	68.75
26.0	295	0.15	1.44	18.58	0.45	1.71	3.15	0.29	75.00
24.0	371	0.15	1.59	20.52	0.60	2.31	3.90	0.36	80.00
23.0	455	0.18	1.77	22.84	0.67	2.98	4.75	0.44	78.82
22.0	545	0.15	1.92	24.77	0.75	3.73	5.65	0.52	83.33
21.5	631	0.13	2.05	26.45	0.72	4.45	6.50	0.60	84.71
21.0	723	0.17	2.22	28.65	0.73	5.18	7.40	0.69	81.11
20.5	848	0.13	2.35	30.32	1.17	6.35	8.70	0.81	90.00
20.0	1013	0.23	2.58	33.29	1.42	7.77	10.35	0.96	86.06
19.0	1187	0.15	2.73	35.23	1.63	9.40	12.13	1.13	91.57
18.0	1477	0.20	2.93	37.81	1.75	11.15	14.08	1.31	89.74
17.0	1947	0.20	3.13	40.39	4.60	15.75	18.88	1.75	95.83
16.0	2493	0.25	3.38	43.61	5.40	21.15	24.53	2.28	95.58
15.5	3338	0.30	3.68	47.48	8.40	29.55	33.23	3.08	96.55
15.0	4471	0.25	3.93	50.71	11.35	40.90	44.83	4.16	97.84
14.5	7027	0.35	4.28	55.23	25.95	66.85	71.13	6.60	98.67
14.0	9738	0.25	4.53	58.45	27.60	94.45	98.98	9.18	99.10
14.0	19602	0.48	5.01	64.65	100.62	195.07	200.08	18.56	99.53
14.0	28668	0.23	5.24	67.61	92.27	287.34	292.58	27.14	99.75
14.0	86268	0.05	5.29	68.26	96.25	383.59	388.88	36.07	99.95

Table C.3.2. Calculated Waterflood Data for Plug "54"

Flow Rate (cc/hr) 20
 Viscosity Ratio (μ_o/μ_w) 10
 Test Temperature ($^{\circ}F$) 73

Pressure (psi)	Time (sec)	Oil Produced (cc)	Cum Oil Produced (cc)	Cum Oil Produced (%OOIP)	Cum Oil Produced (%Cum. Prod.)	Water Produced (cc)	Cum Water Produced (cc)	Water Injected (cc)	Water Injected (PV)	Water Cut (%)
403.0	129	0.62	0.62	9.84	15.27	0.03	0.03	0.65	0.07	4.62
388.0	190	0.28	0.90	14.29	22.17	0.42	0.45	1.35	0.15	60.00
365.0	261	0.23	1.13	17.94	27.83	0.77	1.22	2.35	0.25	77.00
340.0	343	0.23	1.36	21.59	33.50	0.87	2.09	3.45	0.37	79.09
319.0	425	0.13	1.49	23.65	36.70	0.87	2.96	4.45	0.48	87.00
300.0	527	0.20	1.69	26.83	41.63	1.10	4.06	5.75	0.62	84.62
273.0	663	0.18	1.87	29.68	46.06	1.52	5.58	7.45	0.80	89.41
254.0	845	0.12	1.99	31.59	49.01	2.08	7.66	9.65	1.04	94.55
243.0	1021	0.20	2.19	34.76	53.94	1.80	9.46	11.65	1.26	90.00
231.0	1339	0.10	2.29	36.35	56.40	3.60	13.06	15.35	1.66	97.30
224.0	1699	0.20	2.49	39.52	61.33	3.85	16.91	19.40	2.10	95.06
216.0	2173	0.25	2.74	43.49	67.49	5.15	22.06	24.80	2.68	95.37
211.0	2652	0.13	2.87	45.56	70.69	5.37	27.43	30.30	3.27	97.64
201.0	3526	0.20	3.07	48.73	75.62	9.70	37.13	40.20	4.34	97.98
195.0	4644	0.18	3.25	51.59	80.05	12.27	49.40	52.65	5.69	98.55
189.0	5898	0.08	3.33	52.86	82.02	13.84	63.24	66.57	7.19	99.43
181.0	8217	0.22	3.55	56.35	87.44	25.88	89.12	92.67	10.01	99.16
171.0	12803	0.23	3.78	60.00	93.10	51.25	140.37	144.15	15.57	99.55
165.0	17421	0.13	3.91	62.06	96.31	51.57	191.94	195.85	21.15	99.75
165.0	34950	0.15	4.06	64.44	100.00	196.35	388.29	392.35	42.37	99.92

Table C.3.3. Calculated Waterflood Data for Plug "68"

Flow Rate (cc/hr)..... 25
 Viscosity Ratio (μ_o/μ_w)..... 10
 Test Temperature ($^{\circ}$ F)..... 74

Pressure (psi)	Time (sec)	Oil Produced (cc)	Cum. Oil Produced (cc)	Cum. Oil Produced (%OOIP)	Water Produced (cc)	Cum. Water Produced (cc)	Cum. Water Produced (%PV)	Water Injected (cc)	Water Injected (PV)	Water Cut (%)
22.0	78	0.50	0.50	5.43	0.05	10.78	0.05	0.55	0.04	9.09
19.0	121	0.33	0.83	9.02	0.27	17.89	0.32	1.15	0.08	45.00
16.0	171	0.23	1.06	11.52	0.47	22.84	0.79	1.85	0.13	67.14
14.5	223	0.15	1.21	13.15	0.50	26.08	1.29	2.50	0.17	76.92
13.0	295	0.15	1.36	14.78	0.75	29.31	2.04	3.40	0.24	83.33
12.0	376	0.17	1.53	16.63	0.73	32.97	2.77	4.30	0.30	81.11
11.0	501	0.10	1.63	17.72	1.25	35.13	4.02	5.65	0.39	92.59
10.5	635	0.10	1.73	18.80	1.30	37.28	5.32	7.05	0.49	92.86
10.0	778	0.20	1.93	20.98	1.40	41.59	6.72	8.65	0.60	87.50
9.5	1038	0.17	2.10	22.83	2.68	45.26	9.40	11.50	0.80	94.04
9.5	1303	0.14	2.24	24.35	2.76	48.28	12.16	14.40	1.00	95.17
9.2	1767	0.15	2.39	25.98	4.78	51.51	16.94	19.33	1.34	96.96
9.0	2256	0.25	2.64	28.70	5.00	56.90	21.94	24.58	1.71	95.24
8.0	3037	0.20	2.84	30.87	8.15	61.21	30.09	32.93	2.29	97.60
8.0	4177	0.17	3.01	32.72	11.88	64.87	41.97	44.98	3.12	98.59
7.5	6636	0.38	3.39	36.85	26.10	73.06	68.07	71.46	4.96	98.56
7.5	11370	0.40	3.79	41.20	50.50	81.68	118.57	122.36	8.49	99.21
6.5	20844	0.45	4.24	46.09	100.70	91.38	219.27	223.51	15.51	99.56
6.0	25630	0.15	4.39	47.72	50.70	94.61	269.97	274.36	19.04	99.71
6.0	43918	0.20	4.59	49.89	193.95	98.92	463.92	468.51	32.51	99.90
6.0	93010	0.05	4.64	50.43	104.00	100.00	567.92	572.56	39.73	99.95

Table C.3.4. Calculated Waterflood Data for Plug "71"

Flow Rate (cc/hr)..... 25
 Viscosity Ratio (μ_o/μ_w)..... 10
 Test Temperature ($^{\circ}$ F)..... 78

PRESSURE (psi)	TIME (sec)	OIL PRODUCED (cc)	CUM. OIL PRODUCED (cc)	CUM. OIL PRODUCED (%OOIP)	CUM. OIL PRODUCED (%Cum. Prod.)	WATER PRODUCED (cc)	CUM. WATER PRODUCED (cc)	WATER INJECTED (cc)	WATER INJECTED (PV)	WATER CUT (%)
114.0	245	1.80	1.80	23.62	59.41	0.05	0.05	1.85	0.18	2.70
113.0	294	0.18	1.98	25.98	65.35	0.32	0.37	2.35	0.23	64.00
111.0	352	0.16	2.14	28.08	70.63	0.52	0.89	3.03	0.29	76.47
107.0	440	0.08	2.22	29.13	73.27	0.92	1.81	4.03	0.39	92.00
103.0	536	0.08	2.30	30.18	75.91	1.00	2.81	5.11	0.49	92.59
100.0	649	0.05	2.35	30.84	77.56	1.20	4.01	6.36	0.62	96.00
96.0	831	0.08	2.43	31.89	80.20	2.08	6.09	8.52	0.82	96.30
94.0	1079	0.10	2.53	33.20	83.50	2.70	8.79	11.32	1.10	96.43
93.0	1391	0.08	2.61	34.25	86.14	3.42	12.21	14.82	1.43	97.71
91.0	1909	0.05	2.66	34.91	87.79	5.75	17.96	20.62	2.00	99.14
90.0	3017	0.07	2.73	35.83	90.10	12.33	30.29	33.02	3.20	99.44
88.0	5492	0.15	2.88	37.80	95.05	28.05	58.34	61.22	5.93	99.47
101.0	9842	0.07	2.95	38.71	97.36	50.98	109.32	112.27	10.87	99.86
96.0	17620	0.03	2.98	39.11	98.35	101.67	210.99	213.97	20.71	99.97
28.0	36873	0.05	3.03	39.76	100.00	195.15	406.14	409.17	39.61	99.97

Table C.3.5. Calculated Waterflood Data for Plug "73"

Flow Rate (cc/hr)..... 35
 Viscosity Ratio (μ_o/μ_w)..... 10
 Test Temperature ($^{\circ}$ F)..... 78

PRESSURE (psi)	TIME (sec)	OIL PRODUCED (cc)	CUM. OIL PRODUCED (cc)	CUM. OIL PRODUCED (%OOIP)	CUM. OIL PRODUCED (%Cum. Prod.)	WATER PRODUCED (cc)	CUM. WATER PRODUCED (cc)	WATER INJECTED (cc)	WATER INJECTED (PV)	WATER CUT (%)
42.0	255	2.40	2.40	40.68	63.66	0.05	0.05	2.45	0.29	2.04
41.0	317	0.30	2.70	45.76	71.62	0.43	0.48	3.18	0.37	58.90
40.0	391	0.15	2.85	48.31	75.60	0.65	1.13	3.98	0.46	81.25
38.0	481	0.10	2.95	50.00	78.25	0.93	2.06	5.01	0.59	90.29
36.0	611	0.13	3.08	52.20	81.70	1.37	3.43	6.51	0.76	91.33
35.0	800	0.10	3.18	53.90	84.35	2.00	5.43	8.61	1.01	95.24
33.0	1142	0.10	3.28	55.59	87.00	3.70	9.13	12.41	1.45	97.37
32.0	1623	0.10	3.38	57.29	89.66	5.35	14.48	17.86	2.09	98.17
31.0	2478	0.10	3.48	58.98	92.31	9.50	23.98	27.46	3.21	98.96
30.0	3731	0.05	3.53	59.83	93.63	13.85	37.83	41.36	4.83	99.64
29.0	6179	0.08	3.61	61.19	95.76	25.50	63.33	66.94	7.82	99.69
28.0	10722	0.08	3.69	62.54	97.88	51.02	114.35	118.04	13.79	99.84
28.0	20030	0.05	3.74	63.39	99.20	101.75	216.10	219.84	25.68	99.95
28.0	37856	0.03	3.77	63.90	100.00	192.10	408.20	411.97	48.13	99.98

Table C.3.6. Calculated Waterflood Data for Plug "74" (First Run)

Flow Rate (cc/hr)..... 45
 Viscosity Ratio (μ_o/μ_w)..... 10
 Test Temperature ($^{\circ}\text{F}$)..... 73

PRESSURE (psi)	TIME (sec)	OIL PRODUCED (cc)	CUM OIL PRODUCED (cc)	CUM OIL PRODUCED (%OOIP)	CUM OIL PRODUCED (%Cum. Prod.)	WATER PRODUCED (cc)	CUM WATER PRODUCED (cc)	WATER INJECTED (cc)	WATER INJECTED (PV)	WATER CUT (%)
308.0	106	1.27	1.27	20.48	41.91	0.03	0.03	1.30	0.17	2.31
281.0	135	0.35	1.62	26.13	53.47	0.20	0.23	1.85	0.25	36.36
260.0	177	0.20	1.82	29.35	60.07	0.35	0.58	2.40	0.32	63.64
244.0	256	0.15	1.97	31.77	65.02	0.80	1.38	3.35	0.44	84.21
226.0	428	0.15	2.12	34.19	69.97	1.70	3.08	5.20	0.69	91.89
218.0	768	0.12	2.24	36.13	73.93	3.33	6.41	8.65	1.15	96.52
214.0	1147	0.08	2.32	37.42	76.57	3.82	10.23	12.55	1.66	97.95
211.0	1568	0.08	2.40	38.71	79.21	4.17	14.40	16.80	2.23	98.12
207.0	2137	0.08	2.48	40.00	81.85	5.77	20.17	22.65	3.00	98.63
203.0	3040	0.10	2.58	41.61	85.15	9.20	29.37	31.95	4.23	98.92
197.0	5612	0.15	2.73	44.03	90.10	26.45	55.82	58.55	7.75	99.44
189.0	10505	0.12	2.85	45.97	94.06	50.38	106.20	109.05	14.44	99.76
184.0	20480	0.10	2.95	47.58	97.36	102.30	208.50	211.45	28.01	99.90
180.0	28154	0.03	2.98	48.06	98.35	79.02	287.52	290.50	38.48	99.96
172.0	89054	0.05	3.03	48.87	100.00	194.10	481.62	484.65	64.19	99.97

Table C.3.7. Calculated Waterflood Data for Plug "74" (Second Run)

Flow Rate (cc/hr)..... 45
 Viscosity Ratio (μ_o/μ_w)..... 10
 Test Temperature ($^{\circ}F$)..... 75

PRESSURE (psi)	TIME (sec)	OIL PRODUCED (cc)	CUM OIL PRODUCED (cc)	CUM OIL PRODUCED (%OOIP)	OIL PRODUCED (cc)	CUM OIL PRODUCED (cc)	CUM OIL PRODUCED (%Cum.Prod.)	WATER PRODUCED (cc)	CUM WATER PRODUCED (cc)	WATER INJECTED (cc)	WATER INJECTED (PV)	WATER CUT (%)
259.0	190	2.12	2.12	38.90	0.08	67.73	0.08	0.08	0.08	2.20	0.29	3.64
257.0	255	0.17	2.29	42.02	0.53	73.16	0.53	0.61	0.61	2.90	0.38	75.71
251.0	320	0.13	2.42	44.40	0.62	77.32	0.62	1.23	1.23	3.65	0.48	82.67
235.0	623	0.23	2.65	48.62	3.37	84.66	3.37	4.60	4.60	7.25	0.96	93.61
230.0	961	0.05	2.70	49.54	3.85	86.26	3.85	8.45	8.45	11.15	1.48	98.72
231.0	3284	0.25	2.95	54.13	25.93	94.25	25.93	34.38	34.38	37.33	4.94	99.05
233.0	7762	0.05	3.00	55.05	50.45	95.85	50.45	84.83	84.83	87.83	11.63	99.90
235.0	16710	0.08	3.08	56.51	100.70	98.40	100.70	185.53	185.53	188.61	24.98	99.92
234.0	27468	0.05	3.13	57.43	119.95	100.00	119.95	305.48	305.48	308.61	40.88	99.96

Table C.3.8. Calculated Waterflood Data for Plug "75"

Flow Rate (cc/hr)..... 20
 Viscosity Ratio (μ_o/μ_w)..... 10
 Test Temperature ($^{\circ}$ F)..... 72

Pressure (psi)	Time (sec)	Oil Produced (cc)	Cum. Oil Produced (cc)	Cum. Oil Produced (%OIP)	Cum. Oil Produced (%Cum. Prod.)	Water Produced (cc)	Cum. Water Produced (cc)	Water Injected (cc)	Water Injected (PV)	Water Cut (%)
39.8	300	1.60	1.60	25.81	53.69	0.05	0.05	1.65	0.20	3.03
41.0	368	0.15	1.75	28.23	58.72	0.30	0.35	2.10	0.25	66.67
43.0	487	0.20	1.95	31.45	65.44	0.65	1.00	2.95	0.36	76.47
44.2	596	0.13	2.08	33.55	69.80	0.82	1.82	3.90	0.47	86.32
45.4	739	0.08	2.16	34.84	72.48	1.27	3.09	5.25	0.64	94.07
46.6	968	0.13	2.29	36.94	76.85	2.22	5.31	7.60	0.92	94.47
46.6	1234	0.08	2.37	38.23	79.53	2.87	8.18	10.55	1.28	97.29
46.2	1516	0.05	2.42	39.03	81.21	3.10	11.28	13.70	1.66	98.41
45.6	1837	0.05	2.47	39.84	82.89	3.65	14.93	17.40	2.11	98.65
44.5	2308	0.05	2.52	40.65	84.56	5.45	20.38	22.90	2.77	99.09
43.4	3064	0.10	2.62	42.26	87.92	8.70	29.08	31.70	3.84	98.86
42.7	4121	0.10	2.72	43.87	91.28	11.95	41.03	43.75	5.30	99.17
42.4	6480	0.05	2.77	44.68	92.95	26.65	67.68	70.45	8.53	99.81
42.0	11026	0.08	2.85	45.97	95.64	51.42	119.10	121.95	14.76	99.84
42.0	20362	0.08	2.93	47.26	98.32	105.32	224.42	227.35	27.52	99.92
42.0	37980	0.05	2.98	48.06	100.00	196.55	420.97	423.95	51.33	99.97

APPENDIX D

RELATIVE PERMEABILITY CURVES

Figure D.1. Calculated " Relative Permeability " & " Relative Permeability Ratio " Data for Plug Sample "52"

Figure D.2. Calculated " Relative Permeability " & " Relative Permeability Ratio " Data for Plug Sample "54"

Figure D.3. Calculated " Relative Permeability " & " Relative Permeability Ratio " Data for Plug Sample "68"

Figure D.4. Calculated " Relative Permeability " & " Relative Permeability Ratio " Data for Plug Sample "71"

Figure D.5. Calculated " Relative Permeability " & " Relative Permeability Ratio " Data for Plug Sample "73"

Figure D.6. Calculated " Relative Permeability " & " Relative Permeability Ratio " Data for Plug Sample "74" (*First Run*)

Figure D.7. Calculated " Relative Permeability " & " Relative Permeability Ratio " Data for Plug Sample "74" (*Second Run*)

Figure D.8. Calculated " Relative Permeability " & " Relative Permeability Ratio " Data for Plug Sample "75"