AN EXPERIMENTAL STUDY OF ENHANCED OIL RECOVERY APPLICATION IN LIMESTONE MEDIUM USING NaOH SOLUTIONS

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ABSTRACT

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An interest in enhanced oil recovery is increasing due to rising oil prices, rising energy consumption and insufficient oil production from conventional techniques. As an EOR technique, alkaline injection is widely used to recover the trapped oil in pore spaces.

In this study,the use of sodium hydroxide (NaOH) solutions as an enhanced oil recovery technique for limestone formations in South East Turkey was investigated. Routine core analyses (porosity, permeability and grain density) and spontaneous imbibition for oil recovery observation were performed on 9 plug samples from ‘C’ field and 7 plug samples from ‘G’ field. Since the reservoir temperature of ‘C’field (105 °C) is greater than the limitations of spontaneous imbibition test (~100 °C), the tests were performed at three different temperatures of 50 °C, 70 °C and 90 °C in order to observe the effect of temperature on the experiments. As the test fluids, crude oil samples and formation water samples taken from the fields,as well as fresh water and NaOH solutions at different concentrations were used. High pressure mercury injection capillary pressure and pore throat size distribution analyses were conducted on 9 of the plug samples used in the imbibition tests for core characterization. Core flooding tests and interfacial tension measurements were performed following the completion of imbibition tests.

Both imbibition and core flood test results showed that, the existence of NaOH in the water phase and caused additional oil recovery from the samples and reduced interfacial tension between oil and alkaline solution. 1.0wt% NaOH had the highest total oil recovery 69.8%OOIP in field ‘C’ but if the experiments had equal time intervals for each sample, the highest oil recovery might be given by a higher NaOH concentration. The highest oil recovery was given by 0.2wt% NaOH solution 23%OOIP in field ‘G’. But except 0.2wt%, there was a proportional relationship between NaOH concentration and oil recovery. The results show also that, increase in temperature helps to decrease remaining oil saturation.

Key words: *EOR, NaOH, limestone, imbibition, interfacial tension.*

ÖZ

KİREÇTAŞI FORMASYONLARDA NaOH ÇÖZELTİ KULLANILARAK GELİŞTİRİLMİŞ PETROL KURTARIMININ DENEYSEL OLARAK ÇALIŞILMASI

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Geliştirilmiş petrol kurtarımı tekniklerine yönelik ilgi, artan petrol fiyatları, dünyanın enerji ihtiyacı ve konvensiyonel yöntemlerin petrol kurtarımında yetersiz kalması, sebebiyle giderek artıyor. Bir gelişmiş petrol kurtarımı olan alkaline enjeksiyonu ise gözeneklerde hapsedilmiş petrolü kurtarmak amacıyla yaygın olarak kullanılmaktadır.

Bu çalışmada; Güney Doğu Anadolu Bölgesi kireçtaşı formasyonlarında sodyum hidroksit (NaOH) çözeltilerinin gelişmiş petrol kurtarımı tekniği olarak kullanımı araştırılmıştır.

Temel karot analizleri (gözeneklilik, geçirgenlik ve tane yoğunluğu) ve petrol kurtarımını gözlemlemek için kendiliğinden imbibisyon testleri ‘C’ sahasına ait 9 ve ‘G’ sahasına ait 7 adet tapa örneği üzerinde gerçekleştirilmiştir. ‘C’ sahasının rezervuar sıcaklığı (105 °C) kendiliğinden imbibisyon test sınırlamalarının (~100 °C) üzerinde olduğu için, testler sıcaklığın etkisini gözlemlemek amacıyla 50 °C, 70 °C and 90 °C olmak üzere üç farklı sıcaklıkta gerçekleştirilmiştir. Test sıvısı olarak, kullanılan sahalara ait ham petrol ve formasyon suyu örnekleri, tatlı su ve NaOH çözeltileri kullanıldı. Yüksek basınçta cıva enjeksiyonu kapiler basınç ve gözenek boğazı boyutu dağılımı testleri karot karakterizasyonu amacıyla çalışmada kullanılan tapa örneklerinin 9 adedi üzerinde yapılmıştır. Imbibisyon testleri tamamlandıktan sonra, karot öteleme testleri ve ara yüzey gerilimi ölçümleri tamamlanmıştır.

Imbibisyon ve karot öteleme test sonuçlarına göre, su fazı içindeki NaOH varlığının numunelerde ilave petrol kurtarımı sağladığı ve ara yüzey gerilimini düşürdüğü görülmüştür.‘C’ sahasında %1.0’lik NaOH çözeltisi %69.8’lik kurtarımla en yüksek petrol kurtarımını vermiştir. Ancak, testler esnasındaki bekleme süreleri her örnek için eşit tutulsaydı, en yüksek petrol kurtarımı değeri daha yüksek NaOH konsantrasyonlarında elde edilebilirdi. ‘G’ sahasında ise en yüksek sonucu % 23’lük kurtarımla %0.2’lik NaOH çözeltisi vermiştir. Ancak %0.2’lik NaOH çözeltisi dışında, NaOH konsantrasyonu ve petrol kurtarımı arasında doğru orantısal bir ilişki gözlemlenmiştir. Ek olarak, sıcaklık artışının kalıcı petrol doymuşluğunu düşürmeye yardımcı olduğu gözlemlenmiştir.

Anahtar kelimeler: *EOR, NaOH, kireçtaşı, imbibisyon, ara yüzey gerilimi.*

To my beloved mother

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CHAPTER 1

INTRODUCTION

World oil demand continues to increase day by day while conventional reserves are depleting. On average, almost 50% of original oil in place can be recovered by primary and secondary production, rest is remained in the reservoir. This portion is much higher when heavy oil reservoirs are considered.

Tertiary oil recovery (enhanced oil recovery) methods are conducted usually after primary and secondary recovery methods become inefficient. Enhanced oil recovery (EOR) techniques have a vital role for oil industry due to their ability to increase oil recovery factor for almost all kinds of reservoirs. Any method with addition of fluids into the reservoir which are not present, in order to improve oil recovery is called EOR method. Baviere (1991) described EOR as: “EOR consists of methods aimed at increasing ultimate oil recovery by injecting appropriate agents not normally present in the reservoir, such as chemicals, solvents, oxidizers and heat carriers in order to induce new mechanisms for displacing oil”.

One of the major EOR techniques, chemical flooding is gaining interest for over 50 years to recover the trapped oil in the reservoir. According to Lake (1989) alkaline or caustic flooding, which is a type of chemical flooding, is one of the oil recovery techniques that use alkaline chemicals such as sodium hydroxide (NaOH) added water flooding aqueous phase to increase the pH.

In early times, Beckstorm and Van (1927) presented that alkaline compounds increases oil recovery. Numerous researches have been conducted to show the favorable effects of alkaline flooding on oil recovery globally. But there is lack of oil recovery data with chemical flooding for South East region of Turkey. The purpose of this study is to determine the oil recovery factors in limestone reservoirs in South East Turkey using NaOH flooding method. Alkaline flooding was chosen because itwould not be very costly compared to other techniques since this method needs cheaper surface facilities and chemicals used in alkaline flooding such as NaOH solutions are cheaper. (Jennings et al. 1974) A study by Dranchuk et al. (1974) showed that oil recovery is increased more if concentration of the NaOH solution is above 0.1weight% (wt%) when compared to lower concentrations.Therefore, in this study, as an alkaline chemical, NaOH is used due to its high pH value and mixed with aqueous phase at different concentrations from 0.2wt% to 5wt%. Above 5wt%, there may occur some precipitation problems, thus concentration was kept below 5wt%.

To obtain oil recovery data, spontaneous imbibition tests were conducted on 16 core plug samples belonging to 2 different fields. One of the fields has high reservoir temperature which the test system could not reach. Therefore, a part of the spontaneous imbibition tests were performed under 3 different temperature steps and effect of temperature was obtained. Routine core analysis and mercury injection injection capillary pressure analysis for core characterization, core flooding tests for oil recovery data and interfacial tension measurements with various NaOH concentration solutions were conducted on the selected plug samples.

CHAPTER 2

LITERATURE REVIEW

2.1 BasicRock Properties

2.1.1 Capillary Pressure

Capillary pressure, which is one of the fundamental properties of rocks, is caused by pressure difference between two immiscible phases due to interfacial tensions. These two phases become apart from each other since one of them is wetting phase while the other one is non-wetting phase. Capillary pressure can be calculated from; (Tiab and Donaldson 2004).

$$P_c = P_{nw} - P_w \qquad \text{(Eq. 2.1)}$$

where,

P_c = Capillary Pressure, psi

P_{nw} = Pressure of Non-Wetting Phase, psi

P_w = Pressure of Wetting Phase, psi

Also, capillary pressure can be computed in terms of contact angle and interfacial tension by using Young-Laplace Equation. (Helmig 1997)

$$P_c = \frac{2\sigma * \cos\theta}{r_c} \qquad \text{(Eq. 2.2)}$$

where;

P_c = Capillary Pressure, dynes/cm^2

σ = Interfacial Tension between Wetting and Non-Wetting Phase dynes/cm

θ = Contact Angle , degree

r_c = Capillary Tube Radius, cm

Capillary pressure properties can influence the flow and the behavior of fluids in porous media. Therefore, there is a connection between capillary pressure and water saturation which is related to interfacial tension and wettability of phases present in the system. Additionally, pore throat size distribution may affect this connection.Gorring(1966) determined that non-wetting phase saturation is influenced by pore throat size distribution.

Loucks et al. (2009) obtained pore throat size distribution in shale formations in Texas by using capillary pressure analysis. Lindquist et al. (2000) tried X-ray tomography, an alternative way to describe pore throat size distribution in sandstone formations.

2.1.2 Interfacial Tension

Interfacial tension (IFT) is a force per unit length parallel to the interface of two fluids, i.e., perpendicular to the local density or concentration gradient, according to Miller and Neogi (1985). If there are two immiscible fluids interacting with a solid surface, contact of two fluids to each other and contact of fluids to rock surface should be examined all together. Properties such as temperature, salinity, purity or chemicals can affect the interfacial tension. It is known that soap forming chemicals reduce interfacial tension importantly.

When the two immiscible fluids are in contact with a solid, the interactions between the two fluids and the solid must also be considered. Figure 2.1 presents a schematic of the various interfaces and interfacial tensions for a flat rock surface in contact with oil and water.

2.1.3 Wettability

Wettability is the tendency of a fluid to hold on to a rock surface in the existence of another bulk fluid according to Craig (1971).

Petrophysical properties such as waterflooding performance, capillary pressure curves and relative permeability are all influenced by the wettability preference of the reservoir rock since it affects flow of the reservoir fluids.

As Morrow (1990) stated, in terms of oil recovery, wettability is one of most important factors influencing residual oil volume in reservoir. There are several factors affecting wettability such as initial water saturation, mineral components of reservoir rock, temperature and properties of formation water and oil. Kovescek et al. (1993) obtained that in terms of managing multiphase flow and phase trapping, wettability is key element.

Craig (1993) indicated that there are fundamentally three types of rock wettability; oil wet, water wet and neutral or intermediate wet. Oil wet means rock surface has a tendency to be spread by oil instead of water, while water phase is in place. And water wet is the opposite situation when there is presence of reservoir oil. Neutral wet describes a rock surface with no tendency to both oil and water or a rock surface having the properties of oil wet and water wet. Wettability index and contact angle measurements can be utilized to determine the type of rock wettability. Also some properties like capillary pressure curve, relative permeability curve and flooding curve may help to specify the wettability type.

According to Adamson (1982), Young Equation describes wettability when there are multiple fluid and rock phases.

$$\sigma_{os} - \sigma_{ws} = \sigma_{ow} * \cos\theta_c \qquad \text{(Eq. 2.3)}$$

where;

σ_{os} = Oil-Solid Interfacial Tension (dynes/cm)
σ_{ws} = Water-Solid Interfacial Tension (dynes/cm)
σ_{ow} = Oil-Water Interfacial Tension (dynes/cm)
θ_c = Contact Angle (degree)

Wettability can be determined from the contact angle value found from the Eq. 2.3. Craig (1993) stated that contact angle value has a range from 0° to 180°. If the contact angle obtained from water droplet in oil bulk fluid is higher than 90°, reservoir is oil wet. If contact angle is lower than 90°, reservoir is water wet. If contact angle ever comes to 0° or 180°, strongly water wet and strongly oil wet, respectively. For neutral wet reservoirs, contact angle should be around 90°. Figure 2.1 demonstrates the contact angle for oil wet and water wet.

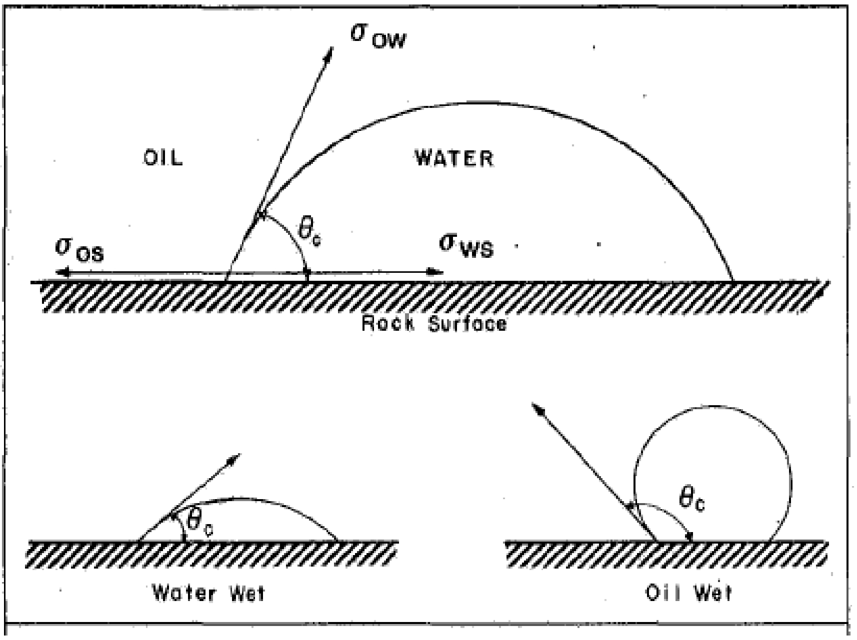


Figure 2.1 Contact Angle for Oil-Wet and Water-Wet Systems (Raza et al. 1968)

Anderson (1986) and Kwan (1998) remarked there are three types of wettability measurements:

- Contact Angel Measurement
- Amott (Forced and Spontaneous Imbibition) Method
- USBM Method

Rao (1999) used the contact angle techniques to observe the effect of wettability in thermal recovery operations. Rao listed the factors that effects temperature dependence of wettability as pH, electro kinetic properties of hydrocarbon-water and solid-water interfaces, and the composition of brine. It was also observed that, calcium carbonate is precipitated out of the brine as temperature increases which yield in strongly water-wet surfaces.

2.1.3.1 Wettability of Carbonate Reservoirs

Flügel (2004) reviewed almost half of the total production in the world is from carbonate reservoirs which are mostly naturally fractured.

Chilingar and Yen (1993) and Treiber and Owens (1972) are both presented carbonate reservoirs tend to be neutral wet to oil wet. Usually it is compelling to produce oil from oil wet reservoir especially with natural fractures. Water flooding is generally chosen for application since it is cost-effective and easier to approach. In oil wet reservoirs, waterflooding is not very effective due to negative capillary forces. With the help of imbibition of injection water into porous medium, oil moves from the pores. But in naturally fractured and oil wet reservoirs, capillary pressure is negative and this causes oil to stay in place. In order to increase oil recovery, wettability of the reservoir needs to be changed to become water wet.

2.1.3.2 Wettability Alteration

As it dominates the residual oil in porous medium, wettability has a very important function for alkaline flooding. The concept of wettability alteration is to reduce internal forces that attach reservoir oil to the reservoir rock.

Four wettability alteration mechanisms are reported by Buckley et al. (1998);

- Surface precipitation
- Ion binding
- Polar interactions
- Acid/base interaction

All of these four mechanisms are applicableto sandstone reservoirs, but ion-binding is not convinient for carbonate reservoirs.

A series of laboratory experiments conducted by Wagner and Leach (1959) demonstrated that rock wettability can be changed from oil wet to water wet by help of water solutions. These water solutions are added some chemicals to obtain different pH values. Chemical added water solutions caused a change in water and oil permeabilities. This situation helped switching the wettability from oil wet to water wet, thus the oil recovery raised. Therefore, they concluded that relative permeability change may yield to more sufficient mobility ratio.

When Mungan (1966) studied some laboratory tests on alkaline flooding and wettability relationship, he found out that temperature affects the results.

2.1.3.3 Wettability Alteration in Carbonate Reservoirs

Borchardt and Yen(1989) mentioned considering the proved oil reservoirs, nearly

50% of them are carbonate reservoirs. Among this 50%, oil recovery would not exceed 30%. Oil wet reservoirs and naturally high fractured carbonate reservoirs tend to have lower oil recovery rates. In this kind of reservoirs, waterflooding is not so powerful even though waterflooding is the widely used enhanced oil recovery technique to increase recovery. Therefore, a necessity of change in wettability in oil wet reservoir emerges.

Tweheyo et al. (2006) remarked that almost 40% additional oil recovery can be achieved by changing injection fluid from formation water to sea water. Also Zhang et al. (2007) clarified the increment in oil recovery in chalk reservoirs.

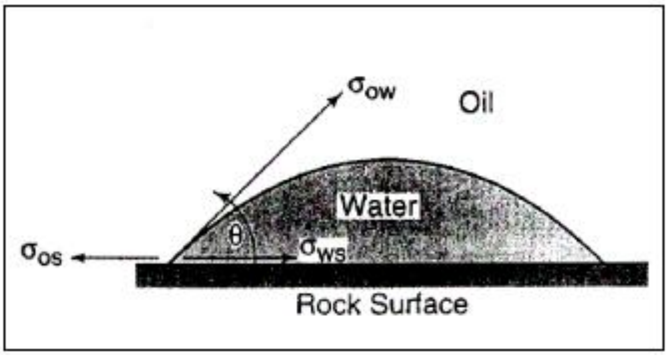


Figure 2.2 Interfacial forces at the interface between two liquids and a solid (Green and Willhite 1998)

There are three methods to measure interfacial tension between phases:

- Pendant bubble method
- Spinning drop method
- Sessile bubble method

Jennings et al. (1974) researched interfacial tension values of oil samples with solutions mixed NaOH at various concentrations using pendant drop method at room conditions. They concluded that IFT is lowered by numerous concentrations for most of the samples.

Cooke et al. (1974) reported putting some alkaline component in aqueous phase works well to decrease interfacial tension between reservoir oil and formation water. In some systems, IFT can be as low as 0.001 mN/m.

Qutubuddin et al. (1984) came up with a result that solution with a convenient NaOH concentration and higher pH value should develop really low interfacial tension.

Ramakrishnan and Wasan (1983) discovered NaOH concentration and salinity both affect the interfacial tension between fluid phases. They reached the lowest IFT values when using NaOH solutions with concentration of 0.01% to 0.1% by weight.

Hamouda and Gomari (2006) studied the temperature effect on wettability of carbonate reservoirs. Due to the modification of calcite surface, carbonate surfaces became less oil-wet at elevated temperatures. Less oil-wet surfaces obtained as temperature increases. This is because a free calcite site to adsorb carboxylic acid reduces at higher temperatures and some short acids become more soluble in aqueous environment.

2.1.4 Imbibition

Imbibition is absorption of wetting phase into porous medium of reservoir. By capillary forces, wetting phase is sucked into the pore spaces.

Properties like capillary pressure, wettability and contact angle are all related to imbibition. At reservoir conditions, it is reservoir’s characteristics that makes imbibing fluids as oil or water. If one of the fluid phases imbibed in a larger volume than the others, that fluid phase is generally the wetting phase.

Buckley (2001) mentioned imbibition is a very significant concept for oil recovery, emerged from capillary forces. These capillary forces generate a surface tension which leads to absorption of liquid. Wettability of the reservoir can be indicated by this behavior.

Morrow and Mason (2001), Morrow and Tang (1999) declared water flow may be assisted or prevented by imbibition and drainage. Whole process depends on wettability preference of reservoir.

There are two main types of imbibition:

- Forced Imbibition
- Spontaneous Imbibition

Capillary pressure behavior with respect to water saturation and forced imbibition and spontaneous imbibition curves can be seen in Figure below.

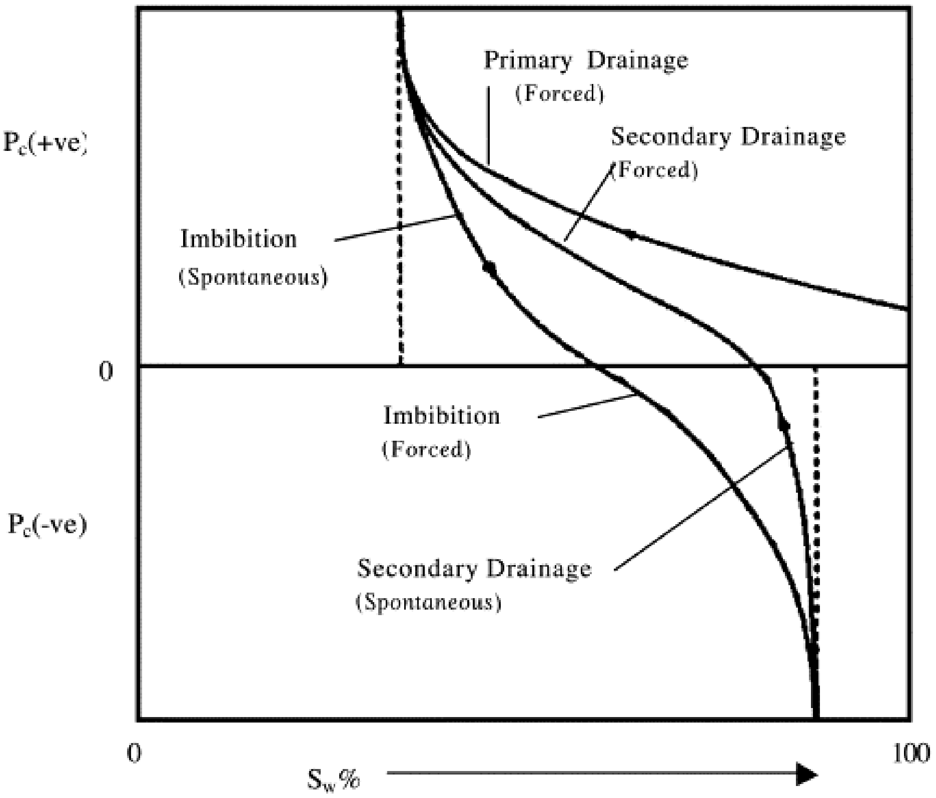


Figure 2.3 Forced and Spontaneous Imbibition (Morrow and Mason 2001)

Standnes and Austad (1999) maintained temperature alteration has a major effect on imbibition measurements since it can modify interfacial tension when working surfactants to change wettability.

Tang (1996) stated that, imbibition recovery is severely affected by increasing temperature while refined oil is not affected considerably. This means oil recovery is not only depends on rock properties but is also affected by interactions between crude oil, brine and rock.

Schembre et al. (1998) used low permeability and high porosity diatomaceous reservoirs core samples to investigate the effect of elevated temperatures (45-230°C) and pressures on imbibition and wettability alteration. They observed that, wettability index is shifting from weakly water-wet to strongly water-wet as temperature increases. Moreover, increase in temperature results in both imbibition rate and extent of oil recovery to increase.

2.1.4.1 Forced Imbibition

Buckley (2001) described forced imbibition as a process that aqueous phase needs to be pressurized to beat the capillary pressure to increase oil recovery.

Morrow and Mason (2001) explained forced imbibition in their laboratory coreflooding tests, by giving force to aqueous phase with a certain pressure gradient.

Edmondson (1965) and Weinbrandt et al. (1975) remarked that in a dynamic displacement system, rising system temperature leads to higher irreducible water saturation and also lower residual oil saturation.

2.1.4.2 Spontaneous Imbibition

Morrow and Mason (2001) reported spontaneous imbibition is a really vital concept since recovery of oil in fractured reservoirs is generally take place with help of spontaneous imbibition. Spontaneous imbibition usually occurs in low permeable naturally fractured reservoirs.

Morrow and Mason (2001) presented if formation water imbibed into porous medium, oil production will continue after the initial production. In Ekofisk Field in North Sea, spontaneous imbibition recovered a huge amount of reservoir oil. Studies are still being conducted to understand this naturally occurring process.

Zhang et al. (1986) conducted several laboratory experiments using different kinds of core samples with various lengths and boundary conditions in order to develop spontaneous imbibition.

In their study Tang and Morrow (1999) stated that temperature increase in sandstones results in more water-wet surfaces thus, improved spontaneous imbibition of water. Amott Index increased with temperature was also indicated in the study. Tang and Kovescek (2002) observed that as temperature increases oil saturation remaining after spontaneous water imbibition decreases.

Blunt and Al- Hadrami (2001) stated that wettability alteration with increasing temperature is because of direct desorption of asphaltene macromolecules form the surfaces of rock. Improved spontaneous imbibition of water and oil production is as result of desorption of asphaltene on rock surface which reverts rock surfaces to water-wet surface.

2.2 Enhanced Oil Recovery

Enhanced oil recovery (EOR) is a tertiary oil recovery system which needs additional material into the reservoir fluid or rocks. According to Lake (1989) and Green and Willhite (1998), EOR techniques can be divided into three types which are thermal, gas and chemical techniques. Marle (1991) names the gas methods as miscible methods. Each technique requires different materials and treatments all aimed to decrease residual oil saturation in the reservoir.

When working on an EOR design, petrophysical properties such as porosity, permeability, capillary pressure and wettability should be considered since they influence the process. (Tiab and Donaldson 2004)

2.2.1 Thermal EOR Methods

Thermal recovery, unlike other EOR techniques, needs thermal energy to supply heat directly to the reservoir in order to recover oil.

Latil M. (1980) stated that there two types of thermal recovery processes:

- Steam injection when the heat is generated at the surface before injection
- In-situ combustion when the heat is generated in the reservoir.

Green and Willhite (1998) explained steam injection process needs shallow wells which are less than 3,500 ft to prevent heat losses at the wellbore but in-situ combustion process can go up to 11,500 ft depth since this process is suitable for deep and pressurized reservoirs.

Grease (2001) indicated that there are a few thermal mechanisms for oil recovery. Decreasing the viscosity of reservoir oil by raising the temperature is the most vital mechanism since it is very efficient in presence of heavy oil. Therefore attention on thermal recovery systems will continue to be valid. But the situation is not the same for light oils. Decrease in viscosity of light oil is much less compared to heavy oil.

2.2.2 Gas EOR Methods

The primary objective of gas process is to remove residual oil stuck in reservoir by injecting gas which is miscible in oil. Oil mobility increases when injected gas is dissolved in the reservoir oil. The most widely used methods are using carbon dioxide and dry hydrocarbon gas for injection. In gas methods, the oil is recovered generally through the injection of gas into the reservoir. Gas methods can be named as miscible methods.

Lake (1989), Green and Willhite (1998) claimed gas injection process is successful and produces much oil in light oil, high pressure and low permeability reservoirs. This technique is not appropriate if reservoir pressure is not enough or lack of presence of gas supply.

2.2.3 Chemical EOR Methods

Chemical methods are classified according to the chemical used in solutions. There are four main methods; surfactant flooding, polymer flooding, alkaline-surfactant-polymer (ASP) flooding and alkaline flooding. Chemicals used in these methods can help to decrease interfacial tension, alter the reservoir wettability and control the mobility.

McCafferty and McClaflin (1992) remarked thermal recovery techniques are not sufficient enough for 2/3 of the world’s heavy oil reservoirs. It is because of unsuitability of well depth, porosity and reservoir thickness. In these situations, chemical flooding is a decent option.

According to Taber et al. (1997) there are several screening criteria for chemical flooding methods. First of all, crude oil composition is not so important. But API gravity of oil should be higher than 20° for alkaline and higher than 15° for polymer flooding methods. Viscosity can be in range of 10 – 100 cp. Average permeabilities should be higher than 10 mD since it is very hard to recover oil from low permeability reservoirs. Oil saturation should be higher than 35% for alkaline and higher than 50% for polymer flooding.

2.2.3.1 Surfactants

Surfactants are usually identified as surface active agents. The main ability is to reduce tension between phases. There are several kinds of surfactants typically.

Shinoda et al. (1963) and Rosen (1989) described the surfactants as significant type of molecules. They both divided them into two categories; hydrophilic and hydrophobic.

Priyanto et al. (2001) made an additional categorization according to surfactant ions which are cationic, anionic, nonionic and amphoteric. Cationic surfactant has positive ions, anionic surfactant has negative ions and nonionic surfactant has no charge. Amphoteric surfactants usually have alkaline and acidic characteristics. But carboxylic and nitrogen properties of surfactants are the main consideration.

Most of the researches are agree on that surfactants can change reservoir wettability. This method can be very expensive and so it is not so practical. But rising oil prices will continue to support using surfactants for this aim.

Morrow and Mason (2001) mentioned that oil recovery can be increased by changing reservoir wettability from oil wet to water wet with the help of surfactants.

Li and Horne (2002), Spinler et al. (2000) both worked on surfactant added spontaneous imbibition in carbonate rocks. They concluded wettability can be changed by chemical interaction between components of surfactant and reservoir rock.

Hognesen et al. (2004) studied a new numerical model to see how surfactants affect oil wet carbonate reservoirs and spontaneous imbibition of surfactant solutions.

Garrett (1972), Ferrell et al. (1988), Maerker and Gale (1992), Green and Willhite (1998) all arrived at a consensus that the concentration range for usage of surfactants, which is between 2% and 10%, is unfavorably high. But as Gogarty (1977) explained it may offer very well results in laboratory scale, however in the field scale loss of chemical additives may take place due to high concentration.

Okandan (1977) studied experimentally the effect of surfactants when mixed to water flooding on heavy oil limestone reservoirs. She also used additional chemicals such as Na-Silicate and Na-Dodecyl-Benzene-Sulfonate and concluded that these chemicals help to lower the contact angle between reservoir rock and oil.

2.2.3.2 Polymers

Polymers are chemicals that can be dissolved in water and helpful to recover the mobility ratio of oil water interface. In order to alter the flow of water in porous media, polymers usually have higher molecular weights. When the reservoir is oil wet or intermediate wet, it is not so easy to recover oil which is stuck into the pores and polymer flooding is known to be very effective in these situations.

Sorbie (1991) categorized the polymers as polyacrylamides and polysaccharides. Polyacrylamides are molecules which has acrylamide molecule as monomeric unit. Usually for field operations hydrolyzed polyacrylamides (HPAM) are employed. Also polyacrylamides can be affected from shearing and formation water salinity. Polysaccharides are made of bacterial fermentation of the saccharide molecules. Formation water salinity and shearing do not affect polysaccharides.

In all enhanced oil recovery methods, mobility control is one of the most vital objectives. Mobility can be controlled by some solutions added chemicals to modify fluid viscosity.

According to Sheng (2011), due to its ability to raise apparent viscosity of injection solution, polymer is the most widely used mobility control agent.

Lake (1989) described polymer flooding as polymer added waterflood solution in order to reduce the mobility. It also provides an increment in viscosity and lower mobility. Therefore, volumetric sweep efficiency increases. In presence of high mobility ratio of waterflooding, polymer flooding can be cost-effective and practical in heterogeneous reservoirs.

2.2.3.3 Alkaline

Alkaline enhanced recovery is one of the most well-studied and carried out technique for enhanced oil recovery (EOR).

Alkaline fluids include hydroxyl ions (OH-) when dissolved. Nutting (1925) who brings the concept of alkaline flooding, found out that sodium carbonate was very powerful to take off oil from the glass surface by accident and applied for the first patent about this alkaline flooding technique for enhanced oil recovery concept. (Atkinson 1927) Alkaline mixtures which can be used for oil recovery usually have higher pH values and include chemicals like sodium hydroxide (NaOH), sodium carbonate (Na_2CO_3) and sodium silicate (Na_2O_3Si). Lochte and Littman (1955), Chatterjee et al. (1998) stated that chemicals used for alkaline flooding such as NaOH, get in touch with acid in oil and build up in-situ surfactants. This kind of contact helps oil recovery enhancement.But because of the opposite mobility ratio between reservoir fluids' phases when considering heavy oil, not all studies on the alkaline flooding were successful (Liu 2006).

Every reservoir has its own specific reservoir oil and this variation may cause various attitudes with alkaline solutions when the conditions such as reservoir temperature, pH and formation water salinity change. Among all factors acidic ingredients in reservoir oil is the most essential one as nearly all researches are agreed on.

Since it can predict the quantity of the soap created with alkaline solutions interaction, the total acid number is one of the most significant properties. Total acid number (TAN) is the amount of potassium hydroxide required to neutralize acids in the oil.

One of the major factors effecting oil recovery is wettability. Morrow (1990) suggested that wettability alteration may change fluid paths in porous media which can lead to recover more oil from reservoir. In an oil wet reservoir, oil is placed in smaller pores and water is placed in larger pores. But according to Wagner and Leach (1959), Emery et al. (1970), Ehrlich et al. (1977), Olsen et al. (1990) chemicals with higher pH values can change wettability of the pores from oil wet to water wet. Especially for oil wet carbonate reservoirs, the only way to apply water imbibition is to switch wettability.

Graue and Johnson (1974) stated that alkaline flooding increases oil recovery when compared to waterflooding under reservoir conditions. Similarly, oil recovery from alkaline flooding can reach up to 58% while recovery from waterflooding is much lower, resulted by Arteaga-Cardona et al. (1996).

Taylor et al. (1990) mentioned not only the type but also alkaline solution concentration has a huge influence on oil recovery and interfacial tension change.

Leach et al. (1962) and Emery et al. (1970) both approached to the fact that alkaline solutions can change wettability and in parallel with improvement in oil recovery for oil wet reservoirs. Although Beckstorm and Van (1927) presented sodium carbonate as alkaline solution increased oil recovery, it has been demonstrated that sodium hydroxide and potassium hydroxide at low concentrations also efficient.

Radke and Somerton (1983) expressed a few approach for alkaline solution interaction with formation. These are; compatible and incompatible dissolution reactions, surface hydrolysis reactions exchange and hardness ions from liquids.

Dong and Liu (1988) mentioned the reason why oil recovery is enhanced by alkaline flooding is physico-chemical interactions such as chemical reactions. Those interactions cause decreased interfacial tension and therefore oil-water emulsions are obtained. Wagner and Leach (1959) put chemicals into solutions made with water to change pH and noticed a change of wettability of reservoir, subsequently increase in oil recovery.

Turksoy and Bagci (2000) conducted alkaline coreflooding tests using carbonate samples with 2 kinds of oil (Raman and Garzan Field crude oils) at several pressure conditions and room temperature. Finding the suitable concentration for alkaline solution which results the minimal interfacial tension between oil and alkaline compound is main purpose of that study. Numerous experiments with several salinities and flow rates were carried out. They concluded that flow rate has a worthy effect on Garzan crude oil.

Campbell (1977) conducted a series of experiments on relatively heavy oil samples to state the effect of alkaline mixed solutions. During the study, characteristics of chemicals were compared by focusing on sodium hydroxide and sodium orthosilicate. To prove the increase in oil recovery, he used sodium hydroxide with 0.2% concentration and sodium orthosilicate with 0.2% - 0.6% concentration. Experiments with other concentrations of sodium hydroxide were narrow due to lack of core samples.

Jennings et al. (1974) studied if the alkaline solutions used flooding method is whether suitable or not for heavy oil recovery in North America reservoirs. He used sodium hydroxide as alkaline chemical and concentration range was kept between 0.05% and 0.5% by weight. Coreflooding tests were conducted using a glass bead pack and it was noted that in-situ emulsification occurred. This emulsification helped the change in the flow by plugging the water passes and hence sweep efficiency increased.

For alkaline flooding in enhanced oil recovery, there are a few mechanisms recommended. Johnson et al. (1976) summarized mechanisms as; wettability alteration, emulsification with coalescence, emulsification with entrainment and emulsification with entrapment.

There are more than a few mechanisms in literature according to various researches, because properties of porous medium and all reservoir fluids should be considered well while working on mechanisms.

CHAPTER 3

STATEMENT OF THE PROBLEM

Only a certain amount of oil recovery can be reached by primary and secondary production. In order to recover from the original oil place, tertiary production methods should be considered.

The main aim of this study is to understand the effects of NaOH solution on oil recovery for limestone reservoirs. Different concentrations of NaOH were used to obtain additional oil recovery and lower interfacial tension. Also effect of temperature on oil recovery was studied in this thesis. In addition, influence of concentration and pressure on interfacial tension was investigated.

This study also aims to promote the use of chemical enhanced oil recovery methods in Turkish oil industry.

CHAPTER 4

EXPERIMENTAL PROCEDURE AND SETUP

4.1 Sample Preparation

Firstly, all of the core samples were cleaned from hydrocarbon contents by using Soxhlet toluene extraction system (Fig 4.1).

Figure 4.1 Soxhlet Extraction Core Cleaning System

The soxhlet toluen extraction system is used to dissolve hydrocarbon and formation brine from plug sample with the help of toluen. System consists of heater, glass tubings and toluene. We can predict whether the sample is clean or not, by following the color of the toluen in the system. When its color gets bright enough it means it is ready for further process. Toluene boils in boiling bowl and vaporizes, then it reaches continuous cool water circulation at the top of the glass tubings, condenses and drops right to chamber of core samples. While liquid toluene fills the chamber, it cleans the sample. When toluene fills the chamber as it gets unclean, liquid phase siphons back to toluene reservoir and process repeats.

Afterwards, the samples were immersed in alcohol bath and placed in a vacuumed-oven system to clean any possible salt remaining in the pores of the samples due to drilling fluid and formation water. Then the samples were dried in a temperature-controlled oven at 70 °C.

4.2 Routine Core Analysis

4.2.1 Porosity Measurement

Helium porosimeter (Fig 4.2) is a device used to measure the porosity of reservoir rock samples at room conditions. The porosimeter works on the principle of Boyle’s Law of gas expansion to determine pore volume and grain volume at isothermal conditions.

Figure 4.2 Helium Porosimeter

Since volume of the plug sample is required in Boyle-Mariotte to calculate porosity, length, diameter and weight of the cylindrical plug samples were measured. Dimension measurements were made with electronic calipers. At least 2 values were recorded and the average values were taken as final measurements. Weight is measured by precision balance.

Helium supply is connected to the system. Clean and dry plug samples were individually placed in the matrix cap according to plug sample diameter and connected to the porosimeter. Helium, at a known pressure of 100 psig from a reference cell of known volume was allowed to expand into the matrix cap and into the available pore spaces. When differential pressure stabilized, the volume of expansion was recorded by software and used to calculate the grain volume Boyle's law. Data collecting software keeps measurements and calculates the parameters considering the calibration data. Bulk volumes of the samples were determined by measuring the length and diameter of the samples and then applying appropriate mathematical formulas.

4.2.2 Permeability Measurement

Permeability is a main porous medium property which determines the flow capacity of the rock through its pores. Permeability is estimated by laboratory measurements. In order to calculate permeability using Darcy Equation, length and diameter of the plug samples were measured. Measurements were made with electronic compass. At least 2 values were recorded and the average values were taken as final measurements.

Air Permeameter used for conducting the test (Fig 4.3). VINCI Gasperm is a device designed for permeability determination at steady state conditions, room temperature and confining pressure. Gas flows through the core sample at different pressure and flow rate stages. There is a pressure transducer at the inlet of the core holder to measure inlet pressure and a flow meter to measure flow rate. For permeability measurement, clean and dry plug samples were placed in the Hassler type core holder of the steady-state air permeameter at a confining pressure of 300 psig. The stabilized flow rate of dried air through the core sample was monitored and differential pressure across the plug sample was measured and used in conjunction with the measured sample length and cross-sectional area to calculate permeability using Darcy’s law.

Figure 4.3 Air Permeameter

4.3 Spontaneous Imbibition Tests

Initially, selected plug samples were completely saturated with formation water. Afterwards, the samples were placed in a hydrostatic type core holder and at least 5 pore volume of the formation water was flooded through the sample at a constant flow rate to maintain stability, with 500 psi confining pressure and at 50˚C and 65˚C reservoir temperaturesto ensure 100% water saturation and to measure absolute water permeability. Subsequently, 5 pore volume of dead oil flooded through the samples under the same condition to set the samples initial water saturation (S_{wi}). Produced amount of water and oil effective permeabilities at initial water saturation ($k_o@S_{wi}$) were measured.

When the plug samples were removed from the core holder, they were ready for spontaneous imbibition test and they were placed in the imbibition cells. (Fig 4.4.) Then, depending on the situation, the cells were filled with the formation water, fresh water or solutions prepared with fresh water at different concentrations. Then, the cells were checked at regular intervals over time.

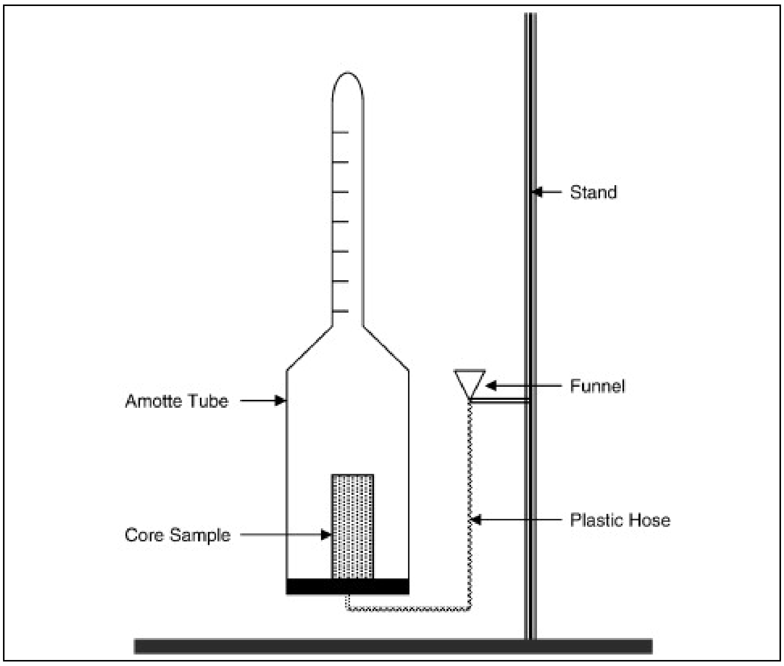


Figure 4.4 Imbibition Cell Apparatus

4.4 Core Flooding Tests

Core flooding tests were conducted by steady-state displacement method at 50 °C temperature with a closed core flooding system. Two accumulators for oil and fresh water were place inside of the system and another two accumulators for NaOH solutions were place outside of coreflooding system. ISCO pumps were used to inject fluids into the plug samples. Saturation and flooding processes were made under 500 psi overburden pressure. Coreholder and two inside accumulators were heater by oven, while the other accumulators were heated by heating belts. There were pressure transducers attached to core holder to measure inlet and outlet pressures. Before injecting any fluid, all lines were filled with in order to prevent plugging and dead volumes.

Initially, the core sample was completely saturated with formation water by flooding and water permeability (k_w) was measured at constant flow rate. Afterwards, crude oil was injected through the core sample to obtain initial water saturation (S_{wi}). Then, the sample was flooded by using formation water to monitor oil production. Residual oil saturation (S_{or}) and total recovery from waterflooding process were determined by oil production.

After injecting certain volume of formation water, 2% and 5% NaOH solutions prepared by fresh water were flooded through the each sample respectively to see any additional oil production was possible or not. Amount of oil recovery was recorded through each step.

4.5 Interfacial Tension (IFT) Measurement Tests

The interfacial tension measurement tests were performed to obtain the tension between two liquid phases at reservoir temperature and pressure.

The instrument (Fig 4.5) used to measure IFT has ability to obtain liquid-solid contact angle with sessile drop method and liquid-liquid interfacial tension with pendant drop method. In this study a liquid drop was generated at the tip of a needle when the chamber was filled with bulk fluid at reservoir conditions. Drop fluid was the crude oil from ‘C’ and ‘G’ fields in all of the experiments. But bulk fluid was changed to see the relationship between crude oil and different kinds of alkalinesolutions. Solutions used in spontaneous imbibition tests were used for IFT measurements also. Over 300 tests with 8 different solutions were performed.

Unlike the spontaneous imbibition test system, IFT system can work in very high temperature and pressure conditions. Therefore, 105 °C and 65 °Creservoir temperatures was kept constant but while different pressures were monitored.

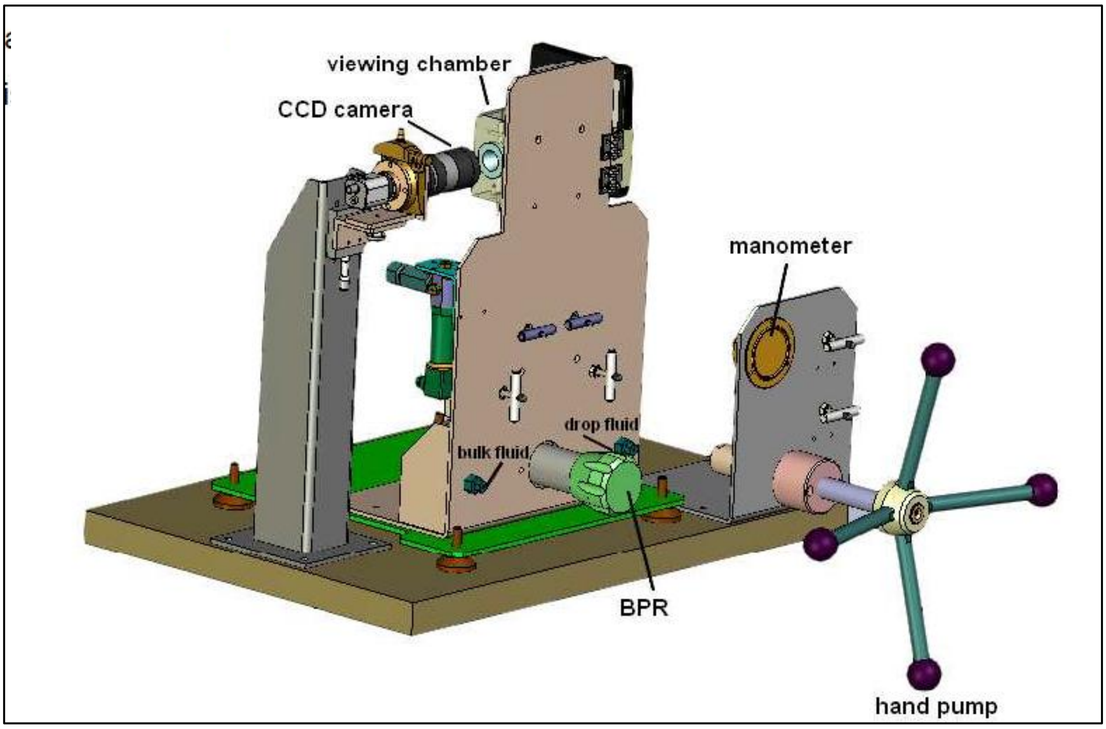
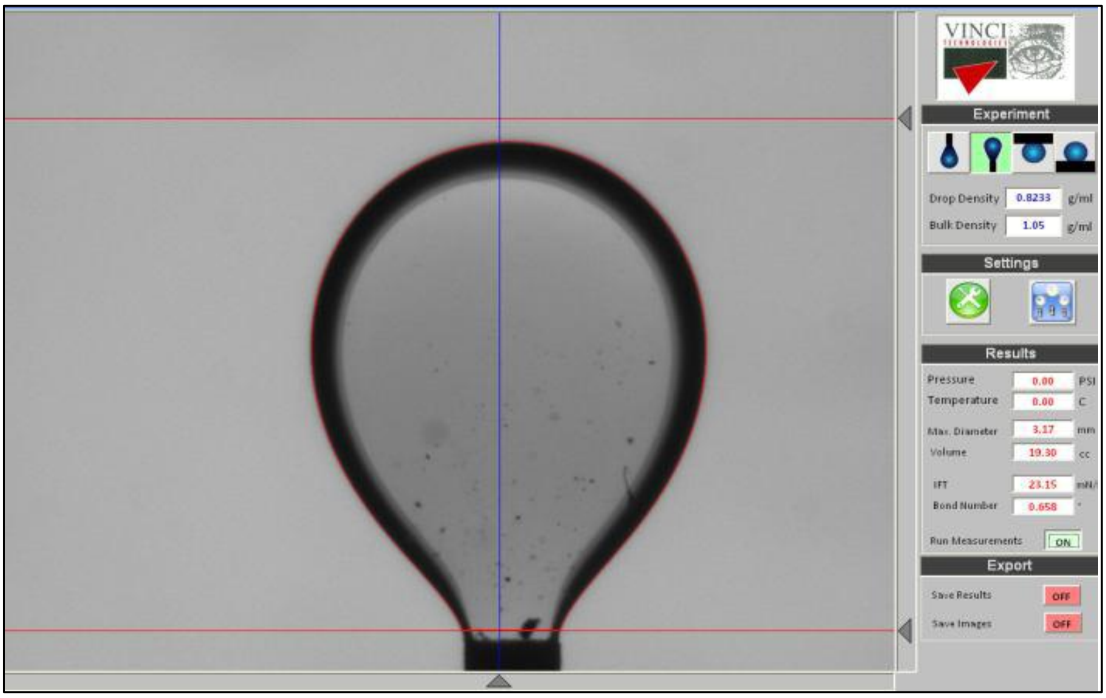


Figure 4.5 Interfacial Tension Meter

There is a viewing cell with sapphire windows which makes cell totally visible. Cell is viewed by a calibrated video camera system. There are two pumps attached to the cell. One of them directly fills the chamber with bulk fluid while other one generates the liquid drop through a capillary needle. An optical video camera with a connection to a computer is mounted to see the shape of the drop. Drop shape can be adjusted by the help of live image. Special software is used to process images immediately and some parameters were recorded at the same time. Right and left contact angles of drop, drop volume, drop diameter and interfacial tension values were displayed on the screen. All measurements were dependent on temperature and pressure.



Drop Density 0.8233 g/ml
Bulk Density 1.05 g/ml
Pressure 0.00 PSI
Temperature 0.00 C
Max. Diameter 3.17 mm
Volume 19.30 cc
IFT 23.15 mN/
Bond Number 0.658 *
Run Measurements ON
Save Results OFF
Save Images OFF

Figure 4.6 Display Image of a Sample Liquid Drop

4.6 High Pressure Mercury Injection Capillary Pressure Tests

Capillary pressure tests were conducted by high pressure (0-60.000cpsi) mercury injection test system (Fig 4.7).

Mercury injection capillary pressure test system depends on a concept that mercury invasion to pore spaces at numerous pressure steps. By the help of this test system, densities, pore volume and pore throat size distributions can be computed. Pore size distribution with this method has range from 0.003 to 1000 micrometers. There were four low pressure and two high pressure ports in the system.

Figure 4.7 Autopore IV 9500 HPMICP

At the beginning, core samples were crushed into small particles that can fit into the penetrometers. Penetrometers were chosen according to core sample porosity and grain density. Crushed samples were placed into suitable penetrometers at specified weights and operated at the low pressure analysis ports. All the air in penetrometers was vacuumed in this stage. Samples were vacuumed up to 50 μm-Hg pressure and waited to be stabilized. Then, filling with mercury process started at a pressure of 2.5 psia. All pressure steps in vacuuming and filling process were determined in equilibrium conditions.

After penetrometers were full with mercury, they were put in high pressure analysis ports. Mercury saturation at each pressure is obtained from the ratio of cumulative intrusion at each pressure to the cumulative intrusion at 59.979 psia. Therefore, 0% mercury saturation shows the start of the intrusion and 100 % mercury saturation represents the time when the entire pore volume of the sample is filled with mercury. These pressure values were adjusted as requested before the experiments particularly for these samples.

Similarly, pore throat size diameter values were plotted versus change in mercury saturation between two pressure steps. Pore throat size diameter for each pressure step is calculated by utilizing contact angle, surface tension and pressure values.

CHAPTER 5

RESULTS and DISCUSSION

5.1 Core Properties

5.1.1 Basic Rock Properties

Routine core analysis was performed on 9 core plug samples from C field and 7 core plug samples from G field belonging to limestone formations. For this study, it was important to choose plug samples from both fields that have similar rock properties. Average porosities of plug samples of ‘C’ and ‘G’ fields were 10.7% and 14.8%, respectively. Also, permeability was one of the major criteria for choosing the suitable core samples for laboratory experiments. Average permeabilities for ‘C’ and ‘G’ fields were 14.32 md and 13.54 md, respectively.

Basic core analysis test results and average values were presented in the Table 5.1 and Table 5.2. The porosity versus permeability X-plot is presented in Figure 5.1.

Table 5.1 Routine Core Analysis Test Results of 'C' Field Core Samples.

Sample No	Porosity (%)	Pore Volume (cc)	Air Permeability (md)	Klinkenberg Permeability (md)	Grain Density (g/cc)
381	12.5	9.52	22.82	18.72	2.73
382	11.2	8.72	31.25	26.12	2.73
383	10.4	8.47	14.07	11.21	2.73
384	10.7	8.78	11.49	9.04	2.73
385	9.4	7.78	6.21	4.71	2.73
386	10.2	8.52	5.15	3.86	2.73
388	10.1	8.45	16.33	13.13	2.74
389	9.6	8.03	6.72	5.12	2.74
390	12.6	10.57	14.88	11.90	2.75
AVERAGE	10.7	8.76	14.32	11.53	2.73

Table 5.2 Routine Core Analysis Test Results of 'G' Field Core Samples.

Sample No	Porosity (%)	Pore Volume (cc)	Air Permeability (md)	Klinkenberg Permeability (md)	Grain Density (g/cc)
201	13.7	13.64	9.20	7.15	2.70
206	13.1	9.82	15.88	12.74	2.69
212	13.9	9.31	10.55	8.26	2.69
214	12.6	13.52	12.81	10.15	2.69
217	18.6	15.79	15.26	12.22	2.69
218	12.2	15.04	18.34	14.85	2.70
228	19.3	11.16	12.72	10.07	2.69
AVERAGE	14.8	12.61	13.54	10.78	2.69

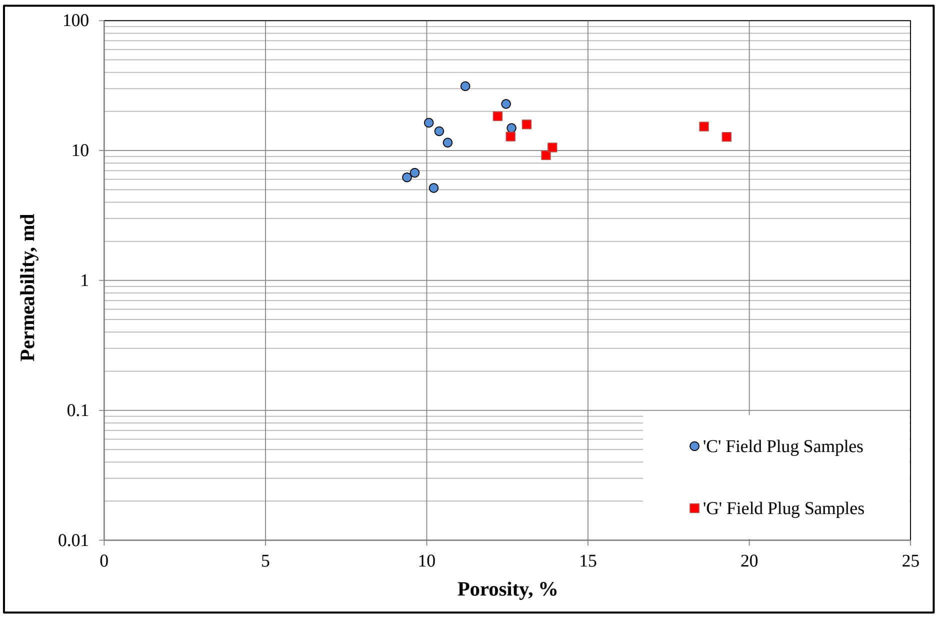


Figure 5.1 Porosity vs Permeability X-Plot.

5.1.2 Pore Throat Size Distribution with Mercury Injection Capillary Pressure Analysis

Capillary pressure curves were obtained by simply plotting mercury saturation values at each pressure step. Firstly, drainage (intrusion) curve was obtained by measuring the amount of mercury that enters the evacuated pores of the samples at different pressure steps.

Each measuring pressure steps was entered to the computer software for the analysis. The pressure steps start from 2.51 psia and increases to 59.979 psia to obtain drainage (intrusion) curve. Then, by releasing the applied pressure from 59.979 psia to 17.7 psia, the imbibition (extrusion) type capillary pressure curve is obtained. Finally, drainage mercury injection test data were used to calculate pore throat size distribution curves of the samples.Capillary pressure and pore throat size distribution data and curves of ‘C’ field core plug samples were presented in Appendix (A).

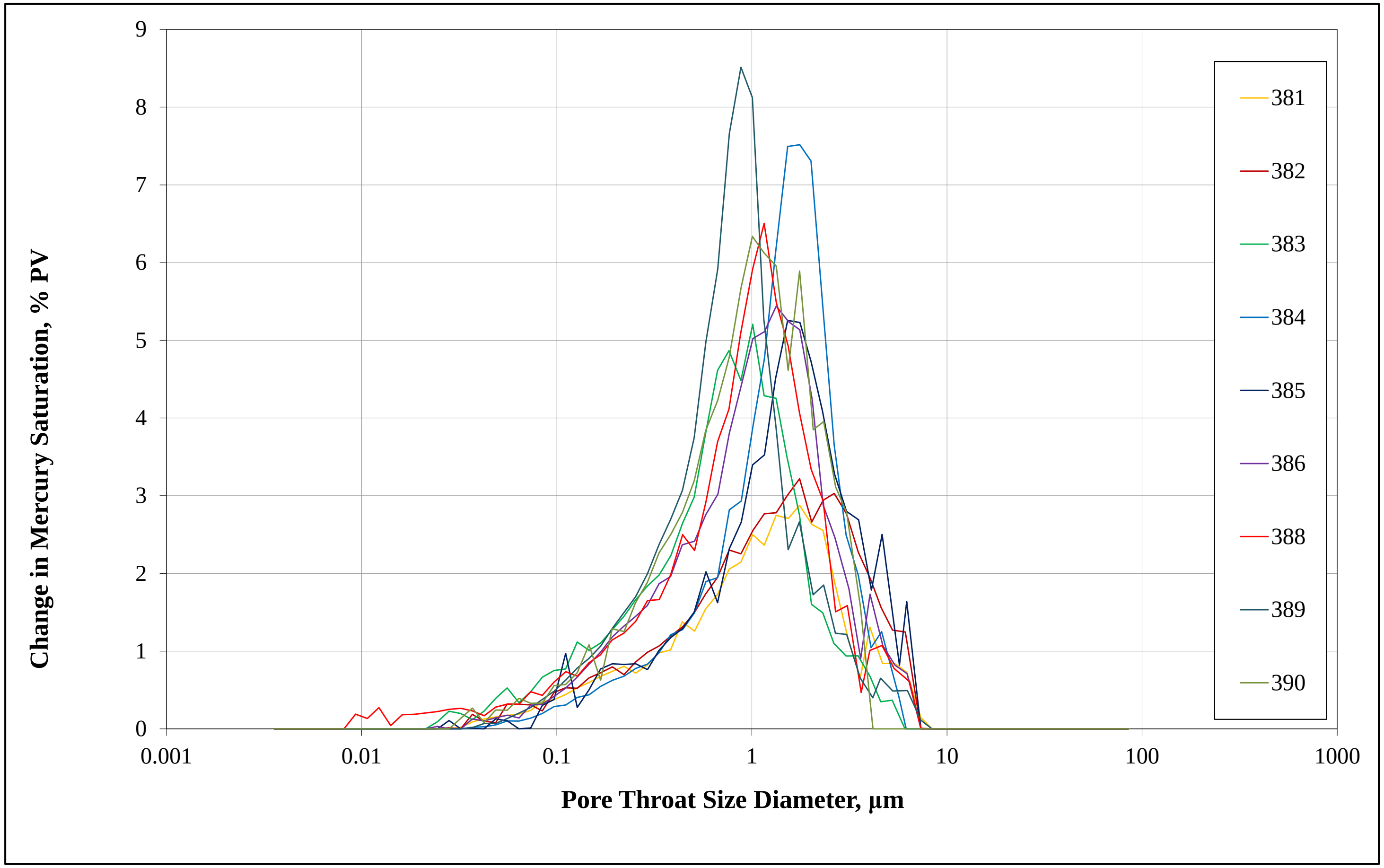


Figure 5.2 Pore Throat Size Distribution Curves ‘C’ Field (Sample No. 381 - 390)

5.2 Fluid Properties

Formation water and dead oil samples belonging to ‘C’and ‘G’ fields and fresh water were used for the experiments conducted in this study. Properties of the test fluids were given through Table 5.3 - 5.6, and Figure 5.2 – 5.5. These measurement results were obtained from Turkish Petroleum Corporation Research Center Laboratories.

Table 5.3 Viscosity and Density of ‘C’ Field Dead Oil at Different Temperatures.

Temperature (°C)	Viscosity (cp)	Density (g/cc)
15.6	24.0	0.881
30	17.3	0.873
35	15.4	0.867
40	13.7	0.865
50	11.1	0.858
70	7.6	0.844
90	4.5	0.823

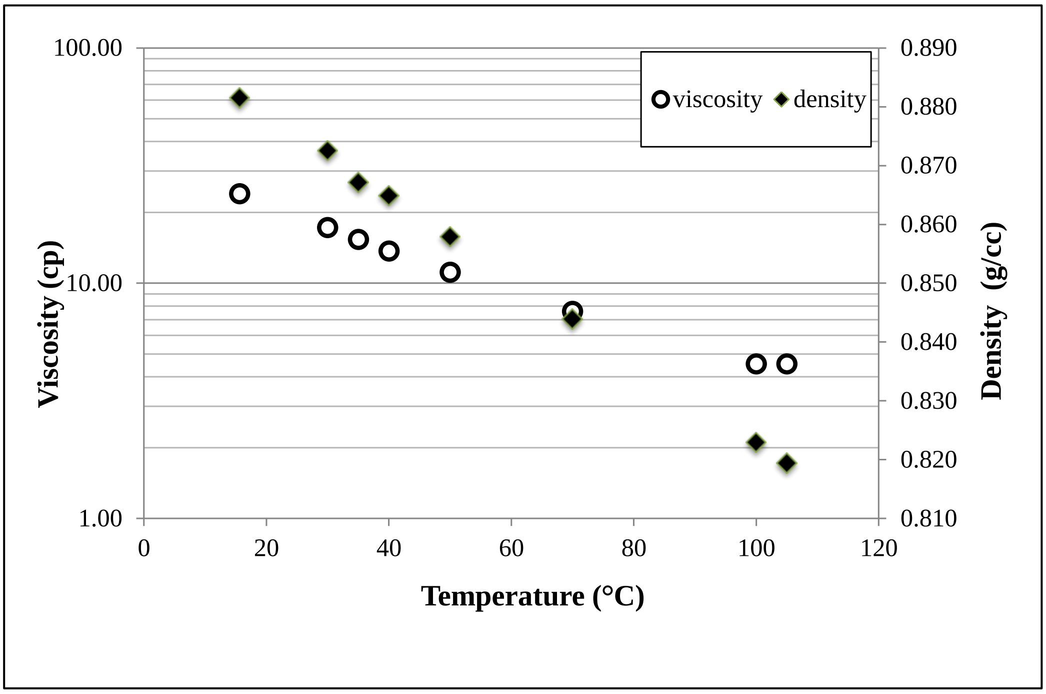


Figure 5.3 Viscosity and Density – Temperature Relationship of ‘C’ Field Dead Oil.

Table 5.4 Viscosity and Density of 'C' Field Formation Water at Different Temperatures.

Temperature (°C)	Viscosity (cp)	Density (g/cc)
15.6	1.1	1.014
30	0.8	1.011
35	0.8	1.008
40	0.7	1.007
50	0.6	1.002
70	0.4	0.993
90	0.3	0.985

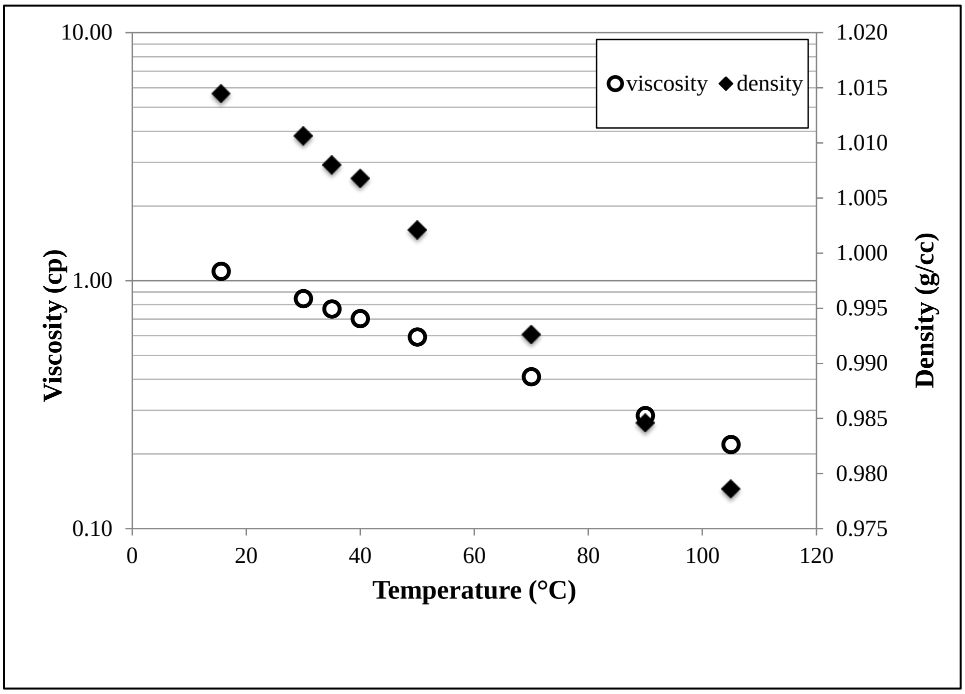


Figure 5.4 Viscosity and Density – Temperature Relationship of 'C' Field Formation Water.

Table 5.5 Viscosity and Density of ‘G’ Field Dead Oil at Different Temperatures.

Temperature (°C)	Viscosity (cp)	Density (g/cc)
15.6	276.85	0.924
20	247.10	0.921
25	219.08	0.917
35	163.75	0.910
45	109.25	0.903
55	31.75	0.896
65	21.58	0.890

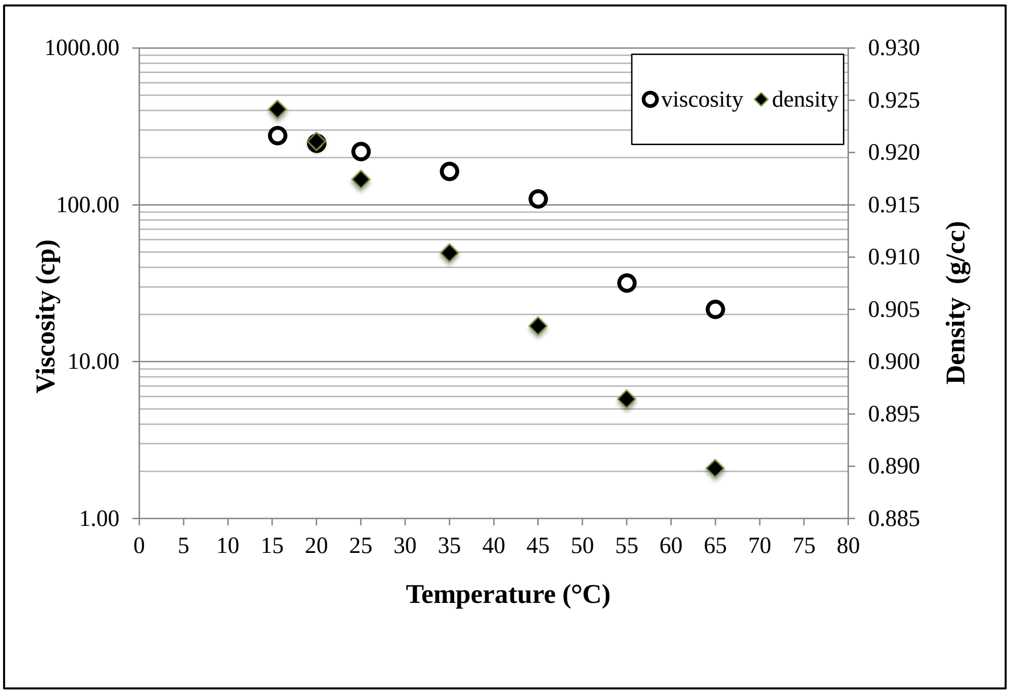


Figure 5.5 Viscosity and Density – Temperature Relationship of ‘G’ Field Dead Oil.

Table 5.6 Viscosity and Density of 'G' Field Formation Water at Different Temperatures.

Temperature (°C)	Viscosity (cp)	Density (g/cc)
15.6	1.15	1.019
20	1.10	1.017
25	1.03	1.015
35	0.90	1.011
45	0.77	1.007
55	0.64	1.003
65	0.51	0.999

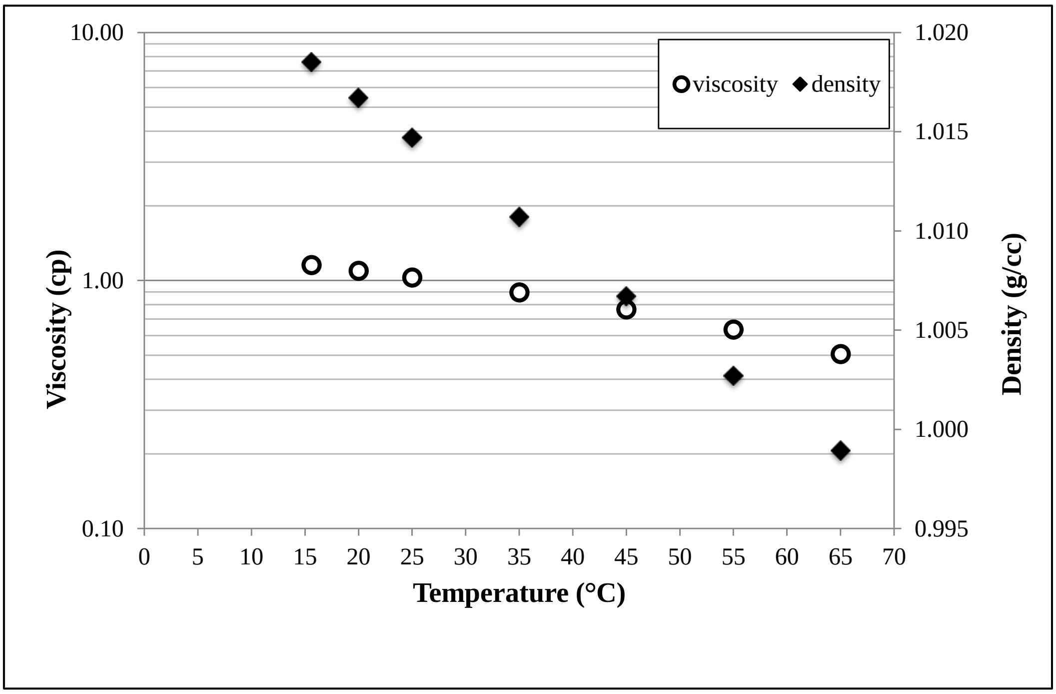


Figure 5.6 Viscosity and Density – Temperature Relationship of 'G' Field Formation Water.

Table 5.7 'C' Field Formation Water Analysis Dissolved Solids Results.

CATIONS	**mg/l**	**ppm**	**epm**	**epm (%)**
Sodium	6028.00	5940.26	258.40	40.99
Potassium	232.90	229.51	5.88	0.93
Calcium	585.80	577.27	28.81	4.57
Magnesium	102.50	101.01	8.31	1.32
Iron (Total)	<0.01			
Strontium	28.50	28.09	0.64	0.10
Barium	0.27	0.26	0.00	0.00
ANION	**mg/l**	**ppm**	**epm**	**epm (%)**
Chloride	11023.95	10863.50	306.35	48.60
Sulfonate	975.00	960.81	19.98	3.17
Carbonate	0.00	0.00	0.00	0.00
Bicarbonate	123.56	121.76	2.00	0.32

Table 5.8 'C' Field Formation Water Analysis Other Parameters Results.

pH	7.95 / 25.8 °C
Sp. Gravity	1.015 / 15.6 °C
Resistivity (21.9 °C)	0.32 ohm-m
Total Dissolved Solids	19.100 mg/l
Total Salinity (NaCl)	18.166 mg/l
Conductivity (21.9 °C)	31600 µS/cm
Acidity	8.92 mg/l CaCO3

Table 5.9 'G' Field Formation Water Analysis Dissolved Solids Results.

CATIONS	**mg/l**	**ppm**	**epm**	**epm (%)**
Sodium	7484.00	7352.75	319.84	39.71
Potassium	243.10	238.84	6.11	0.76
Calcium	752.80	739.60	36.91	4.58
Magnesium	319.90	314.29	25.87	3.21
Iron (Total)	0.10	0.09	0.01	0.00
Strontium	90.60	89.01	2.03	0.25
Barium	0.57	0.56	0.01	0.00
ANION	**mg/l**	**ppm**	**epm**	**epm (%)**
Chloride	14458.00	14204.45	400.57	49.73
Sulfonate	550.00	540.35	11.24	1.40
Carbonate	0.00	0.00	0.00	0.00
Bicarbonate	182.37	179.17	2.94	0.36

Table 5.10 'G' Field Formation Water Analysis Other Parameters Results.

pH	7.85 / 19.6 °C
Sp. Gravity	1.018 / 15.6 °C
Resistivity (21.9 °C)	0.26 ohm-m
Total Dissolved Solids	24081 mg/l
Total Salinity (NaCl)	23825 mg/l
Conductivity (21.9 °C)	38900 µS/cm
Acidity	0 mg/l CaCO3

Table 5.11 Fresh Water Analysis Dissolved Solids Results.

DISSOLVED SOLIDS				
CATIONS	**mg/l**	**ppm**	**epm**	**epm (%)**
Sodium	5.30	5.30	0.23	3.43
Potassium	1.61	1.61	0.04	0.61
Calcium	40.71	40.70	2.03	30.25
Magnesium	10.62	10.62	0.87	13.02
Iron (Total)	<0.01			
Strontium	0.16	0.16	0.00	0.05
Barium	0.02	0.02	0.00	0.00
ANION	**mg/l**	**ppm**	**epm**	**epm (%)**
Chloride	2.90	2.90	0.08	1.22
Sulfonate	15.00	15.00	0.31	4.65
Carbonate	12.15	12.15	0.40	6.03
Bicarbonate	166.81	166.77	2.74	40.74

Table 5.12 Fresh Water Analysis Other Parameters Results.

OTHER PARAMETERS	
pH	8.25 / 24.2 °C
Sp. Gravity	1.000 / 15.6 °C
Resistivity (25.7 °C)	31.35 ohm-m
Total Dissolved Solids	255 mg/l
Total Salinity (NaCl)	5 mg/l
Conductivity (25.7 °C)	319 µS/cm
Acidity	0.00 mg/l CaCO3

5.3 Imbibition Test Results

The purpose of imbibition experiments was to determine whether oil production increases or not by reducing the interfacial tension (IFT) between formation water and oil phase utilizing alkaline application. For this purpose,9 plug samples from ‘C’ field and 7 plug samples from ‘G’ field were chosen according to their suitability for spontaneous imbibition test. During the sample preparation phase, firstly formation water was flooded through the 100% saturated samples and absolute water permeabilities (k_w) was obtained. And then, crude oil was flooded, initial water saturations (S_{wi}) and oil permeabilities at initial water saturations ($k_o@S_{wi}$) were obtained. Fundamental properties of the samples and end points dataobtained during the sample preparation phase of imbibition tests were presented in Table 5.13 and Table 5.14.

Spontaneous imbibition tests can be run under atmospheric pressure up to boiling temperature of water. Since 105 °C the reservoir temperature of ‘C’ field is above the limitation of the working temperature (Max 100 °C), the tests were performed at three different temperatures (50 °C, 70 °C and 90 °C). First set of the tests contained 9 plug samples from field ‘C’. Firstly, all of the imbibition tests were started at 50 °C, and, when the imbibition of water (or oil production) finished, temperature of the air bath was increased to 70 °C and then to 90 °C respectively to see the effect of temperature on the test results. The second set of spontaneous imbibitions tests were conducted at 65 °C constant oven temperature and 7 core samples from ‘G’ field were used. An overview and close-up photos taken during some of the imbibition tests were presented in Figure 5.7 and 5.8.

Since the fresh water is a convenient source for water that can be used in possible EOR application, fresh water and formation water were used first in the imbibition tests (core plug 381, 382, 383, 201, 206) to determine the reference level of oil recovery without any additive.

For the further experiments, different concentrations of NaOH solutions (from

0.2wt% to 5wt%) were used and all of them were prepared by using fresh water. All test results were given in Figure 5.9 – 5.11. The blue circles in the figures indicated the temperature increase from 50 °C to 70 °C and the red squares indicated the change from 70 °C to 90°C. In order to be sure about the repeatability of the tests results, fresh water, 1wt% and 2wt% solutions of NaOH were repeated with different core plug samples from ‘C’ field.Test results were presented in Figure 5.12 – 5.14.The imbibition tests of ‘G’ field were not repeated.

Table 5.13 End-Points Data Obtained from Imbibition Experiments of ‘C’ Field.

Sample No	Porosity (%)	Pore Volume (cc)	k_w (md)	S_{wi} (%)	k_o @ S_{wi} (md)
381	12.5	9.52	1.67	33.0	0.85
382	11.2	8.72	4.43	52.0	3.35
383	10.4	8.47	4.25	24.0	1.97
384	10.7	8.78	3.61	40.0	2.21
385	9.4	7.78	2.50	22.0	0.70
386	10.2	8.52	1.18	21.0	0.23
388	10.1	8.45	6.84	36.0	3.48
389	9.6	8.03	3.41	22.0	0.51
390	12.6	10.57	4.80	47.0	2.72

Table 5.14 End-Points Data Obtained from Imbibition Experiments of 'G' Field.

Sample No	Porosity (%)	Pore Volume (cc)	k_w (md)	S_{wi} (%)	k_o @ S_{wi} (md)
201	13.7	13.64	0.53	0.44	0.84
206	13.1	9.82	2.02	0.34	1.87
212	13.9	9.31	4.23	0.25	0.47
214	12.6	13.52	3.31	0.26	1.64
217	18.6	15.79	5.43	0.44	0.10
218	12.2	15.04	4.64	0.49	0.11
228	19.3	11.16	3.07	0.21	1.27

Figure 5.7 Overview of Imbibition Tests

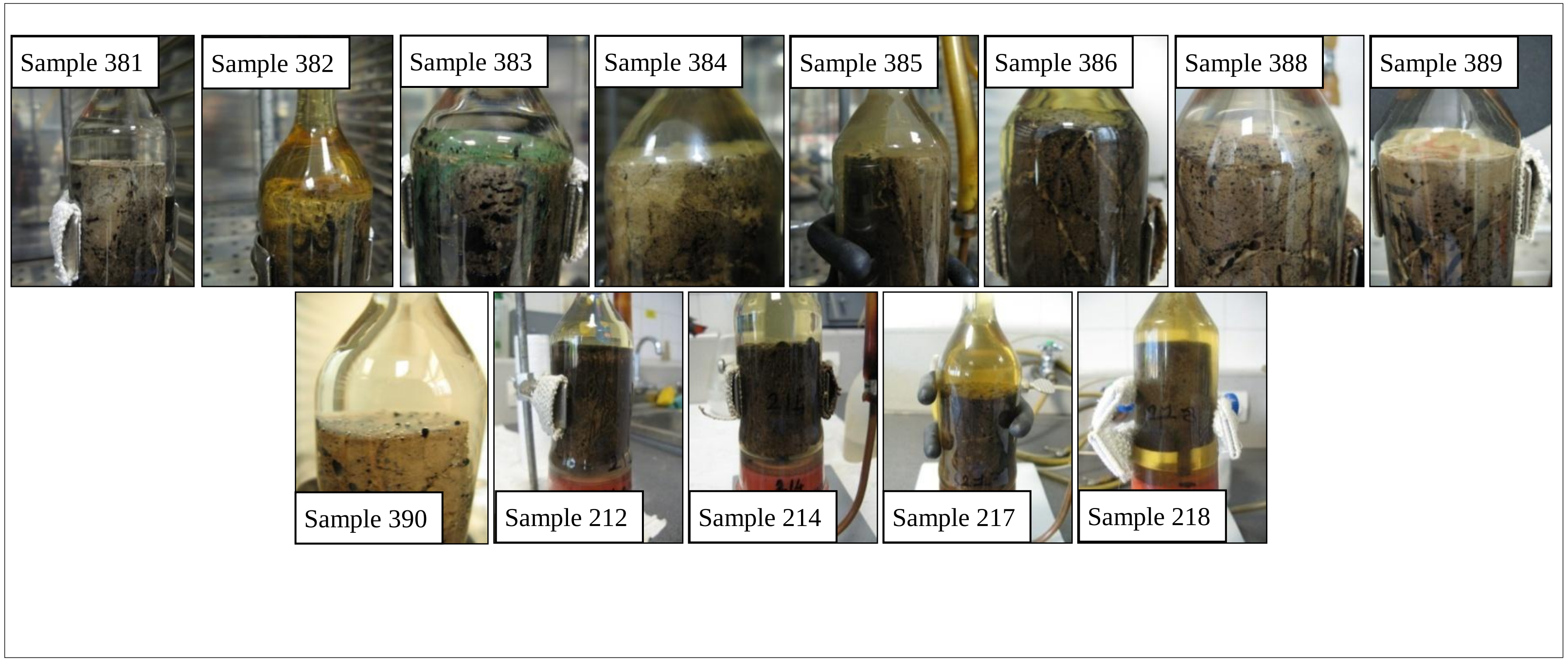


Figure 5.8 Close-Up Pictures of Some of the Samples Imbibition Tests.

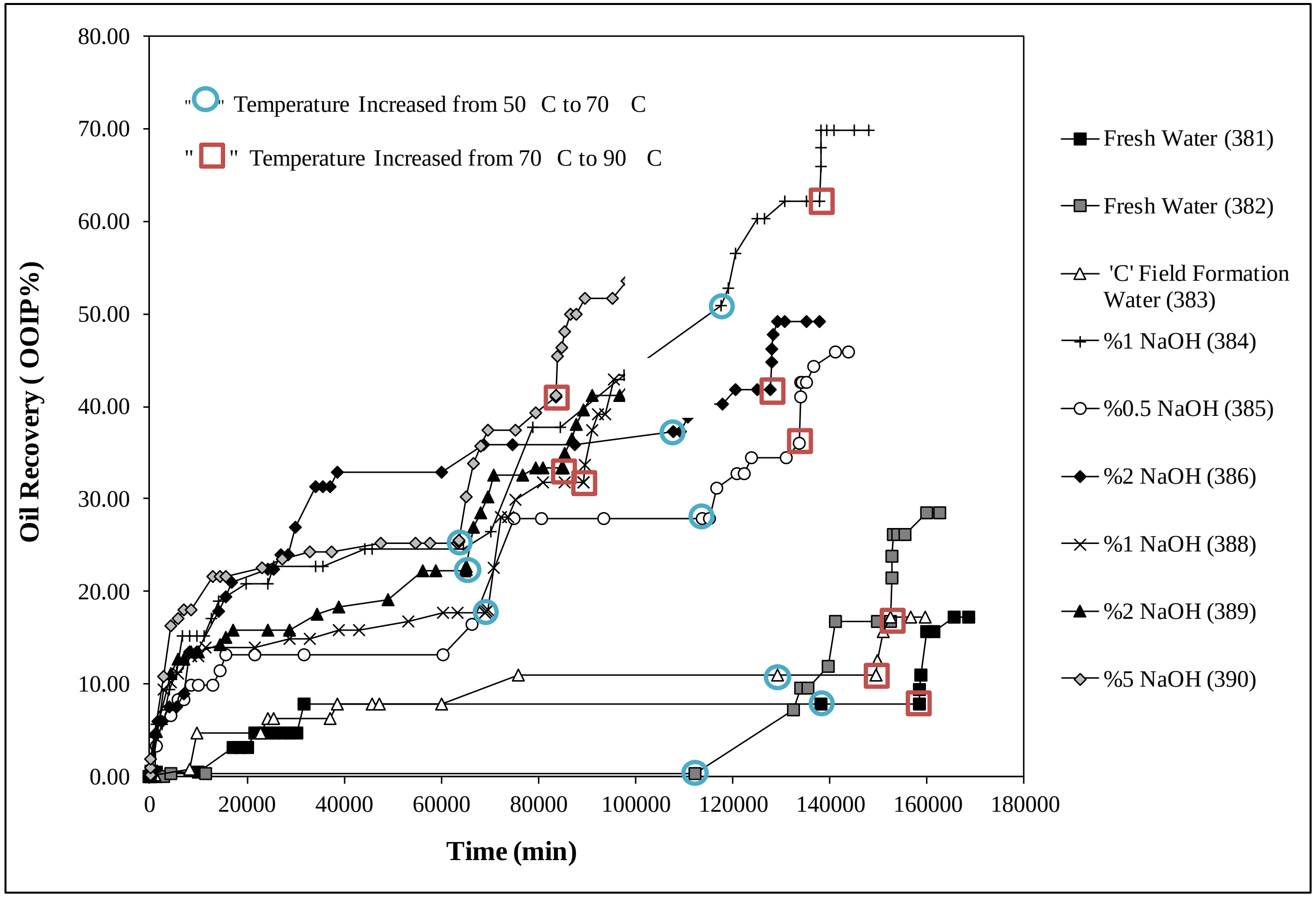


Figure 5.9 Oil Recovery (OOIP%) versus Time Obtained from Imbibition Test for ‘C’ Field at Different Temperatures.

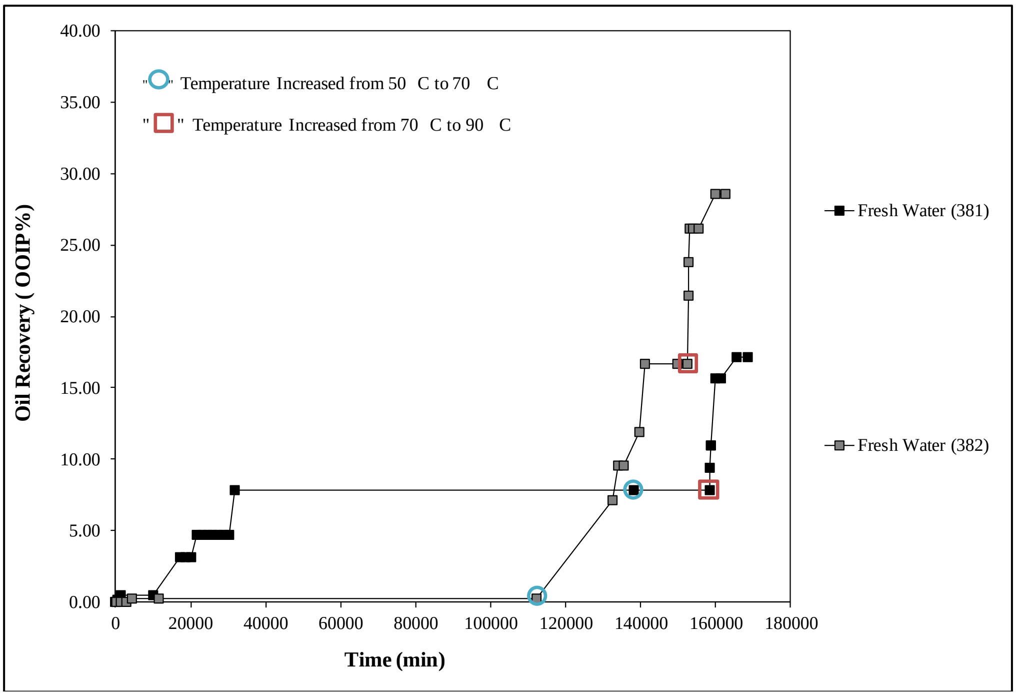


Figure 5.10 Oil Recovery (OOIP%) versus Time Obtained from Imbibition Test for Sample No. 381-382.

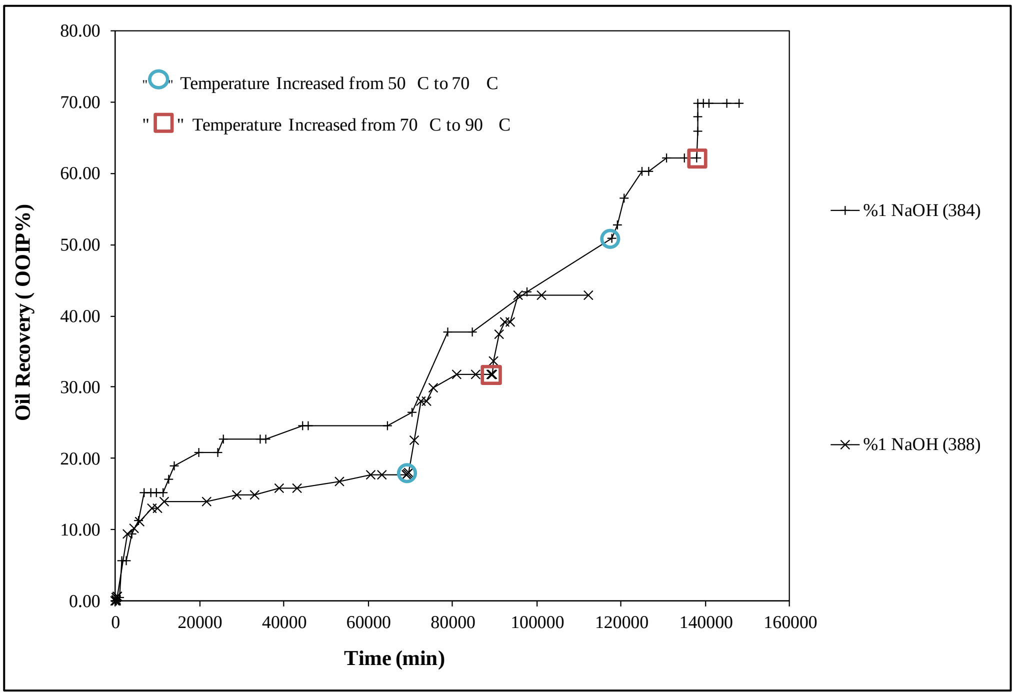


Figure 5.11 Oil Recovery (OOIP%) versus Time Obtained from Imbibition Test for Sample No. 384-388.

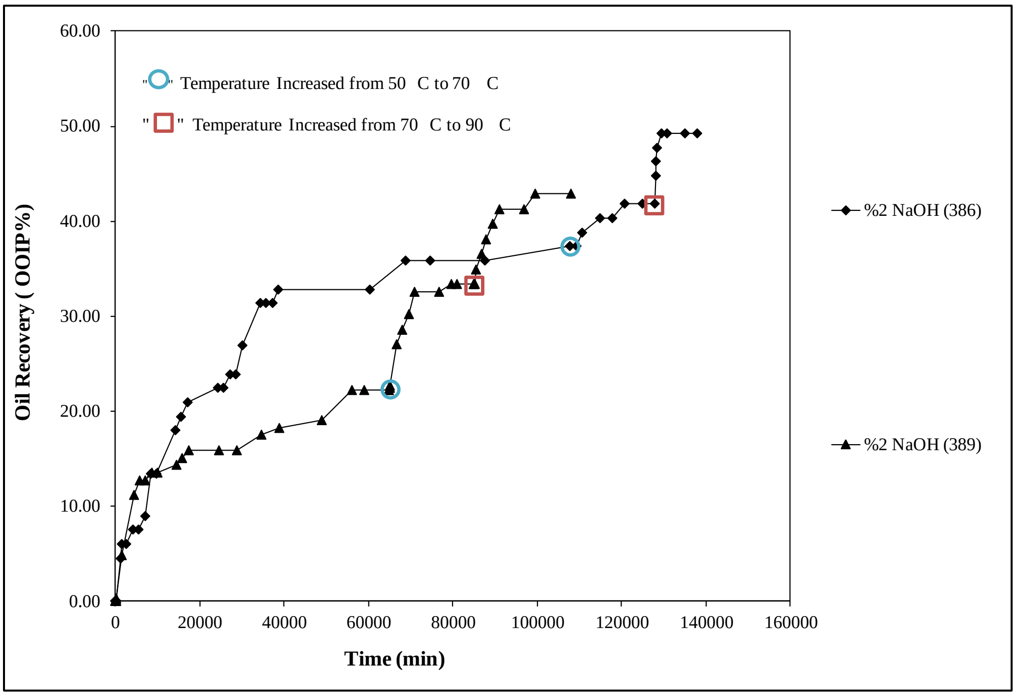


Figure 5.12 Oil Recovery (OOIP%) versus Time Obtained from Imbibition Test for Sample No. 386-389.

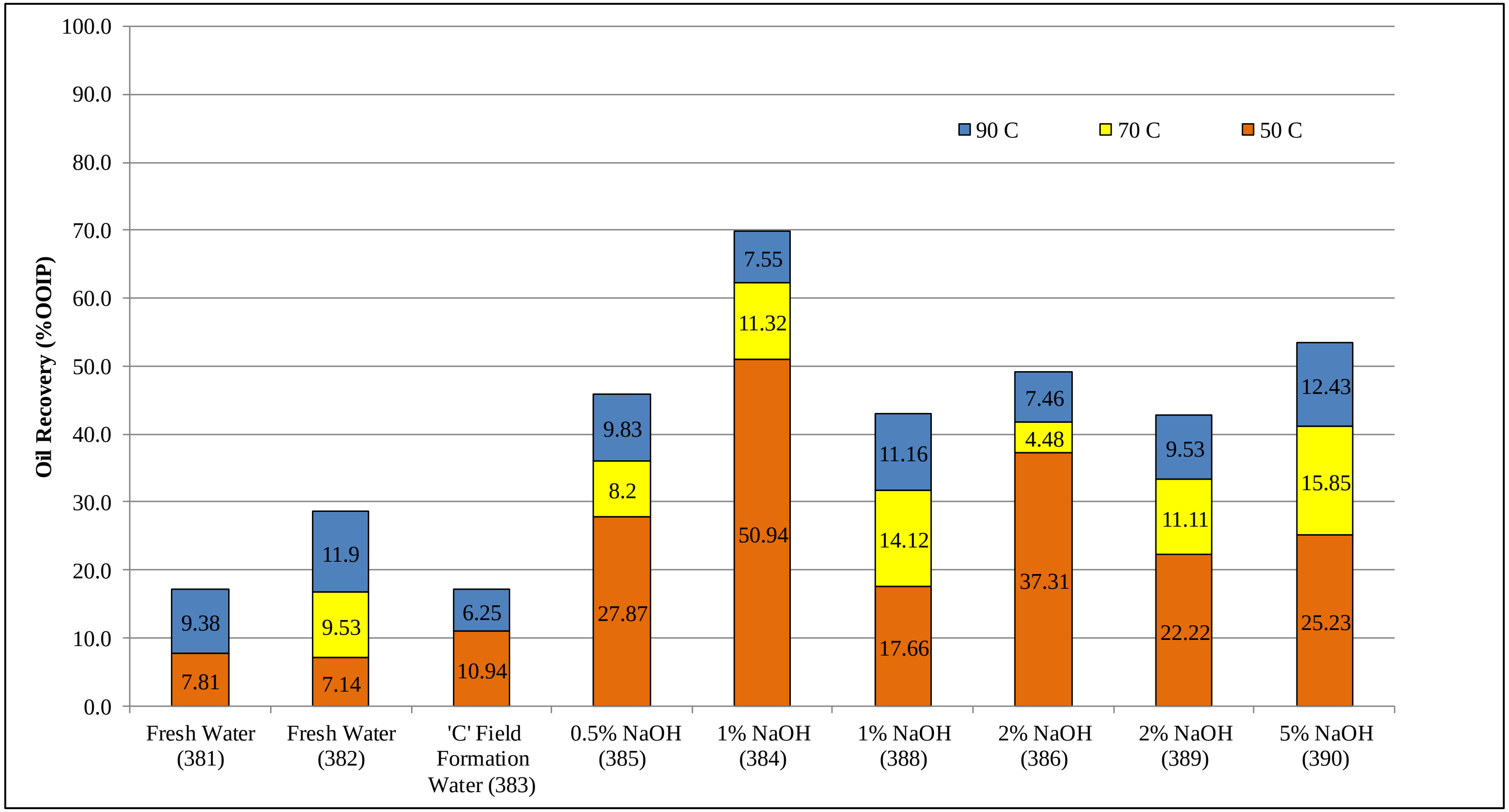


Figure 5.13 Effect of Temperature on Oil Recovery Performance of Imbibition Test for ‘C’ Field.

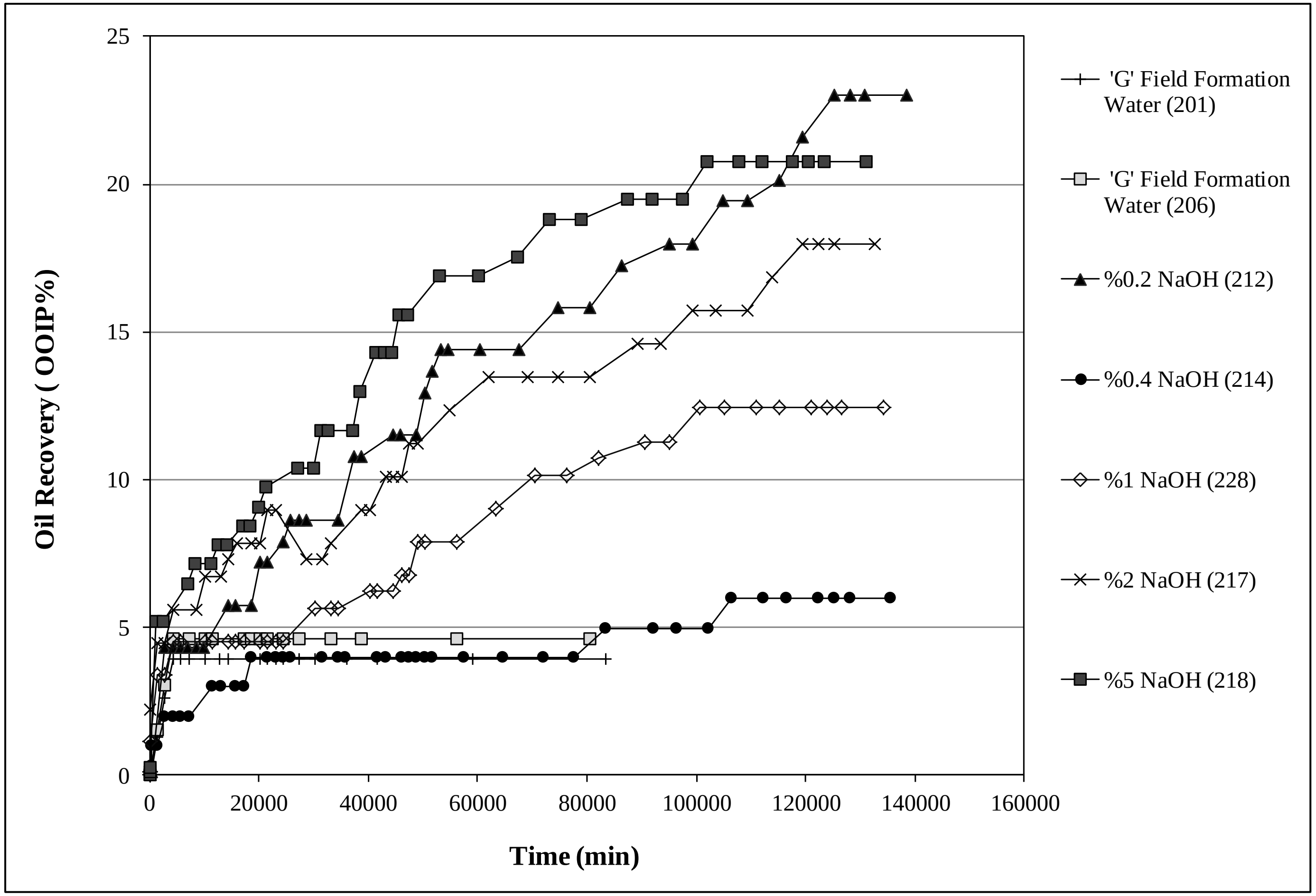


Figure 5.14 Oil Recovery (OOIP%) versus Time Obtained from Imbibition Test for ‘G’ Field at 65 °C.

All of the 16 core plug samples selected for this study were used in spontaneous imbibition tests. For the first set of experiments, as shown in Figure 5.9, fresh water resulted the lowest oil recovery in terms of original oil in place at 50 °C. Fresh water was applied to two of samples and both of them had the same result around 7.5%. At 50 °C, 1.0wt% NaOH showed the highest oil recovery with 50.9%OOIP. Although 2 of the samples did not responded to temperature increase to 70 °C, oil recoveries were raised between 4.5% and 15.9%OOIP when temperature increased up to 70 °C. Increase in additional oil recovery continued for all samples between 6.3% and 12.4%OOIP when temperature increased up to 90 °C (Fig. 51.3). The expansion of oil due to increase in temperature was responsible of some portion of oil recovery. However, in this study the effect of temperature on the expansion of oil was not taken into consideration since the aim is to understand the effect of different NaOH concentrations.

In terms of total recovery, the lowest recoveries were given by fresh water and formation water which were exactly the same result 17.2%OOIP (Fig. 5.10). Sample No. 384 with 1.0wt% NaOH had the highest total oil recovery 69.8%OOIP followed by 5.0wt% and 2.0wt%. All samples had different time intervals at each temperature step. When considering the time intervals, some samples might have higher oil recoveries if there were more time. At about 100 000 minutes of experiment, 5.0wt% NaOH had the highest oil recovery and at that point, it might be said that there was a relationship between NaOH concentration and oil recovery. Also, when 1.0wt% solution was repeated on another plug sample, there was huge drop about 22% in total oil recovery (Fig. 5.11). Accordingly, 2.0wt% NaOH solution was repeated on another spontaneous imbibition test and resulted in 6% percent drop in total recovery compared to previous test run which was acceptable and still below 5.0wt% NaOH oil production (Fig. 5.12).

Second set of the spontaneous imbibition tests on ‘G’ field plug samples showed that the lowest recovery was given by formation water 3.9%OOIP and the highest oil recovery was given by the 0.2wt% NaOH solution 23%OOIP (Fig. 5.14). It was suprising that the highest recovery was occurred from the lowest NaOH concentration. However, other concentrations were arranged in order. 5.0wt% gave the second highest recovery followed by 2.0wt%, 1.0wt% and 0.4wt%, respectively. If we except 0.2wt% NaOH solution, results showed that as NaOH concentration increased oil recovery increased. 0.2wt% might be the optimum concentration for this set of experiments but there should be additional studies to prove this.

From all imbibition experiments, it was concluded that existence of NaOH in the water phase and increase in the temperature caused additional oil recovery from the samples. Results of this study proved the study by Tang and Kovescek (2002) in point of as temperature increases oil saturation remaining after spontaneous imbibition decreases.

5.4 Core Flooding Test Results

After completion of imbibition tests, core flooding tests were conducted on 3 plug samples (381, 382, and 383) to make sure the additional oil recovery with NaOH solutions under dynamic conditions. Firstly, core samples having OOIP were flooded with formation water to state water flooding performance without any additive. After certain amount of the water flooded through the samples, 2% and 5% NaOH solutions were used for the second and the third stage of the core flooding tests respectively. Oil recovery curves and end point data obtained in this part of the study were presented in Figure 5.12 and Table 5.15.

Coreflooding tests were performed on three core plug samples (Sample No. 381, 382, 383) from ‘C’ field and three different fluids, since coreflooding test system was not available to perform additional tests.

Table 5.15 End-Points Data Obtained from Core Flooding Experiments.

Field	Plug No	Porosity (%)	Pore Volume (cc)	kw (md)	Swi (%)	ko @ Swi (md)	Sor[*] (%)	Sor[**] (%)	Sor[***] (%)
C	381	12.5	9.52	1.73	33.0	1.08	59.8	42.7	31.3
C	382	11.2	8.72	4.43	42.0	3.72	60.8	52.6	47.4
C	383	10.4	8.47	4.68	28.0	0.47	47.6	36.7	27.1

[*] After formation water flooding

[**] After 2% NaOH flooding

[***] After 5% NaOH flooding

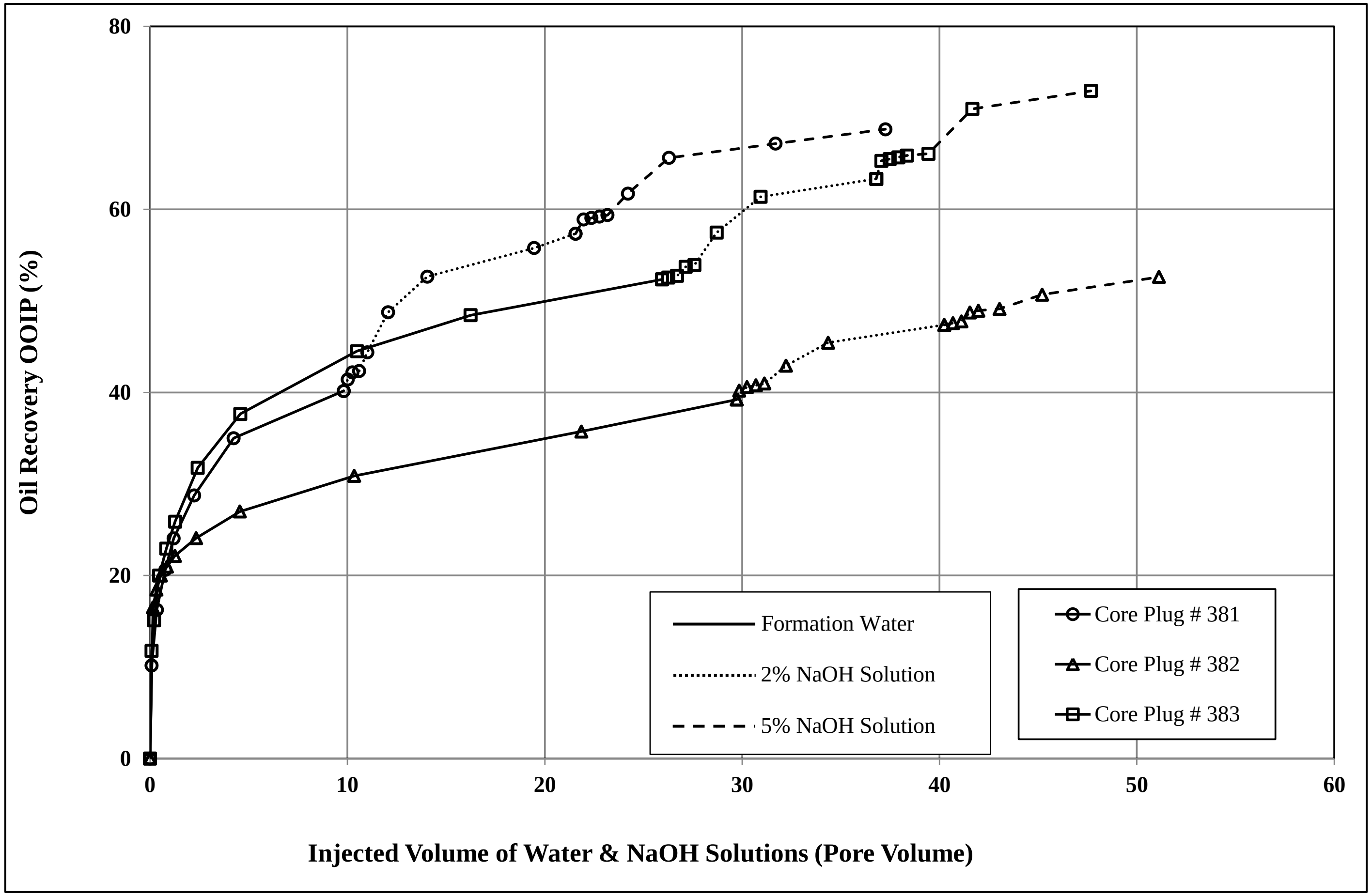


Figure 5.15 Oil Recoveries by Injection of Water and NaOH Solutions at 50 °C.

Coreflooding test results showed that, existence of NaOH in the water phase changed oil production trend and improved water flooding performance. At waterflooding stage, samples 381, 382 and 383 had approximately 40%, 40%, 52% oil recovery in terms of original oil in place, respectively. At 2.0wt% NaOH solution flooding stage, every core sample had additional oil recovery on average 12%OOIP. Also, remaining oil saturations were decreased about 12.1% on all of the samples. In addition, increasing of NaOH concentration from 2% to 5% slightly increased cumulative oil production on samples. Average recovery by 5.0wt% NaOH solution was 8.5%OOIP. Remaining oil saturations of plug samples were reduced 8.7% on average. Therefore it was resulted that mixing NaOH to aqeous phase helped to recover more remaining oil at dynamic conditions,too. This conclusion was the same as Graue and Johnson stated in 1974 that alkaline flooding increases oil recovery when compared to waterflooding under reservoir conditions. Likewise, Arteaga-Cardona et al. (1996) reached to a result which was similar to the result of this study, that oil recovery from alkaline flooding can reach up to 58% while recovery from waterflooding is much lower.

5.5 Interfacial Tension(IFT) Measurements Test Results

Alkalinesolutions like NaOH solution are known to reduce IFT and alter the wettability by increasing mobility of oil through porous media. Throughout the experiments, crude oil and formation water samples from ‘C’ and ‘G’ fields, fresh waterand NaOH solution at various concetrations were used at 65 °Cfor ‘G’ field and 105 °C for ‘C’ field.

Interfacial tension measurements were conducted for both fields. For ‘C’ field, 6 different bulk fluids and one drop fluid were used. As a drop fluid, ‘C’ field crude oil sample was used for all measurements. Measurements were done under 105 °C reservoir temperature and various pressure steps.

For ‘G’ field, as drop fluid crude oil from ‘G’ field was used. Tests were performed under 65 °C constant reservoir temperature.

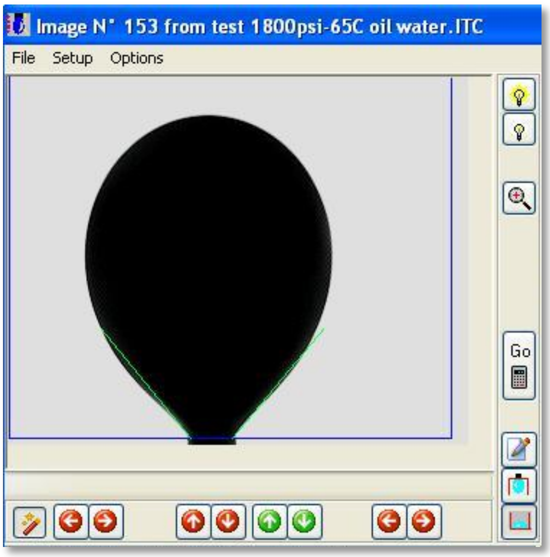


Figure 5.16 Sample Measurement Liquid Drop at 1800 psi and 65 °C for ‘G’ Field.

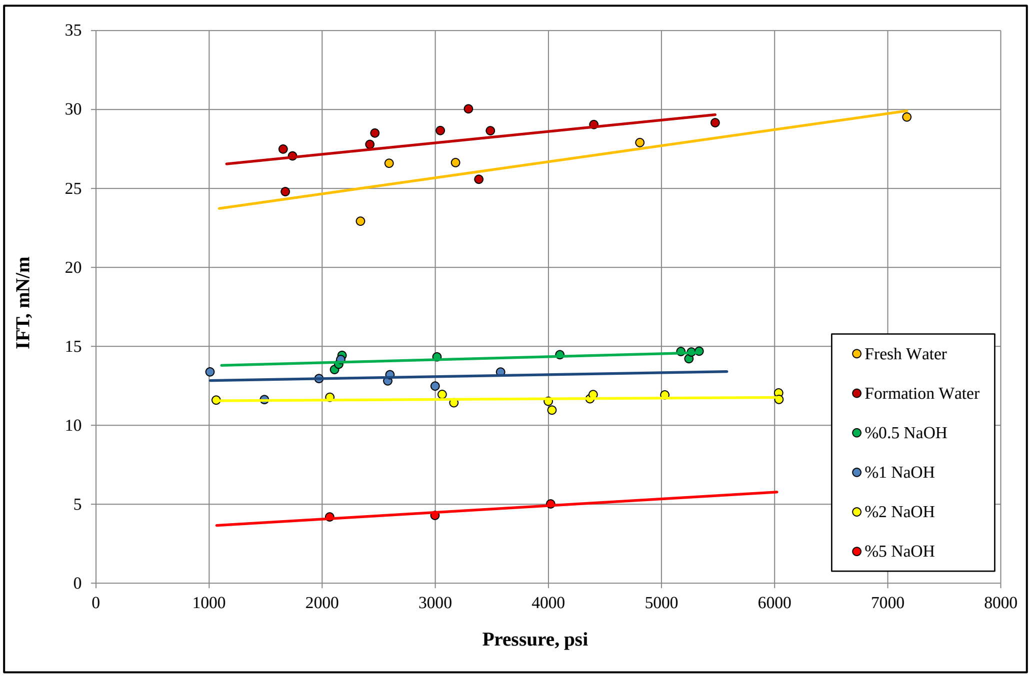


Figure 5.17 Interfacial Tension versus Pressure for Different Solutions at 105 °C for 'C' Field.

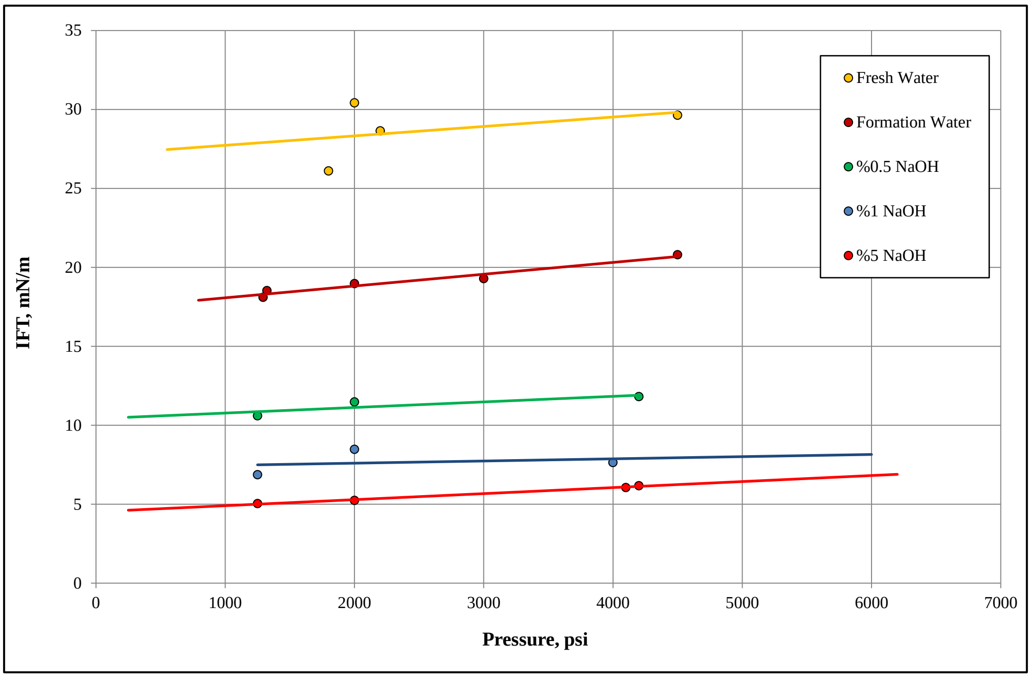


Figure 5.18 Interfacial Tension versus Pressure for Different Solutions at 65 °C for 'G' Field.

As shown in Figure 5.17, interfacial tension measurements for ‘C’ field formation water showed the highest IFT value which was about 28 mN/m. Fresh water had similar IFT value compared to formation water but on average, it was lower. When 0.5wt% NaOH added to fresh water, IFT decreased slightly. IFT continued to decrease as NaOH concentration increased, but 0.5wt%, 1.0wt% and 2.0wt% solutions resulted in very close to each other, yet still there was an order. However, there was a huge difference in IFT when concentration changed from 2.0wt% to 5.0wt%. 5.0wt% NaOH solution gave us the best interfacial tension as low as 5 mN/m . Therefore, these results indicated that interfacial tension decreased as a subsequent of increase in NaOH concentration.

In experiments of ‘G’ field, fresh water interfacial tension measurement results were almost the same as ‘C’ field (Fig. 5.18). But formation water IFT value was nearly 2/3 of ‘C’ field formation water result. Salinity difference might lead to this difference. Ramakrishnan and Wasan (1983) discovered NaOH concentration and formation water salinity both affect the interfacial tension between fluid phases. They reached the lowest IFT values when using NaOH solutions with concentration of 0.01% to 0.1% by weight. This low concetrations were not studied in this study since some of the field researches showed that there may occur concentration loss problems during injection. (Surkalo 1990) Similarly, increase in NaOH concentration lowered IFT for other concentrations too. But compared to ‘C’ field, 0.5wt% and 1.0wt% had lower results, nearly 11 mN/m and 7.5 mN/m respectively. 5.0wt% NaOH solution had IFT result as 5.5 mN/m which was very close to previous 5.0wt% IFT measurements.

There was a correlation between NaOH concentrations and IFT measurements. Although results of two fields were not matching each other perfectly, it was obtained that as NaOH concentration increased, interfacial tension decreased.

CHAPTER 6

CONCLUSIONS

This research study was focused on the effects of NaOH solutions as an enhanced oil recovery method for limestone medium.On the suitable samples selected from limestone formation, spontaneous imbibition tests, core flood test and interfacial tension measurements were performed to obtain the effects of NaOH concentration and temperature.

Spontaneous imbibition tests of 'C' and 'G' fields showed that addition of NaOH as an alkali compound increased the oil recovery when compared to fresh water and formation water in limestone reservoirs. 1.0wt% and 0.2wt% NaOH solutions resulted the highest oil recoveries. However, time intervals were not the same for each sample and when considering the time intervals, some samples might have higher oil recoveries if there were more time and it might be said that there was a proportional relationship between NaOH concentration and oil recovery except 0.2wt% NaOH solution used in ‘G’ field. Fresh water, 1.0wt% and 2.0wt% NaOH solutions were applied twice to different plugs from 'C' field and oil recovery results were inconsistent. This result might be caused from different rock properties of different core samples. Also, temperature increase during the imbibition tests led to increase in oil recovery for all solutions and core samples.

Coreflooding tests also resulted that mixing NaOH to aqeous phase helped to recover more remaining oil from limestone medium after waterflooding at dynamic conditions.

Moreover, the existence of NaOH in water phase definitely effected interfacial tension. Studies in this experiments presented that NaOH concentration had a substantial effect. As NaOH increased, interfacial tension decreased in all of the experiments.

For a possible field application it is highly recommended that, NaOH solutions should be prepared with fresh water. Laboratory experiences showed that, if formation water is used to prepare the solutions, some solubility problems occur.

CHAPTER 7

FUTURE WORK

For future works, it is strongly suggested that there should be more experiments on ‘C’ and ‘G’ field samples. Since imbibition tests require nearly 4 months to perform, repeatability studies were not included in this study due to lack of time. In order to obtain repeatability, imbibition tests should be conducted on the same core plug samples and all solutions should be used for both of the fields.Also, coreflooding tests should be repeated on the same core samples with the same solutions and also with different combinations of solutions. Other concentrations of NaOH (lower than 0.2%wt and higher than 5%wt), which were not studied in this research,should be experimented in order to obtain the optimum concentration. Also, wettability alteration is a major concern that should be taken into account. For that reason, contact angle measurements should be done with various NaOH concentrations to observe wettability change in core samples of 'C' and 'G' fields.

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APPENDIX A

CAPILLARY PRESSURE TEST DATA AND CURVES

Table A.1 Capillary Pressure Test Drainage Data Sample No. 381

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
2.51	85	100	557	0.4	63
3.04	70	100	639	0.3	62
3.57	60	100	733	0.3	61
4.21	51	100	841	0.3	60
4.95	43	100	965	0.2	60
5.84	37	100	1108	0.19	59
6.9	31	100	1272	0.17	58.2
8.1	26	100	1458	0.15	57.6
9.5	22	100	1673	0.13	57.1
11.2	19	100	1920	0.11	56.7
13.2	16	100	2204	0.10	56.3
15.6	14	100	2530	0.08	55.9
18.4	12	100	2900	0.07	55.7
21.6	10	100	3329	0.06	55.5
25.5	8	100	3821	0.06	55.3
29.0	7	100	4381	0.05	55.2
34.3	6	99	5028	0.04	55.1
39.6	5	98	5771	0.04	55.0
45.6	5	97	6621	0.03	54.9
53.0	4	96	7600	0.03	54.9
59	4	95	8722	0.02	54.9
68	3	94	10016	0.021	54.9
80	3	92	11493	0.019	54.9
92	2	90	13190	0.016	54.9
105	2.0	87	15135	0.014	54.9
122	1.8	84	17371	0.012	54.9
139	1.5	82	19938	0.011	54.9

Table A.1 Capillary Pressure Test Drainage Data Sample No. 381 (cont'd)

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
160	1.3	79	22890	0.0093	54.9
184	1.2	77	26273	0.0081	54.9
211	1.0	74	30150	0.0071	54.9
243	0.9	72	34595	0.0062	54.9
279	0.8	70	39698	0.0054	54.9
319	0.7	68	45559	0.0047	54.9
368	0.6	67	52272	0.0041	54.9
420	0.5	65	59977	0.0036	54.9
485	0.4	64			

Table A.2 Capillary Pressure Test Imbibition Data Sample No. 381

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59977	0.0036	54.94	882	0.242	54.9
51596	0.0041	54.94	759	0.281	54.9
44376	0.0048	54.94	651	0.327	54.9
38168	0.0056	54.94	562	0.380	54.9
32823	0.0065	54.94	483	0.441	55.1
28231	0.0076	54.94	415	0.514	55.4
24285	0.0088	54.94	358	0.596	55.8
20890	0.0102	54.94	309	0.690	56.2
17969	0.0119	54.94	265	0.804	56.4
15452	0.0138	54.94	227	0.941	56.8
13292	0.0160	54.94	195	1.09	57.2
11438	0.0186	54.94	169	1.26	57.6
9838	0.0217	54.94	145	1.47	58.1
8459	0.0252	54.94	125	1.70	58.7
7278	0.0293	54.94	108	1.98	59.3
6259	0.0341	54.9	92.0	2.32	60.0
5387	0.0396	54.9	79.5	2.68	60.9
4631	0.0461	54.9	68.6	3.11	61.7
3980	0.0536	54.9	58.0	3.68	62.9
3420	0.0624	54.9	50.8	4.20	63.8
2942	0.0725	54.9	43.9	4.86	65.5
2531	0.0843	54.9	38.0	5.61	66.8
2175	0.0981	54.9	32.0	6.66	68.0
1869	0.114	54.9	27.5	7.74	69.6
1610	0.132	54.9	23.9	8.94	71.6
1385	0.154	54.9	23.6	9.06	71.7
1191	0.179	54.9	17.7	12.08	74.2
1025	0.208	54.9			

Table A.3 Capillary Pressure Test Drainage Data Sample No. 382

P_c. psia	**d. µm**	**S_w. %**	**P_c. psia**	**d. µm**	**S_w. %**
2.51	85	100	555	0.4	54
3.03	70	100	637	0.3	53
3.57	60	100	733	0.3	52
4.21	51	100	841	0.3	51
4.96	43	100	965	0.2	50
5.84	37	100	1107	0.19	49
6.9	31	100	1271	0.17	48.6
8.1	26	100	1457	0.15	48.0
9.5	22	100	1673	0.13	47.4
11.2	19	100	1921	0.11	46.9
13.2	16	100	2203	0.10	46.4
15.6	14	100	2532	0.08	46.2
18.4	12	100	2904	0.07	45.9
21.6	10	100	3331	0.06	45.6
25.5	8	100	3827	0.06	45.3
29.0	7	100	4381	0.05	45.2
34.9	6	99	5030	0.04	45.1
40.6	5	97	5772	0.04	44.9
46.4	5	96	6626	0.03	44.9
52.6	4	94	7601	0.03	44.9
61	4	92	8725	0.02	44.9
70	3	89	10017	0.021	44.9
81	3	86	11490	0.019	44.9
92	2	83	13191	0.016	44.9
105	2.0	80	15138	0.014	44.9
121	1.8	77	17374	0.012	44.9
140	1.5	74	19935	0.011	44.9
160	1.3	71	22890	0.0093	44.9
184	1.2	69	26272	0.0081	44.9
211	1.0	66	30150	0.0071	44.9
242	0.9	64	34599	0.0062	44.9
279	0.8	61	39704	0.0054	44.9
320	0.7	59	45558	0.0047	44.9
367	0.6	58	52272	0.0041	44.9
421	0.5	56	59977	0.0036	44.9
483	0.4	55			

Table A.4 Capillary Pressure Test Imbibition Data Sample No. 382

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59977	0.0036	44.90	883	0.241	44.9
51598	0.0041	44.90	760	0.281	44.9
44381	0.0048	44.90	651	0.327	44.9
38163	0.0056	44.90	561	0.380	44.9
32821	0.0065	44.90	482	0.442	44.9
28228	0.0076	44.90	415	0.514	45.1
24284	0.0088	44.90	357	0.598	45.5
20886	0.0102	44.90	309	0.689	45.9
17968	0.0119	44.90	265	0.805	46.4
15447	0.0138	44.90	226	0.943	46.7
13291	0.0160	44.90	195	1.10	47.3
11438	0.0186	44.90	167	1.27	47.9
9830	0.0217	44.90	144	1.48	48.5
8465	0.0252	44.90	125	1.71	49.2
7275	0.0293	44.90	108	1.97	49.8
6260	0.0341	44.9	92.6	2.30	50.8
5385	0.0396	44.9	78.9	2.70	51.7
4634	0.0460	44.9	69.0	3.09	52.6
3980	0.0536	44.9	59.5	3.59	53.9
3422	0.0623	44.9	51.0	4.18	55.3
2943	0.0725	44.9	43.9	4.85	57.1
2530	0.0843	44.9	37.1	5.74	59.1
2177	0.0980	44.9	32.2	6.63	60.6
1872	0.114	44.9	27.5	7.75	62.9
1610	0.132	44.9	23.8	8.95	64.9
1385	0.154	44.9	20.7	10.31	67.3
1190	0.179	44.9	18.0	11.88	69.4
1024	0.208	44.9			

Table A.5 Capillary Pressure Test Drainage Data Sample No. 383

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
2.51	85	100	555	0.4	47
3.03	70	100	637	0.3	45
3.57	60	100	733	0.3	43
4.21	51	100	841	0.3	41
4.96	43	100	964	0.2	40
5.84	37	100	1107	0.19	39
6.9	31	100	1271	0.17	37.6
8.1	26	100	1457	0.15	36.6
9.5	22	100	1673	0.13	35.5
11.2	19	100	1921	0.11	34.7
13.2	16	100	2203	0.10	33.9
15.6	14	100	2532	0.08	33.3
18.4	12	100	2904	0.07	32.8
21.6	10	100	3331	0.06	32.5
25.5	8	100	3827	0.06	31.9
29.0	7	100	4381	0.05	31.5
35.0	6	100	5030	0.04	31.3
40.8	5	100	5772	0.04	31.2
46.6	5	99	6626	0.03	31.0
52.8	4	99	7601	0.03	30.8
61	3	98	8725	0.02	30.7
70	3	97	10017	0.021	30.7
81	3	96	11489	0.019	30.7
92	2	94	13190	0.016	30.7
106	2.0	93	15138	0.014	30.7
122	1.8	90	17374	0.012	30.7
141	1.5	86	19935	0.011	30.7
160	1.3	82	22890	0.0093	30.7
185	1.2	78	26272	0.0081	30.7
211	1.0	73	30150	0.0071	30.7
243	0.9	68	34599	0.0062	30.7
279	0.8	63	39704	0.0054	30.7
320	0.7	59	45558	0.0047	30.7
367	0.6	55	52272	0.0041	30.7
421	0.5	52	59977	0.0036	30.7
483	0.4	49			

Table A.6 Capillary Pressure Test Imbibition Data Sample No. 383

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59977	0.0036	30.68	883	0.241	30.7
51598	0.0041	30.68	760	0.281	30.7
44381	0.0048	30.68	651	0.328	31.1
38163	0.0056	30.68	561	0.380	31.5
32821	0.0065	30.68	482	0.442	32.0
28228	0.0076	30.68	415	0.514	32.5
24284	0.0088	30.68	357	0.598	33.0
20886	0.0102	30.68	309	0.690	33.6
17969	0.0119	30.68	265	0.805	34.3
15447	0.0138	30.68	226	0.943	34.8
13290	0.0160	30.68	195	1.10	35.6
11438	0.0186	30.68	167	1.27	36.4
9830	0.0217	30.68	144	1.48	37.3
8465	0.0252	30.68	125	1.71	38.4
7275	0.0293	30.68	108	1.98	39.6
6258	0.0341	30.7	92.6	2.30	41.3
5385	0.0396	30.7	79.0	2.70	42.9
4633	0.0460	30.7	69.0	3.09	44.4
3979	0.0536	30.7	59.5	3.59	46.3
3422	0.0623	30.7	50.9	4.19	48.2
2943	0.0725	30.7	43.9	4.85	50.5
2530	0.0843	30.7	37.2	5.74	53.2
2177	0.0980	30.7	32.2	6.62	55.1
1872	0.114	30.7	27.6	7.74	56.5
1610	0.132	30.7	23.8	8.95	57.8
1385	0.154	30.7	20.7	10.31	59.1
1190	0.179	30.7	18.0	11.82	60.2
1023	0.208	30.7			

Table A.7 Capillary Pressure Test Drainage Data Sample No. 384

P_c. psia	**d. µm**	**S_w. %**	**P_c. psia**	**d. µm**	**S_w. %**
2.51	85	100	556	0.4	33
3.03	70	100	639	0.3	32
3.57	60	100	731	0.3	31
4.21	51	100	840	0.3	30
4.96	43	100	965	0.2	30
5.84	37	100	1107	0.19	29
6.9	31	100	1272	0.17	28.6
8.1	26	100	1458	0.15	28.2
9.5	22	100	1675	0.13	27.8
11.2	19	100	1920	0.11	27.5
13.2	16	100	2203	0.10	27.2
15.6	14	100	2530	0.08	27.0
18.4	12	100	2902	0.07	26.9
21.6	10	100	3333	0.06	26.8
25.5	8	100	3820	0.06	26.7
29.0	7	100	4379	0.05	26.6
34.5	6	100	5029	0.04	26.6
37.6	6	100	5769	0.04	26.6
46.1	5	98	6624	0.03	26.6
52.3	4	97	7602	0.03	26.6
61	4	95	8726	0.02	26.6
70	3	93	10015	0.021	26.6
81	3	89	11492	0.019	26.6
93	2	84	13189	0.016	26.6
106	2.0	76	15137	0.014	26.6
121	1.8	69	17371	0.012	26.6
140	1.5	61	19933	0.011	26.6
161	1.3	55	22891	0.0093	26.6
184	1.2	51	26272	0.0081	26.6
212	1.0	47	30148	0.0071	26.6
241	0.9	44	34597	0.0062	26.6
278	0.8	41	39697	0.0054	26.6
320	0.7	39	45559	0.0047	26.6
367	0.6	37	52272	0.0041	26.6
421	0.5	36	59977	0.0036	26.6
483	0.4	34			

Table A.8 Capillary Pressure Test Imbibition Data Sample No. 384

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59977	0.0036	26.56	881	0.242	26.6
51596	0.0041	26.56	759	0.281	26.6
44381	0.0048	26.56	652	0.327	26.6
38166	0.0056	26.56	561	0.380	26.8
32825	0.0065	26.56	480	0.445	27.1
28232	0.0076	26.56	415	0.514	27.5
24285	0.0088	26.56	356	0.598	27.8
20888	0.0102	26.56	308	0.692	28.3
17963	0.0119	26.56	265	0.806	28.8
15451	0.0138	26.56	229	0.933	29.4
13293	0.0160	26.56	195	1.10	30.1
11433	0.0187	26.56	168	1.27	31.0
9834	0.0217	26.56	145	1.47	31.9
8463	0.0252	26.56	125	1.71	33.0
7277	0.0293	26.56	108	1.98	34.2
6263	0.0341	26.6	93.0	2.29	35.9
5385	0.0396	26.6	79.8	2.67	37.8
4632	0.0460	26.6	69.1	3.09	40.1
3980	0.0536	26.6	60.0	3.55	42.8
3419	0.0624	26.6	50.0	4.26	46.0
2943	0.0725	26.6	44.4	4.81	49.8
2531	0.0843	26.6	37.7	5.65	53.8
2178	0.0979	26.6	32.8	6.51	57.7
1871	0.114	26.6	27.7	7.71	61.6
1609	0.133	26.6	23.9	8.93	64.2
1385	0.154	26.6	20.7	10.33	65.8
1192	0.179	26.6	18.2	11.72	67.5
1026	0.208	26.6			

Table A.9 Capillary Pressure Test Drainage Data Sample No. 385

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
2.51	85	100	556	0.4	41
3.03	70	100	639	0.3	40
3.57	60	100	731	0.3	40
4.21	51	100	840	0.3	39
4.96	43	100	965	0.2	38
5.84	37	100	1107	0.19	37
6.9	31	100	1272	0.17	36.3
8.1	26	100	1458	0.15	35.8
9.5	22	100	1675	0.13	35.5
11.2	19	100	1920	0.11	34.5
13.2	16	100	2203	0.10	34.2
15.6	14	100	2530	0.08	33.9
18.4	12	100	2902	0.07	33.9
21.6	10	100	3333	0.06	33.9
25.5	8	100	3820	0.06	33.8
29.0	7	100	4379	0.05	33.6
34.3	6	99	5029	0.04	33.6
37.4	6	98	5769	0.04	33.6
45.8	5	95	6624	0.03	33.6
52.0	4	93	7602	0.03	33.5
61	4	91	8726	0.02	33.5
70	3	88	10015	0.021	33.5
80	3	85	11492	0.019	33.5
93	2	81	13189	0.016	33.5
106	2.0	76	15137	0.014	33.5
121	1.8	71	17372	0.012	33.5
140	1.5	65	19933	0.011	33.5
161	1.3	61	22891	0.0093	33.5
184	1.2	57	26272	0.0081	33.5
212	1.0	54	30148	0.0071	33.5
242	0.9	51	34597	0.0062	33.5
278	0.8	49	39697	0.0054	33.5
320	0.7	47	45559	0.0047	33.5
367	0.6	45	52272	0.0041	33.5
421	0.5	44	59977	0.0036	33.5
483	0.4	43			

Table A.10 Capillary Pressure Test Imbibition Data Sample No. 385

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59977	0.0036	33.51	881	0.242	33.5
51596	0.0041	33.51	759	0.281	33.5
44381	0.0048	33.51	652	0.327	33.5
38166	0.0056	33.51	561	0.380	33.5
32825	0.0065	33.51	480	0.445	33.5
28232	0.0076	33.51	415	0.514	33.5
24285	0.0088	33.51	356	0.598	33.5
20888	0.0102	33.51	308	0.692	33.6
17963	0.0119	33.51	265	0.806	34.1
15451	0.0138	33.51	229	0.933	34.7
13293	0.0160	33.51	195	1.10	35.3
11433	0.0187	33.51	168	1.27	36.2
9834	0.0217	33.51	145	1.47	37.0
8463	0.0252	33.51	125	1.71	37.9
7277	0.0293	33.51	108	1.98	39.0
6263	0.0341	33.5	93.0	2.29	40.5
5385	0.0396	33.5	79.7	2.67	42.1
4632	0.0460	33.5	69.0	3.09	44.1
3980	0.0536	33.5	59.9	3.56	46.4
3419	0.0624	33.5	50.0	4.27	49.1
2942	0.0725	33.5	44.3	4.82	52.2
2531	0.0843	33.5	37.6	5.67	55.7
2178	0.0979	33.5	32.6	6.53	59.4
1871	0.114	33.5	27.6	7.74	63.9
1609	0.133	33.5	23.8	8.96	67.6
1385	0.154	33.5	20.6	10.36	70.4
1192	0.179	33.5	18.2	11.69	73.7
1026	0.208	33.5			

Table A.11 Capillary Pressure Test Drainage Data Sample No. 386

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
2.51	85	100	557	0.4	37
3.04	70	100	638	0.3	35
3.57	60	100	732	0.3	33
4.21	51	100	840	0.3	32
4.95	43	100	964	0.2	31
5.84	37	100	1108	0.19	29
6.9	31	100	1271	0.17	28.5
8.1	26	100	1457	0.15	27.7
9.5	22	100	1672	0.13	27.0
11.2	19	100	1919	0.11	26.5
13.2	16	100	2203	0.10	26.0
15.6	14	100	2530	0.08	25.7
18.4	12	100	2899	0.07	25.4
21.6	10	100	3329	0.06	25.3
25.5	8	100	3820	0.06	25.1
29.0	7	100	4381	0.05	25.0
34.2	6	99	5027	0.04	24.9
39.4	5	99	5770	0.04	24.7
45.5	5	98	6620	0.03	24.7
52.8	4	96	7599	0.03	24.7
59	4	95	8722	0.02	24.7
68	3	93	10015	0.021	24.7
80	3	91	11493	0.019	24.7
92	2	88	13189	0.016	24.7
105	2.0	84	15134	0.014	24.7
121	1.8	78	17370	0.012	24.7
138	1.5	73	19937	0.011	24.7
160	1.3	68	22890	0.0093	24.7
184	1.2	63	26272	0.0081	24.7
211	1.0	58	30149	0.0071	24.7
242	0.9	53	34594	0.0062	24.7
278	0.8	49	39697	0.0054	24.7
318	0.7	46	45559	0.0047	24.7
367	0.6	44	52271	0.0041	24.7
419	0.5	41	59976	0.0036	24.7
484	0.4	39			

Table A.12 Capillary Pressure Test Imbibition Data Sample No. 386

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59976	0.0036	24.70	881	0.242	24.7
51595	0.0041	24.70	758	0.281	24.7
44375	0.0048	24.70	651	0.328	24.7
38167	0.0056	24.70	561	0.380	24.7
32822	0.0065	24.70	483	0.442	25.1
28230	0.0076	24.70	414	0.515	25.4
24284	0.0088	24.70	357	0.597	26.1
20889	0.0102	24.70	308	0.692	26.7
17967	0.0119	24.70	265	0.806	27.3
15451	0.0138	24.70	226	0.944	28.3
13291	0.0160	24.70	195	1.10	29.2
11437	0.0186	24.70	168	1.27	30.3
9837	0.0217	24.70	145	1.47	32.0
8458	0.0252	24.70	125	1.71	33.1
7277	0.0293	24.70	107	1.99	34.3
6258	0.0341	24.7	91.3	2.34	35.7
5386	0.0396	24.7	78.9	2.70	37.8
4630	0.0461	24.7	67.6	3.16	39.7
3979	0.0536	24.7	57.3	3.72	42.2
3420	0.0624	24.7	50.2	4.25	44.2
2941	0.0725	24.7	43.4	4.91	47.5
2530	0.0843	24.7	37.5	5.69	50.3
2174	0.0981	24.7	31.5	6.76	52.7
1868	0.114	24.7	27.1	7.88	55.2
1610	0.132	24.7	23.4	9.11	58.2
1384	0.154	24.7	23.1	9.23	58.2
1190	0.179	24.7	17.2	12.39	61.5
1024	0.208	24.7			

Table A.13 Capillary Pressure Test Drainage Data Sample No. 388

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
2.51	85	100	556	0.4	37
3.04	70	100	636	0.3	36
3.57	60	100	732	0.3	34
4.21	51	100	840	0.3	33
4.95	43	100	965	0.2	31
5.84	37	100	1108	0.19	30
6.9	31	100	1273	0.17	29.4
8.1	26	100	1458	0.15	28.5
9.5	22	100	1672	0.13	27.9
11.2	19	100	1918	0.11	27.1
13.2	16	100	2202	0.10	26.5
15.6	14	100	2529	0.08	26.1
18.4	12	100	2899	0.07	25.6
21.6	10	100	3329	0.06	25.3
25.5	8	100	3822	0.06	25.0
29.0	7	100	4381	0.05	24.7
33.2	6	100	5027	0.04	24.5
39.8	5	99	5772	0.04	24.3
46.0	5	98	6622	0.03	24.0
53.0	4	97	7600	0.03	23.8
59	4	96	8724	0.02	23.6
69	3	95	10014	0.021	23.4
79	3	93	11494	0.019	23.2
92	2	90	13189	0.016	23.0
106	2.0	87	15134	0.014	23.0
122	1.8	83	17377	0.012	22.7
139	1.5	78	19934	0.011	22.5
160	1.3	72	22889	0.0093	22.4
185	1.2	66	26270	0.0081	22.4
212	1.0	60	30147	0.0071	22.4
244	0.9	55	34597	0.0062	22.4
279	0.8	51	39698	0.0054	22.4
320	0.7	47	45559	0.0047	22.4
367	0.6	44	52272	0.0041	22.4
420	0.5	42	59976	0.0036	22.4
483	0.4	39			

Table A.14 Capillary Pressure Test Imbibition Data Sample No. 388

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59976	0.0036	22.36	880	0.242	23.7
51599	0.0041	22.36	757	0.282	24.2
44376	0.0048	22.36	651	0.328	24.5
38170	0.0056	22.36	559	0.381	25.3
32820	0.0065	22.36	481	0.444	25.7
28234	0.0076	22.36	416	0.513	26.3
24284	0.0088	22.36	357	0.598	27.1
20886	0.0102	22.36	306	0.698	27.7
17965	0.0119	22.36	264	0.808	28.5
15456	0.0138	22.36	229	0.933	30.1
13290	0.0160	22.36	196	1.09	30.6
11432	0.0187	22.36	168	1.27	31.5
9832	0.0217	22.36	145	1.47	33.1
8458	0.0252	22.36	124	1.72	34.4
7275	0.0293	22.36	107	2.00	36.2
6258	0.0341	22.4	91.6	2.33	38.1
5383	0.0396	22.4	78.9	2.70	40.5
4633	0.0460	22.4	68.1	3.13	43.5
3979	0.0536	22.4	59.2	3.61	46.0
3421	0.0623	22.4	50.0	4.27	49.3
2943	0.0725	22.4	43.6	4.89	51.7
2530	0.0843	22.4	37.9	5.63	54.3
2174	0.0981	22.4	33.1	6.44	56.3
1868	0.114	22.4	27.5	7.74	57.8
1609	0.133	22.4	23.7	8.99	59.5
1382	0.154	22.4	20.2	10.53	60.6
1190	0.179	22.5	19.4	10.97	60.8
1023	0.208	23.0			

Table A.15 Capillary Pressure Test Drainage Data Sample No. 389

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
2.51	85	100	556	0.4	32
3.03	70	100	638	0.3	30
3.57	60	100	733	0.3	28
4.21	51	100	841	0.3	26
4.96	43	100	964	0.2	25
5.84	37	100	1108	0.19	24
6.9	31	100	1270	0.17	22.4
8.1	26	100	1458	0.15	21.5
9.5	22	100	1675	0.13	20.8
11.2	19	100	1919	0.11	20.1
13.2	16	100	2203	0.10	19.6
15.6	14	100	2529	0.08	19.3
18.4	12	100	2902	0.07	19.0
21.6	10	100	3330	0.06	18.8
25.5	8	100	3821	0.06	18.6
29.0	7	100	4380	0.05	18.6
34.0	6	99	5028	0.04	18.5
40.4	5	99	5771	0.04	18.5
46.7	5	98	6623	0.03	18.5
51.2	4	98	7603	0.03	18.5
59	4	97	8724	0.02	18.5
70	3	96	10014	0.021	18.5
80	3	95	11493	0.019	18.5
91	2	93	13190	0.016	18.5
103	2.1	91	15138	0.014	18.5
122	1.8	89	17372	0.012	18.5
139	1.5	86	19938	0.011	18.5
160	1.3	82	22890	0.0093	18.5
185	1.2	77	26272	0.0081	18.5
212	1.0	69	30148	0.0071	18.5
243	0.9	60	34598	0.0062	18.5
278	0.8	53	39700	0.0054	18.5
319	0.7	47	45559	0.0047	18.5
368	0.6	42	52274	0.0041	18.5
421	0.5	38	59978	0.0036	18.5
484	0.4	35			

Table A.16 Capillary Pressure Test Imbibition Data Sample No. 389

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59978	0.0036	18.50	880	0.242	18.5
51596	0.0041	18.50	757	0.282	18.5
44379	0.0048	18.50	650	0.328	18.5
38166	0.0056	18.50	561	0.380	18.5
32825	0.0065	18.50	482	0.442	18.8
28232	0.0076	18.50	417	0.512	19.3
24284	0.0088	18.50	357	0.597	20.0
20891	0.0102	18.50	306	0.696	20.8
17963	0.0119	18.50	264	0.807	21.7
15455	0.0138	18.50	227	0.939	22.8
13286	0.0161	18.50	196	1.09	23.9
11434	0.0187	18.50	168	1.27	25.2
9832	0.0217	18.50	146	1.47	26.7
8455	0.0252	18.50	125	1.70	28.4
7278	0.0293	18.50	108	1.98	30.3
6256	0.0341	18.5	92.5	2.31	32.4
5384	0.0396	18.5	79.7	2.67	34.7
4634	0.0460	18.5	68.7	3.10	37.2
3977	0.0536	18.5	59.3	3.60	39.5
3419	0.0624	18.5	51.2	4.17	41.4
2941	0.0725	18.5	43.7	4.88	42.9
2530	0.0843	18.5	37.7	5.65	44.2
2178	0.0979	18.5	32.4	6.59	45.0
1876	0.114	18.5	28.2	7.57	46.0
1608	0.133	18.5	24.2	8.81	46.8
1378	0.155	18.5	20.3	10.49	47.5
1192	0.179	18.5	18.1	11.78	48.0
1025	0.208	18.5			

Table A.17 Capillary Pressure Test Drainage Data Sample No. 390

P_c. psia	**d. µm**	**S_w. %**	**P_c. psia**	**d. µm**	**S_w. %**
2.51	85	100	556	0.4	29
3.03	70	100	638	0.3	27
3.57	60	100	733	0.3	25
4.21	51	100	841	0.3	23
4.96	43	100	964	0.2	22
5.84	37	100	1108	0.19	21
6.9	31	100	1270	0.17	20.0
8.1	26	100	1458	0.15	19.0
9.5	22	100	1675	0.13	18.2
11.2	19	100	1919	0.11	17.7
13.2	16	100	2204	0.10	17.1
15.6	14	100	2530	0.08	16.8
18.4	12	100	2902	0.07	16.4
21.6	10	100	3330	0.06	16.0
25.5	8	100	3821	0.06	15.8
29.0	7	100	4381	0.05	15.6
34.0	6	100	5029	0.04	15.5
40.4	5	100	5772	0.04	15.2
46.6	5	100	6623	0.03	15.1
51.1	4	100	7603	0.03	15.1
59	4	99	8725	0.02	15.1
70	3	96	10014	0.021	15.1
79	3	93	11493	0.019	15.1
91	2	89	13190	0.016	15.1
103	2.1	85	15138	0.014	15.1
121	1.8	79	17373	0.012	15.1
139	1.5	74	19939	0.011	15.1
160	1.3	68	22891	0.0093	15.1
185	1.2	62	26272	0.0081	15.1
212	1.0	56	30148	0.0071	15.1
243	0.9	50	34599	0.0062	15.1
279	0.8	46	39700	0.0054	15.1
319	0.7	41	45560	0.0047	15.1
368	0.6	37	52274	0.0041	15.1
422	0.5	34	59979	0.0036	15.1
484	0.4	31			

Table A.18 Capillary Pressure Test Imbibition Data Sample No. 390

P_c. psia	d. µm	S_w. %	P_c. psia	d. µm	S_w. %
59979	0.0036	15.08	880	0.242	15.1
51597	0.0041	15.08	757	0.282	15.1
44379	0.0048	15.08	651	0.328	15.1
38166	0.0056	15.08	562	0.380	15.1
32826	0.0065	15.08	483	0.442	15.1
28233	0.0076	15.08	417	0.511	15.1
24284	0.0088	15.08	357	0.597	15.1
20891	0.0102	15.08	307	0.695	15.3
17963	0.0119	15.08	265	0.806	16.4
15455	0.0138	15.08	228	0.937	17.9
13286	0.0161	15.08	196	1.09	19.2
11435	0.0187	15.08	169	1.26	20.9
9832	0.0217	15.08	146	1.46	23.3
8455	0.0252	15.08	126	1.70	25.2
7278	0.0293	15.08	108	1.98	27.3
6257	0.0341	15.1	92.8	2.30	29.8
5385	0.0396	15.1	80.0	2.67	32.4
4635	0.0460	15.1	69.0	3.09	34.9
3977	0.0536	15.1	59.5	3.58	37.1
3420	0.0624	15.1	51.4	4.15	39.3
2942	0.0725	15.1	43.9	4.86	41.0
2531	0.0843	15.1	38.0	5.62	42.4
2179	0.0979	15.1	32.6	6.54	43.5
1876	0.114	15.1	28.4	7.51	44.8
1608	0.133	15.1	24.4	8.73	46.3
1378	0.155	15.1	20.5	10.38	47.4
1192	0.179	15.1	18.3	11.64	48.3
1025	0.208	15.1			

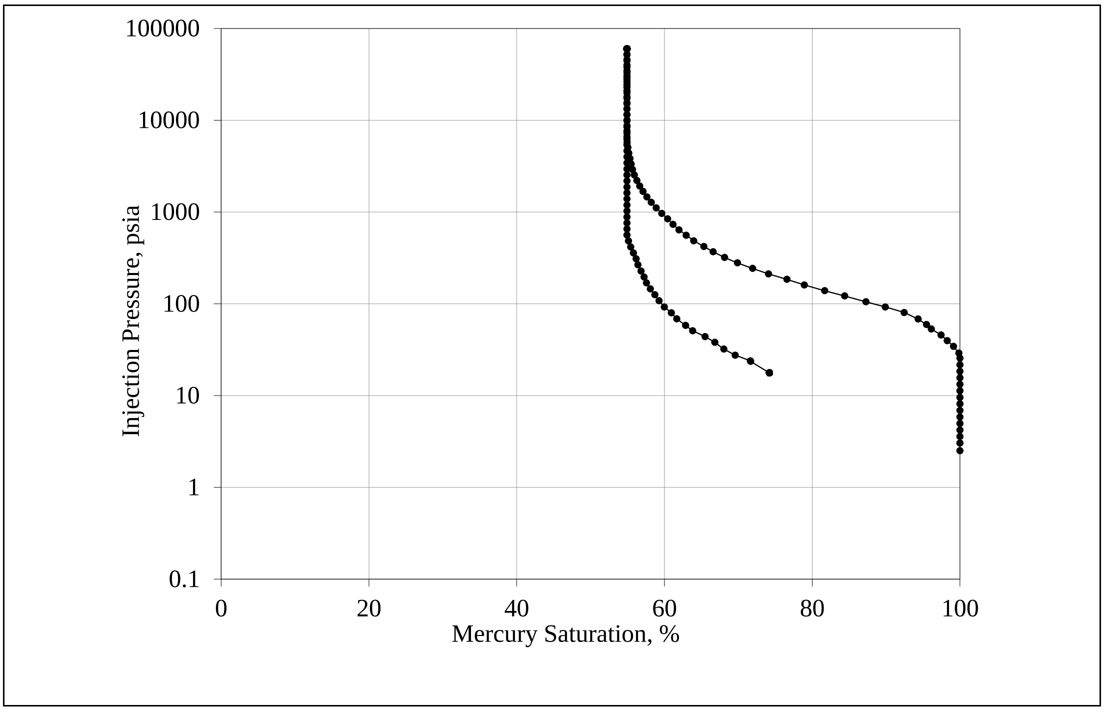

Figure A.1 Capillary Pressure Curves (Sample No. 381)

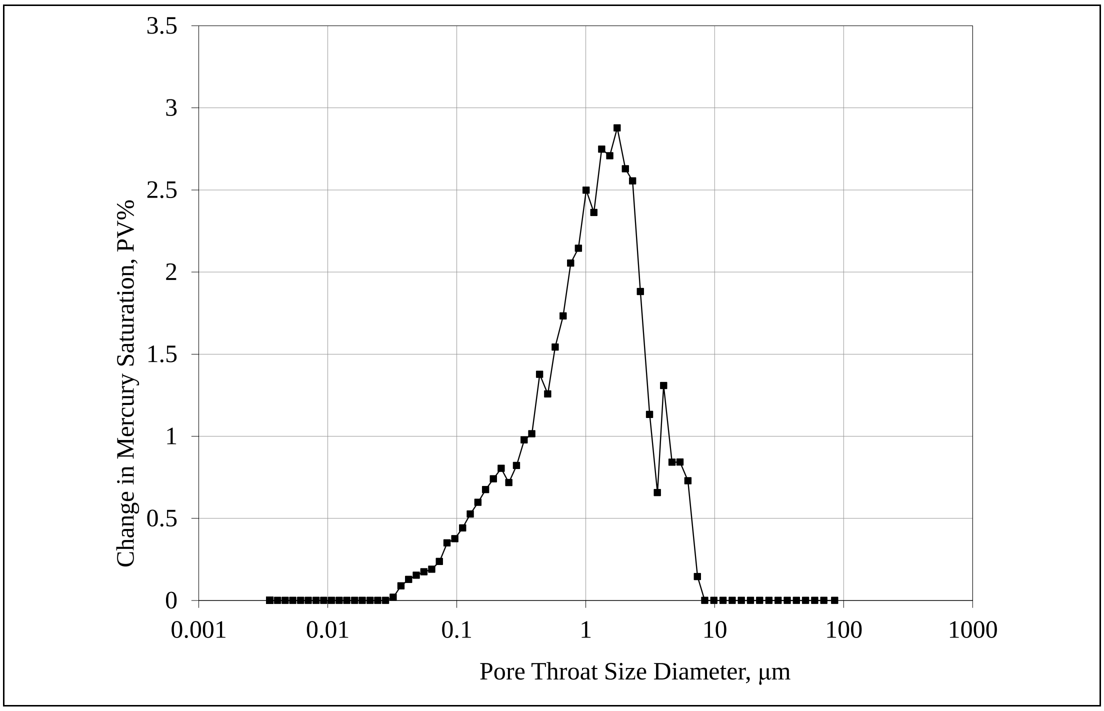

Figure A.2 Pore Throat Size Distribution Curves (Sample No. 381)

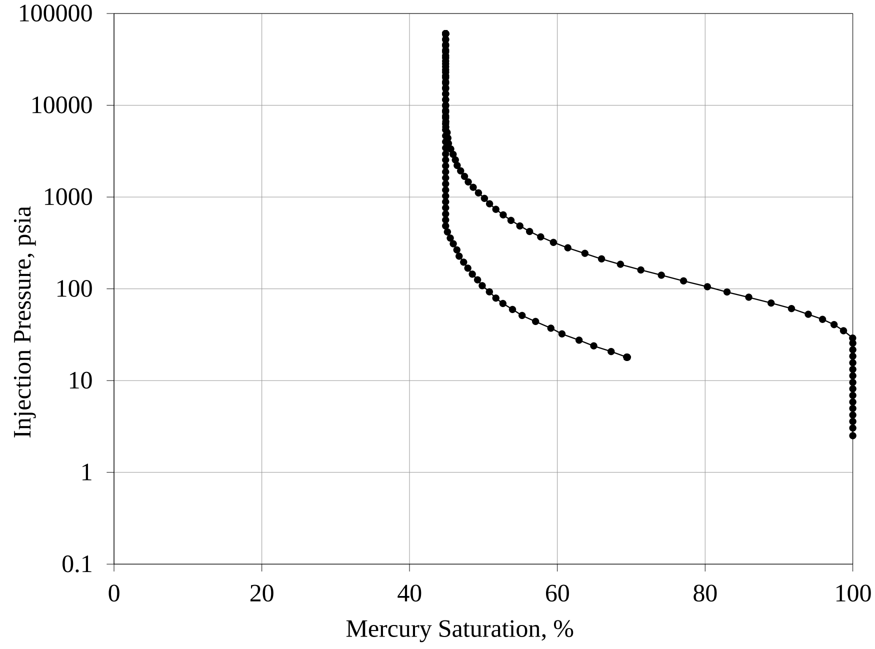

Figure A.3 Capillary Pressure Curves (Sample No. 382)

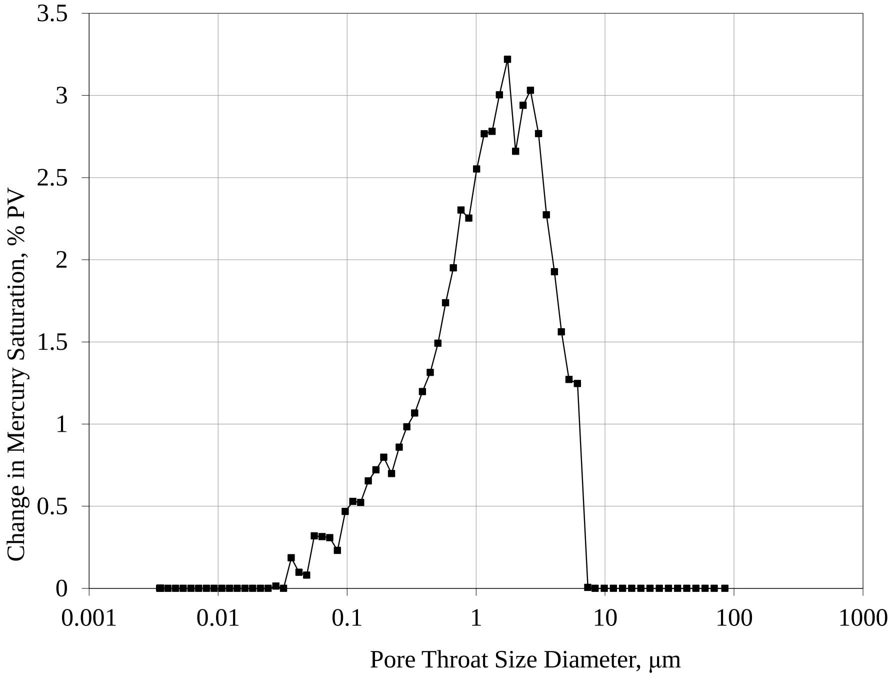

Figure A.4 Pore Throat Size Distribution Curves (Sample No. 382)

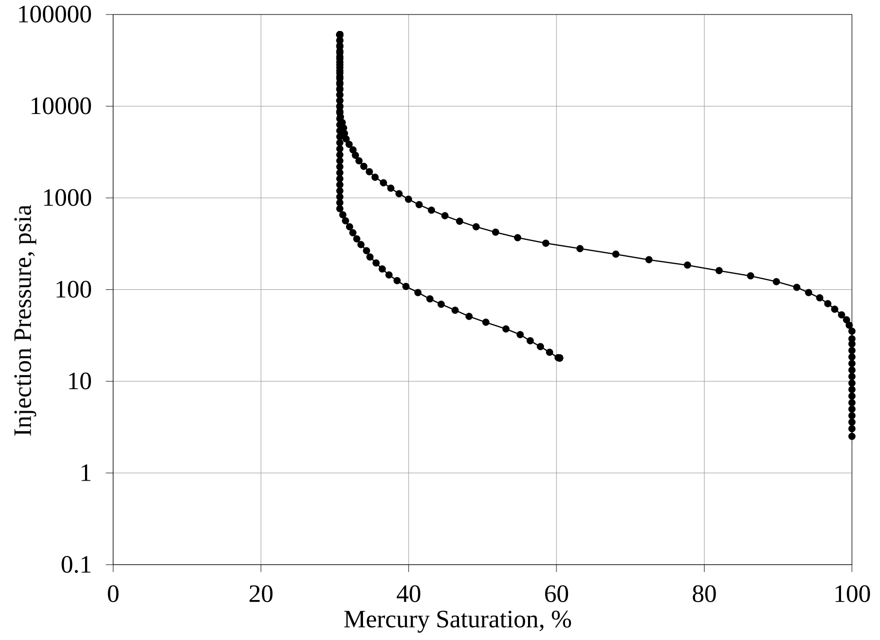

Figure A.5 Capillary Pressure Curves (Sample No. 383)

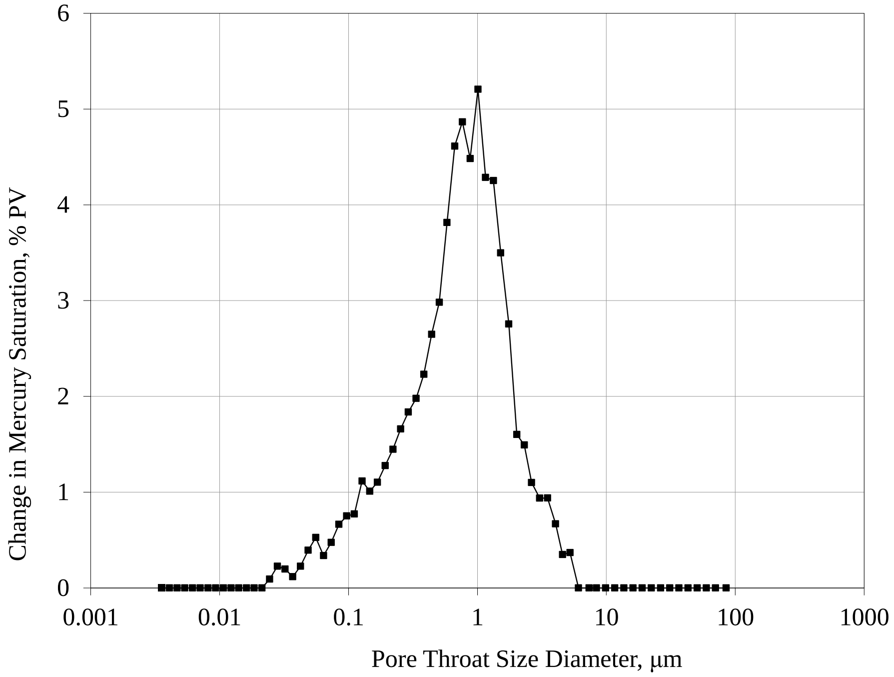

Figure A.6 Pore Throat Size Distribution Curves (Sample No. 383)

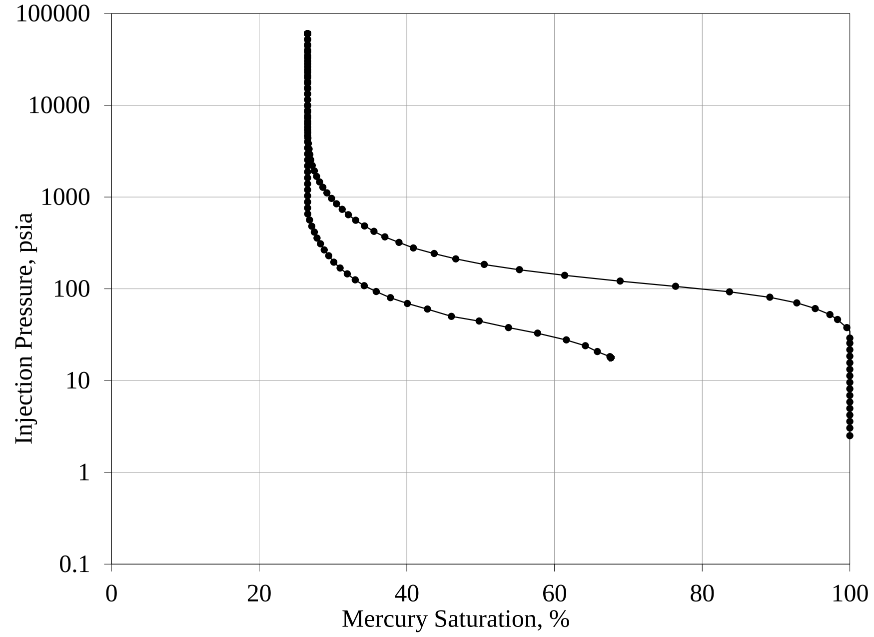

Figure A.7 Capillary Pressure Curves (Sample No. 384)

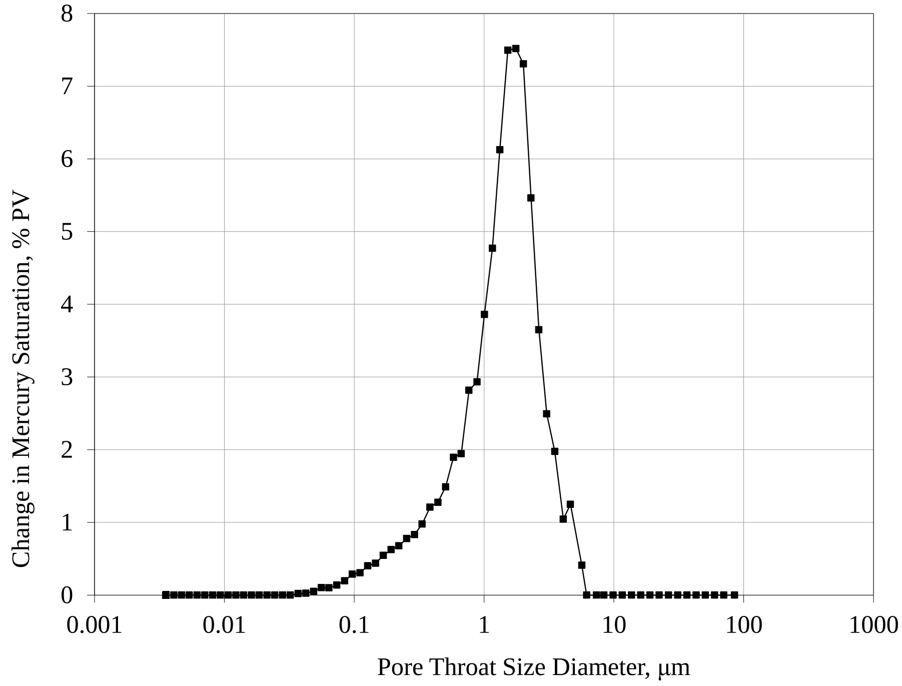

Figure A.8 Pore Throat Size Distribution Curves (Sample No. 384)

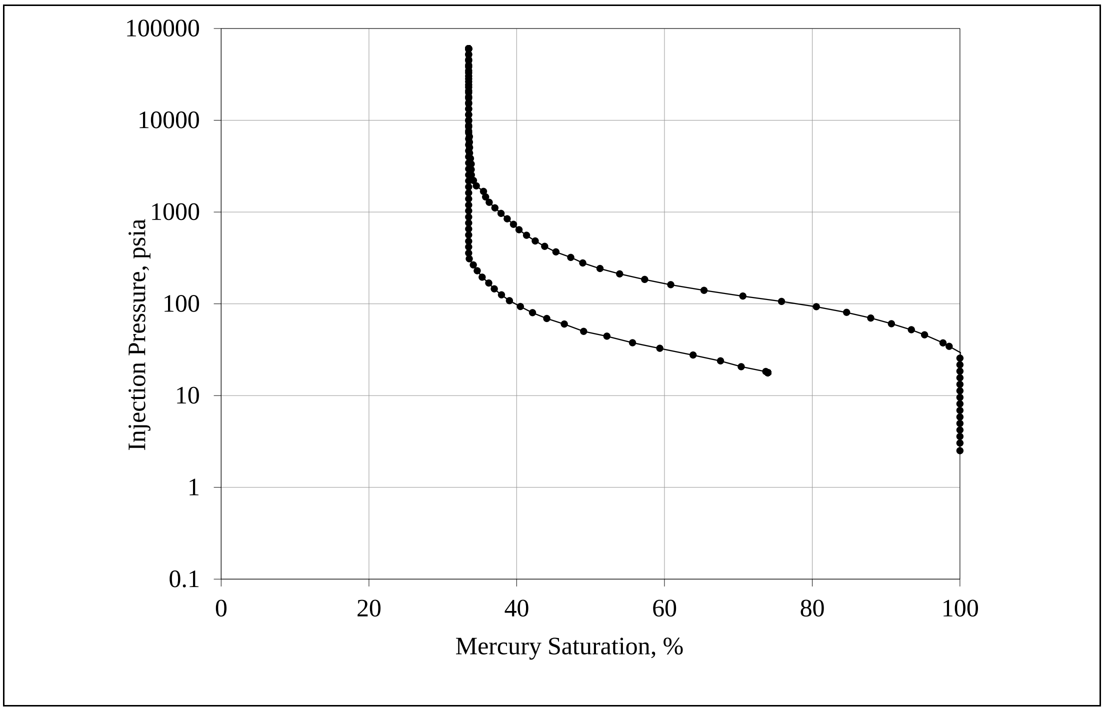

Figure A.9 Capillary Pressure Curves (Sample No. 385)

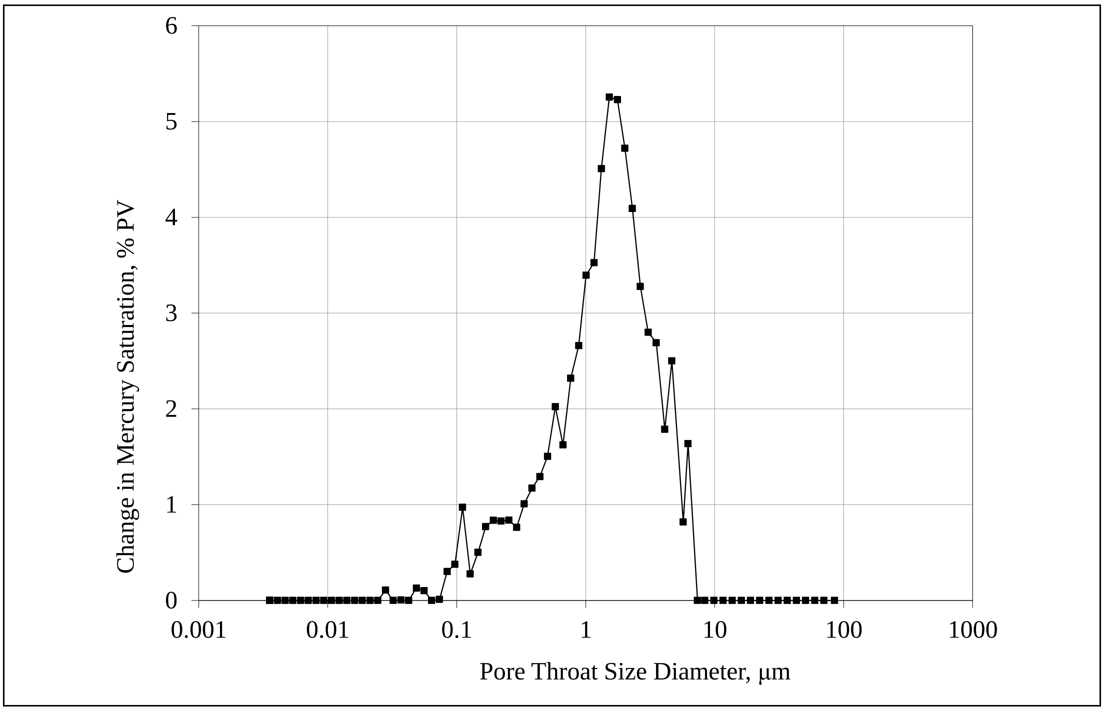

Figure A.10 Pore Throat Size Distribution Curves (Sample No. 385)

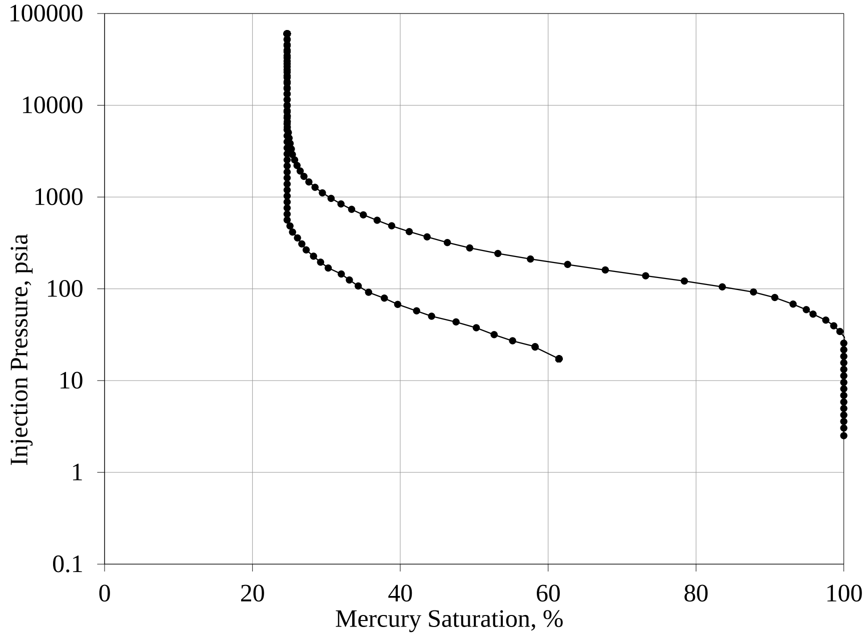

Figure A.11 Capillary Pressure Curves (Sample No. 386)

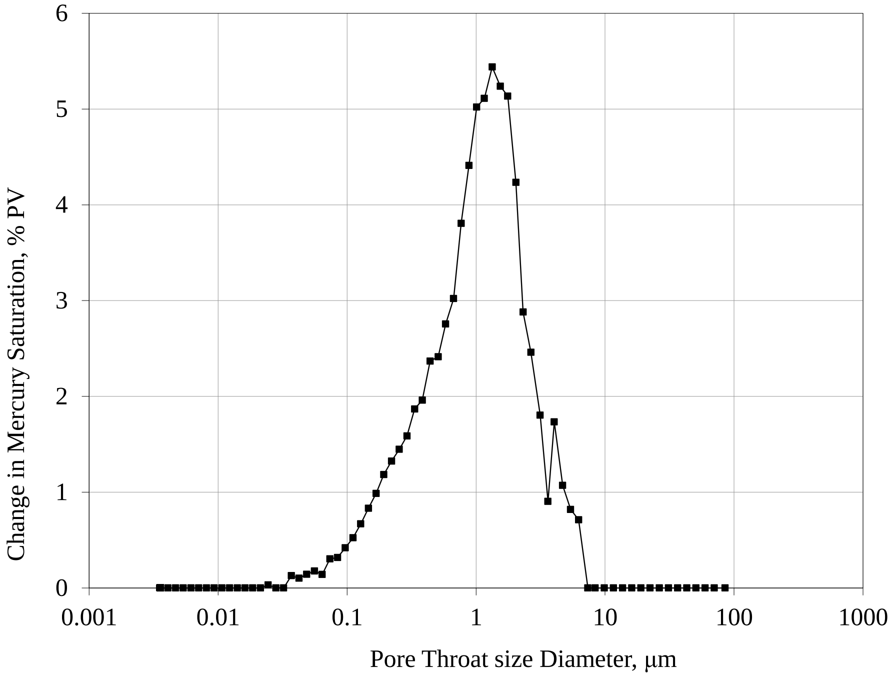

Figure A.12 Pore Throat Size Distribution Curves (Sample No. 386)

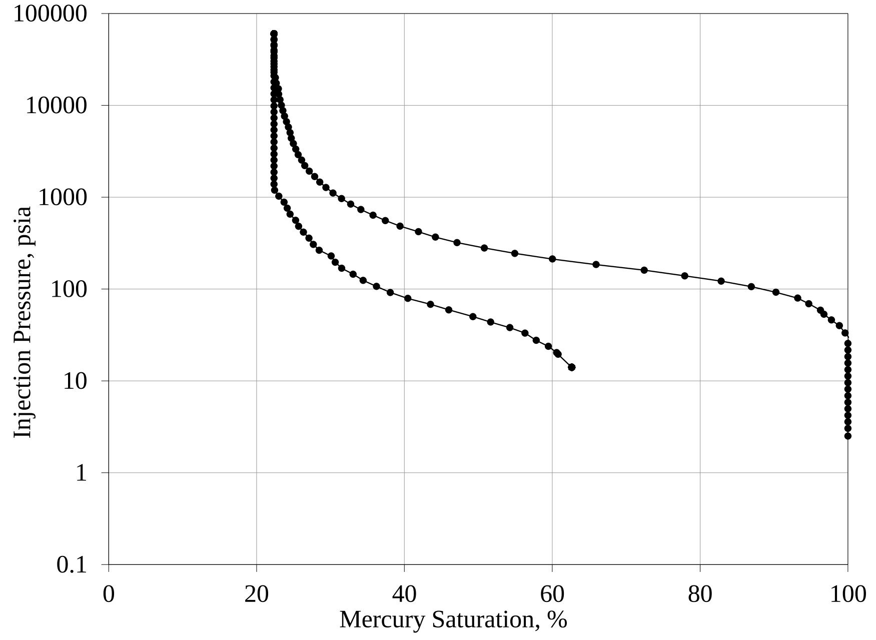

Figure A.13 Capillary Pressure Curves (Sample No. 388)

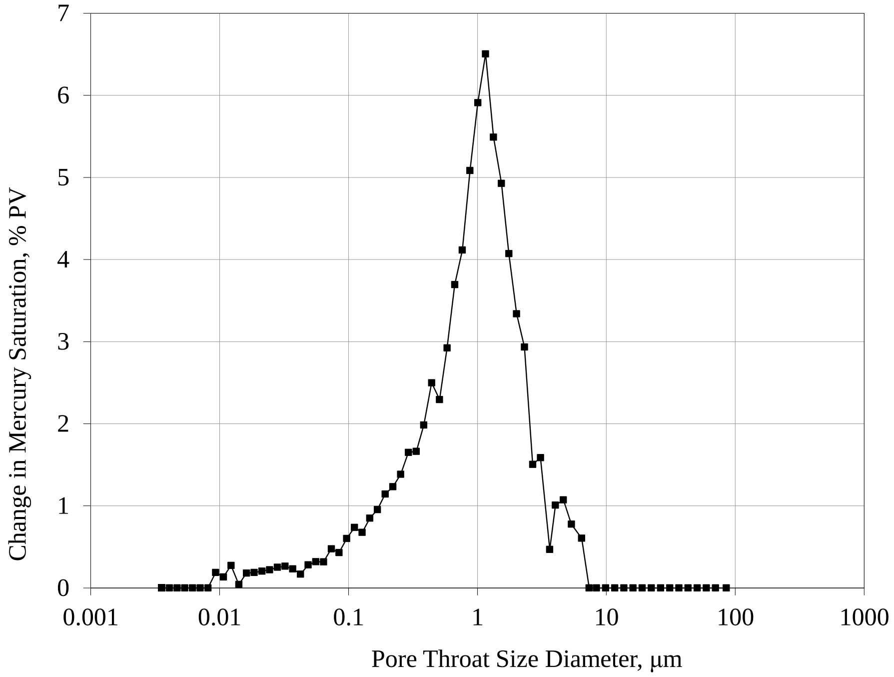

Figure A.14 Pore Throat Size Distribution Curves (Sample No. 388)

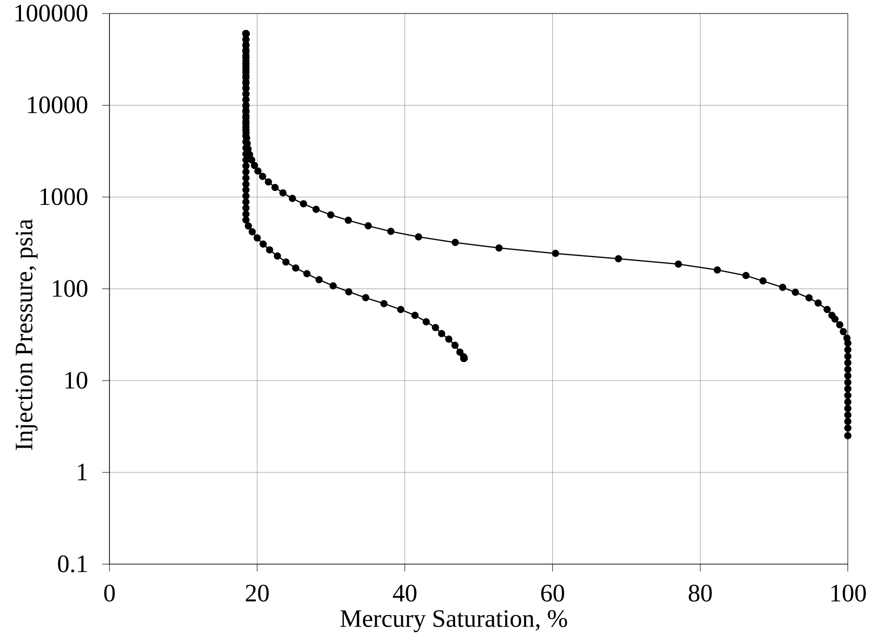

Figure A.15 Capillary Pressure Curves (Sample No. 389)

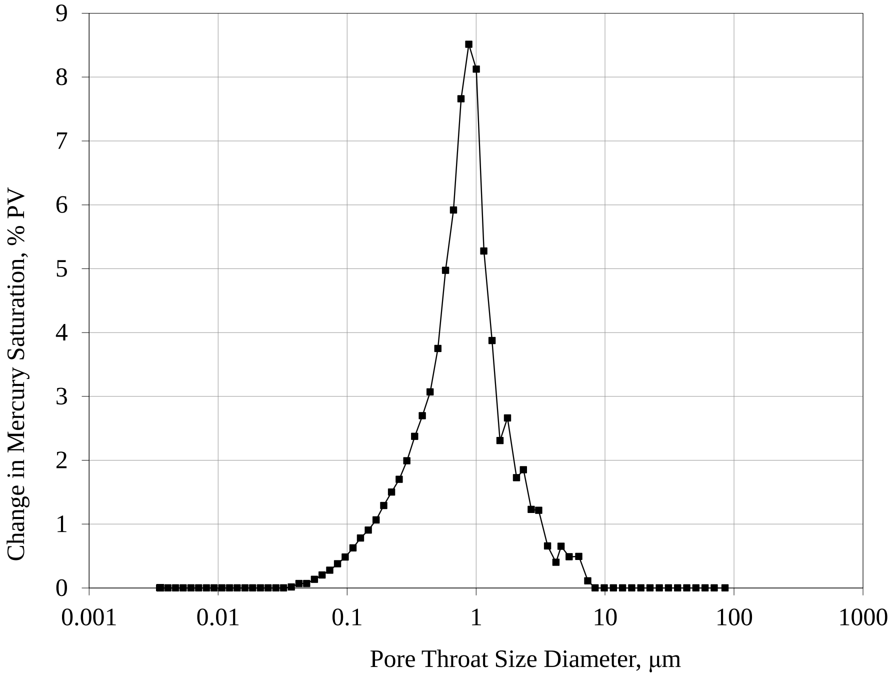

Figure A.16 Pore Throat Size Distribution Curves (Sample No. 389)

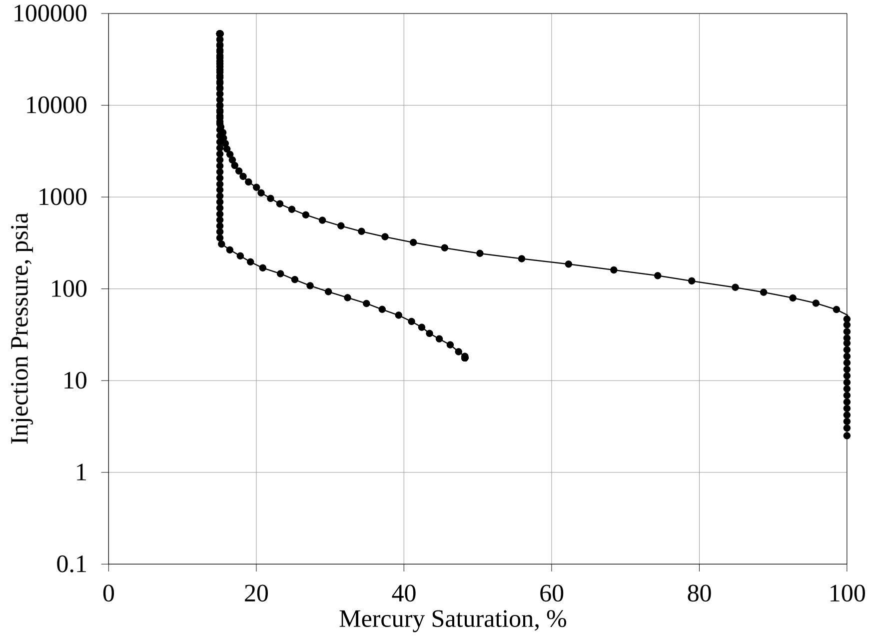

Figure A.17 Capillary Pressure Curves (Sample No. 390)

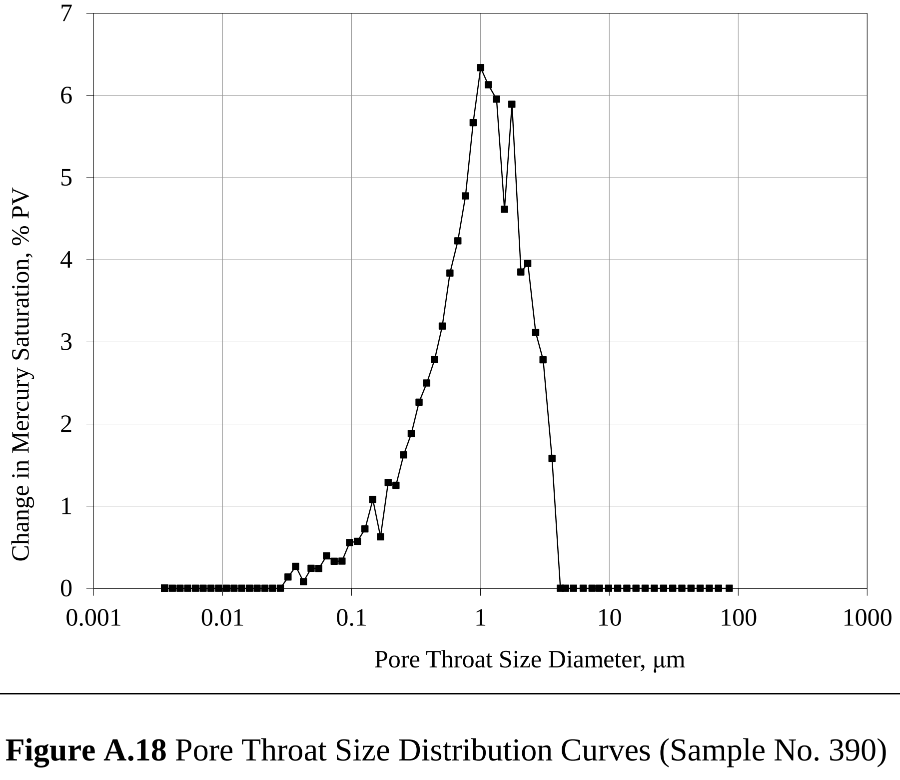

Figure A.18 Pore Throat Size Distribution Curves (Sample No. 390)

APPENDIX B

SPONTANEOUS IMBIBITION TEST AND CALCULATION DATA

Table B.1 Spontaneous Imbibition Test Readings of Sample No. 381-382

Sample No:		**381**		**Sample No:**		**382**	
L (cm)	6.768	PV (cc)	9.52	L (cm)	6.919	PV (cc)	8.72
D (cm)	3.79	ϕ (%)	12.50	D (cm)	3.79	ϕ (%)	11.20
k_L (md)	18.72	A (cm^2)	11.28	k_L (md)	26.12	A (cm^2)	11.28
%100 Water Saturation				**%100 Water Saturation**			
DP (psi)	26	T(^{0}C)	50	DP (psi)	10	T(^{0}C)	50
DV (cc)	0.5	μ_ω (cp)	0.59	DV (cc)	0.5	μ_ω (cp)	0.59
DT (sec)	60	k_w (md)	1.67	DT (sec)	60	k_w (md)	4.43
Oil Flooding				**Oil Flooding**			
Produced Water (cc)…………….		6.40		Produced Water (cc)…………….		4.20	
S_{wir}		0.33		S_{wir}		0.52	
k_o @ S_{wir}				k_o @ S_{wir}			
DP (psi)	116	T(^{0}C)	50	DP (psi)	10	T(^{0}C)	50
DV (cc)	0.06	μo (cp)	11.14	DV (cc)	0.02	μo (cp)	11.14
DT (sec)	60	k_o (md)	0.85	DT (sec)	60	k_o (md)	3.35
Imbibition				**Imbibition**			
Date		Oil Produced (cc)		Date		Oil Produced (cc)	
21.12.12 10:00		0.00		25.12.12 09:45		0.00	
21.12.12 19:00		0.00		25.12.12 11:00		0.00	
21.12.12 19:30		0.01		25.12.12 12:00		0.00	
22.12.12 09:00		0.03		25.12.12 13:00		0.00	
28.12.12 09:00		0.03		25.12.12 15:00		0.00	
02.1.13 10:00		0.20		27.12.12 10:00		0.00	
04.1.13 10:00		0.20		28.12.12 10:00		0.01	
05.1.13 10:00		0.30		13.3.13 10:00		0.01	
07.1.13 10:00		0.30		27.3.13 09:00		0.30	
09.1.13 10:00		0.30		28.3.13 10:00		0.40	
11.1.13 10:00		0.30		29.3.13 10:00		0.40	
12.1.13 10:00		0.50		01.4.13 10:00		0.50	
10.4.13 09:00		0.50		02.4.13 10:00		0.70	
10.4.13 12:00		0.60		10.4.13 09:00		0.70	
10.4.13 14:00		0.70		10.4.13 12:00		0.90	
10.4.13 16:00		0.70		10.4.13 14:00		1.00	
11.4.13 10:00		1.00		10.4.13 16:00		1.10	
12.4.13 10:00		1.00		12.4.13 10:00		1.10	
15.4.13 10:00		1.10		15.4.13 10:00		1.20	
17.4.13 10:00		1.10		17.4.13 10:00		1.20	

Table B.2 Spontaneous Imbibition Test Readings of Sample No. 383

Sample No:		**383**	
L (cm)	7.259	PV (cc)	8.47
D (cm)	3.78	ϕ (%)	10.40
k_L (md)	11.21	A (cm^2)	11.22
%100 Water Saturation			
DP (psi)	11	T(^{0}C)	50
DV (cc)	0.5	μ_ω (cp)	0.59
DT (sec)	60	k_w (md)	4.25
Oil Flooding			
Produced Water (cc)		6.40	
S_{wir}		0.24	
k_o @ S_{wir}			
DP (psi)	179	T(^{0}C)	50
DV (cc)	0.2	μo (cp)	11.14
DT (sec)	60	k_o (md)	1.97
Imbibition			
Date		Oil Produced (cc)	
27.12.12 15:05		0.00	
27.12.12 17:00		0.00	
28.12.12 10:00		0.01	
02.1.13 10:00		0.05	
03.1.13 10:00		0.30	
12.1.13 10:00		0.30	
13.1.13 10:00		0.40	
22.1.13 10:00		0.40	
23.1.13 10:00		0.50	
29.1.13 10:00		0.50	
07.2.13 10:00		0.50	
18.2.13 10:00		0.70	
10.4.13 09:00		0.70	
10.4.13 12:00		0.70	
10.4.13 14:00		0.80	
10.4.13 16:00		0.80	
11.4.13 10:00		1.00	
12.4.13 10:00		1.10	
17.4.13 10:00		1.10	

Table B.3 Spontaneous Imbibition Test Readings of Sample No. 384

Sample No:		**384**	
L (cm)	7.316	PV (cc)	8.78
D (cm)	3.79	ϕ (%)	10.70
k_L (md)	9.04	A (cm^2)	11.28
%100 Water Saturation			
DP (psi)	13	T(^{0}C)	50
DV (cc)	0.5	μ_ω (cp)	0.59
DT (sec)	60	k_w (md)	3.61
Oil Flooding			
Produced Water (cc)		5.30	
S_{wir}		0.40	
k_o @ S_{wir}			
DP (psi)	16	T(^{0}C)	50
DV (cc)	0.02	μo (cp)	11.14
DT (sec)	60	k_o (md)	2.21
Imbibition			
Date	Oil Produced (cc)	Date	Oil Produced (cc)
04.1.13 15:00	0.00	22.2.13 10:00	1.40
04.1.13 17:00	0.00	28.2.13 10:00	2.00
05.1.13 09:00	0.02	04.3.13 10:00	2.00
05.1.13 15:00	0.30	13.3.13 10:00	2.30
06.1.13 09:00	0.30	27.3.13 09:00	2.70
07.1.13 09:00	0.50	28.3.13 10:00	2.80
08.1.13 09:00	0.60	29.3.13 10:00	3.00
09.1.13 09:00	0.80	01.4.13 10:00	3.20
10.1.13 09:00	0.80	02.4.13 10:00	3.20
12.1.13 09:00	0.80	05.4.13 10:00	3.30
13.1.13 09:00	0.90	08.4.13 10:00	3.30
14.1.13 09:00	1.00	10.4.13 09:00	3.30
18.1.13 10:00	1.10	10.4.13 12:00	3.50
21.1.13 10:00	1.10	10.4.13 14:00	3.60
22.1.13 10:00	1.20	10.4.13 16:00	3.70
28.1.13 10:00	1.20	11.4.13 10:00	3.70
29.1.13 10:00	1.20	12.4.13 10:00	3.70
04.2.13 10:00	1.30	15.4.13 10:00	3.70
18.2.13 10:00	1.30	17.4.13 10:00	3.70

Table B.4 Spontaneous Imbibition Test Readings of Sample No. 384

Sample No:		**385**	
L (cm)	7.375	PV (cc)	7.78
D (cm)	3.78	ϕ (%)	9.40
k_L (md)	4.71	A (cm^2)	11.22
%100 Water Saturation			
DP (psi)	19	T(^{0}C)	50
DV (cc)	0.5	μ_ω (cp)	0.59
DT (sec)	60	k_w (md)	2.50
Oil Flooding			
Produced Water (cc)		6.10	
S_{wir}		0.22	
k_o @ S_{wir}			
DP (psi)	51	T(^{0}C)	50
DV (cc)	0.02	μo (cp)	11.14
DT (sec)	60	k_o (md)	0.70
Imbibition			

Date	Oil Produced (cc)	Date	Oil Produced (cc)
07.1.13 10:30	0.00	04.3.13 10:00	1.70
07.1.13 12:00	0.00	13.3.13 10:00	1.70
07.1.13 13:00	0.01	27.3.13 09:00	1.70
07.1.13 15:00	0.01	28.3.13 10:00	1.70
08.1.13 10:00	0.20	29.3.13 10:00	1.90
09.1.13 10:00	0.40	01.4.13 10:00	2.00
10.1.13 10:00	0.40	02.4.13 10:00	2.00
11.1.13 10:00	0.50	03.4.13 10:00	2.10
12.1.13 10:00	0.50	08.4.13 10:00	2.10
13.1.13 10:00	0.60	10.4.13 09:00	2.20
16.1.13 10:00	0.60	10.4.13 12:00	2.50
17.1.13 10:00	0.70	10.4.13 14:00	2.60
18.1.13 10:00	0.80	10.4.13 16:00	2.60
22.1.13 10:00	0.80	11.4.13 10:00	2.60
18.2.13 10:00	0.80	12.4.13 10:00	2.70
22.2.13 10:00	1.00	15.4.13 10:00	2.80
28.2.13 10:00	1.70	17.4.13 10:00	2.80

Table B.5 Spontaneous Imbibition Test Readings of Sample No. 386

Sample No:		**386**	
L (cm)	7.39	PV (cc)	8.52
D (cm)	3.79	ϕ (%)	10.20
k_L (md)	3.86	A (cm^2)	11.28
%100 Water Saturation			
DP (psi)	8	T(^{0}C)	50
DV (cc)	0.1	μ_ω (cp)	0.59
DT (sec)	60	k_w (md)	1.18
Oil Flooding			
Produced Water (cc)		6.70	
S_{wir}		0.21	
k_o @ S_{wir}			
DP (psi)	157	T(^{0}C)	50
DV (cc)	0.02	μo (cp)	11.14
DT (sec)	60	k_o (md)	0.23
Imbibition			

Date	Oil Produced (cc)	Date	Oil Produced (cc)
11.1.13 14:30	0.00	05.2.13 10:00	2.10
11.1.13 15:00	0.00	06.2.13 10:00	2.10
11.1.13 16:00	0.00	07.2.13 10:00	2.20
11.1.13 17:00	0.00	22.2.13 10:00	2.20
12.1.13 09:00	0.30	28.2.13 10:00	2.40
12.1.13 16:30	0.40	04.3.13 10:00	2.40
13.1.13 09:00	0.40	13.3.13 10:00	2.40
14.1.13 10:00	0.50	27.3.13 09:00	2.50
15.1.13 10:00	0.50	28.3.13 10:00	2.50
16.1.13 10:00	0.60	29.3.13 10:00	2.60
17.1.13 10:00	0.90	01.4.13 10:00	2.70
18.1.13 10:00	0.90	03.4.13 10:00	2.70
21.1.13 10:00	1.20	05.4.13 10:00	2.80
22.1.13 10:00	1.30	08.4.13 10:00	2.80
23.1.13 10:00	1.40	10.4.13 09:00	2.80
28.1.13 10:00	1.50	10.4.13 12:00	3.00
29.1.13 10:00	1.50	10.4.13 14:00	3.10
30.1.13 10:00	1.60	10.4.13 16:00	3.20
31.1.13 10:00	1.60	11.4.13 10:00	3.30
01.2.13 10:00	1.80	12.4.13 10:00	3.30
04.2.13 10:00	2.10	17.4.13 10:00	3.30

Table B.6 Spontaneous Imbibition Test Readings of Sample No. 388

Sample No:		**388**	
L (cm)	7.455	PV (cc)	8.45
D (cm)	3.79	ϕ (%)	10.10
k_L (md)	13.13	A (cm^2)	11.25
%100 Water Saturation			
DP (psi)	7	T(^{0}C)	50
DV (cc)	0.5	μ_ω (cp)	0.59
DT (sec)	60	k_w (md)	6.84
Oil Flooding			
Produced Water (cc)		5.38	
S_{wir}		0.36	
k_o @ S_{wir}			
DP (psi)	26	T(^{0}C)	50
DV (cc)	0.05	μo (cp)	11.15
DT (sec)	60	k_o (md)	3.48
Imbibition			

Date	Oil Produced (cc)	Date	Oil Produced (cc)
30.4.13 10:30	0.00	17.6.13 09:30	0.95
30.4.13 11:30	0.00	17.6.13 10:30	0.95
30.4.13 12:30	0.01	17.6.13 14:00	0.96
30.4.13 13:30	0.02	17.6.13 17:00	0.97
30.4.13 14:30	0.02	18.6.13 17:00	1.21
30.4.13 15:30	0.03	19.6.13 17:00	1.51
30.4.13 16:30	0.03	20.6.13 17:00	1.51
02.5.13 10:00	0.50	21.6.13 17:00	1.61
03.5.13 10:00	0.55	25.6.13 17:00	1.71
04.5.13 10:00	0.60	28.6.13 17:00	1.71
06.5.13 10:00	0.70	01.7.13 10:00	1.71
07.5.13 10:00	0.70	01.7.13 10:30	1.71
08.5.13 10:00	0.75	01.7.13 13:00	1.71
15.5.13 10:00	0.75	01.7.13 17:00	1.81
20.5.13 10:00	0.80	02.7.13 17:00	2.01
23.5.13 10:00	0.80	03.7.13 12:00	2.11
27.5.13 10:00	0.85	04.7.13 11:00	2.11
30.5.13 10:00	0.85	05.7.13 17:00	2.31
06.6.13 10:00	0.90	09.7.13 16:00	2.31
11.6.13 10:00	0.95	17.7.13 09:30	2.31

Table B.7 Spontaneous Imbibition Test Readings of Sample No. 389

Sample No:		**389**	
L (cm)	7.421	PV (cc)	8.03
D (cm)	3.78	ϕ (%)	9.60
k_L (md)	5.12	A (cm^2)	11.24
%100 Water Saturation			
DP (psi)	14	T(^{0}C)	50
DV (cc)	0.5	μ_{ω} (cp)	0.59
DT (sec)	60	k_w (md)	3.41
Oil Flooding			
Produced Water (cc)		6.30	
S_{wir}		0.22	
k_o @ S_{wir}			
DP (psi)	176	T(^{0}C)	50
DV (cc)	0.05	μo (cp)	11.14
DT (sec)	60	k_o (md)	0.51

Imbibition

Date	Oil Produced (cc)	Date	Oil Produced (cc)
03.5.13 10:30	0.00	17.6.13 14:00	1.41
03.5.13 12:30	0.00	17.6.13 17:00	1.43
03.5.13 13:30	0.01	18.6.13 17:00	1.70
03.5.13 14:30	0.01	19.6.13 17:00	1.80
04.5.13 10:00	0.30	20.6.13 17:00	1.90
06.5.13 10:00	0.70	21.6.13 17:00	2.05
07.5.13 10:00	0.80	25.6.13 17:00	2.05
08.5.13 10:00	0.80	27.6.13 17:00	2.10
09.5.13 10:00	0.85	28.6.13 17:00	2.10
10.5.13 10:00	0.85	01.7.13 10:00	2.10
13.5.13 10:00	0.90	01.7.13 10:30	2.10
14.5.13 10:00	0.95	01.7.13 13:00	2.10
15.5.13 10:00	1.00	01.7.13 17:00	2.20
23.5.13 10:00	1.00	02.7.13 17:00	2.30
27.5.13 10:00	1.10	03.7.13 12:00	2.40
30.5.13 10:00	1.15	04.7.13 11:00	2.50
06.6.13 10:00	1.20	05.7.13 17:00	2.60
11.6.13 10:00	1.40	09.7.13 16:00	2.60
13.6.13 10:00	1.40	11.7.13 14:00	2.70
17.6.13 10:30	1.40	17.7.13 09:30	2.70

Table B.8 Spontaneous Imbibition Test Readings of Sample No. 390

Sample No:		**390**	
L (cm)	7.455	PV (cc)	10.57
D (cm)	3.78	ϕ (%)	12.60
k_L (md)	11.90	A (cm^2)	11.22
%100 Water Saturation			
DP (psi)	10	T(^{0}C)	50
DV (cc)	0.5	μ_ω (cp)	0.59
DT (sec)	60	k_w (md)	4.80
Oil Flooding			
Produced Water (cc)		5.55	
S_{wir}		0.47	
k_o @ S_{wir}			
DP (psi)	40	T(^{0}C)	50
DV (cc)	0.06	μo (cp)	11.15
DT (sec)	60	k_o (md)	2.72

Imbibition

Date	Oil Produced (cc)	Date	Oil Produced (cc)
04.5.13 10:30	0.00	17.6.13 10:30	1.40
04.5.13 11:30	0.00	17.6.13 14:00	1.41
04.5.13 12:30	0.01	17.6.13 17:00	1.42
04.5.13 13:30	0.05	18.6.13 17:00	1.68
04.5.13 14:30	0.10	19.6.13 17:00	1.88
06.5.13 10:00	0.60	20.6.13 17:00	1.98
07.5.13 10:00	0.90	21.6.13 17:00	2.08
08.5.13 10:00	0.95	25.6.13 17:00	2.08
09.5.13 10:00	1.00	28.6.13 17:00	2.18
10.5.13 10:00	1.00	01.7.13 10:00	2.28
13.5.13 10:00	1.20	01.7.13 10:30	2.28
14.5.13 10:00	1.20	01.7.13 13:00	2.29
15.5.13 10:00	1.20	01.7.13 17:00	2.52
20.5.13 10:00	1.25	02.7.13 09:00	2.57
23.5.13 10:00	1.30	02.7.13 17:00	2.67
27.5.13 10:00	1.35	03.7.13 12:00	2.77
30.5.13 10:00	1.35	04.7.13 11:00	2.77
06.6.13 10:00	1.40	05.7.13 17:00	2.87
11.6.13 10:00	1.40	09.7.13 16:00	2.87
13.6.13 10:00	1.40	11.7.13 14:00	2.97
17.6.13 09:30	1.40	17.7.13 09:30	2.97

Table B.9 Spontaneous Imbibition Test Readings of Sample No. 201-206

Sample No:		**201**		**Sample No:**		**206**	
L (cm)	7.219	PV (cc)	13.64	L (cm)	4.975	PV (cc)	9.82
D (cm)	3.79	ϕ (%)	16.80	D (cm)	3.79	ϕ (%)	17.50
k_L (md)	7.15	A (cm^2)	11.28	k_L (md)	12.74	A (cm^2)	11.28
%100 Water Saturation				**%100 Water Saturation**			
DP (psi)	33	T(^{0}C)	65	DP (psi)	15	T(^{0}C)	65
DV (cc)	0.2	μ_ω (cp)	0.560	DV (cc)	0.5	μ_ω (cp)	0.560
DT (sec)	60	k_w (md)	0.53	DT (sec)	60	k_w (md)	2.02
Oil Flooding				**Oil Flooding**			
Produced Water (cc)		7.60		Produced Water (cc)		6.50	
S_{wir}		0.44		S_{wir}		0.34	
k_o @ S_{wir}				k_o @ S_{wir}			
DP (psi)	81	T(^{0}C)	65	DP (psi)	25	T(^{0}C)	65
DV (cc)	0.02	μo (cp)	21.58	DV (cc)	0.02	μo (cp)	21.58
DT (sec)	60	k_o (md)	0.84	DT (sec)	60	k_o (md)	1.87
Imbibition				**Imbibition**			
Date		Oil Produced (cc)		Date		Oil Produced (cc)	
19.8.13 09:45		0.00		21.8.13 09:30		0.00	
19.8.13 14:00		0.01		22.8.13 09:30		0.10	
19.8.13 17:00		0.01		23.8.13 09:30		0.20	
20.8.13 09:30		0.10		24.8.13 09:30		0.30	
21.8.13 09:30		0.20		26.8.13 09:30		0.30	
22.8.13 09:30		0.30		28.8.13 09:20		0.30	
23.8.13 09:30		0.30		29.8.13 09:30		0.30	
24.8.13 09:30		0.30		02.9.13 09:30		0.30	
26.8.13 09:30		0.30		03.9.13 09:30		0.30	
28.8.13 09:30		0.30		04.9.13 09:30		0.30	
29.8.13 09:30		0.30		05.9.13 09:30		0.30	
02.9.13 09:30		0.30		07.9.13 09:30		0.30	
03.9.13 09:30		0.30		09.9.13 09:30		0.30	
04.9.13 09:30		0.30		13.9.13 09:30		0.30	
05.9.13 09:30		0.30		17.9.13 09:30		0.30	
07.9.13 09:30		0.30		29.9.13 09:30		0.30	
09.9.13 09:30		0.30		16.10.13 09:30		0.30	
13.9.13 09:30		0.30					
17.9.13 09:30		0.30					
29.9.13 09:30		0.30					
16.10.13 09:30		0.30					

Table B.10 Spontaneous Imbibition Test Readings of Sample No. 212

Sample No:		**212**	
L (cm)	6.96	PV (cc)	9.31
D (cm)	3.79	ϕ (%)	13.90
k_L (md)	8.26	A (cm^2)	11.28
%100 Water Saturation			
DP (psi)	10	T(^{0}C)	65
DV (cc)	0.5	μ_ω (cp)	0.560
DT (sec)	60	k_w (md)	4.23
Oil Flooding			
Produced Water (cc)		6.95	
S_{wir}		0.25	
k_o @ S_{wir}			
DP (psi)	140	T(^{0}C)	65
DV (cc)	0.02	μo (cp)	21.58
DT (sec)	60	k_o (md)	0.47
Imbibition			

Date	Oil Produced (cc)	Date	Oil Produced (cc)
21.3.14 10:20	0.00	21.4.14 09:00	0.80
21.3.14 11:30	0.00	22.4.14 09:00	0.80
21.3.14 13:45	0.00	24.4.14 09:00	0.80
21.3.14 17:00	0.01	25.4.14 09:00	0.90
23.3.14 09:00	0.30	26.4.14 09:00	0.95
24.3.14 09:15	0.30	27.4.14 09:00	1.00
25.3.14 09:00	0.30	28.4.14 09:00	1.00
26.3.14 09:00	0.30	02.5.14 10:10	1.00
27.3.14 09:15	0.30	07.5.14 09:15	1.00
28.3.14 09:15	0.30	12.5.14 09:30	1.10
31.3.14 09:10	0.40	16.5.14 08:30	1.10
01.4.14 09:30	0.40	20.5.14 09:30	1.20
03.4.14 09:30	0.40	26.5.14 09:15	1.25
04.4.14 09:30	0.50	29.5.14 09:00	1.25
05.4.14 09:30	0.50	02.6.14 08:30	1.35
07.4.14 09:30	0.55	05.6.14 09:10	1.35
08.4.14 09:30	0.60	09.6.14 09:20	1.40
09.4.14 09:30	0.60	12.6.14 09:30	1.50
10.4.14 09:30	0.60	16.6.14 08:30	1.60
14.4.14 09:30	0.60	18.6.14 09:00	1.60
16.4.14 09:00	0.75	20.6.14 08:45	1.60
17.4.14 09:00	0.75	25.6.14 14:00	1.60

Table B.11 Spontaneous Imbibition Test Readings of Sample No. 214

Sample No:		**214**	
L (cm)	6.09	PV (cc)	13.52
D (cm)	3.78	ϕ (%)	12.60
k_L (md)	10.15	A (cm^2)	11.22
%100 Water Saturation			
DP (psi)	9	T(^{0}C)	65
DV (cc)	0.4	μ_ω (cp)	0.560
DT (sec)	60	k_w (md)	3.31
Oil Flooding			
Produced Water (cc)	10.05		
S_{wir}	0.26		
k_o @ S_{wir}			
DP (psi)	35	T(^{0}C)	65
DV (cc)	0.02	μo (cp)	21.58
DT (sec)	60	k_o (md)	1.64
Imbibition			
Date	Oil Produced (cc)	Date	Oil Produced (cc)
23.3.14 09:30	0.00	24.4.14 09:00	0.40
23.3.14 10:30	0.00	25.4.14 09:00	0.40
23.3.14 12:30	0.00	26.4.14 09:00	0.40
23.3.14 13:30	0.01	27.4.14 09:00	0.40
23.3.14 14:30	0.01	28.4.14 09:00	0.40
23.3.14 15:30	0.03	02.5.14 10:10	0.40
23.3.14 16:00	0.10	07.5.14 09:15	0.40
24.3.14 09:15	0.10	12.5.14 09:30	0.40
25.3.14 09:00	0.20	16.5.14 08:30	0.40
26.3.14 09:00	0.20	20.5.14 09:30	0.50
27.3.14 09:15	0.20	26.5.14 09:15	0.50
28.3.14 09:15	0.20	29.5.14 09:00	0.50
31.3.14 09:10	0.30	02.6.14 08:30	0.50
01.4.14 09:30	0.30	05.6.14 09:10	0.60
04.4.14 09:30	0.30	09.6.14 09:20	0.60
05.4.14 09:30	0.40	12.6.14 09:30	0.60
07.4.14 09:30	0.40	16.6.14 08:30	0.60
16.4.14 09:00	0.40	18.6.14 09:00	0.60
17.4.14 09:00	0.40	20.6.14 08:45	0.60
22.4.14 09:00	0.40	25.6.14 14:00	0.60

Table B.12 Spontaneous Imbibition Test Readings of Sample No. 217

Sample No:		**217**	
L (cm)	6.22	PV (cc)	15.79
D (cm)	3.78	ϕ (%)	18.60
k_L (md)	12.22	A (cm^2)	11.22
%100 Water Saturation			
DP (psi)	7	T(^{0}C)	65
DV (cc)	0.5	μ_{ω} (cp)	0.560
DT (sec)	60	k_w (md)	5.43
Oil Flooding			
Produced Water (cc)		8.90	
S_{wir}		0.44	
k_o @ S_{wir}			
DP (psi)	577	T(^{0}C)	65
DV (cc)	0.02	μo (cp)	21.58
DT (sec)	60	k_o (md)	0.10
Imbibition			
Date	Oil Produced (cc)	Date	Oil Produced (cc)
25.3.14 09:00	0.00	25.4.14 09:00	0.90
25.3.14 13:00	0.20	26.4.14 09:00	0.90
26.3.14 09:00	0.40	27.4.14 09:00	1.00
27.3.14 09:15	0.40	28.4.14 09:00	1.00
28.3.14 09:15	0.50	02.5.14 10:10	1.10
31.3.14 09:10	0.50	07.5.14 09:15	1.20
01.4.14 09:30	0.60	12.5.14 09:30	1.20
03.4.14 09:30	0.60	16.5.14 08:30	1.20
04.4.14 09:30	0.65	20.5.14 09:30	1.20
05.4.14 09:30	0.70	26.5.14 09:15	1.30
08.4.14 09:30	0.70	29.5.14 09:00	1.30
09.4.14 09:30	0.80	02.6.14 08:30	1.40
10.4.14 09:30	0.80	05.6.14 09:10	1.40
14.4.14 09:30	0.65	09.6.14 09:20	1.40
16.4.14 09:00	0.65	12.6.14 09:30	1.50
17.4.14 09:00	0.70	16.6.14 08:30	1.60
21.4.14 09:00	0.80	18.6.14 09:00	1.60
22.4.14 09:00	0.80	20.6.14 08:45	1.60
24.4.14 09:00	0.90	25.6.14 14:00	1.60

Table B.13 Spontaneous Imbibition Test Readings of Sample No. 218

Sample No:		**218**	
L (cm)	6.08	PV (cc)	15.04
D (cm)	3.78	ϕ (%)	12.20
k_L (md)	14.85	A (cm^2)	11.22
%100 Water Saturation			
DP (psi)	8	T(^{0}C)	65
DV (cc)	0.5	μ_ω (cp)	0.560
DT (sec)	60	k_w (md)	4.64
Oil Flooding			
Produced Water (cc)		7.70	
S_{wir}		0.49	
k_o @ S_{wir}			
DP (psi)	525	T(^{0}C)	65
DV (cc)	0.02	μo (cp)	21.5776
DT (sec)	60	k_o (md)	0.11
Imbibition			

Date	Oil Produced (cc)	Date	Oil Produced (cc)
26.3.14 14:30	0.00	24.4.14 09:00	1.10
26.3.14 15:30	0.00	25.4.14 09:00	1.10
26.3.14 16:30	0.01	26.4.14 09:00	1.10
26.3.14 17:30	0.02	27.4.14 09:00	1.20
27.3.14 09:15	0.40	28.4.14 09:00	1.20
28.3.14 09:15	0.40	02.5.14 10:10	1.30
31.3.14 09:10	0.50	07.5.14 09:15	1.30
01.4.14 09:30	0.55	12.5.14 09:30	1.35
03.4.14 09:30	0.55	16.5.14 08:30	1.45
04.4.14 09:30	0.60	20.5.14 09:30	1.45
05.4.14 09:30	0.60	26.5.14 09:15	1.50
07.4.14 09:30	0.65	29.5.14 09:00	1.50
08.4.14 09:30	0.65	02.6.14 08:30	1.50
09.4.14 09:30	0.70	05.6.14 09:10	1.60
10.4.14 09:30	0.75	09.6.14 09:20	1.60
14.4.14 09:30	0.80	12.6.14 09:30	1.60
16.4.14 09:00	0.80	16.6.14 08:30	1.60
17.4.14 09:00	0.90	18.6.14 09:00	1.60
21.4.14 09:00	0.90	20.6.14 08:45	1.60
22.4.14 09:00	1.00	25.6.14 14:00	1.60

Table B.14 Spontaneous Imbibition Test Readings of Sample No. 228

Sample No:		**228**	
L (cm)	7.53	PV (cc)	11.16
D (cm)	3.78	ϕ (%)	19.30
k_L (md)	10.07	A (cm^2)	11.22
%100 Water Saturation			
DP (psi)	15	T(^{0}C)	65
DV (cc)	0.5	μ_ω (cp)	0.560
DT (sec)	60	k_w (md)	3.07
Oil Flooding			
Produced Water (cc)		8.85	
S_{wir}		0.21	
k_o @ S_{wir}			
DP (psi)	56	T(^{0}C)	65
DV (cc)	0.02	μo (cp)	21.58
DT (sec)	60	k_o (md)	1.27
Imbibition			
Date	Oil Produced (cc)	Date	Oil Produced (cc)
24.3.14 09:15	0.00	21.4.14 09:00	0.55
24.3.14 10:30	0.01	22.4.14 09:00	0.55
24.3.14 13:00	0.10	24.4.14 09:00	0.55
25.3.14 09:00	0.30	25.4.14 09:00	0.60
26.3.14 09:00	0.30	26.4.14 09:00	0.60
27.3.14 09:15	0.40	27.4.14 09:00	0.70
28.3.14 09:15	0.40	02.5.14 10:10	0.70
31.3.14 09:10	0.40	07.5.14 09:15	0.80
01.4.14 09:30	0.40	12.5.14 09:30	0.90
03.4.14 09:30	0.40	16.5.14 08:30	0.90
04.4.14 09:30	0.40	20.5.14 09:30	0.95
05.4.14 09:30	0.40	26.5.14 09:15	1.00
07.4.14 09:30	0.40	29.5.14 09:00	1.00
08.4.14 09:30	0.40	02.6.14 08:30	1.10
09.4.14 09:30	0.40	05.6.14 09:10	1.10
10.4.14 09:30	0.40	09.6.14 09:20	1.10
14.4.14 09:30	0.50	16.6.14 08:30	1.10
16.4.14 09:00	0.50	20.6.14 08:45	1.10
17.4.14 09:00	0.50	25.6.14 14:00	1.10

Table B.15 Spontaneous Imbibition Calculation Data of Sample No. 381

Fresh Water (381)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
540	0.00	0.00	0.00
570	0.01	0.11	0.16
1380	0.03	0.32	0.47
10020	0.03	0.32	0.47
17280	0.20	2.10	3.13
18720	0.20	2.10	3.13
20160	0.20	2.10	3.13
21600	0.30	3.15	4.69
23040	0.30	3.15	4.69
24480	0.30	3.15	4.69
25920	0.30	3.15	4.69
27360	0.30	3.15	4.69
28800	0.30	3.15	4.69
30240	0.30	3.15	4.69
31680	0.50	5.25	7.81
138180	0.50	5.25	7.81
158340	0.50	5.25	7.81
158520	0.60	6.30	9.38
158640	0.70	7.35	10.94
158760	0.70	7.35	10.94
159840	1.00	10.50	15.63
161280	1.00	10.50	15.63
165600	1.10	11.55	17.19
168480	1.10	11.55	17.19

Table B.16 Spontaneous Imbibition Calculation Data of Sample No. 382

Fresh Water (382)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
75	0.00	0.00	0.00
135	0.00	0.00	0.00
195	0.00	0.00	0.00
255	0.00	0.00	0.00
315	0.00	0.00	0.00
1455	0.00	0.00	0.00
2895	0.00	0.00	0.00
4335	0.01	0.11	0.24
11535	0.01	0.11	0.24
112335	0.01	0.11	0.24
132435	0.30	3.44	7.14
133935	0.40	4.59	9.52
135375	0.40	4.59	9.52
139695	0.50	5.73	11.90
141135	0.70	8.03	16.67
149775	0.70	8.03	16.67
152595	0.70	8.03	16.67
152775	0.90	10.32	21.43
152895	1.00	11.47	23.81
153015	1.10	12.61	26.19
154095	1.10	12.61	26.19
155535	1.10	12.61	26.19
159855	1.20	13.76	28.57
162735	1.20	13.76	28.57

Table B.17 Spontaneous Imbibition Calculation Data of Sample No. 383

‘C’ Formation Water (383)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
55	0.00	0.00	0.00
115	0.00	0.00	0.00
1135	0.01	0.12	0.16
8335	0.05	0.59	0.78
9775	0.30	3.54	4.69
22735	0.30	3.54	4.69
24175	0.40	4.72	6.25
25615	0.40	4.72	6.25
37135	0.40	4.72	6.25
38575	0.50	5.90	7.81
45775	0.50	5.90	7.81
47215	0.50	5.90	7.81
60175	0.50	5.90	7.81
76015	0.70	8.26	10.94
129235	0.70	8.26	10.94
149395	0.70	8.26	10.94
149575	0.70	8.26	10.94
149695	0.80	9.45	12.50
149815	0.80	9.45	12.50
150895	1.00	11.81	15.63
152335	1.10	12.99	17.19
156655	1.10	12.99	17.19
159535	1.10	12.99	17.19

Table B.18 Spontaneous Imbibition Calculation Data of Sample No. 384

%1 NaOH (384)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
60	0.00	0.00	0.00
120	0.00	0.00	0.00
1080	0.02	0.23	0.38
1440	0.30	3.42	5.66
2520	0.30	3.42	5.66
3960	0.50	5.69	9.43
5400	0.60	6.83	11.32
6840	0.80	9.11	15.09
8280	0.80	9.11	15.09
9720	0.80	9.11	15.09
11160	0.80	9.11	15.09
12600	0.90	10.25	16.98
14040	1.00	11.39	18.87
19860	1.10	12.53	20.75
24180	1.10	12.53	20.75
25620	1.20	13.67	22.64
34260	1.20	13.67	22.64
35700	1.20	13.67	22.64
44340	1.30	14.81	24.53
45780	1.30	14.81	24.53
64500	1.30	14.81	24.53
70260	1.40	15.95	26.42
78900	2.00	22.78	37.74
84660	2.00	22.78	37.74

Table B.18 Spontaneous Imbibition Calculation Data of Sample No. 384 (cont'd)

%1 NaOH (384)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
97620	2.30	26.20	43.40
117720	2.70	30.75	50.94
119220	2.80	31.89	52.83
120660	3.00	34.17	56.60
124980	3.20	36.45	60.38
126420	3.20	36.45	60.38
130740	3.30	37.59	62.26
135060	3.30	37.59	62.26
137880	3.30	37.59	62.26
138060	3.50	39.86	66.04
138180	3.60	41.00	67.92
138300	3.70	42.14	69.81
139380	3.70	42.14	69.81
140820	3.70	42.14	69.81
145140	3.70	42.14	69.81
148020	3.70	42.14	69.81

Table B.19 Spontaneous Imbibition Calculation Data of Sample No. 385

%0.5 NaOH (385)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
30	0.00	0.00	0.00
90	0.00	0.00	0.00
150	0.01	0.13	0.16
210	0.01	0.13	0.16
270	0.01	0.13	0.16
1410	0.20	2.57	3.28
2850	0.40	5.14	6.56
4290	0.40	5.14	6.56
5730	0.50	6.43	8.20
7170	0.50	6.43	8.20
8610	0.60	7.71	9.84
10050	0.60	7.71	9.84
12930	0.60	7.71	9.84
14370	0.70	9.00	11.48
15810	0.80	10.28	13.11
21570	0.80	10.28	13.11
31650	0.80	10.28	13.11
60450	0.80	10.28	13.11
66210	1.00	12.85	16.39
74850	1.70	21.85	27.87
80610	1.70	21.85	27.87
93570	1.70	21.85	27.87
113670	1.70	21.85	27.87

Table B.19 Spontaneous Imbibition Calculation Data of Sample No. 385 (cont’d)

%0.5 NaOH (385)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
120930	2.00	25.71	32.79
115170	1.70	21.85	27.87
116610	1.90	24.42	31.15
131010	2.10	26.99	34.43
133830	2.20	28.28	36.07
134010	2.50	32.13	40.98
134130	2.60	33.42	42.62
134250	2.60	33.42	42.62
135330	2.60	33.42	42.62
136770	2.70	34.70	44.26
141090	2.80	35.99	45.90
143970	2.80	35.99	45.90

Table B.20 Spontaneous Imbibition Calculation Data of Sample No. 386

%2 NaOH (386)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
30	0.00	0.00	0.00
90	0.00	0.00	0.00
150	0.00	0.00	0.00
1110	0.30	3.52	4.48
1560	0.40	4.69	5.97
2550	0.40	4.69	5.97
4050	0.50	5.87	7.46
5490	0.50	5.87	7.46
6930	0.60	7.04	8.96
8370	0.90	10.56	13.43
9810	0.90	10.56	13.43
14130	1.20	14.08	17.91
15570	1.30	15.26	19.40
17010	1.40	16.43	20.90
24210	1.50	17.61	22.39
25650	1.50	17.61	22.39
27090	1.60	18.78	23.88
28530	1.60	18.78	23.88
29970	1.80	21.13	26.87
34290	2.10	24.65	31.34
35730	2.10	24.65	31.34
37170	2.10	24.65	31.34
38610	2.20	25.82	32.84
60210	2.20	25.82	32.84
68850	2.40	28.17	35.82

Table B.20 Spontaneous Imbibition Calculation Data of Sample No. 386 (cont'd)

%2 NaOH (386)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
74610	2.40	28.17	35.82
87570	2.40	28.17	35.82
107670	2.50	29.34	37.31
109170	2.50	29.34	37.31
110610	2.60	30.52	38.81
114930	2.70	31.69	40.30
117810	2.70	31.69	40.30
120690	2.80	32.86	41.79
125010	2.80	32.86	41.79
127830	2.80	32.86	41.79
128010	3.00	35.21	44.78
128130	3.10	36.38	46.27
128250	3.20	37.56	47.76
129330	3.30	38.73	49.25
130770	3.30	38.73	49.25
135090	3.30	38.73	49.25
137970	3.30	38.73	49.25

Table B.21 Spontaneous Imbibition Calculation Data of Sample No. 388

%1 NaOH (388)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
60	0.00	0.00	0.00
120	0.01	0.12	0.19
180	0.02	0.24	0.37
240	0.02	0.24	0.37
300	0.03	0.36	0.56
360	0.03	0.36	0.56
2850	0.50	5.92	9.29
4290	0.55	6.51	10.22
5730	0.60	7.10	11.15
8610	0.70	8.28	13.01
10050	0.70	8.28	13.01
11490	0.75	8.88	13.94
21570	0.75	8.88	13.94
28770	0.80	9.47	14.87
33090	0.80	9.47	14.87
38850	0.85	10.06	15.80
43170	0.85	10.06	15.80
53250	0.90	10.65	16.73
60450	0.95	11.24	17.66
63330	0.95	11.24	17.66
69060	0.95	11.24	17.66
69120	0.95	11.24	17.66
69330	0.96	11.36	17.84
69510	0.97	11.48	18.03
70950	1.21	14.32	22.49

Table B.21 Spontaneous Imbibition Calculation Data of Sample No. 388 (cont'd)

%1 NaOH (388)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
72390	1.51	17.87	28.07
73830	1.51	17.87	28.07
75270	1.61	19.05	29.93
81030	1.71	20.24	31.78
85350	1.71	20.24	31.78
89250	1.71	20.24	31.78
89280	1.71	20.24	31.78
89430	1.71	20.24	31.78
89670	1.81	21.42	33.64
91110	2.01	23.79	37.36
92250	2.11	24.97	39.22
93630	2.11	24.97	39.22
95430	2.31	27.34	42.94
101130	2.31	27.34	42.94
112260	2.31	27.34	42.94

Table B.22 Spontaneous Imbibition Calculation Data of Sample No. 201

‘G’ Formation Water (201)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
255	0.01	0.07	0.13
435	0.01	0.07	0.13
1425	0.10	0.73	1.32
2865	0.20	1.47	2.63
4305	0.30	2.20	3.95
5745	0.30	2.20	3.95
7185	0.30	2.20	3.95
10065	0.30	2.20	3.95
12945	0.30	2.20	3.95
14385	0.30	2.20	3.95
20145	0.30	2.20	3.95
21585	0.30	2.20	3.95
23025	0.30	2.20	3.95
24465	0.30	2.20	3.95
27345	0.30	2.20	3.95
30225	0.30	2.20	3.95
35985	0.30	2.20	3.95
41745	0.30	2.20	3.95
59025	0.30	2.20	3.95
83505	0.30	2.20	3.95

Table B.23 Spontaneous Imbibition Calculation Data of Sample No. 206

'G' Formation Water (206)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
1440	0.10	1.02	1.54
2880	0.20	2.04	3.08
4320	0.30	3.05	4.62
7200	0.30	3.05	4.62
10070	0.30	3.05	4.62
11520	0.30	3.05	4.62
17280	0.30	3.05	4.62
18720	0.30	3.05	4.62
20160	0.30	3.05	4.62
21600	0.30	3.05	4.62
24480	0.30	3.05	4.62
27360	0.30	3.05	4.62
33120	0.30	3.05	4.62
38880	0.30	3.05	4.62
56160	0.30	3.05	4.62
80640	0.30	3.05	4.62

Table B.24 Spontaneous Imbibition Calculation Data of Sample No. 212

%0.2 NaOH (212)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
70	0.00	0.00	0.00
205	0.00	0.00	0.00
400	0.01	0.11	0.14
2800	0.30	3.22	4.32
4255	0.30	3.22	4.32
5680	0.30	3.22	4.32
7120	0.30	3.22	4.32
8575	0.30	3.22	4.32
10015	0.30	3.22	4.32
14330	0.40	4.30	5.76
15790	0.40	4.30	5.76
18670	0.40	4.30	5.76
20110	0.50	5.37	7.19
21550	0.50	5.37	7.19
24430	0.55	5.91	7.91
25870	0.60	6.44	8.63
27310	0.60	6.44	8.63
28750	0.60	6.44	8.63
34510	0.60	6.44	8.63
37360	0.75	8.06	10.79
38800	0.75	8.06	10.79

Table B.24 Spontaneous Imbibition Calculation Data of Sample No. 212 (cont'd)

%0.2 NaOH (212)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
44560	0.80	8.59	11.51
46000	0.80	8.59	11.51
48880	0.80	8.59	11.51
50320	0.90	9.67	12.95
51760	0.95	10.20	13.67
53200	1.00	10.74	14.39
54640	1.00	10.74	14.39
60470	1.00	10.74	14.39
67615	1.00	10.74	14.39
74830	1.10	11.82	15.83
80530	1.10	11.82	15.83
86350	1.20	12.89	17.27
94975	1.25	13.43	17.99
99280	1.25	13.43	17.99
105010	1.35	14.50	19.42
109370	1.35	14.50	19.42
115140	1.40	15.04	20.14
119470	1.50	16.11	21.58
125170	1.60	17.19	23.02
128080	1.60	17.19	23.02
130945	1.60	17.19	23.02
138460	1.60	17.19	23.02

Table B.25 Spontaneous Imbibition Calculation Data of Sample No. 214

%0.4 NaOH (214)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
60	0.00	0.00	0.00
120	0.00	0.00	0.00
180	0.00	0.00	0.00
240	0.01	0.07	0.10
300	0.01	0.07	0.10
360	0.03	0.22	0.30
390	0.10	0.74	1.00
1425	0.10	0.74	1.00
2850	0.20	1.48	1.99
4290	0.20	1.48	1.99
5745	0.20	1.48	1.99
7185	0.20	1.48	1.99
11500	0.30	2.22	2.99
12960	0.30	2.22	2.99
15840	0.30	2.22	2.99
17280	0.30	2.22	2.99
18720	0.40	2.96	3.98
21600	0.40	2.96	3.98
23040	0.40	2.96	3.98
24480	0.40	2.96	3.98
25920	0.40	2.96	3.98
31680	0.40	2.96	3.98
34530	0.40	2.96	3.98

Table B.25 Spontaneous Imbibition Calculation Data of Sample No. 214 (cont'd)

%0.4 NaOH (214)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
35970	0.40	2.96	3.98
41730	0.40	2.96	3.98
43170	0.40	2.96	3.98
46050	0.40	2.96	3.98
47490	0.40	2.96	3.98
48930	0.40	2.96	3.98
50370	0.40	2.96	3.98
51810	0.40	2.96	3.98
57640	0.40	2.96	3.98
64785	0.40	2.96	3.98
72000	0.40	2.96	3.98
77700	0.40	2.96	3.98
83520	0.50	3.70	4.98
92145	0.50	3.70	4.98
96450	0.50	3.70	4.98
102180	0.50	3.70	4.98
106540	0.60	4.44	5.97
112310	0.60	4.44	5.97
116640	0.60	4.44	5.97
122340	0.60	4.44	5.97
125250	0.60	4.44	5.97
128115	0.60	4.44	5.97
135630	0.60	4.44	5.97

Table B.26 Spontaneous Imbibition Calculation Data of Sample No. 228

%1 NaOH (228)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
75	0.01	0.09	0.11
225	0.10	0.90	1.13
1425	0.30	2.69	3.39
2865	0.30	2.69	3.39
4320	0.40	3.58	4.52
5760	0.40	3.58	4.52
10075	0.40	3.58	4.52
11535	0.40	3.58	4.52
14415	0.40	3.58	4.52
15855	0.40	3.58	4.52
17295	0.40	3.58	4.52
20175	0.40	3.58	4.52
21615	0.40	3.58	4.52
23055	0.40	3.58	4.52
24495	0.40	3.58	4.52
30255	0.50	4.48	5.65
33105	0.50	4.48	5.65
34545	0.50	4.48	5.65
40305	0.55	4.93	6.21
41745	0.55	4.93	6.21

Table B.26 Spontaneous Imbibition Calculation Data of Sample No. 228 (cont'd)

%1 NaOH (228)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
44625	0.55	4.93	6.21
46065	0.60	5.38	6.78
47505	0.60	5.38	6.78
48945	0.70	6.27	7.91
50385	0.70	6.27	7.91
56215	0.70	6.27	7.91
63360	0.80	7.17	9.04
70575	0.90	8.06	10.17
76275	0.90	8.06	10.17
82095	0.95	8.51	10.73
90720	1.00	8.96	11.30
95025	1.00	8.96	11.30
100755	1.10	9.86	12.43
105115	1.10	9.86	12.43
110885	1.10	9.86	12.43
115215	1.10	9.86	12.43
120915	1.10	9.86	12.43
123825	1.10	9.86	12.43
126690	1.10	9.86	12.43
134205	1.10	9.86	12.43

Table B.27 Spontaneous Imbibition Calculation Data of Sample No. 217

%2 NaOH (217)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
240	0.20	1.27	2.25
1440	0.40	2.53	4.49
2895	0.40	2.53	4.49
4335	0.50	3.17	5.62
8650	0.50	3.17	5.62
10110	0.60	3.80	6.74
12990	0.60	3.80	6.74
14430	0.65	4.12	7.30
15870	0.70	4.43	7.87
18750	0.70	4.43	7.87
20190	0.70	4.43	7.87
21630	0.80	5.07	8.99
23070	0.80	5.07	8.99
28830	0.65	4.12	7.30
31680	0.65	4.12	7.30
33120	0.70	4.43	7.87
38880	0.80	5.07	8.99
40320	0.80	5.07	8.99
43200	0.90	5.70	10.11
44640	0.90	5.70	10.11

Table B.27 Spontaneous Imbibition Calculation Data of Sample No. 217 (cont'd)

%2 NaOH (217)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
46080	0.90	5.70	10.11
47520	1.00	6.33	11.24
48960	1.00	6.33	11.24
54790	1.10	6.97	12.36
61935	1.20	7.60	13.48
69150	1.20	7.60	13.48
74850	1.20	7.60	13.48
80670	1.20	7.60	13.48
89295	1.30	8.23	14.61
93600	1.30	8.23	14.61
99330	1.40	8.87	15.73
103690	1.40	8.87	15.73
109460	1.40	8.87	15.73
113790	1.50	9.50	16.85
119490	1.60	10.13	17.98
122400	1.60	10.13	17.98
125265	1.60	10.13	17.98
132780	1.60	10.13	17.98

Table B.28 Spontaneous Imbibition Calculation Data of Sample No. 218

%5 NaOH (218)			
Time(min)	Oil (cc)	Oil (%PV)	Oil (%OOIP)
0	0.00	0.00	0.00
60	0.00	0.00	0.00
120	0.01	0.07	0.13
180	0.02	0.13	0.26
1125	0.40	2.66	5.19
2565	0.40	2.66	5.19
6880	0.50	3.32	6.49
8340	0.55	3.66	7.14
11220	0.55	3.66	7.14
12660	0.60	3.99	7.79
14100	0.60	3.99	7.79
16980	0.65	4.32	8.44
18420	0.65	4.32	8.44
19860	0.70	4.65	9.09
21300	0.75	4.99	9.74
27060	0.80	5.32	10.39
29910	0.80	5.32	10.39
31350	0.90	5.98	11.69
32790	0.90	5.98	11.69
37110	0.90	5.98	11.69

APPENDIX C

INTERFACIAL TENSION MEASUREMENT TEST DATA

Table C.1 Interfacial Tension Measurement Test Data for ‘C’ Field

Bulk Fluid	Drop Fluid	P (psi)	T (°C)	IFT (mN/m)
Fresh Water	‘C’Crude Oil	2340	105	22.92
Fresh Water	‘C’Crude Oil	2592	105	26.59
Fresh Water	‘C’Crude Oil	3180	105	26.63
Fresh Water	‘C’Crude Oil	4810	105	27.90
Fresh Water	‘C’Crude Oil	7170	105	29.51
‘C’ Formation Water	‘C’Crude Oil	1675	105	24.79
‘C’ Formation Water	‘C’Crude Oil	1739	105	27.06
‘C’ Formation Water	‘C’Crude Oil	2422	105	27.78
‘C’ Formation Water	‘C’Crude Oil	3046	105	28.66
‘C’ Formation Water	‘C’Crude Oil	3294	105	30.04
‘C’ Formation Water	‘C’Crude Oil	3385	105	25.58
‘C’ Formation Water	‘C’Crude Oil	1655	105	27.48
‘C’ Formation Water	‘C’Crude Oil	2467	105	28.50
‘C’ Formation Water	‘C’Crude Oil	3488	105	28.65
‘C’ Formation Water	‘C’Crude Oil	4402	105	29.04
‘C’ Formation Water	‘C’Crude Oil	5475	105	29.16
%0.5 NaOH Solution	‘C’Crude Oil	2110	105	13.52
%0.5 NaOH Solution	‘C’Crude Oil	2147	105	13.87
%0.5 NaOH Solution	‘C’Crude Oil	2176	105	14.42
%0.5 NaOH Solution	‘C’Crude Oil	3015	105	14.33
%0.5 NaOH Solution	‘C’Crude Oil	4102	105	14.47
%0.5 NaOH Solution	‘C’Crude Oil	5172	105	14.66

Table C.2 Interfacial Tension Measurement Test Data for ‘C’ Field

Bulk Fluid	Drop Fluid	P (psi)	T (°C)	IFT (mN/m)
%0.5 NaOH Solution	‘C’Crude Oil	5243	105	14.21
%0.5 NaOH Solution	‘C’Crude Oil	5266	105	14.64
%0.5 NaOH Solution	‘C’Crude Oil	5334	105	14.68
%1 NaOH Solution	‘C’Crude Oil	1009	105	13.38
%1 NaOH Solution	‘C’Crude Oil	1490	105	11.62
%1 NaOH Solution	‘C’Crude Oil	1972	105	12.95
%1 NaOH Solution	‘C’Crude Oil	2164	105	14.15
%1 NaOH Solution	‘C’Crude Oil	2581	105	12.81
%1 NaOH Solution	‘C’Crude Oil	2600	105	13.19
%1 NaOH Solution	‘C’Crude Oil	3000	105	12.48
%1 NaOH Solution	‘C’Crude Oil	3578	105	13.36
%2 NaOH Solution	‘C’Crude Oil	1064	105	11.59
%2 NaOH Solution	‘C’Crude Oil	2069	105	11.76
%2 NaOH Solution	‘C’Crude Oil	3062	105	11.95
%2 NaOH Solution	‘C’Crude Oil	3165	105	11.42
%2 NaOH Solution	‘C’Crude Oil	4000	105	11.52
%2 NaOH Solution	‘C’Crude Oil	4032	105	10.96
%2 NaOH Solution	‘C’Crude Oil	4396	105	11.93
%2 NaOH Solution	‘C’Crude Oil	5030	105	11.92
%2 NaOH Solution	‘C’Crude Oil	6036	105	12.04
%2 NaOH Solution	‘C’Crude Oil	6040	105	11.63
%5 NaOH Solution	‘C’Crude Oil	2067	105	4.19

Table C.3 Interfacial Tension Measurement Test Data for ‘G’ Field

Bulk Fluid	**Drop Fluid**	**P (psi)**	**T (°C)**	**IFT (mN/m)**
Fresh Water	‘G’ Crude Oil	2000	65	30.41
Fresh Water	‘G’ Crude Oil	1800	65	26.10
Fresh Water	‘G’ Crude Oil	2200	65	28.64
Fresh Water	‘G’ Crude Oil	4500	65	29.64
‘G’ Formation Water	‘G’ Crude Oil	1323	65	18.52
‘G’ Formation Water	‘G’ Crude Oil	1293	65	18.10
‘G’ Formation Water	‘G’ Crude Oil	2000	65	18.96
‘G’ Formation Water	‘G’ Crude Oil	3000	65	19.29
‘G’ Formation Water	‘G’ Crude Oil	4500	65	20.80
%1 NaOH Solution	‘G’ Crude Oil	2000	65	8.47
%1 NaOH Solution	‘G’ Crude Oil	1250	65	6.86
%1 NaOH Solution	‘G’ Crude Oil	4000	65	7.63
%5 NaOH Solution	‘G’ Crude Oil	2000	65	5.24
%5 NaOH Solution	‘G’ Crude Oil	1250	65	5.04
%5 NaOH Solution	‘G’ Crude Oil	4100	65	6.06
%5 NaOH Solution	‘G’ Crude Oil	4200	65	6.17
%0.5 NaOH Solution	‘G’ Crude Oil	2000	65	11.48
%0.5 NaOH Solution	‘G’ Crude Oil	1250	65	10.59
%0.5 NaOH Solution	‘G’ Crude Oil	4200	65	11.81